Exhibit 1- Administration

1-Staff-1
Updated Revenue Requirement Work Form (RRWF) and Models

Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on sheet 3 Data_Input_Sheet. Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 Tracking Sheet and may also be included on other sheets in the RRWF to assist understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2022 Electricity Distributor Rate Applications webpage.

Response:

In responding to various interrogatories Grimsby Power has changed and submitted the following set of models.

1	4-Staff-47 LRAMVA Workform and 1568 of DVA Sch out by $494	DVA Continuity Schedule Tariff Schedule and Bill Impact Model
2	8-Staff-51 Requirment to file RTSR updated June 24, 2021	RTSR Workform Tariff Schedule and Bill Impact Model
3	9-Staff-56 Update 1518 and 1548 with 2021 Actual and Forecast principal and interest amounts	DVA Continuity Schedule Tariff and Bill Impacts
4	8-NPEI-7 Change unit for Emb Dist Rate Riders from $/kWh to $/kW	Updated Tariff and Bill Impacts
5	8-NPEI-8 Add regulatory charges to Tariif and Bill impact for ED	Updated Tariff and Bill Impacts
6	3-VECC-25 and 3-VECC-27 update loss factor in Load Forecast to 4.56 and update 2022 customer count to 230 from 341.	Load Forecast, Cost Allocation, Revenue Requirement, PILs, Tariff and Bill Impacts, Chapter 2 Appendicies

1-Staff-2

Customer Satisfaction
Ref: EB-2015-0072 Decision and Order, August 18, 2016, page 7
Exhibit 1, Tab 6, page 6 of 18

Preamble:

The OEB stated in the decision:

> In addition to the emphasis on productivity, the RRFE stresses the importance of outcome based regulation. The OEB expects there to be a correlation between more money being spent and improved outcomes. Grimsby Power described the need to increase customer communications particularly as it relates to outages. Given the increase in OM&A approved, the OEB expects that Grimsby Power will improve customers' satisfaction in the area of customer communications. Grimsby Power is encouraged to monitor its operating performance and improvement in customer satisfaction and to report the results in its next rate application.

When discussing the improvement in customer satisfaction in 2019 survey, it was noted that:

> GPI renewed its website with better power outage information, added a feature to our phone system that relays power outage information as well as creating an account on social media to allow customers to better track outage related information.

Question(s):

a) Please provide a comprehensive list of activities implemented since 2016 to improve customer satisfaction in the area of customer communications.

b) Grimsby Power explained that the main contributor to the drop in customer satisfaction from 2015 (92%) to 2016 (75.4%) was a change in survey methodology. The 2015 result represented the overall satisfaction while the 2016 results reflected a weighted score of several questions. Grimsby Power stated that considering only overall satisfaction, the score would have been 81% for 2016, 90% for 2018, and 91% for 2021.

   i. Excluding the impact of the methodology change, there was still a drop in the overall satisfaction from 2015 (92%) to 2016 (81%), please explain the drivers.

   ii. Grimsby Power noted that it began utilizing standard questions and methodologies developed by the Innovative Research Group in its biannual customer satisfaction survey starting in 2016. With respect to customer satisfaction, please compare and identify differences in the list of

questions and methodologies utilized by Grimsby Power and those conducted by other distributors, known as the UtilityPulse survey.[1]

iii. Please provide a copy of Grimsby Power's latest customer satisfaction survey report.

Response:

a) Since 2016 Grimsby Power has completed the following activities to help improve customer satisfaction:
- Updated the Grimsby Power website with more online forms and easy to use contact information
- Improved communication during outages using our website with automated outage information including indicating showing the outage on a map and the number of customers affected
- Improved communication during outages using Twitter and again the website
- Improved communication during outages with automated message on our phone system
- Participated in community events to answer any questions customers have regarding our services
- Increased the percentage of calls answered within 30 seconds from 70% to 90%
- We typically respond to customer inquiries within two days

b)

i. The customer satisfaction survey took place in the first quarter of 2017. During this time RPP prices were the highest they had been. Effective November 1, 2016 the electricity prices were 8.7¢ off peak, 13.2¢ mid peak and 18¢ on peak. Grimsby Power believes the high RPP rates had an impact on customer satisfaction comments received at the end of the survey were related to the high cost of electricity. Shortly after the survey took place the Fair Hydro Act was announced and the price consumers paid for electricity started to come down.

[1] For example, Halton Hills Hydro Inc. filed its 2018 Electricity Utility Customer Satisfaction Survey as part of its 2021 Cost of Service Application (EB-2020-0026, Exhibit 2, DSP Appendix B Customer Engagement Results, Appendix C).

ii. Specific customer satisfaction measurements have not been defined across the industry. The Ontario Energy Board (OEB) had instructed all electricity distributors to review and develop measurements in these areas and begin tracking by July 1, 2014. The OEB plans to review information provided by electricity distributors over the next few years and implement a commonly defined measure for these areas in the future. As a result, each electricity distributor may have different measurements of performance until the OEB provides specific direction regarding a commonly defined measure.

As a way to standardize the survey and provide results that could be compared year over year Grimsby Power chose to implement the survey created by Innovative Research Group in conjunction with the EDA and a working group. Grimsby Power has reviewed the HHI customer satisfaction survey conducted by Utility Pulse. In that survey the specific questions asked during the survey are not provided. Grimsby Power cannot compare and identify differences in questions if specific questions are not noted in the UtilityPulse survey as they are for our survey. Grimsby Power also cannot comment on how the scores may have been weighted as the methodologies for the UtilityPulse survey are not provided and are likely different than our survey. Also, each Utility may pose different questions during different years making it impossible to compare between distributors. Grimsby Power has provided the results of other utilities that are known to have used the survey produced by Innovative Research group and Grimsby Power does compare favourably. Lastly, Grimsby Power questions the relevance of the questions and methodology underpinning a UtilityPulse survey that was not used by Grimsby Power to survey its customers.

LDC	2019 CSI	2021 CSI	Difference*
Center Wellington Hydro	80.0	80.0	0.0
EPCOR	73.0	74.0	1.0
ERTH Power	77.0	78.0	1.0
Grimsby Power	79.0	79.0	0.0
Lakefront Utilities	81.0	78.0	-3.0
Lakeland Power	76.0	79.0	3.0
NOTL Hydro	79.0	79.0	0.0
Orangeville Hydro	78.0	76.0	-2.0
Ottawa River Power Corp	80.0	81.0	1.0
Renfrew Hydro	86.0	86.0	0.0
Rideau St. Lawrence Distribution	81.0	82.0	1.0
Tillsonburg Hydro	79.0	80.0	1.0
Wasaga Distribution	82.0	81.0	-1.0
Wellington North Power	81.0	80.0	-1.0
Average for CHEC Utilities	**79.4**	**79.5**	**0.1**

iii. Grimsby Power has filed the latest Customer Satisfaction survey as Appendix 1 of 1-Staff-2.

2021 Grimsby Power Customer Satisfaction Survey

Filed: October 28, 2021

Introduction and Summary

Thank you for selecting Redhead Media Solutions Inc. for this important project for Grimsby Power. 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 Grimsby Power. 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

Introduction and Summary

This final report contains data specifically for Grimsby Power.

The survey is comprised of 401 randomly selected interviews of Grimsby Power 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 Grimsby Power 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 Grimsby Power, 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 Grimsby Power. 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.

Grimsby Power's 2021 Customer Satisfaction Index Score is 79%, This is the same as the 2019 score (79%) and the same as the average of all LDCs (79%).

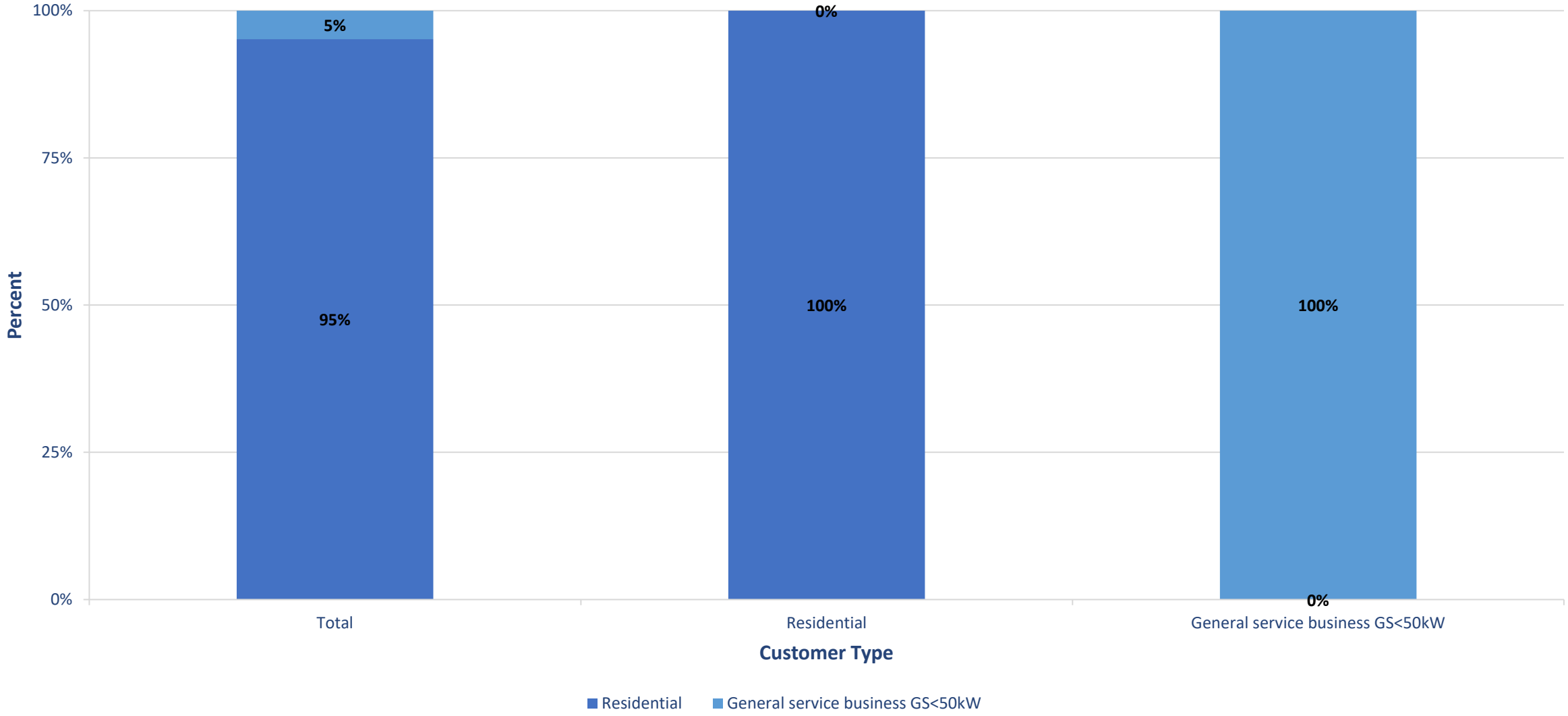
This falls within a very tight spectrum of index scores we processed for all LDCs that participated in the 2019 survey via Redhead. When the confidence interval is applied to all index scores, there is significant overlap between LDCs which underlines the statistical similarity of performance and satisfaction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

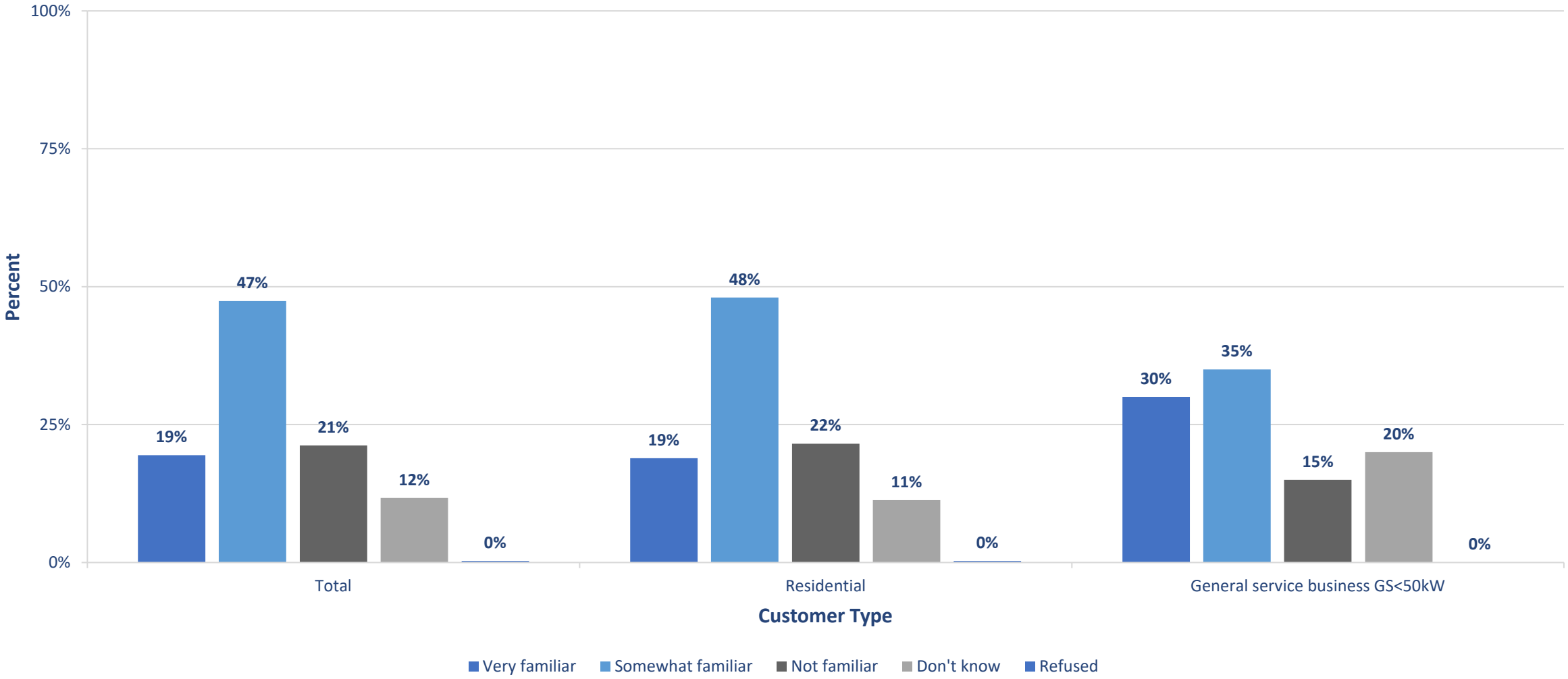
Customer Type



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

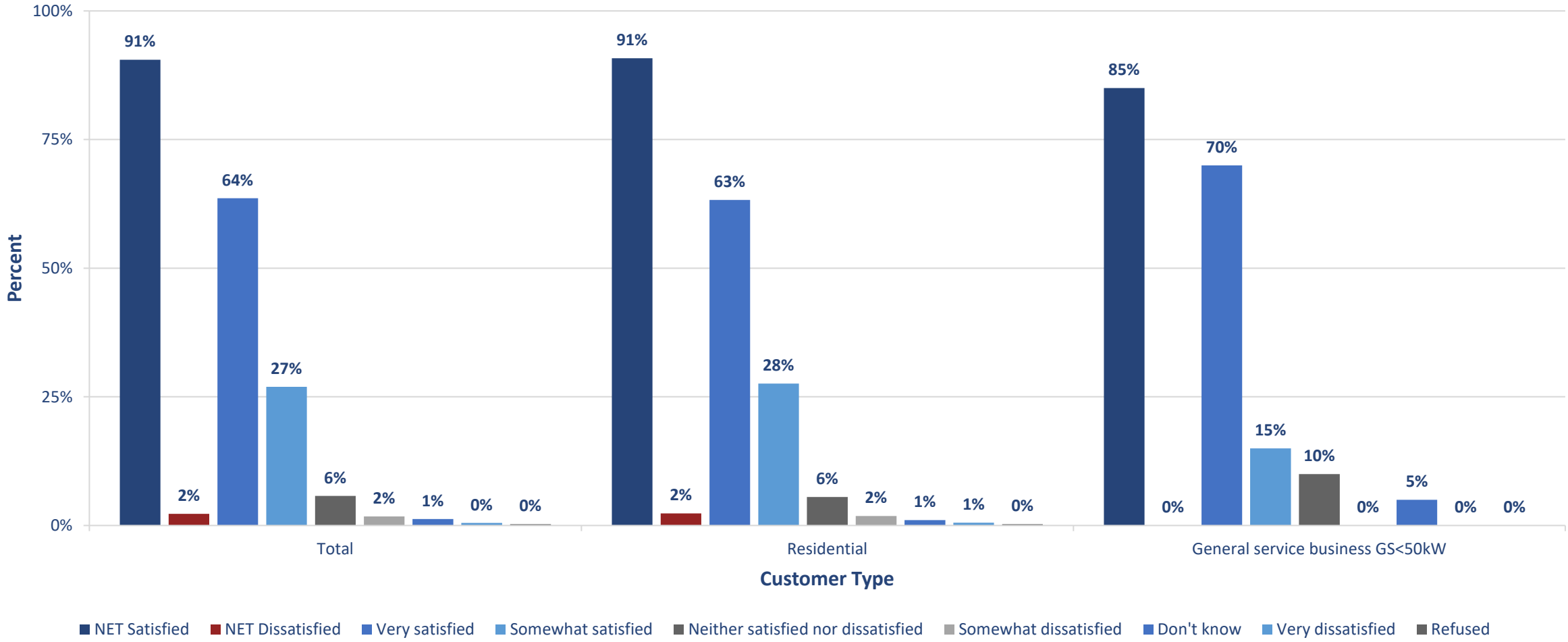
QUESTIONS/DATA

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



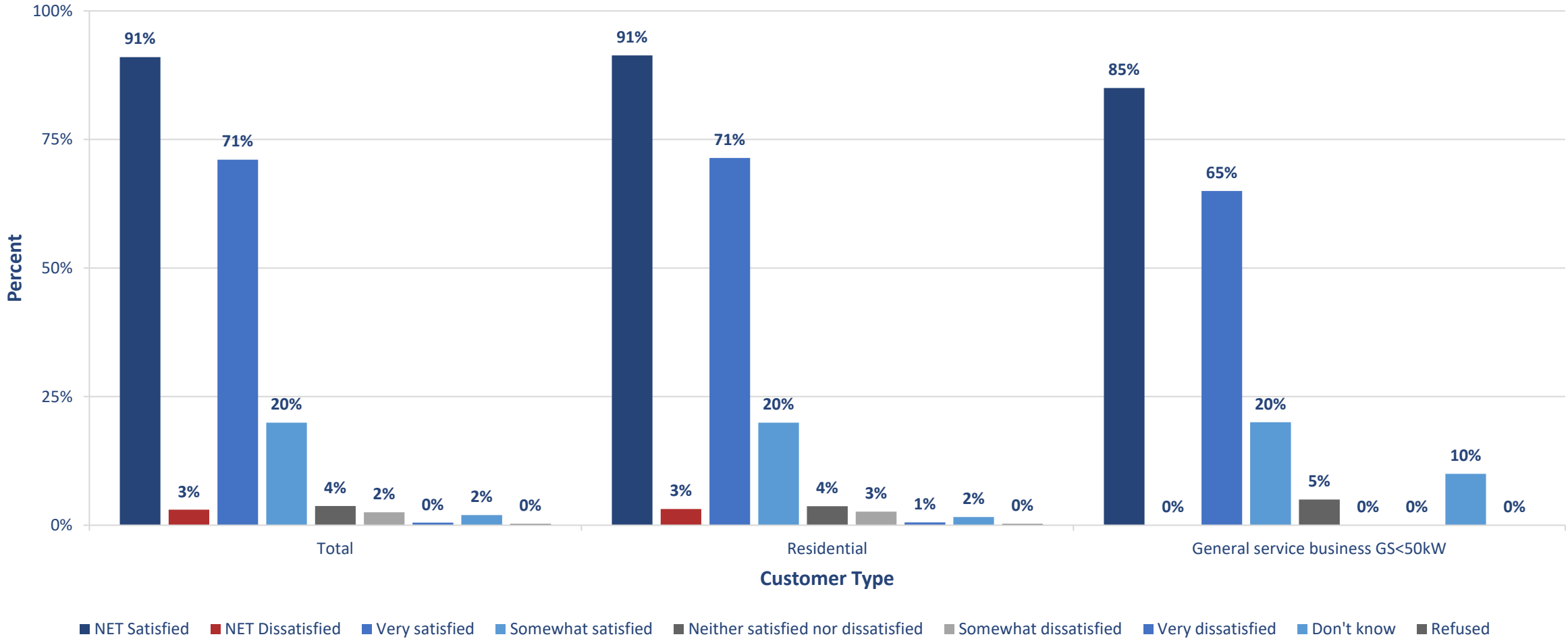
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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



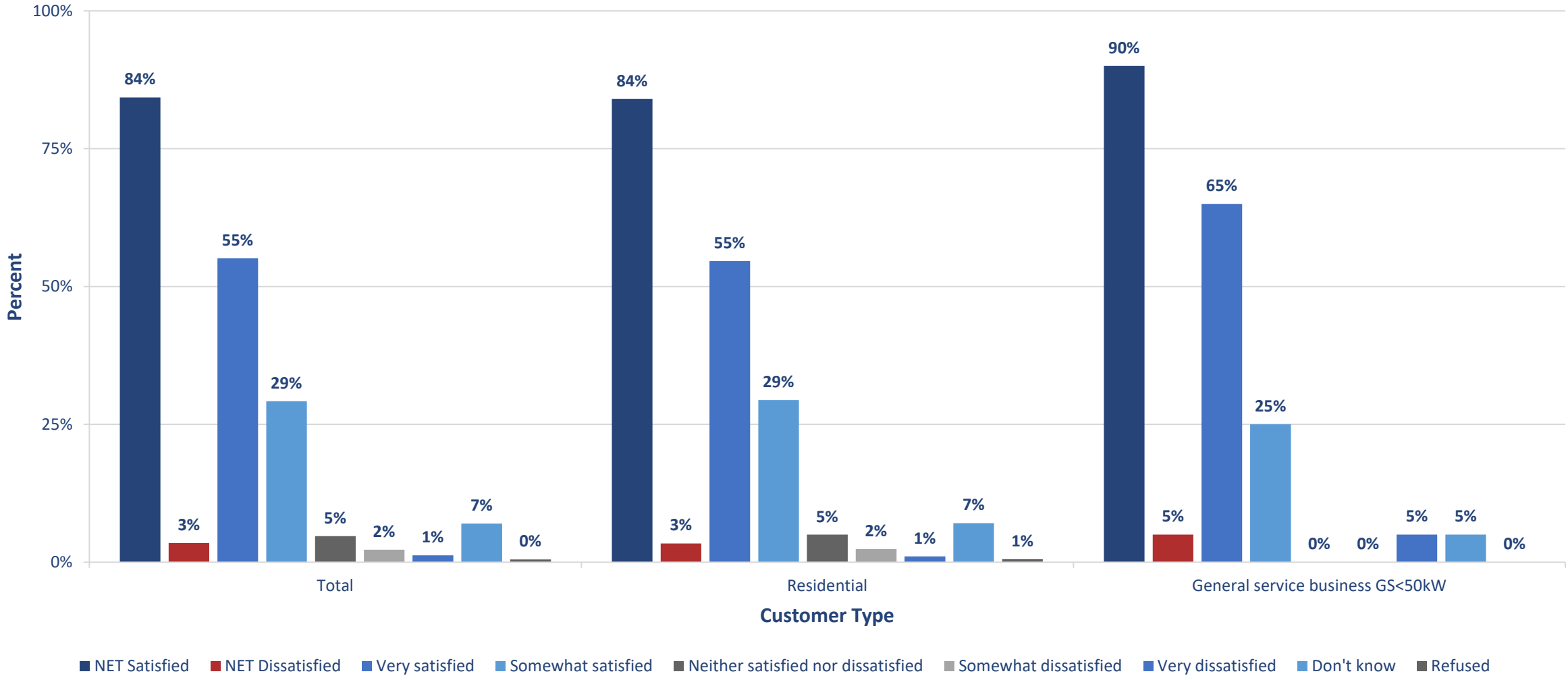
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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 Grimsby Power based on...?



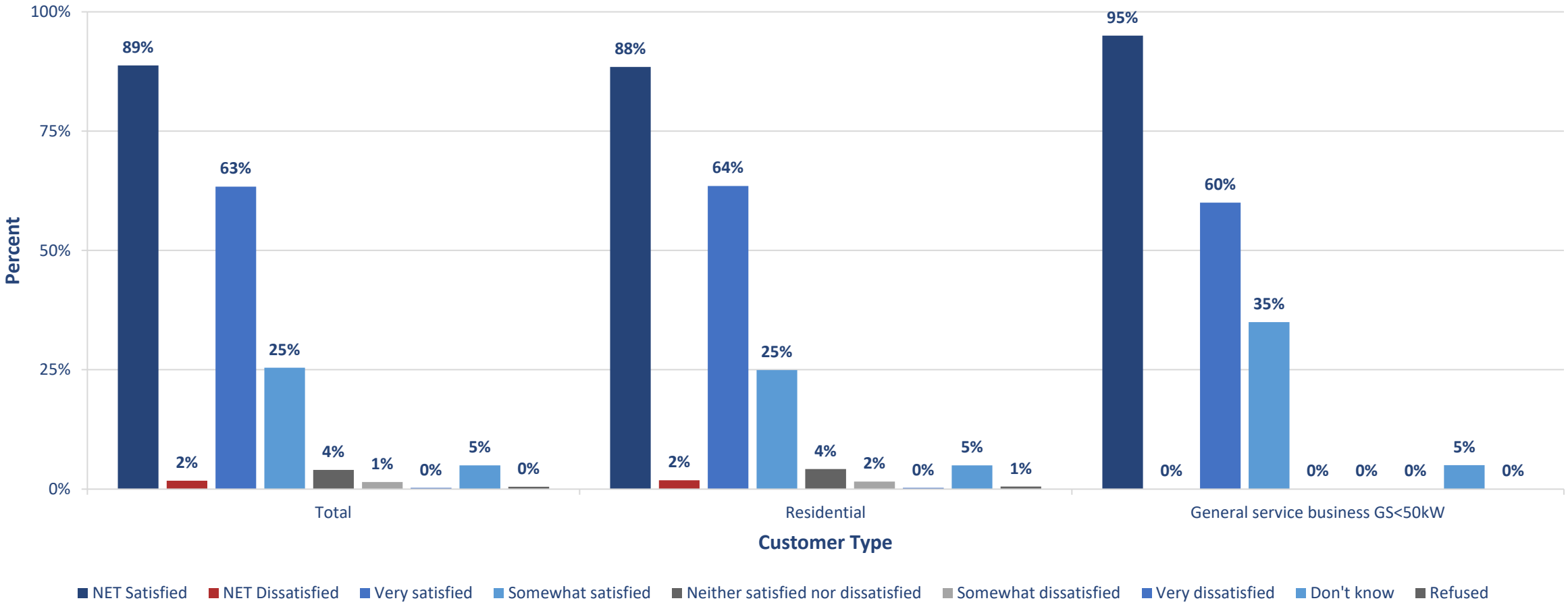
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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 Grimsby Power based on...?



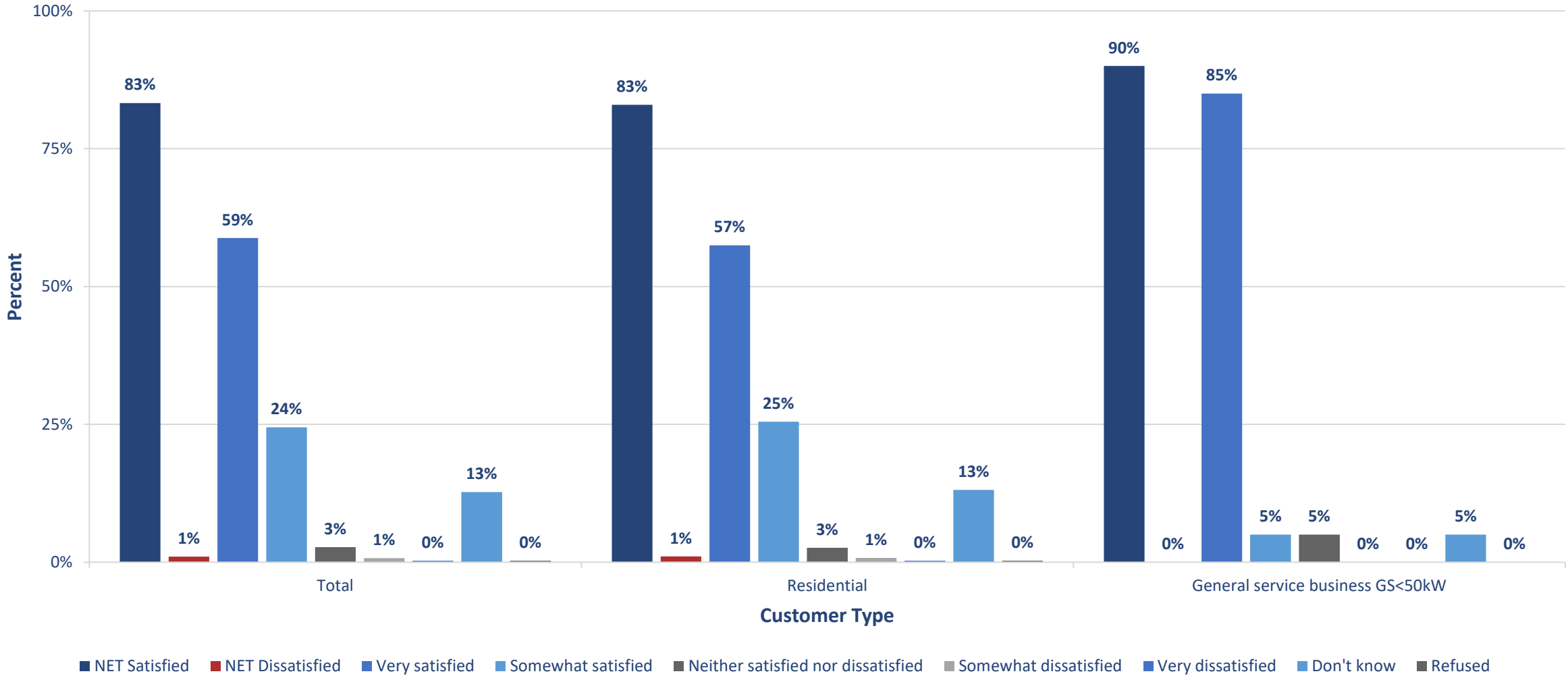
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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 Grimsby Power based on...?



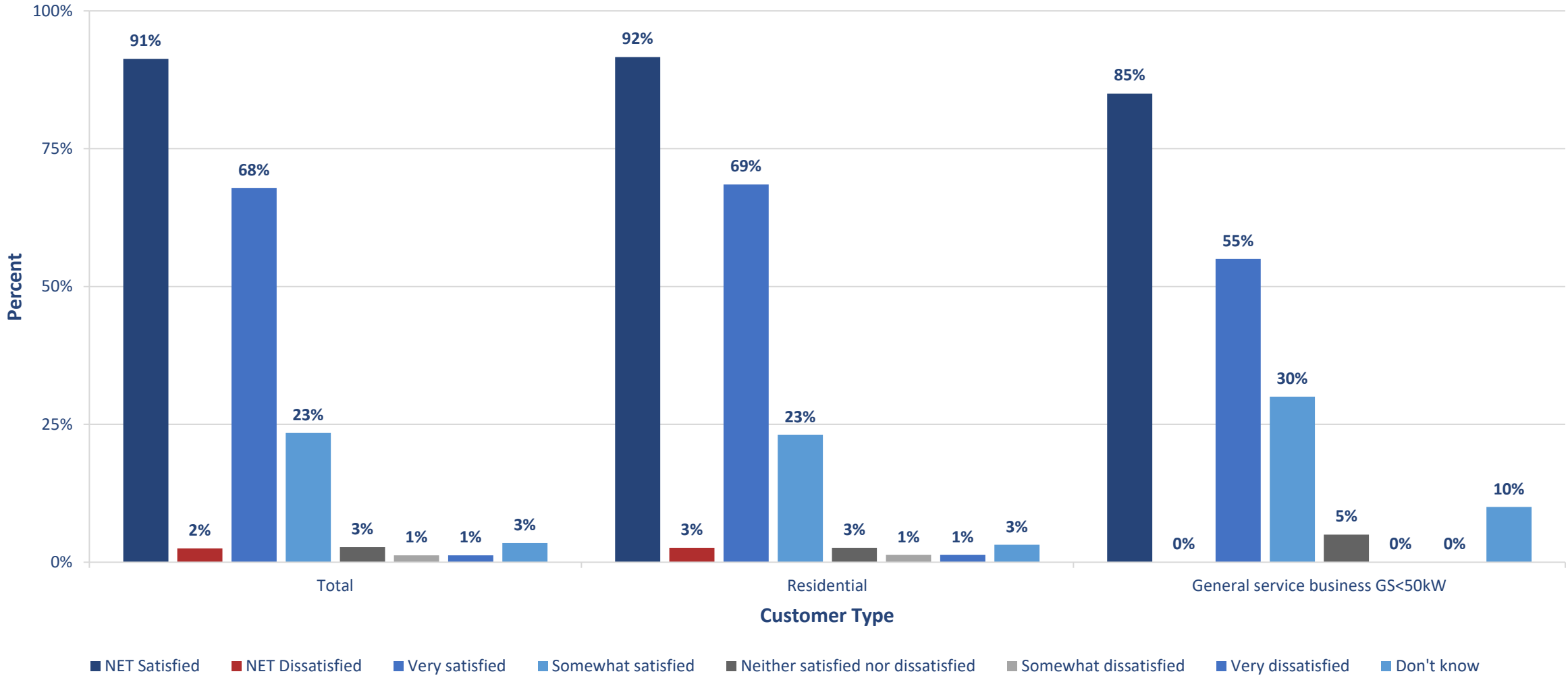
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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



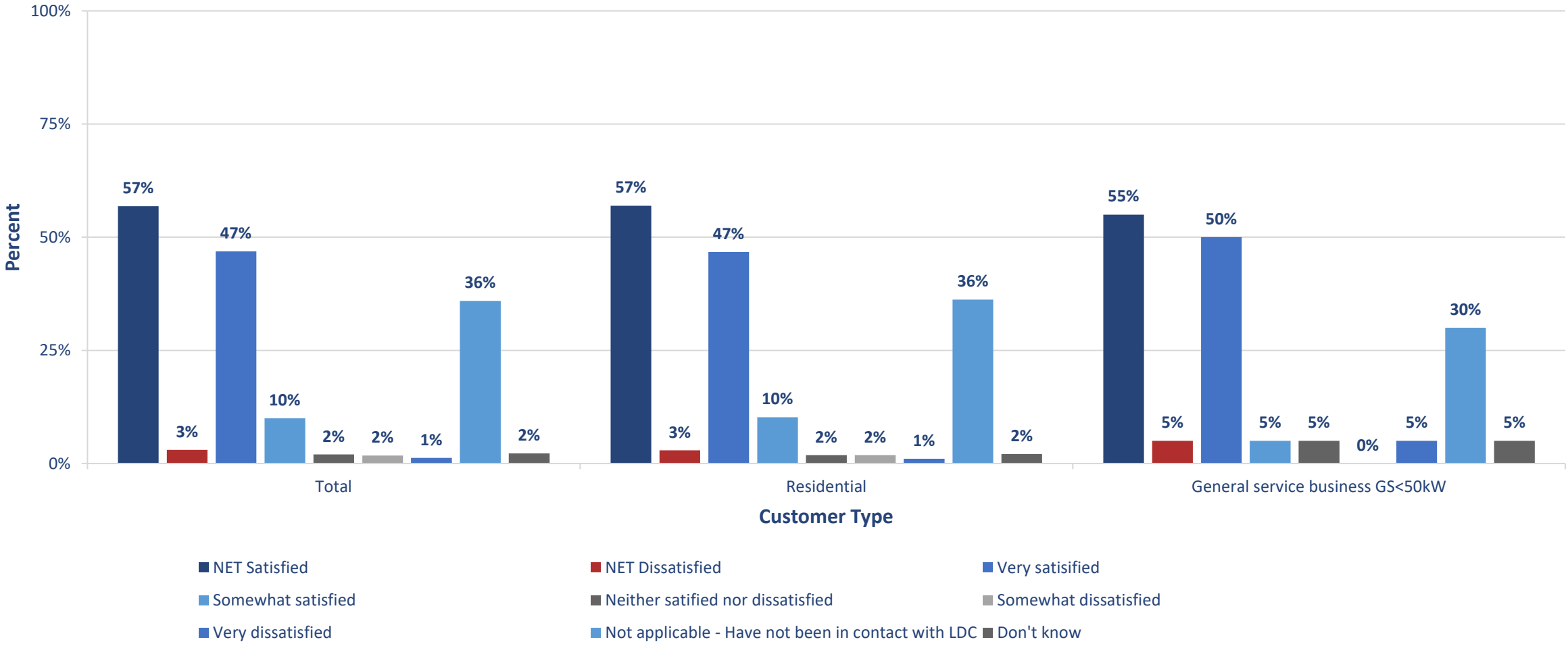
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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



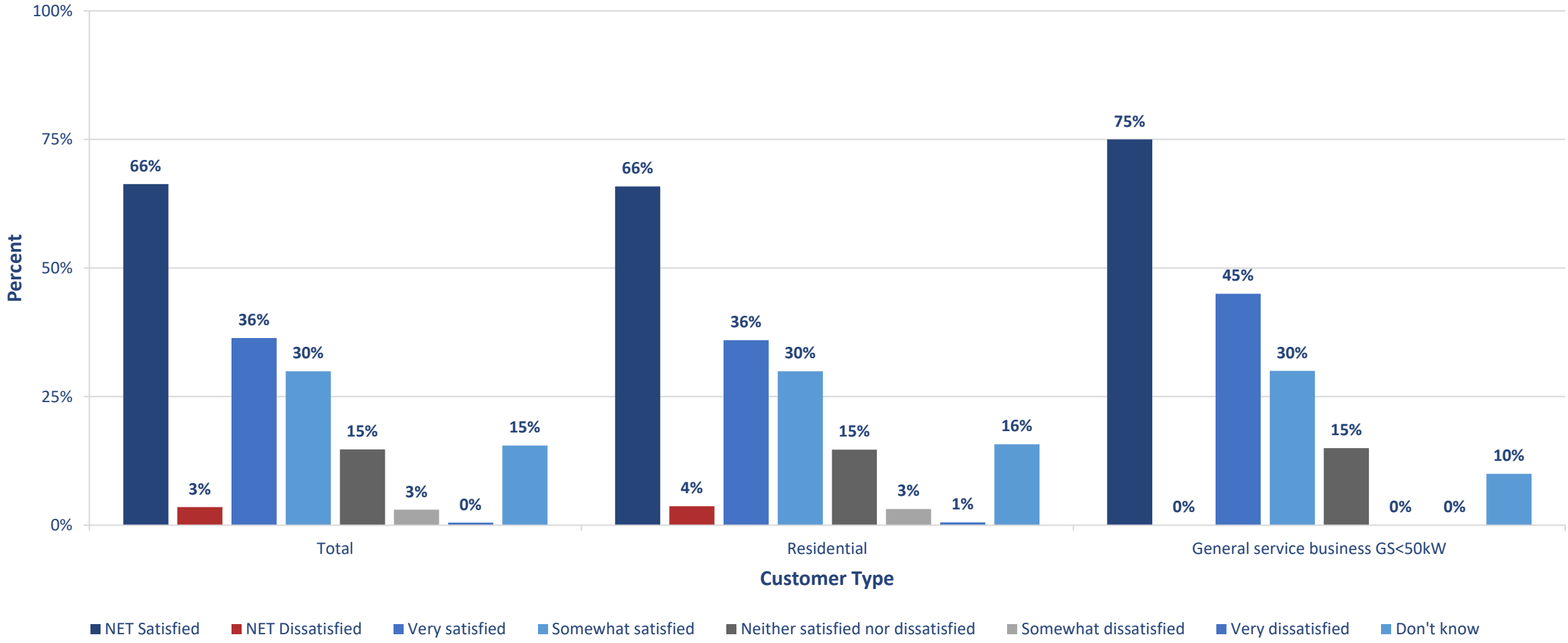
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

How satisfied are you with the customer service you have received when dealing with employees of Grimsby Power, whether on the telephone, via email, in person or through online conversations including social media?



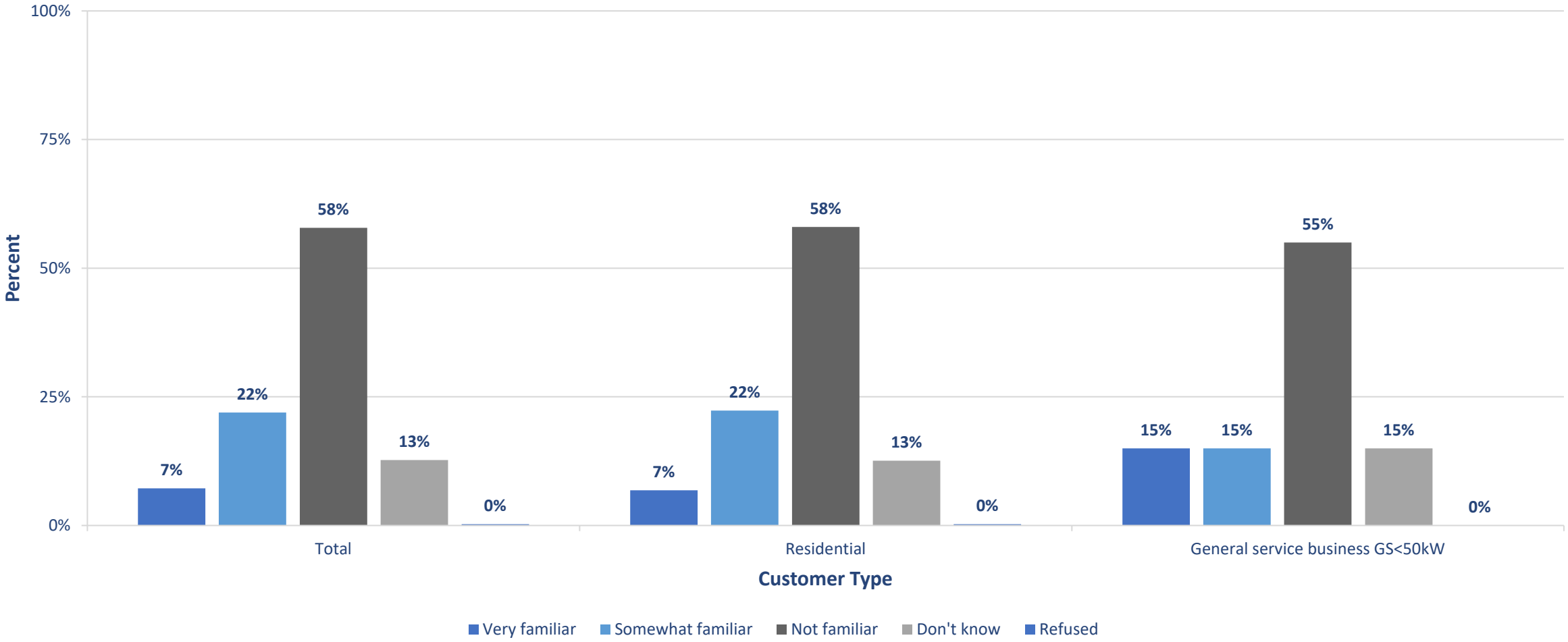
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

How satisfied are you with the communications that you may receive from Grimsby Power without talking directly to an employee, including information found on their website, bill inserts, advertising, notices, emails, or social media sites?



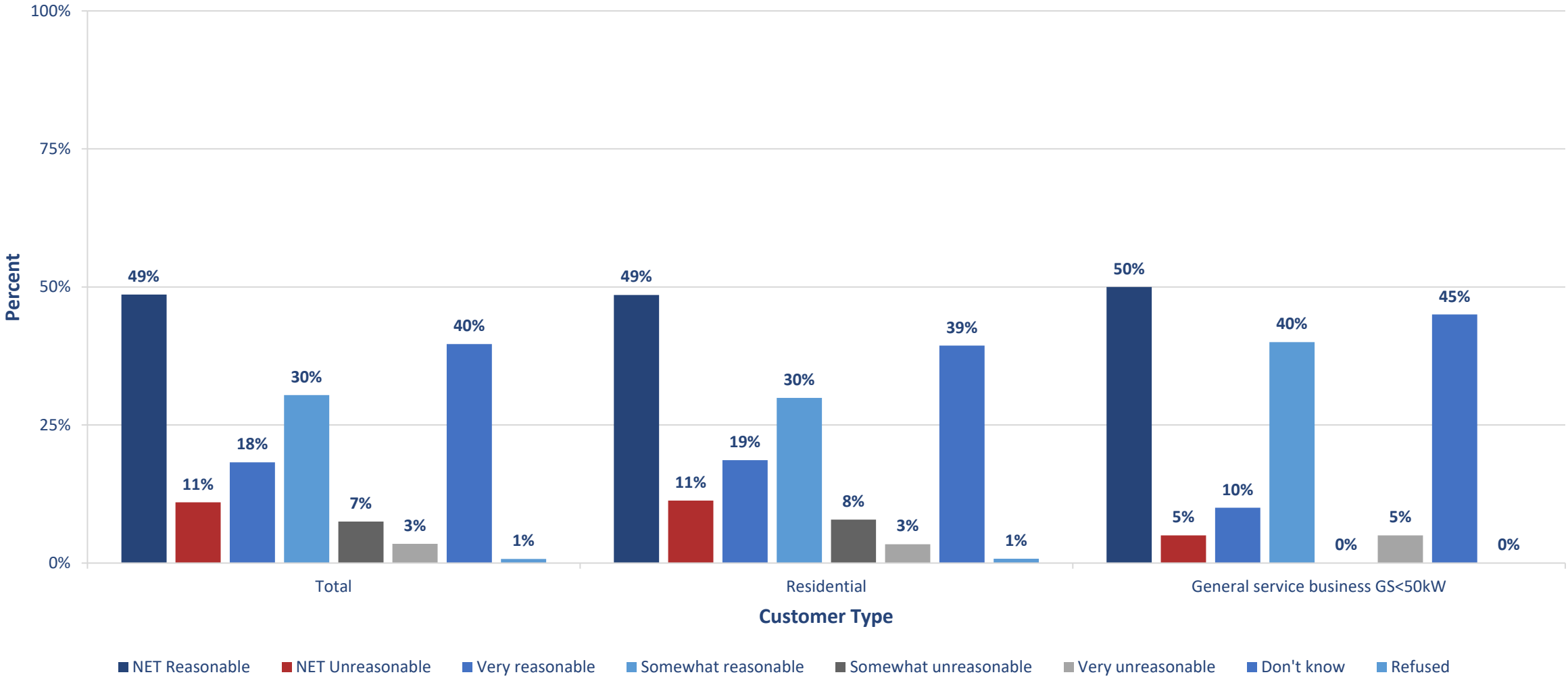
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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



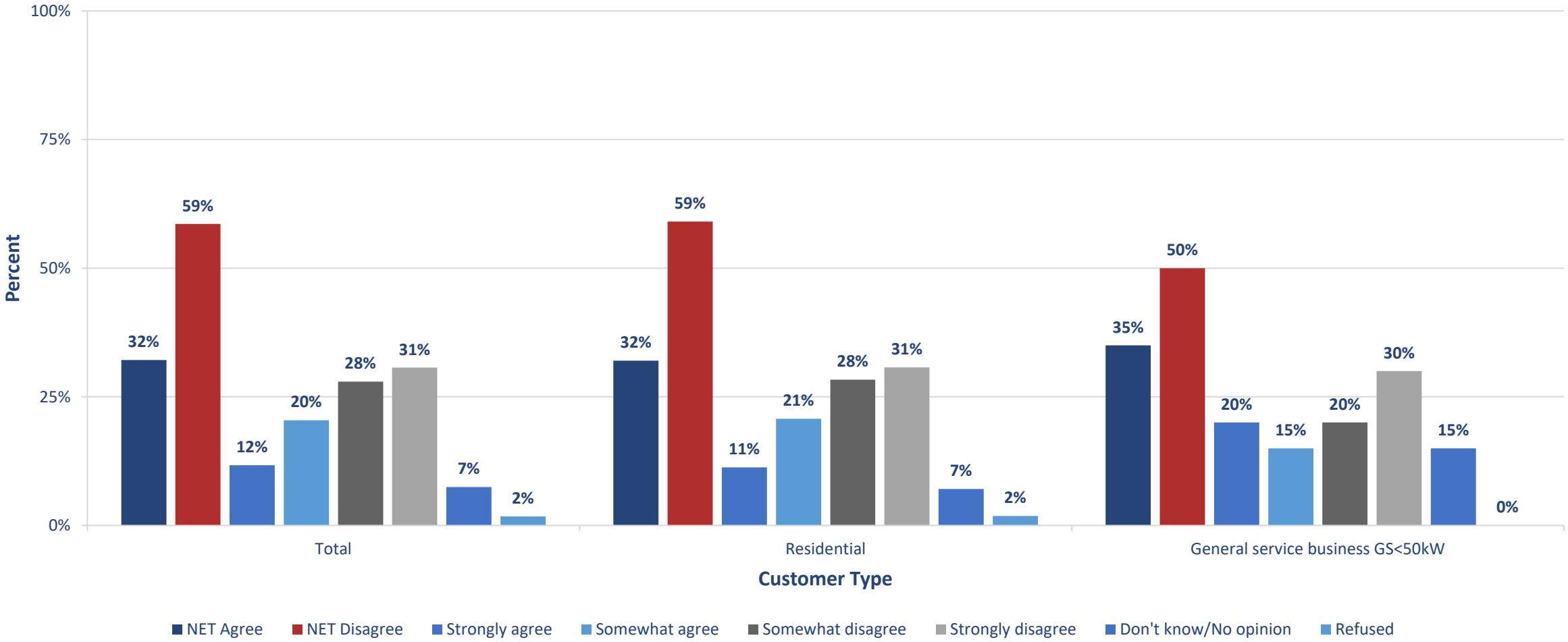
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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



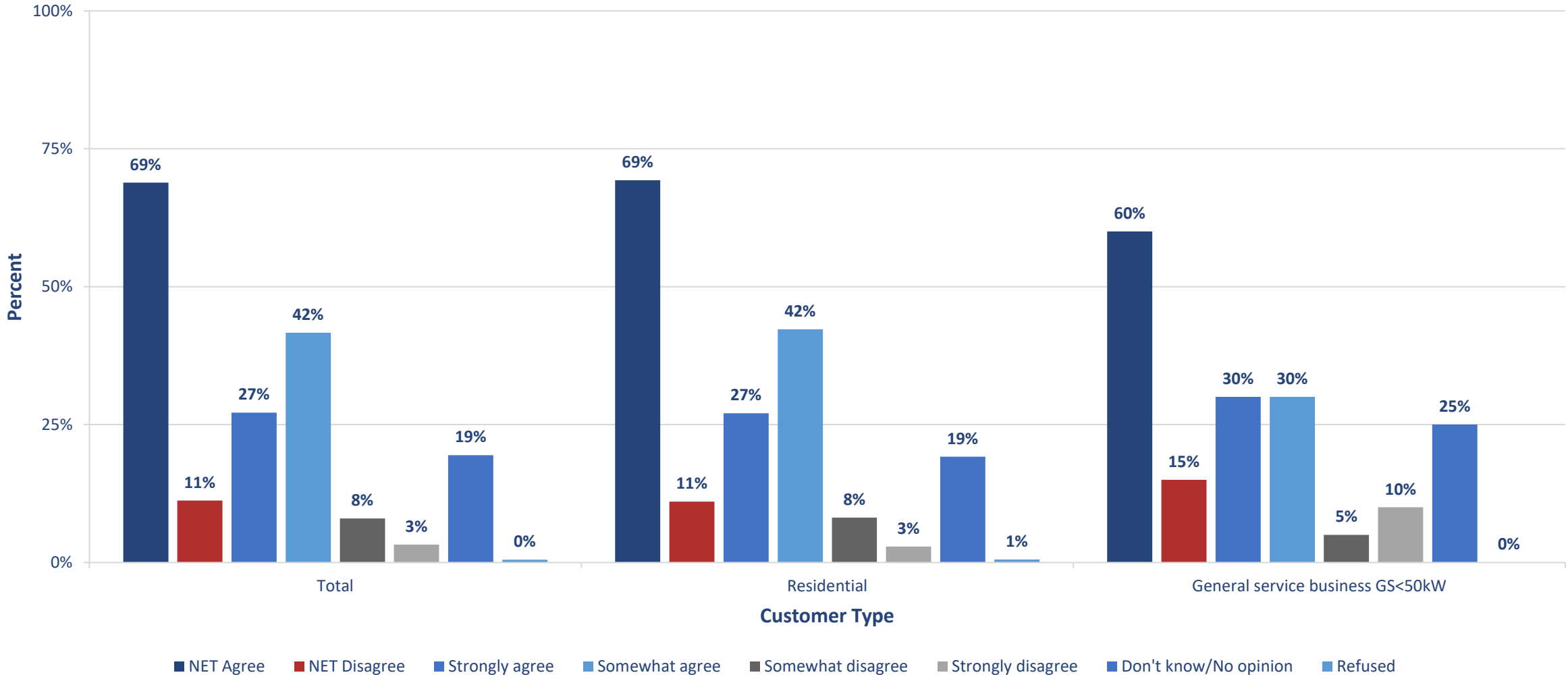
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

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?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

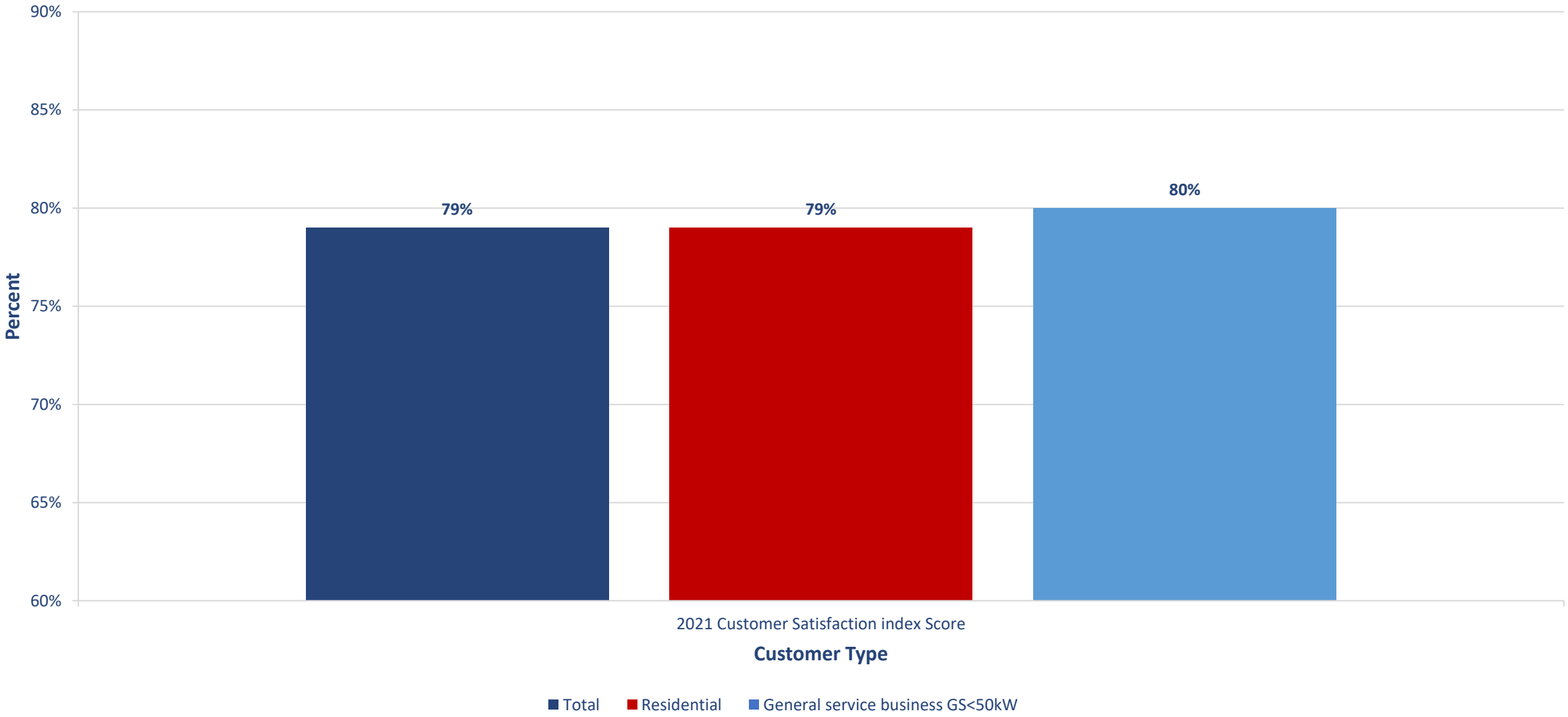
Customers are well served by the electricity system in Ontario: To what extent do you agree with the following statements regarding the electricity system in Ontario?



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

CUSTOMER SATISFACTION INDEX

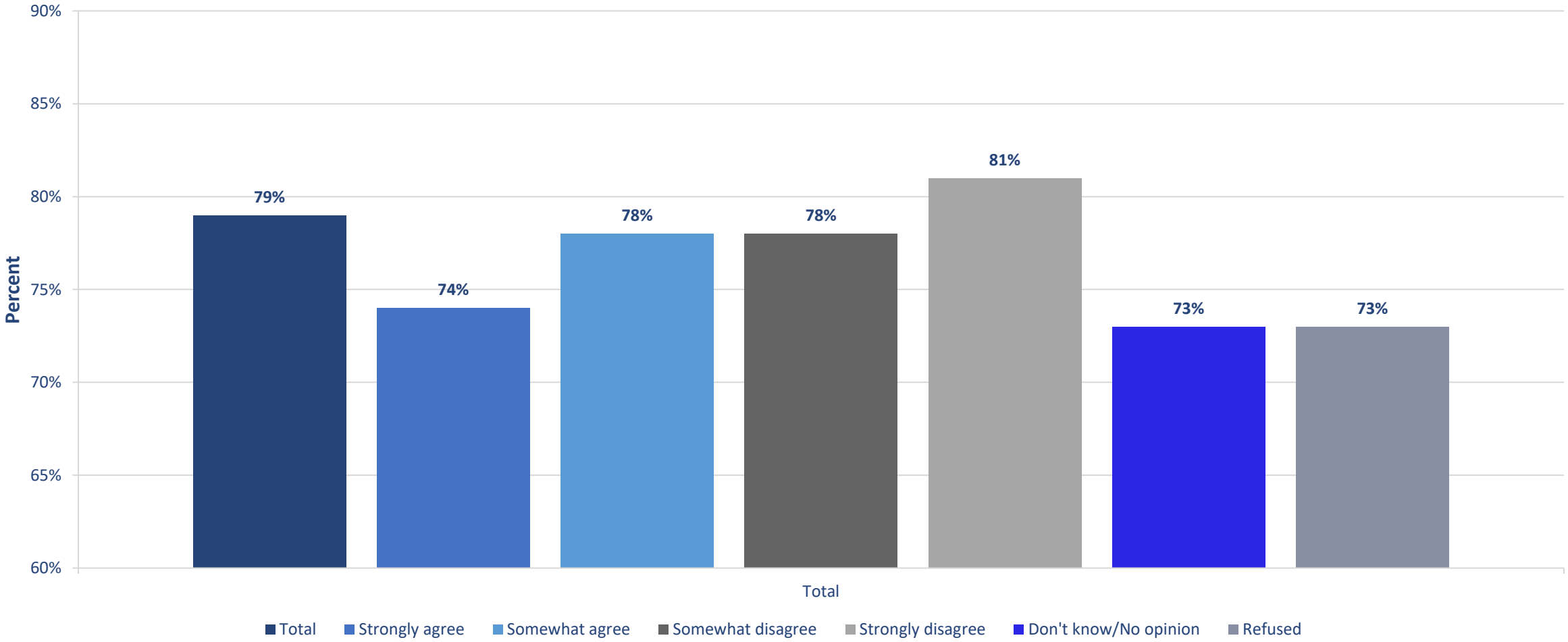
2021 Customer Satisfaction Index Score



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

Customer Satisfaction Index by the following statement:

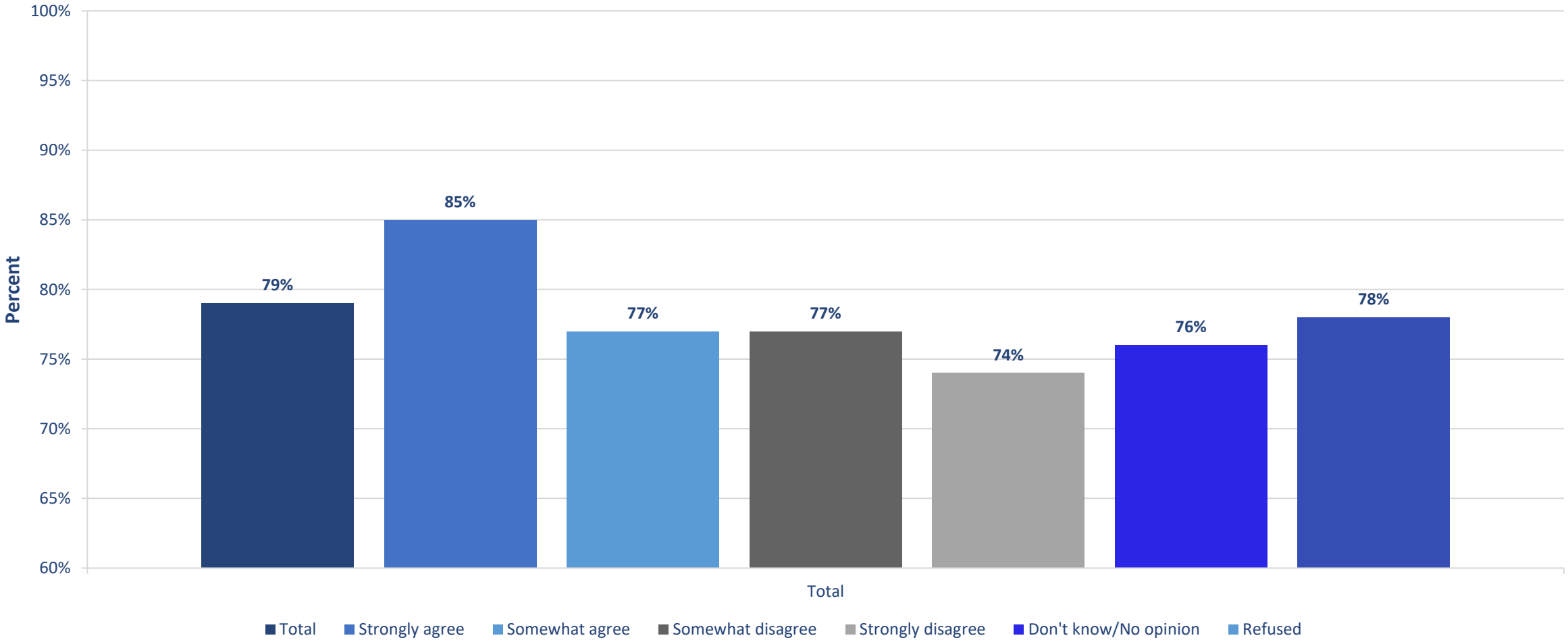
The cost of my electricity bill has a major impact on [my personal finances/bottom line]



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

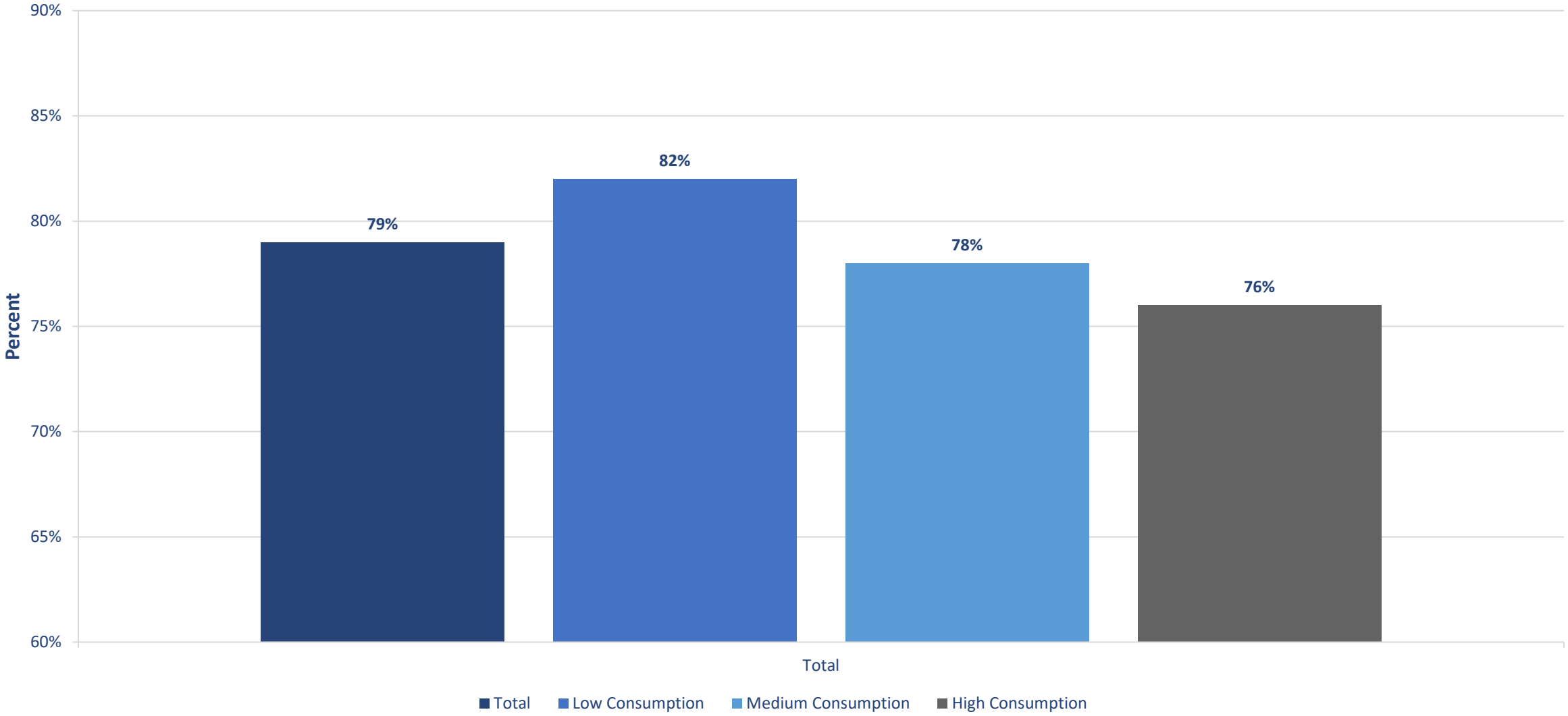
Customer Satisfaction Index by the following statement:

Customers are well served by the electricity system in Ontario



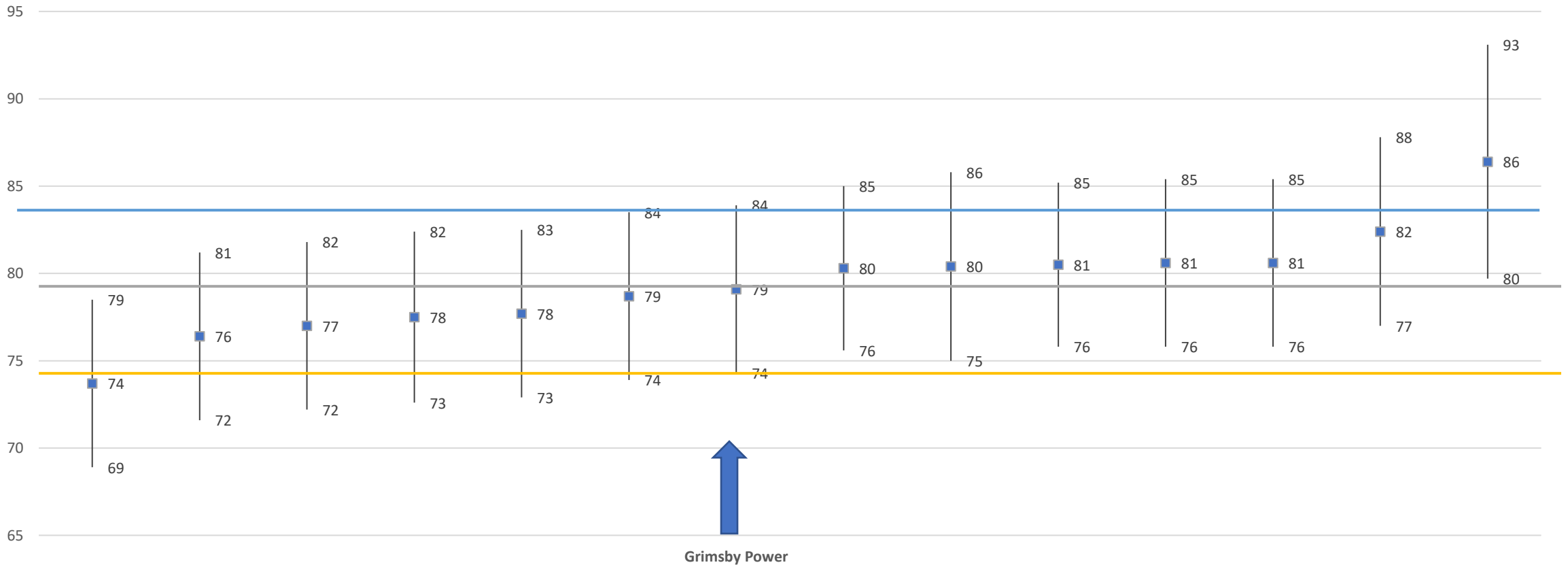
Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

Customer Satisfaction Index by consumption



Source: Redhead Media Solutions/Advanis telephone random customer survey, January 13-February 25, 2021, n=401, accurate 4.8 percentage points plus or minus, 19 times out of 20.

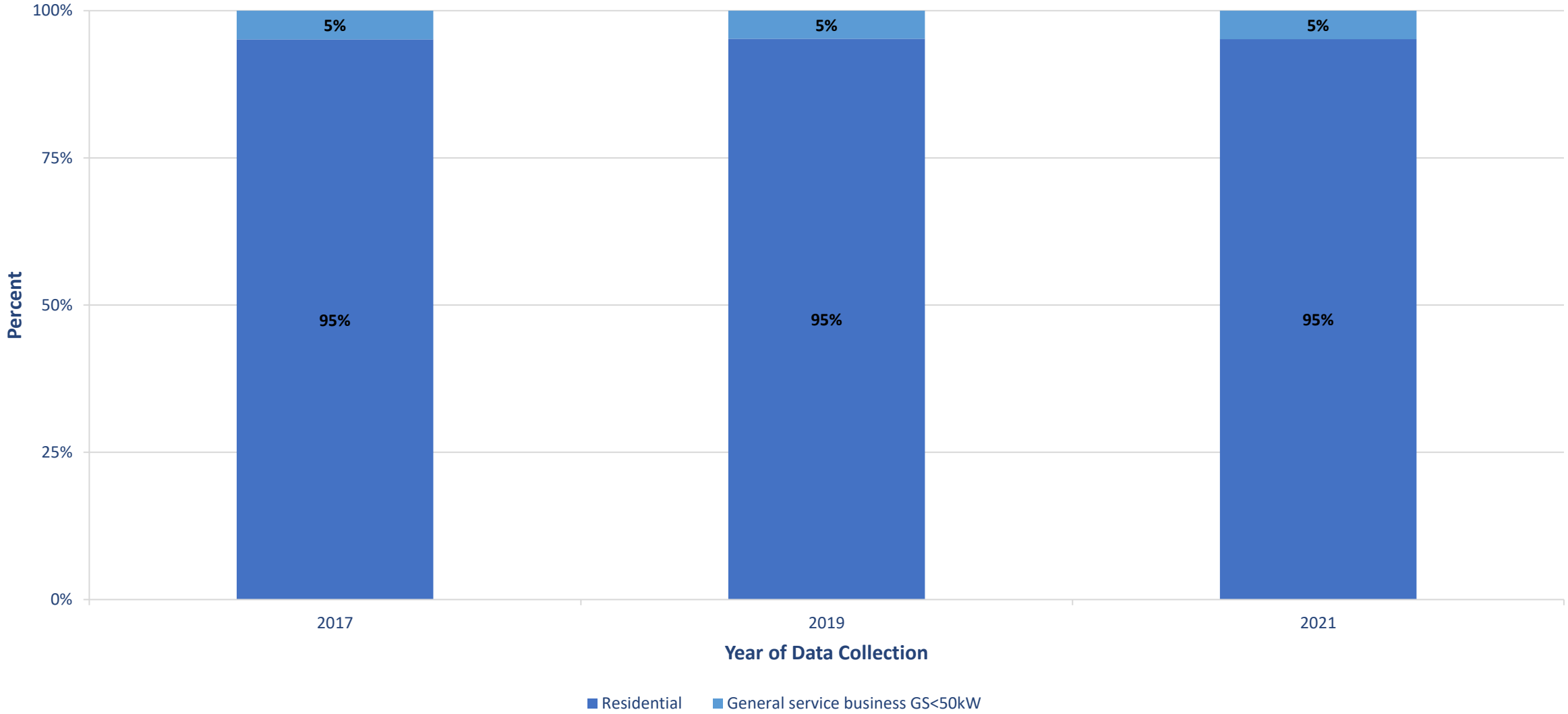
Customer Satisfaction Index Score Comparison to External LDCs
Upper and Lower Bound



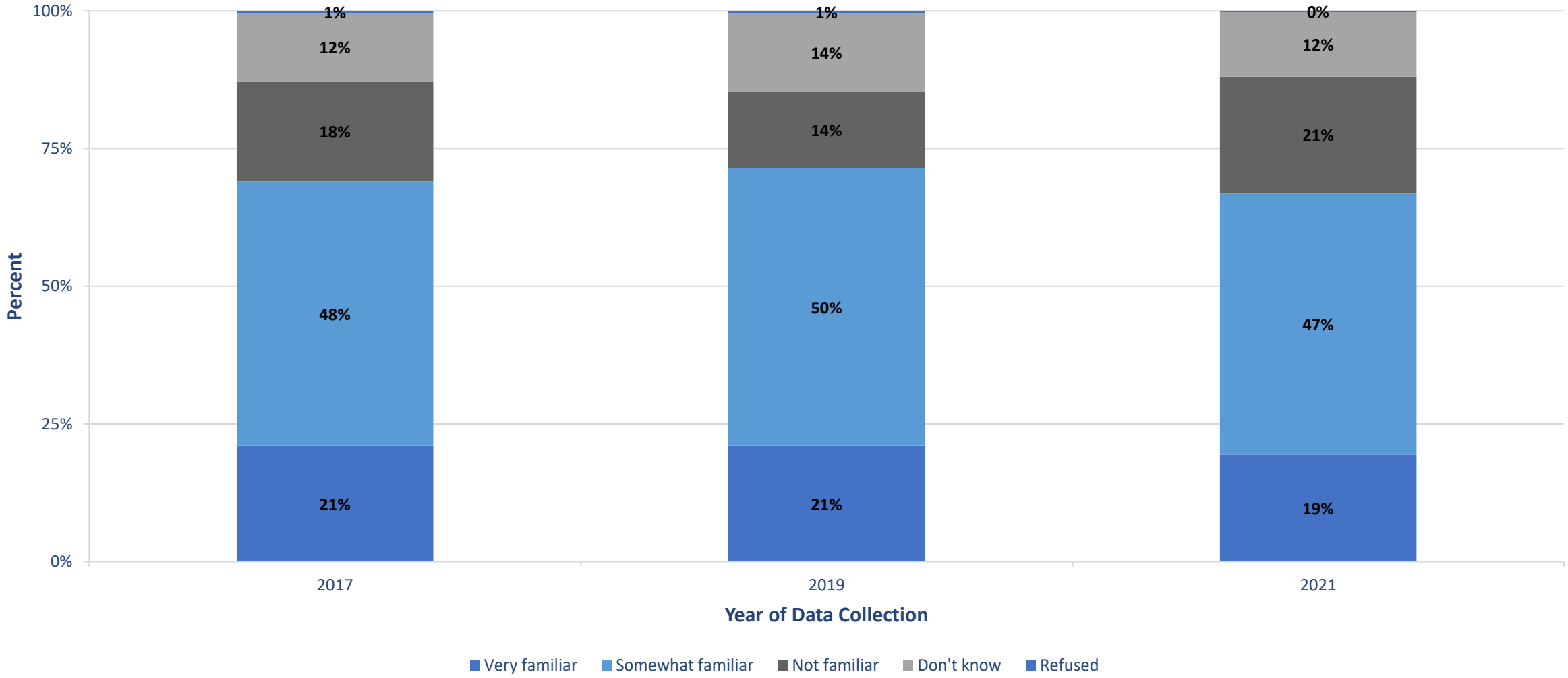
- The lines denote Grimsby Power's upper and lower bound based on the CSI Score.
- Almost all LDCs confidence intervals overlap, similar to 2019.
- Grimsby Power overlaps with all LDCs, indicating statistical uniformity.

CORE COMPARATIVE DATA 2017-2021

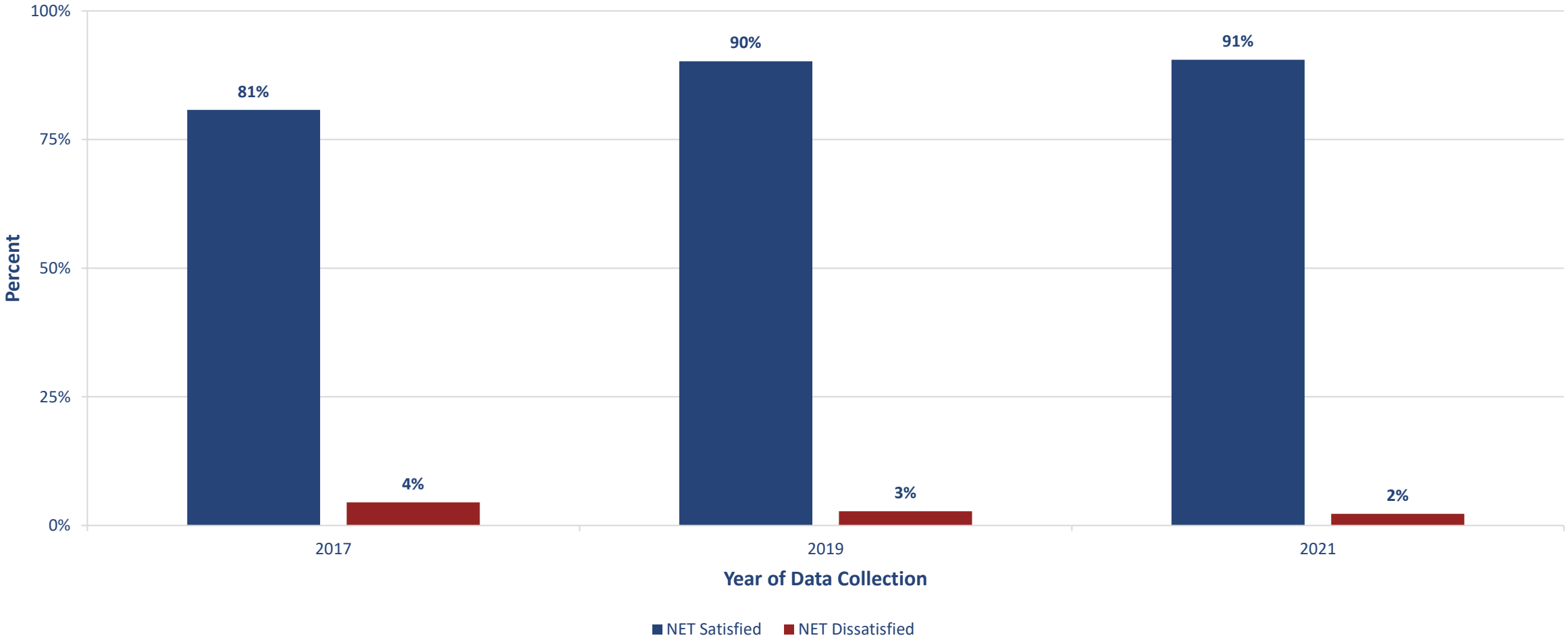
Customer Type



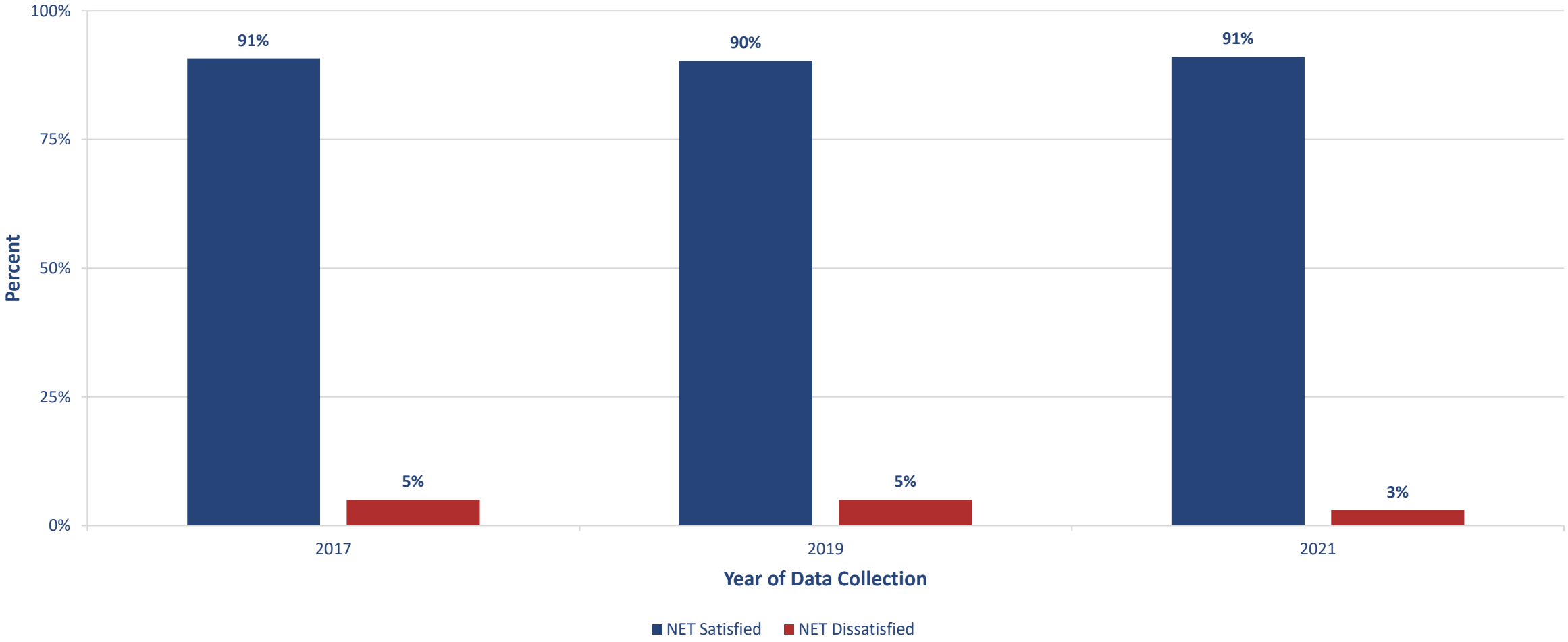
How familiar are you with Grimsby Power, which operates the electricity distribution system in your community?



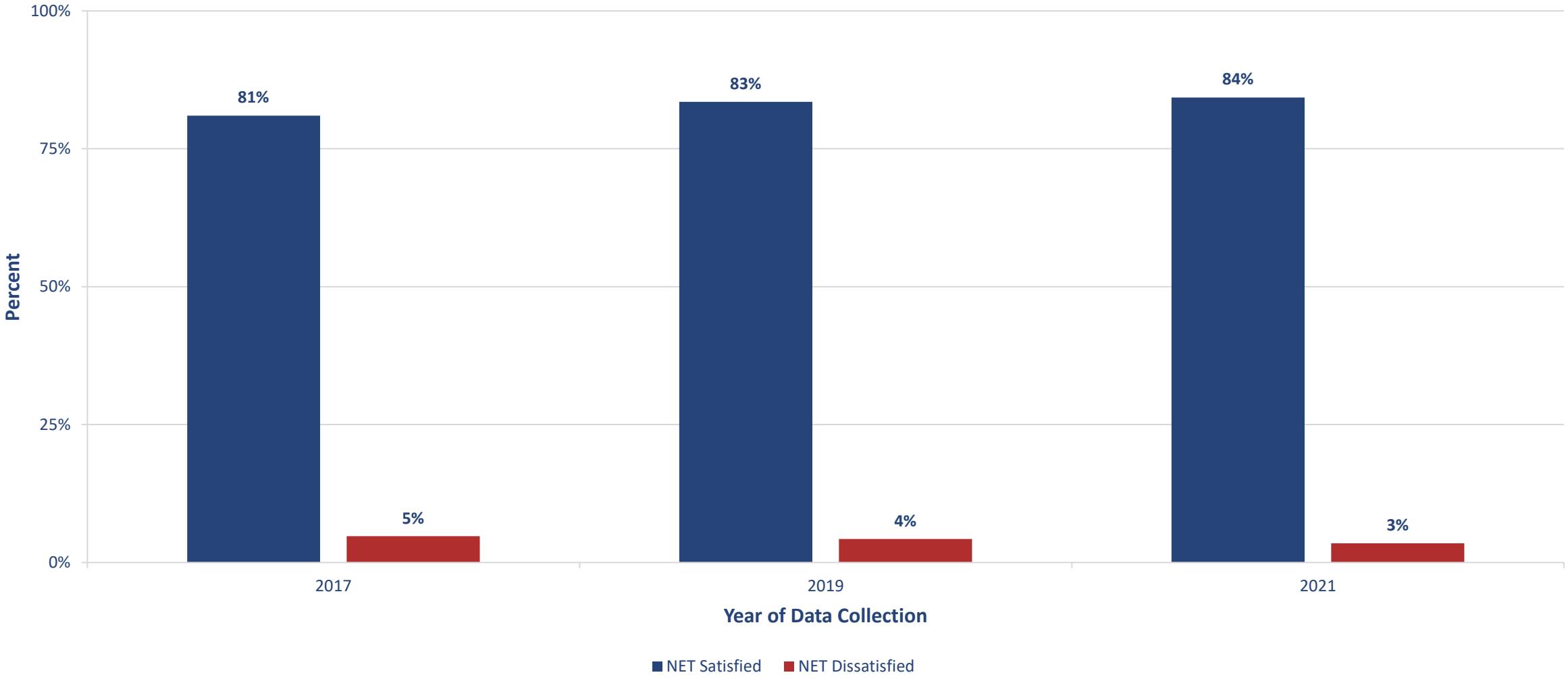
Thinking specifically about the services provided to you and your community by Grimsby Power, overall, how satisfied are you with the services that you receive from Grimsby Power?



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 Grimsby Power 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 Grimsby Power based on...?



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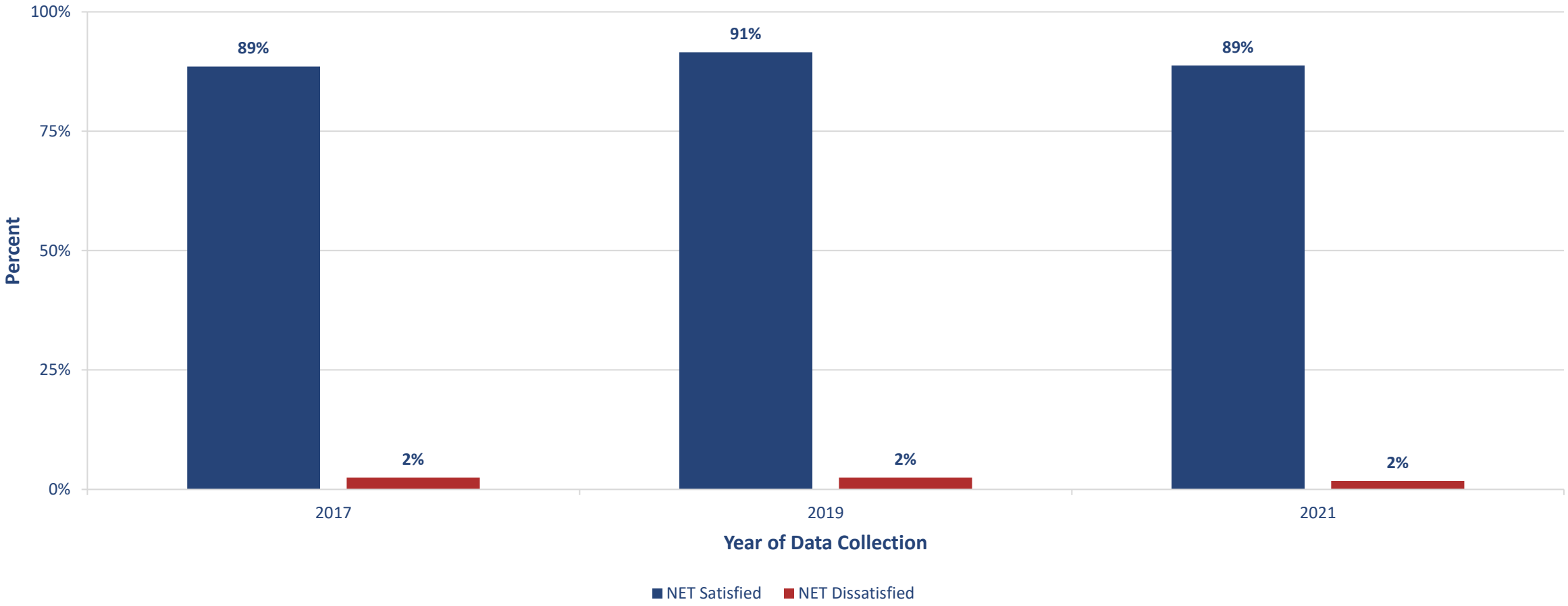
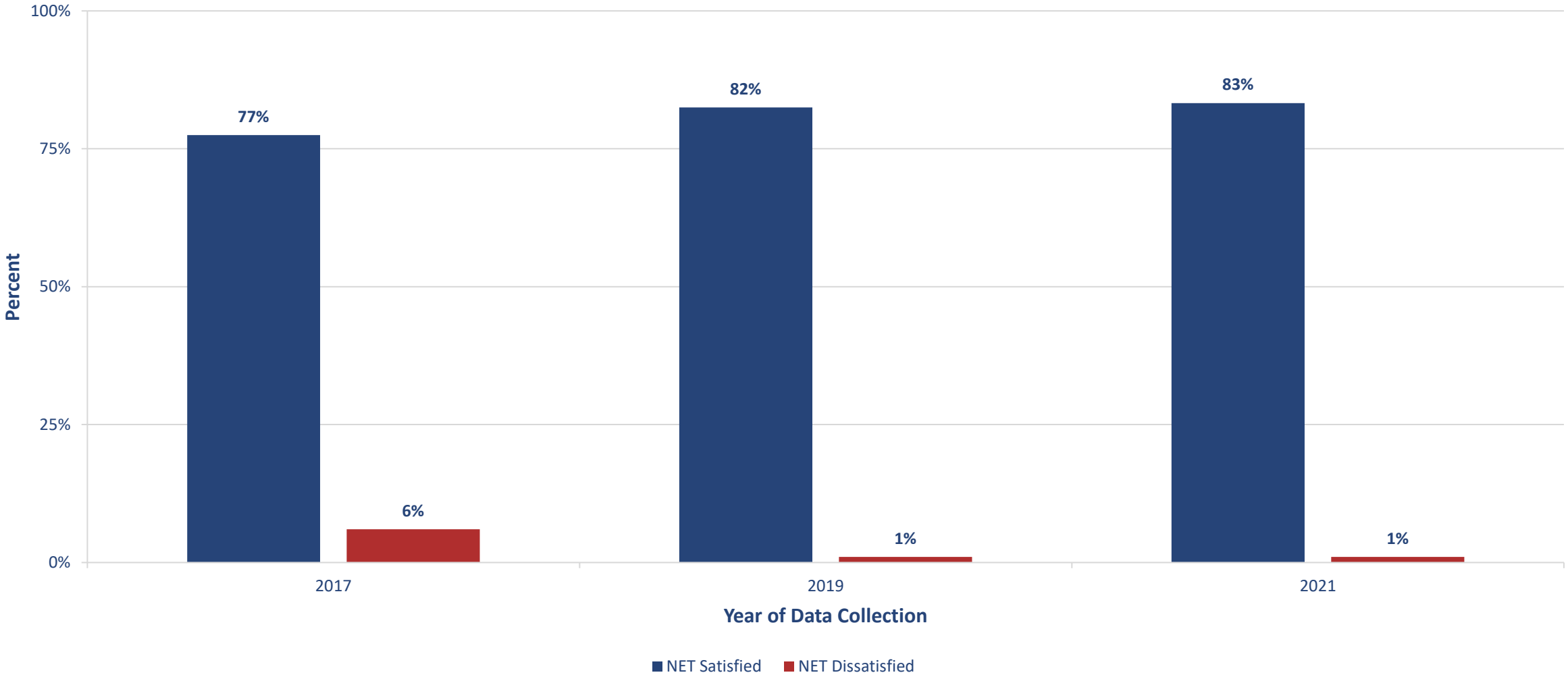
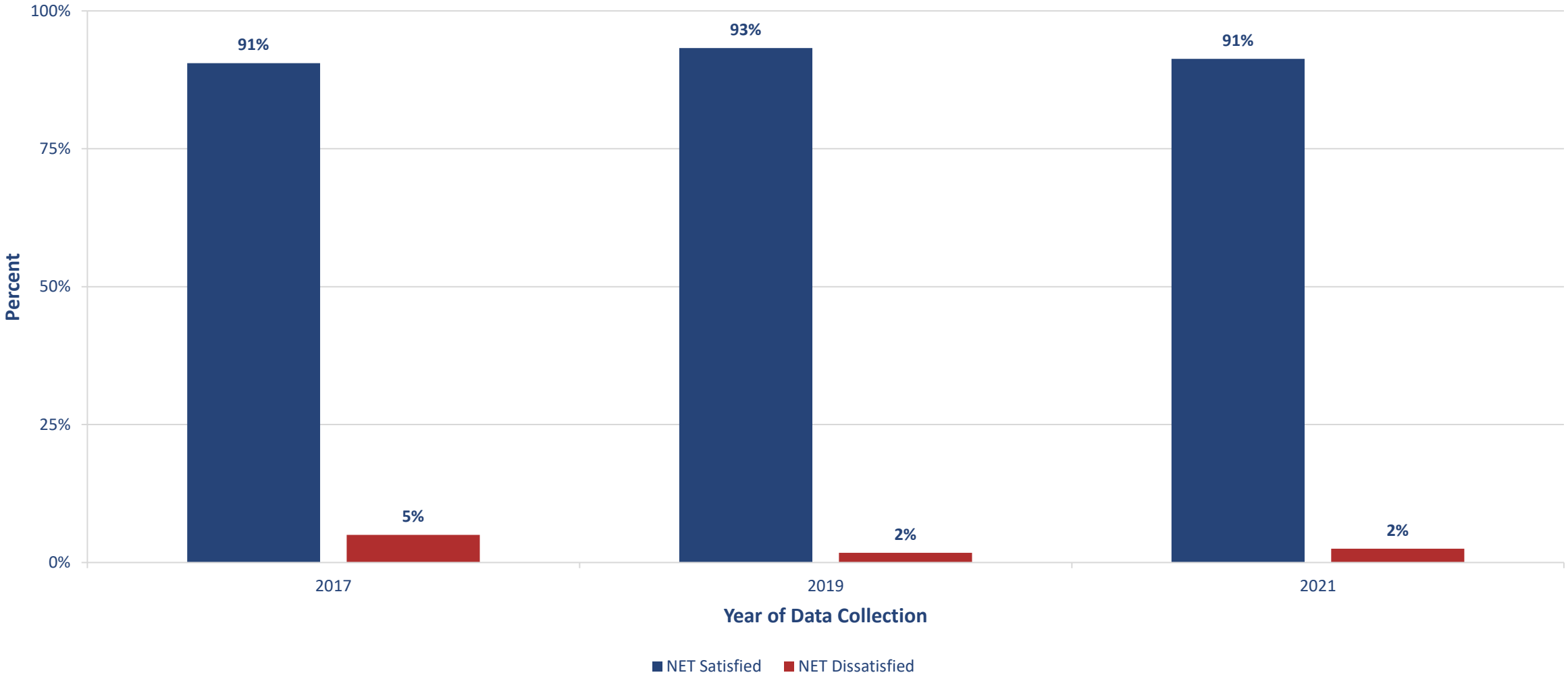


Providing accurate bills: How satisfied are you with the bills that you receive from Grimsby Power based on them...?



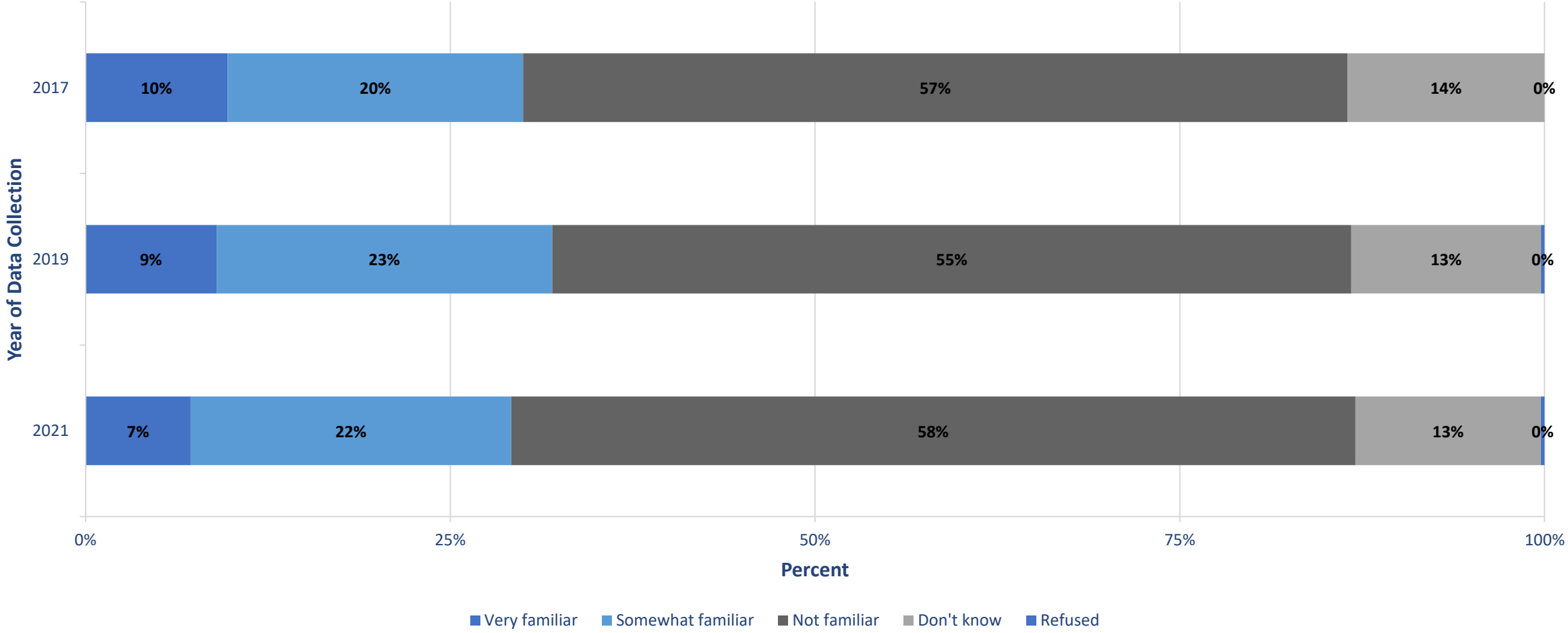
Providing convenient options to both receive and pay your bills: How satisfied are you with the bills that you receive from Grimsby Power based on them...?



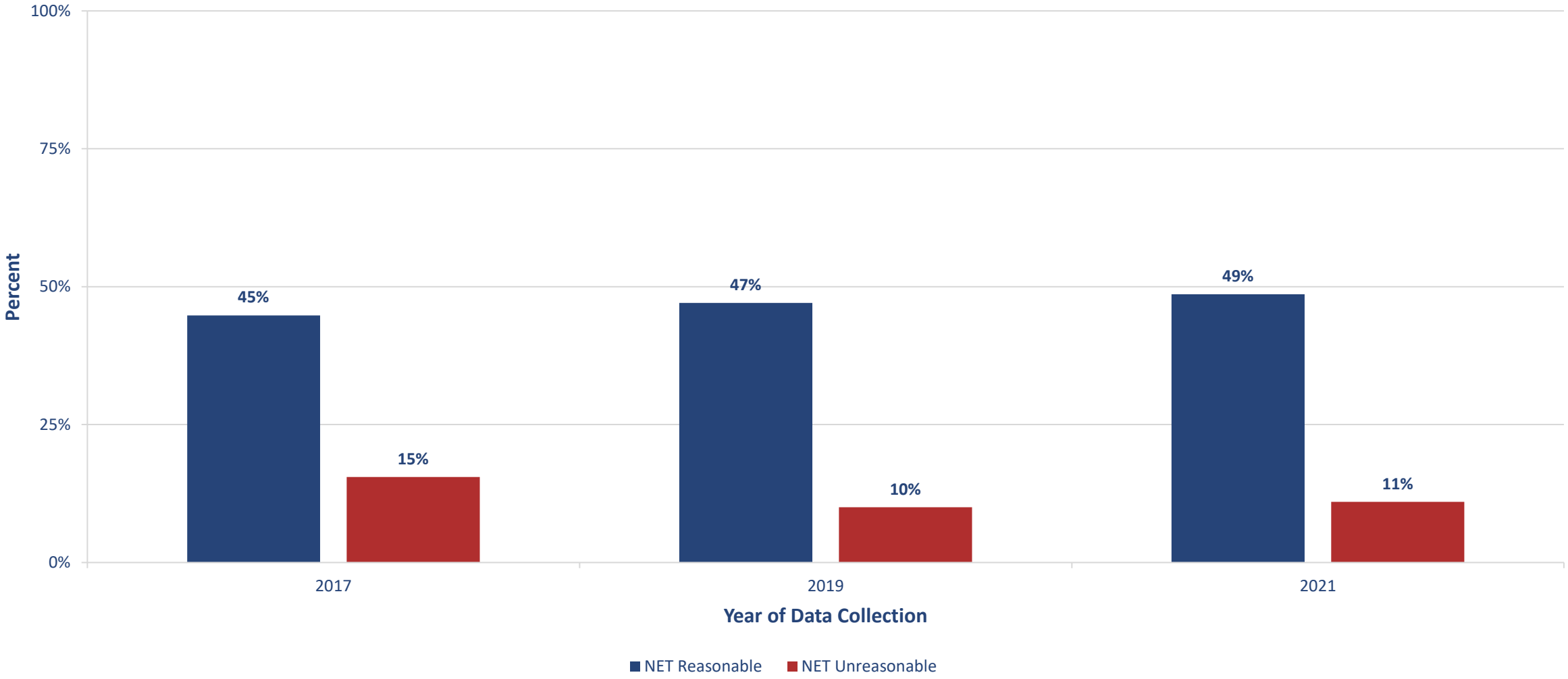
How satisfied are you with the customer service you have received when dealing with employees of Grimsby Power, whether on the telephone, via email, in person or through online conversations including social media?

How satisfied are you with the communications that you may receive from Grimsby Power without talking directly to an employee, including information found on their website, bill inserts, advertising, notices, emails, or social media sites?

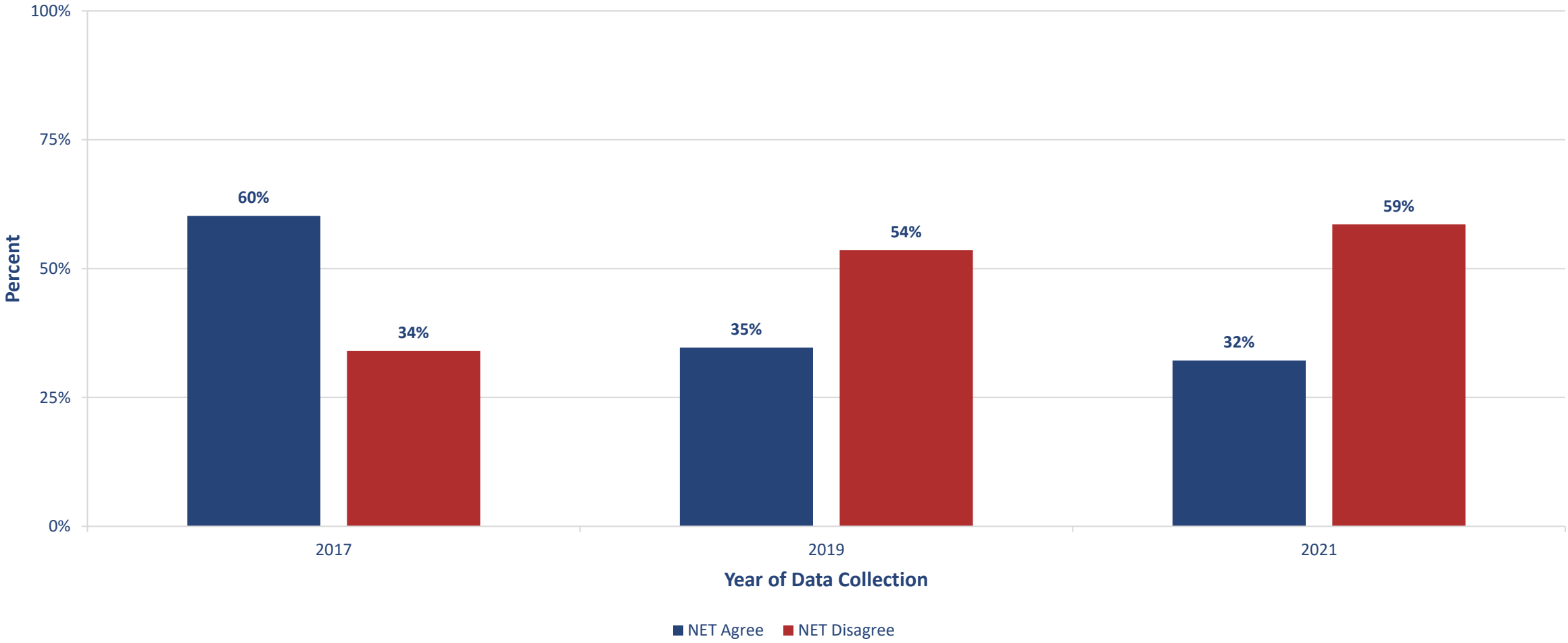
How familiar are you with the percentage of your electricity bill that went to Grimsby Power? So, NOT the portions allocated to power generation companies, transmission companies, the provincial government and regulatory agencies.



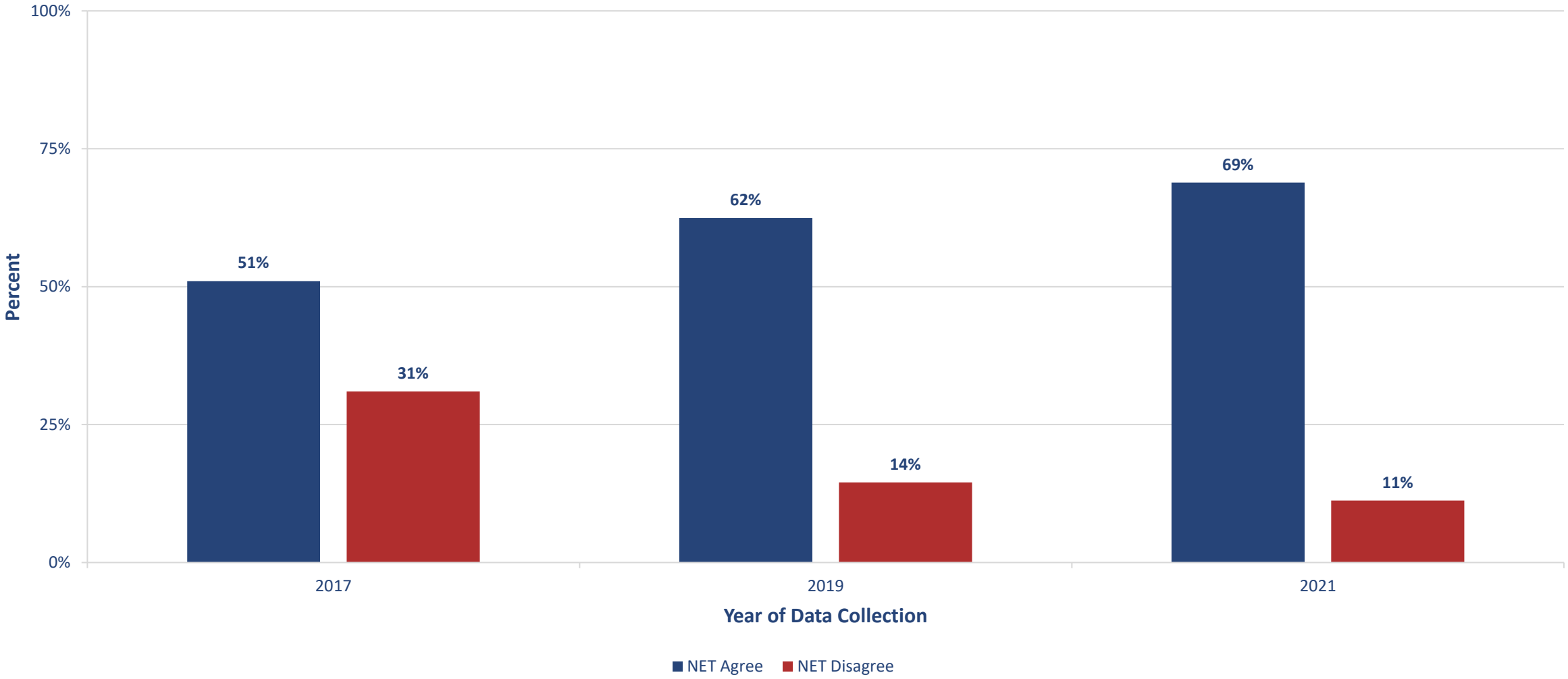
Do you feel that the percentage of your total electricity bill that you pay to Grimsby Power for the services they provide is...?



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?



Customers are well served by the electricity system in Ontario: To what extent do you agree with the following statements regarding the electricity system in Ontario?



METHODOLOGY

Methodology Summary

Commissioned by	Grimsby Power Inc.
Sample size	401 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 Grimsby Power
Time of calling	4PM-9PM Weekdays, 10AM-5PM Saturdays, scheduled callbacks
In-field dates	January 13-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

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 Grimsby Power's service territory(ies). Service territories were determined based on customer lists provided by Grimsby Power.

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 ±4.8 percentage points, 19 times out of 20.

Since Grimsby Power has a finite population, we used the specific population sizes (i.e., the number of samples records received from Grimsby Power) 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 Grimsby Power. 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 Grimsby Power. 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 13-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 Grimsby Power;
- 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 Grimsby Power are provided below. The sum of the regional population proportions within an LDC may not equal 100% due to rounding.

Methodology Tables

Margin of error

LDC	Customer Records from LDC	Completed Surveys	Sample Size as % of Customer list	Margin of Error @ 95% confidence level
Grimsby Power	10,991	401	3.65%	+/- 4.8%

Sample weighting

Grimsby Power						
Regions Flagged in Sample	Low Volume Rate Class	Clean, Deduplicated Sample Received	Rate Class Proportion	Estimated Customer Proportion	Weighted Sample Count	Unweighted Sample Count
TOTAL	Residential	10,460	95%	100%	382	381
	General Service < 50 kW	531	5%		19	20
					401	401

Thank You

We greatly appreciate working on this important project for Grimsby Power 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.

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Bracebridge, ON
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grimsbypower
your local power provider


REDHEAD INC
MEDIA SOLUTIONS

1-Staff-3

Inflation Factor
Ref: Exhibit 1, Tab 3, page 6 of 28

Preamble:

When discussing the 2022 budgeting process, Grimsby Power noted that a forecasted consumer price index was utilized as the general inflation factor.

Question(s):

a) Please specify the general inflation factor utilized for the 2022 OM&A budget.

b) Please explain what categories of expenses this general inflation factor applied to.

c) Please provide the range of inflation factors utilized to adjust third-party expenses for the 2022 OM&A budget.

Response:

a) The general inflation factor utilized for 2022 OM&A budget was 2.2%.

b) The general inflation factor applied to wages, benefits and third party expenses.

c) For third party expenses if an increase was stipulated in the specific agreement - that specific increase was used; for all others the company used 2.2%. The agreement increases ranged from 1.8% to 3%.

1-Staff-4

SAIDI/SAIFI Performance

Ref: Exhibit 1, Tab 3, page 16 of 28
Exhibit 2, Tab 3, Attachment 1, page 32 of 678
Responses to OEB Staff Clarification Question-4

Preamble:

Grimsby Power reported its system reliability performance in the scorecard:

Performance Outcomes	Performance Categories	Measures	2016	2017	2018	2019
Operational Effectiveness	System Reliability	SAIDI	0.55	1.20	1.73	5.00
		SAIFI	0.69	0.99	1.17	3.44

Question(s):

a) Please confirm measures reported for each year over the 2016-2019 period in the table above excludes both Loss of Supply and Major Event Days (MEDs).

b) Grimsby Power noted that excluding the two specific events in April and May of 2019, the calculations would have yielded a SAIDI of 3.87 and a SAIFI of 3.06. Please explain which cause code these two specific events fall under.

c) Grimsby Power stated that “GPI’s reliability metrics results in 2019 were abnormally high due to loss of supply, and adverse weather that were not classified as Major Events.” Please provide Grimsby Power’s process for determining MEDs and the specific determination or calculations of the MED threshold for 2019.

d) Please confirm Grimsby Power did not record any MEDs over the period of 2016-2020.

e) Please provide a breakdown of reliability performance (number of interruptions, number of customer interruptions, and number of customer-hours of interruptions) by cause code for each year over the historical period of 2016-2020.

f) Please review and discuss the historical trend of interruptions due to Defective Equipment.

g) Does Grimsby Power track interruptions due to Defective Equipment by equipment type? If so, please provide a further breakdown of historical interruptions due to Defective Equipment by year and by equipment type.

Response:

a) Confirmed.

b) April 2019 event was classified under OEB Cause Code 0 (Unknown/Other – Customer interruptions with no apparent cause that contributed to the outage) and May 2019 event was classified under OEB Cause Code 5 (Defective Equipment – Customer interruptions resulting from distributor equipment failures).

c) Grimsby Power follows OEB specified process for determining MEDs (Process came in effect on May 3, 2016 – EB-2015-0182 Report of the Board: Electricity Distribution System Reliability: Major Events, Reporting on Major Events and Customer Specific Measures).

d) Confirmed.

e) Please see Table below.

	2016		2017		2018	
Number of Interruptions	119	Cause Code 0 - 4 Cause Code 1 - 26 Cause Code 2 - 3 Cause Code 3 - 5 Cause Code 4 - 8 Cause Code 5 - 27 Cause Code 6 - 2 Cause Code 7 - 5 Cause Code 8 - 1 Cause Code 9 - 38	92	Cause Code 0 - 4 Cause Code 1 - 22 Cause Code 2 - 0 Cause Code 3 - 11 Cause Code 4 - 9 Cause Code 5 - 22 Cause Code 6 - 3 Cause Code 7 - 3 Cause Code 8 - 0 Cause Code 9 - 18	131	Cause Code 0 - 7 Cause Code 1 - 29 Cause Code 2 - 3 Cause Code 3 - 11 Cause Code 4 - 3 Cause Code 5 - 36 Cause Code 6 - 7 Cause Code 7 - 3 Cause Code 8 - 2 Cause Code 9 - 30
Number of Customer interruptions	15,790	Cause Code 0 - 15 Cause Code 1 - 531 Cause Code 2 - 8,010 Cause Code 3 - 3,785 Cause Code 4 - 2,587 Cause Code 5 - 407 Cause Code 6 - 15 Cause Code 7 - 55 Cause Code 8 - 14 Cause Code 9 - 371	11,259	Cause Code 0 - 2,298 Cause Code 1 - 849 Cause Code 2 - 0 Cause Code 3 - 4,377 Cause Code 4 - 2,066 Cause Code 5 - 1,395 Cause Code 6 - 61 Cause Code 7 - 19 Cause Code 8 - 0 Cause Code 9 - 194	15,790	Cause Code 0 - 3,790 Cause Code 1 - 521 Cause Code 2 - 2,271 Cause Code 3 - 4,715 Cause Code 4 - 4 Cause Code 5 - 762 Cause Code 6 - 3,532 Cause Code 7 - 72 Cause Code 8 - 2 Cause Code 9 - 121
Number of Customer-hours of interruptions	13,319	Cause Code 0 - 10 Cause Code 1 - 1,148 Cause Code 2 - 7,197 Cause Code 3 - 2,655 Cause Code 4 - 1,184 Cause Code 5 - 492 Cause Code 6 - 18 Cause Code 7 - 66 Cause Code 8 - 1 Cause Code 9 - 548	13,595	Cause Code 0 - 690 Cause Code 1 - 1,237 Cause Code 2 - 0 Cause Code 3 - 6,008 Cause Code 4 - 2,865 Cause Code 5 - 978 Cause Code 6 - 84 Cause Code 7 - 1,267 Cause Code 8 - 0 Cause Code 9 - 466	23,171	Cause Code 0 - 5,139 Cause Code 1 - 1,252 Cause Code 2 - 3,253 Cause Code 3 - 5,279 Cause Code 4 - 8 Cause Code 5 - 1,488 Cause Code 6 - 5,889 Cause Code 7 - 320 Cause Code 8 - 112 Cause Code 9 - 431

	2019		2020	
Number of Interruptions	109	Cause Code 0 - 9 Cause Code 1 - 15 Cause Code 2 - 1 Cause Code 3 - 8 Cause Code 4 - 3 Cause Code 5 - 33 Cause Code 6 - 20 Cause Code 7 - 1 Cause Code 8 - 0 Cause Code 9 - 19	94	Cause Code 0 - 2 Cause Code 1 - 30 Cause Code 2 - 0 Cause Code 3 - 5 Cause Code 4 - 1 Cause Code 5 - 19 Cause Code 6 - 4 Cause Code 7 - 0 Cause Code 8 - 1 Cause Code 9 - 32
Number of Customer interruptions	46,371	Cause Code 0 - 1,552 Cause Code 1 - 122 Cause Code 2 - 6,155 Cause Code 3 - 26 Cause Code 4 - 47 Cause Code 5 - 5,896 Cause Code 6 - 32,205 Cause Code 7 - 30 Cause Code 8 - 0 Cause Code 9 - 338	10,887	Cause Code 0 - 22 Cause Code 1 - 495 Cause Code 2 - 0 Cause Code 3 - 11 Cause Code 4 - 4 Cause Code 5 - 1,526 Cause Code 6 - 5,488 Cause Code 7 - 0 Cause Code 8 - 2,236 Cause Code 9 - 1,105
Number of Customer-hours of interruptions	64,665	Cause Code 0 - 1,628 Cause Code 1 - 296 Cause Code 2 - 6,258 Cause Code 3 - 41 Cause Code 4 - 112 Cause Code 5 - 13,688 Cause Code 6 - 42,178 Cause Code 7 - 93 Cause Code 8 - 0 Cause Code 9 - 371	7,521	Cause Code 0 - 38 Cause Code 1 - 948 Cause Code 2 - 0 Cause Code 3 - 38 Cause Code 4 - 5 Cause Code 5 - 417 Cause Code 6 - 4,210 Cause Code 7 - 0 Cause Code 8 - 373 Cause Code 9 - 1,492

f) Number of interruptions due to Defective Equipment has been somewhat steady over the historical period (2016- Q27, 2017- Q22, 2018- Q36, 2019- Q33, 2020- Q19). Increased focus on renewal programs is driving the number of such interruptions down as it can be observed in number of such interruptions.

There have been no observed trends based on the interruptions due to Defective Equipment. Grimsby Power does actively review causes of the interruptions and looks for trends in effort to prevent them from reoccurring.

g) Grimsby Power does not track interruptions due to Defective Equipment by equipment type.

1-Staff-5

Benchmarking based on Yearbook Data
Ref: Exhibit 1, Tab 3, page 26 of 28

Question(s):

a) Please update Table 1-7 and Table 1-8 using the 2020 yearbook data.

Response:

a) Table 1-7 and Table 1-8 have been updated with 2020 yearbook data and are presented below.

Table 1-7: OEB 2020 Yearbook - Geographical Benchmarking Cohort

Unitized & Other Statistics For the Year Ended December 31, 2020	Grimsby Power Incorporated	Canadian Niagara Power Inc.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Welland Hydro-Electric System Corp.
OM&A per Customer ($)	307.15	323.46	332.41	312.01	284.35
Net PP&E per Customer ($)	2,556.05	4,207.53	2,685.38	3,721.43	1,419.45
Monthly Residential Service Charge 2020 ($)	28.75	36.76	33.67	29.41	28.82

Table 1-8: OEB 2020 Yearbook - Similar Size Utility Benchmarking Cohort

Unitized & Other Statistics For the Year Ended December 31, 2020	Grimsby Power Incorporated	Algoma Power Inc.	ERTH Power Corporation	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	Niagara-on-the-Lake Hydro Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Ottawa River Power Corporation	Tillsonburg Hydro Inc.	Wasaga Distribution Inc.
OM&A per Customer ($)	307.15	1,113.41	315.41	258.28	389.56	312.01	255.49	430.05	301.54	368.29	248.22
Net PP&E per Customer ($)	2,556.05	9,887.60	2,853.42	1,919.28	2,619.62	3,721.43	1,715.87	2,447.84	1,053.10	2,268.24	1,034.72
Monthly Residential Service Charge 2020 ($)	28.75	46.72	34.08	23.20	34.72	29.41	27.11	27.93	24.14	28.58	23.41

1-Staff-6

Performance Metrics and Benchmarking
Ref: Exhibit 1, Tab 3, Attachment 1, page 18 of 36

Preamble:

With respect to the efficiency rating comes from the Pacific Economics Group report, it was stated that:

> Because of this study, Grimsby Power has expended considerable effort to understand the drivers of its efficiency ranking and has undertaken initiates to improve its scores ultimately achieving best cost efficiency ranking in 2019.

Question(s):

a) Please provide the list of initiatives Grimsby Power has undertaken and explain how these initiatives helped to improve its scores and achieved cost efficiency.

Response:

a) Since the last rate application the company has undertaken the following measures to improve cost efficiency:

- LRAMVA Calculation was brought in-house.

  Since 2016 GPI has been calculating the annual LRAMVA internally. Previously the service was provided by an outside company performing the calculation each year. This change saved GPI $15,000 from the years 2016 to 2020. GPI did utilize a consultant to perform the LRAMVA calculation only in the Cost of Service application.

- In 2018 Grimsby Power began utilizing Utilismart to help invoice customers GS>50 – 4,999. With the use of Utilismart's application, GPI load reads automatically to our CIS system - where previously the reads were entered by internal staff - manually. The move to Utilismart; allowed GPI to eliminate the services of Kinetiq and Peterborough Utility Services and reduce the number of hours spent invoicing GS>50 customers. Initially, in 2018 there was an increase of $10,336, as the two systems ran together in parallel as the new process was being tested. The total savings for the system changes for 2019 was $13,285 and for 2020 it was $14,482.

- Improvements in Payroll and HR

  In 2017 Grimsby Power removed duplicate processes from our Payroll procedure and eliminated outdated software - resulting in a cost savings of $2,500 per year.

In the same year the company started using the CRA website instead of using third party software for issuing T5s and T4As.

The HR software from a third party was discontinued and the work was done in-house resulting in a savings of $1,163.

The Company changed the payroll frequency from weekly to bi-weekly in 2018. This was a major effort and resulted in a cost savings of $1,500 per year in fees paid to the third party.

- Reduced Variable costs for CIS system – issues resolved using in-house expertise.

  Since 2016 GPI has been able to reduce the amount of money and time spent on making changes to our CIS system. GPI has been able to resolve more of the issues with our CIS system using internal resources. Since 2017, GPI has been able to reduce the variable costs associated with the CIS system by $9,213.

- Eliminated manual reads for remaining GS>50 meters - This was a requirement under DSC; the change led to a reduction in operational staff hours out in the field reading meters.

  The elimination of manual reads for MOST meters was complete in 2020. The switch over to MIST meters, removed the need to have the meters manually read and ultimately reduced the number of hours staff spent in the field.

- Starting in 2018, weekly inspections of the NWMTS was performed by GPI employees. GPI previously used a third party vendor. The result was a savings of $3,770.

- In 2017 the company began writing the Audited Financial Statement notes. Previously the notes were written by auditors. The change led to an annual cost savings of $4,200.

- The method of performing locates in the field were reviewed and the process changed by having a contractor perform office lookups and office clears instead of Field Clears. This change in methodology resulted in savings of $5,025. The change in process produces a savings each year depending on the number of office lookups and clears that can be performed.

- As member of Utilities Standards Forum (USF) and Cornerstone Hydro Electric Concepts (CHE) GPI was able to reduce costs for creating and updating common standards, staff training, create policies and procedures that are common in the industry, using consultants at a the lower cost point.

  In 2016 Grimsby Power collaborated with the CHEC group in the delivery of the biennial Customer Satisfaction survey using a different vendor acquired for all members of the CHEC group. This collaboration with the CHEC group resulted in a change to our existing vendor and subsequently produced a cost savings of $10,000 every two years.

- Implemented Remote Deposit Capture (RDC) – The process for submitting cheques was brought in-house by bringing a cheque scanner in house. Previously a staff member would need to go to the bank daily to submit cheques. The process change eliminated labour and truck costs for and employee going to the bank. The overall cost reduction was $4,000 annually and there has been an efficiency improvement in the Accounting Department.

- Switching vendors to EFT payments – the change results in reduced time in processing payments and improves the efficiency in the Accounting Department.

- Updated website to include online moving forms to make the application process more efficient.

  In 2019 GPI redesigned its website. The redesign of the website allowed GPI to bring more forms online where previously forms were only available in PDF form. The move to online forms allows customers easy access to the applications required. It also allowed for easy submission of the forms to GPI.

- Added automated phone message to alleviate phone calls during power outages.

  In 2019 GPI implemented a system that allowed the company to add an automated message to our phone system alerting customers to power outages. GPI found that many of the calls coming in to our office during an outage were customers wanting confirmation of an outage. The use of an automated message advising customers of an outage in their area allowed fewer calls to go through to GPI and the after-hours service.

- Automated final collections process to reduce time taken to deliver notifications.

- Move towards paperless data collection for maintenance plans. GPI has eliminated use of paper and collection of maintenance data for all maintenance plans is done via use of ArcGIS and automatically uploaded for processing and further analysis.

GPI plans to undertake the following measures in the bridge and test year:

- Increase number of e-billing customers:

  In 2021 GPI started implementing and will continue to develop into 2022 a new Customer Account portal (Silverblaze) and a new phone system. The new customer account portal allows customers to have access to one easy to use portal for both e-billing and consumption information. The portal also provides up to dates account payment information and allow customers to compare consumption with others in the area. The new phone system will allow for increased functionality including video meetings without the use of our current GoToMeetings. The system will also allow for improved communications between customer accounts staff and the operations group during outages. Moving to the new system will produce a cost savings of approximately $1,000 per year and will provide greater services and flexibility to Grimsby Power.

- New telephone system – reduce fax line, increase communication between customer accounts and operations staff.

- Improvements to ERP information presentation to make the balance sheet reconciliation process more efficient. Expected time saving is at least 4 hours per month and at least 5 hours saved as part of year-end reconciliation.

- Automate EDI, EFT, and PAP customer payments using electronic bank statement processing. This will save at least 15 hours per month and reduce the chances of billing errors. Checks and verification procedures will remain in place.

- Modernize asset tracking system, which will reduce the time spent on budgeting and forecasting data entry.

- Move more vendors from manual payment systems (cheques) to EFT or other electronic payment systems. This will improve efficiency in settlement and sizeably reduce paper usage.

- Move payroll data entry towards a more automated entry system to reduce the chance of errors and significantly reduce processing time (save at least 3 hrs per biweekly payroll period).

- GPI is proactively working on upgrading existing GPS system for its' fleet. The goal is to have an effective GPS system that could be used for optimization of outage response efforts. The idea is to utilize meter/transformer relationship in GIS to further increase automation for outage reporting purposes across all types of electrical services. So far GPI has managed to successfully automate and utilize smart meters to report outages on the Outage Map on GPI's web page.

- Optimize on use of industry standard material/equipment items. Work with other LDCs in CHEC cooperative on initiative to standardize on equipment used in effort to utilize equipment that is readily used by other LDCs in the cooperative.

- Work on finding ways to minimize inventory. Try to optimize on use of vendors and distributors to minimize stock levels and yet have ability to have all material when needed.

- Try to reduce cost associated with services required for Operating Control Center for NW MTS. Look for other competitive services by other LDCs in effort to minimize this cost.

- Reduce cost associated with annual upkeep of the vacant land around MW MTS. Optimize seasonal grass cutting and look for ways to optimize upkeep services for the vacant land around the station.

- Standardise and try to obtain long term pricing on FR clothing purchases. Implement standardization of purchased FR clothing (models and vendors) in effort to optimize procurement and secure cost saving pricing.

- Try to optimize pole disposal costs. Find the way to dispose old poles for cheaper. The more poles we change to higher the costs are for disposal of old poles which leads to an opportunity to higher potential cost savings.

- SCADA Communication/Integration initiative. As more smart devices are added into the distribution system goal is to integrate them to SCADA and utilize features of SCADA (i.e. automatic alarms) to optimize overall outage response.

- Increase effort on waste recycling. Cost saving are based on refund achieved for scrapped metals.

1-Staff-7

Personnel Plan
Ref: Exhibit 1, Tab 3, Attachment 1, page 36 of 36

Preamble:

It was stated that:

> In 2021, GPI engaged a third party to conduct an assessment of key management positions and a review of the overall organization to analyze future looking risks as it relates to the achievement of corporate goals and ongoing continuity of the business. As a result, a resource strategy plan has been prepared and is in the early stages of implementation. Included in the plan are a talent retention and skills development and coaching program.

Question(s):

a) Please provide a copy of the assessment study prepared by the third party and the resource strategy plan.

b) Please explain how these reports impact Grimsby Power's workforce planning for the 2022 test year and for the 2023-2026 period.

Response:

a) A copy of the assessment study is attached as Appendix 1 of 1-Staff-7. The report has been redacted so as to remove:

- all references to personal confidential information with respect to Grimsby Power's employees; and
- commercially sensitive forward looking confidential information with respect to Grimsby Power's staffing needs that, if made public, could impact Grimsby Power's ability to hire and retain staff.

b) The impact of the report to Grimsby Power's workforce planning is as follows:

    a. For 2022:

        i. As the current organization of staff is not sustainable going forward, the report recommended a recruiting and talent acquisition strategy focused on hiring individuals with specific capability that matches the work environment.

The small size of GPI magnifies the importance of properly planning, selecting and developing each individual in the organization. The impact of having the wrong person in the wrong role is amplified at GPI compared to a large utility. This can have significant negative consequences.

These were the key considerations in the recruitment and selection of two positions: Director of Engineering and Operations and the Accounting Supervisor.

b. For the 2023 -2026 period:

i. The plan creates a long term vision of the organization and implements the changes gradually. The report recommended a long term target GPI organization be identified and developed and the report would be used as a guide to make strategic decisions with organizational and structure changes.

ii. At the management level roles hire people with high-to-low and side-to-side flexibility and capabilities. In order to adapt and manage anticipated changes and turnover in GPI's current staffing complement in the short to mid term period.

The GPI management team challenges of - managing broad accountabilities and dealing with high level to low level tasks are inherent with the size of the organization and therefore will remain in the future.

iii. Training and development opportunities to build the capabilities should be focused on the individuals with high potential to move in the organization and take on more significant role or consider external replacements.

iv. Design the organization around the capabilities and leadership potential of the key staff. This could include retaining talent by allowing the key staff to grow into roles over time, which includes "promotion in place" advancement over time justified by a gradual increase in assigned accountabilities.

March 3, 2021

Resource Strategy Study Final Report

Grimsby Power

CONFIDENTIAL

Prepared BY:

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Filed: October 28, 2021

1. GPI Key Resource Strategy Project

Grimsby Power Incorporated (GPI) engaged Sartor and Associates to conduct an assessment of key management positions and a review of the overall organization to analyze future looking risks for the enterprise in context of achievement of corporate goals and ongoing continuity of the business in the face of future organizational transition.

The project included the following activities:

- The Sartor & Associates Team profiled the key Grimsby Power executives through 2 sessions. A Knowledge Mapping format was used in sessions held with Remy Fernandes (CEO and President) on February 4, 2021 and Mioara Domokos (Director of Finance) on January 29, 2021.
- The Sartor & Associates team also held sessions with the following CEO-once-removed staff at Grimsby Power. A session with Amy La Selva (Regulatory and Customer Accounts Supervisor) was held on February 12, 2021 and a session with Kevin Robins (Operations Supervisor) was held on February 11, 2021.

These activities facilitated the analysis of critical organizational experience-based knowledge from key executives to properly understand Grimsby Power resource strategy options and the future challenges for the organization.

The assessment of the Supervisory positions helped the Sartor & Associates team to fully understand assigned staff responsibilities, organizational challenges and identify future organizational risks and risk mitigations. The information obtained helped the Sartor and Associates team to review future succession planning considerations which are included in the report below.

2. GPI Overview and Background

Grimsby Power Incorporated (GPI) is a Local Distribution Company (LDC) and is responsible for distributing power to customers within the Town of Grimsby. GPI is owned by the Town of Grimsby with FortisOntario holding a 10% share. GPI serves approximately 11,750 mostly residential and commercial electricity customers in the Town of Grimsby municipality.

Mission

GPI is committed to providing the residents and businesses of Grimsby with a safe and reliable supply of electricity while operating effectively and efficiently at an equitable cost.

GPI will grow the business and **increase shareholder value**.

Vision

Grimsby Power's Vision is to:

- Be adaptable
- Continue to provide economical efficient energy
- Be in business for our customers
- Be a locally owned business
- Strive to be efficient in any new operation to meet our customers' needs
- Partner with others to drive economies of scale and scope

GPI Company Performance

In the last three years, when measured against GPI corporate goals, the company has performed well in targeted areas that align with the GPI vision and mission.

- From a safety perspective, since 2008 GPI employees have worked 395,254 hours without a lost time incident.
- From a customer perspective, GPI has achieved call answering of 90% answered within 30 seconds. This exceeds the 65% of calls answered within 30 seconds OEB requirement.
- From a productivity perspective, GPI operates at an industry leading metric of 679 Customers Served per Employee. This is compared to a metric of 546 Customers Served per Employee for comparably sized Ontario utilities (customer base of 10,000 to 20,000).

GPI has one of the lowest OM&A (Operating, Maintenance and Administration) costs per customer in Ontario at $277 per customer. The GPI cost per customer metric is significantly lower (26%) than the $374 OM&A cost per Customer average for Ontario utilities of a similar size (LDCs with a 10,000 to 20,000 customer base).

In the 2020 Ontario Energy Board PEG (Pacific Economics Group) Cost Efficiency Ratings Study, GPI was rated in the top grouping (i.e. Group-1). Out of the 59 LDCs in Ontario, Group-1 represents the top 7 utilities or the top 12% in the province from an efficiency perspective.

These GPI company performance results align closely with the objective of **maximizing shareholder value** and keeping rates as low as possible for the Grimsby community without sacrificing customer satisfaction and safety.

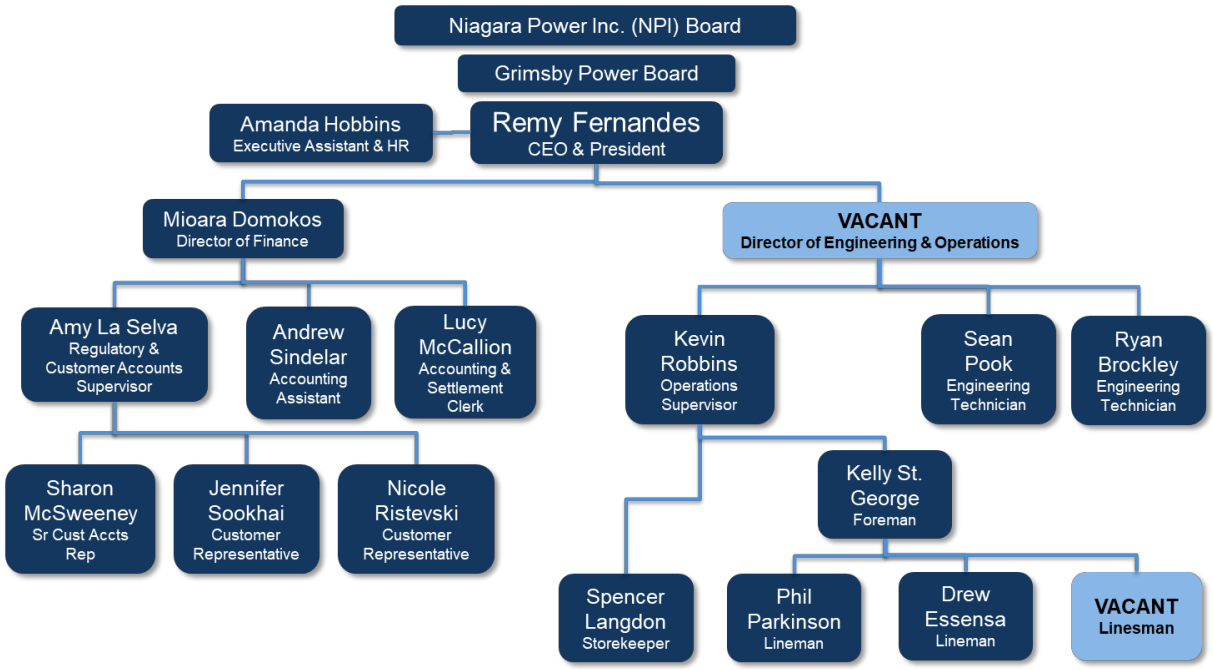
The ability of the GPI management team to maximize the productivity of the resources is reflected in GPI Return on Equity (ROE) improvement over the last 4 years.

- 2016 = 2.39%
- 2017 = 10.92%
- 2018 = 8.48%
- 2019 = 10.02%

3. Situational Assessment

Current Organization

The organization for GPI is shown below.

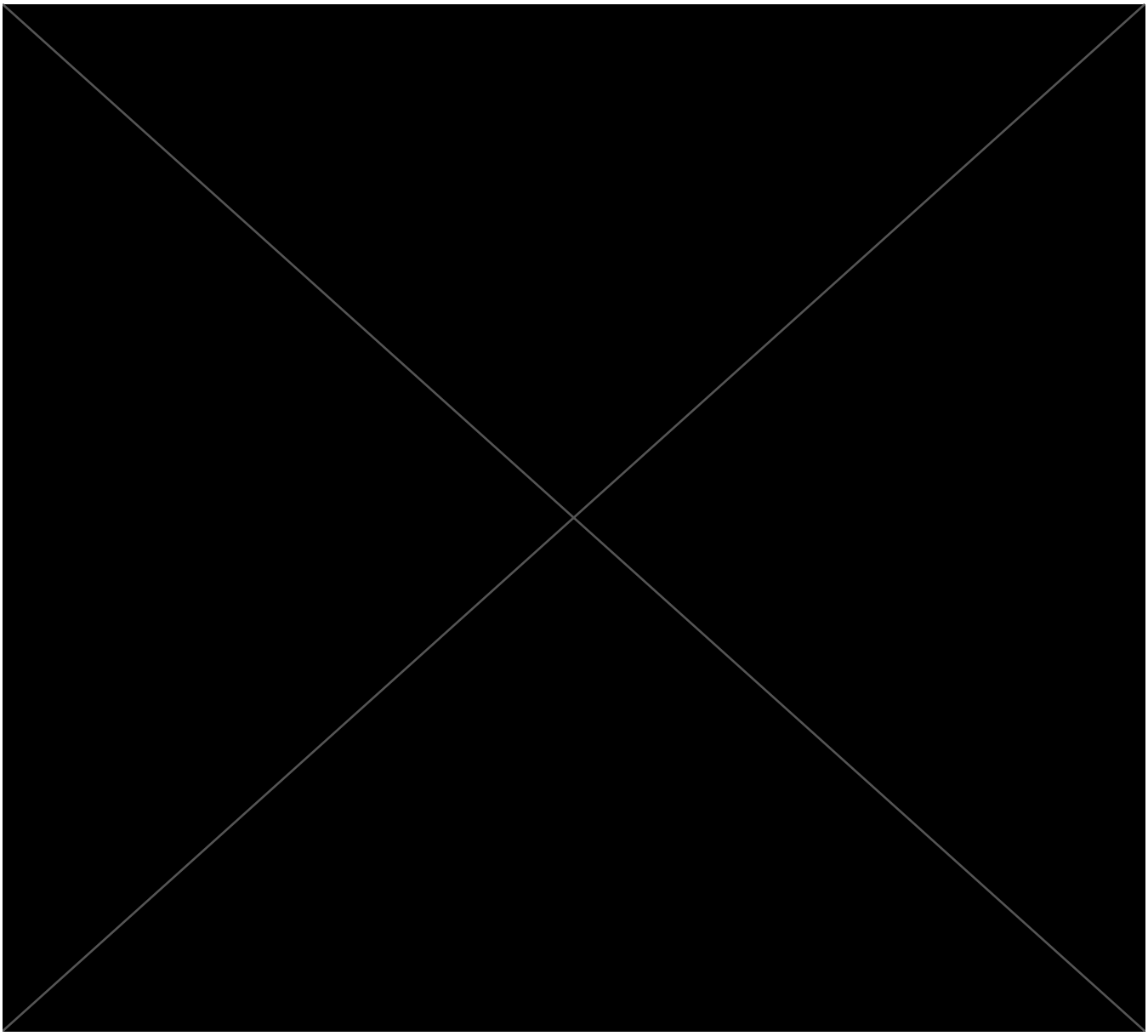


Key observations on current staff profile

- Currently there are no Professional Engineers in the company.
- Remy has been filling in as the Director of Engineering and Operations for the last 3 years.
- There are 2 CGAs (Certified General Accountants) in the company – Mioara Domokos and Andrew Sindelar.
- Depending upon the outcomes of the 2021 GPI OEB Cost of Service application, three more positions could be added in the coming years.
- The three incremental positions being proposed in the Cost of Service application are: Accounting Supervisor, Senior Customer Representative, and an additional Lineman.

Organizational Assessment

To recognize potential risks and succession considerations, we catalogued the stage in career, succession potential and interest in succession for each of the GPI employees.



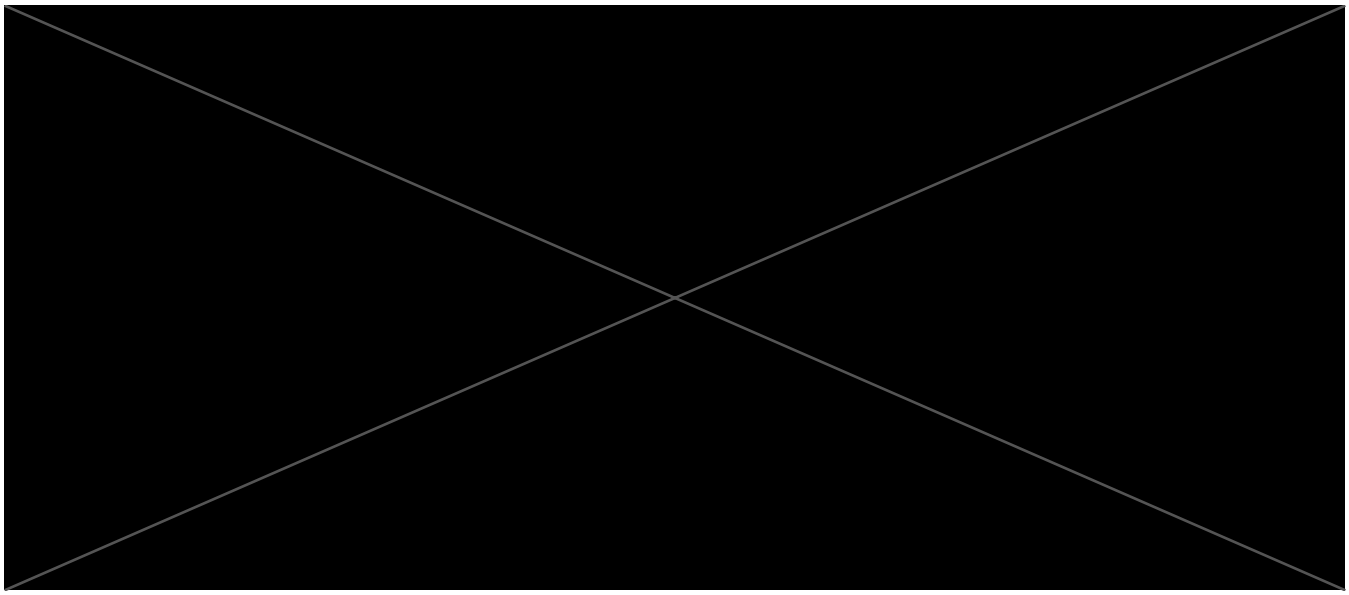
Key takeaways:

- Of the current Management team, [redacted] out of 4 staff [redacted] are likely to retire within [redacted] years.
- We identified [redacted] staff (highlighted by the boxes) as potential target candidates for Retention Plans, Talent Development and Succession Planning. The specifics details of this consideration are provided in the Recommendations Section.
- There are professional level employees in PWU jurisdiction positions – i.e. [redacted].

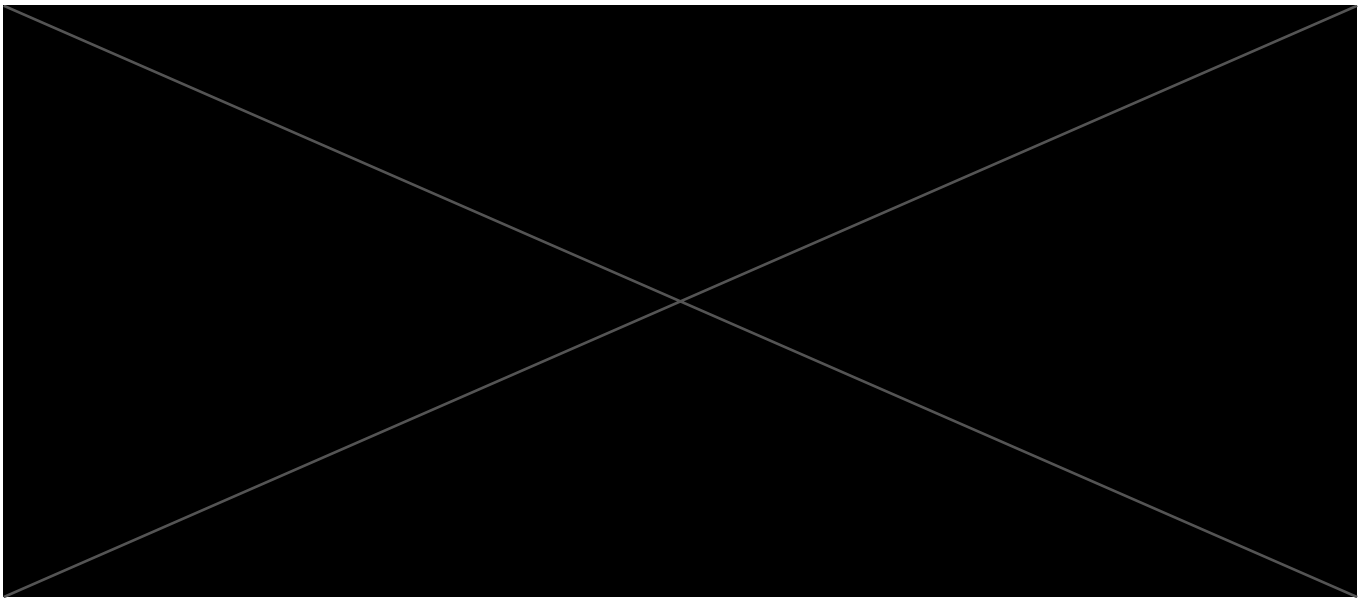
4. Management Team Assessments

To understand how GPI is being managed currently, the Sartor and Associates team conducted sessions with the members of the management team. From an executive perspective, GPI is being led by Remy Fernandes and Mioara Domokos. Amy La Selva and Kevin Robins are the other non-unionized staff in the company with both currently at a Supervisory level.

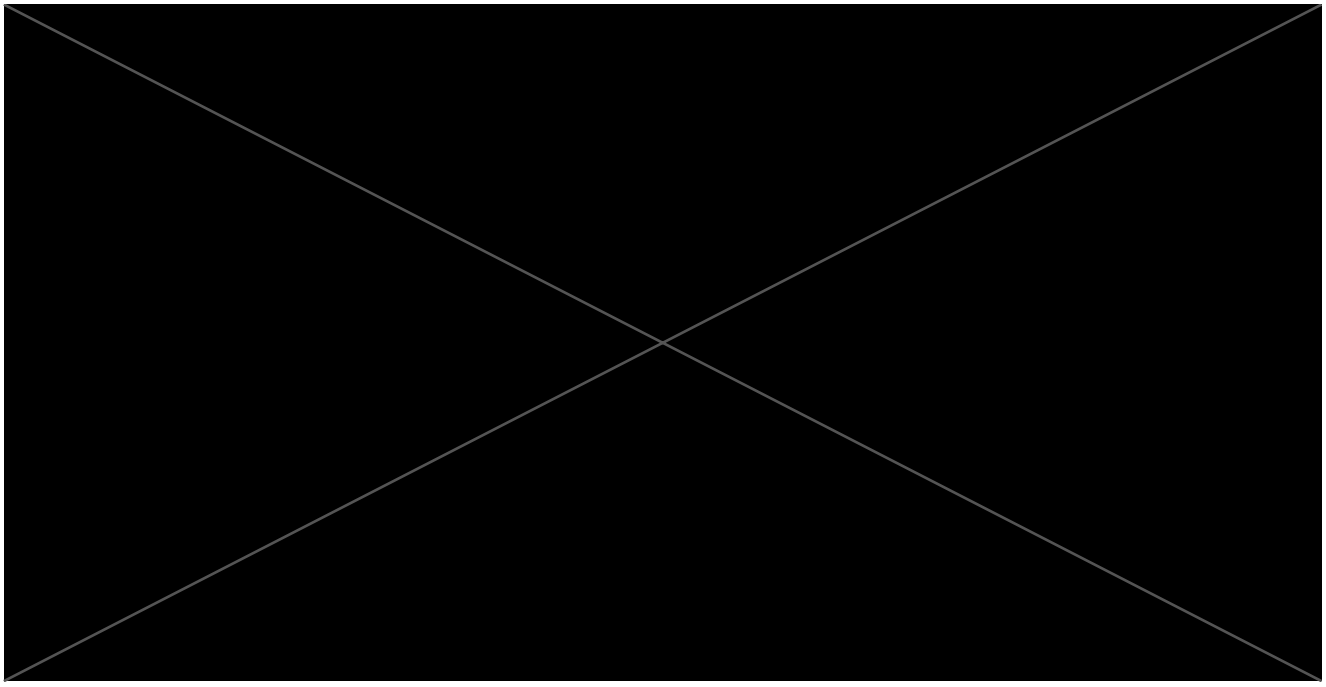
Remy Fernandes – CEO and President



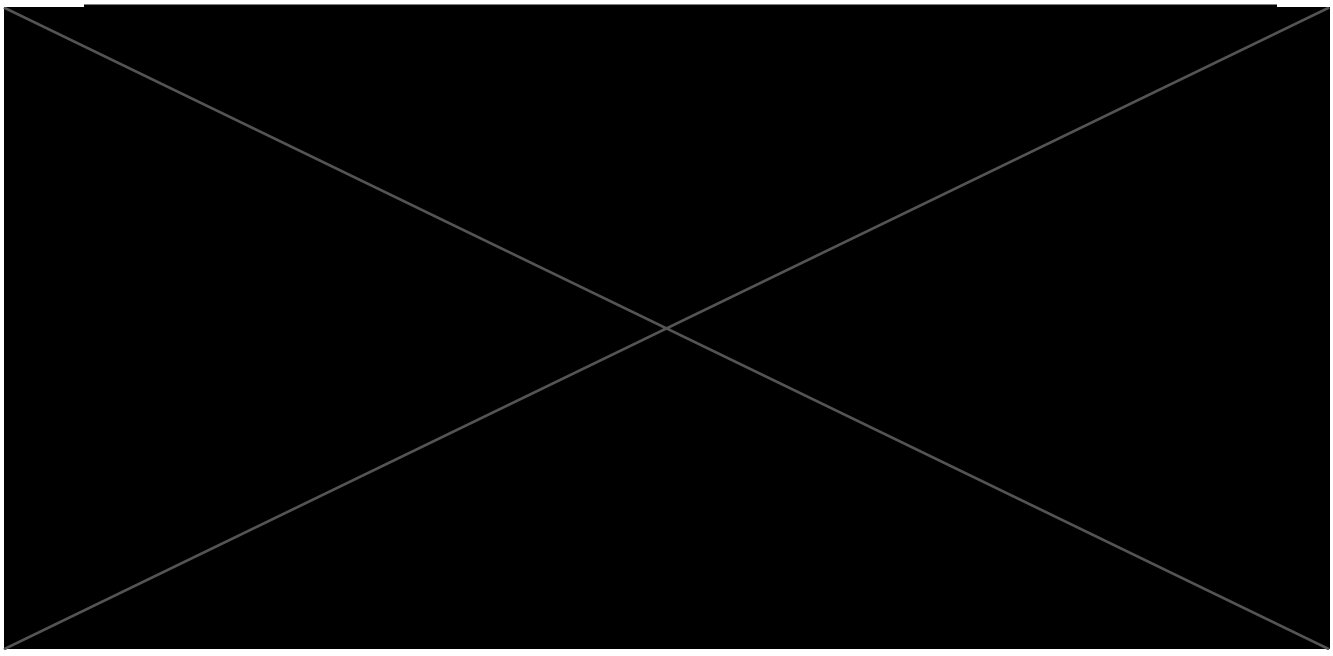
Mioara Domokos – Director of Finance



Amy La Selva – Regulatory and Customer Accounts Supervisor



Kevin Robins – Operations Supervisor



5. Key Organizational Observations and Considerations

a) **Over the last 3 years, the organization has performed well in the face of challenging circumstances but the current model is not sustainable.**

GPI is among the top 7 of 59 Local Distribution Companies in Ontario based on productivity (2020 OEB PEG Report). This reflects the ability of the current leadership team (Remy Fernandes and Mioara Domokos) to effectively set priorities, meet regulatory obligations, motivate their team and deliver target outcomes with limited support team resources. But, although the historical performance has been impressive, the current organization is not sustainable going forward (i.e. Remy Fernandes fulfilling CEO and the Director of Engineering and Operations positions).

b) Based on the current GPI organization structure, the [redacted] year Enterprise Transition Risk for the company is high. [redacted] of the current GPI Management team is expected to be with GPI beyond the next [redacted] year window.

[redacted] are likely to retire within the next [redacted] years. [redacted] is also likely to retire within the next [redacted] years. This leaves [redacted] that is likely to be with GPI beyond the next [redacted] year window. The currently planned recruitment of the Director of Engineering and Operations position will help improve this situation.

c) **Top level GPI roles will require people with high-to-low and side-to-side flexibility and capabilities**.

The GPI executive challenges of managing broad accountabilities and dealing with high level to low level tasks for senior level positions are inherent with the size of the organization and therefore will remain in the long term. GPI recruiting and talent acquisition strategies should focus in on hiring individuals with a specific capability profile that matches the work environment. This assumes no acquisition or merger activity in the mid-to-long term.

d) **Large capability gaps between organizational levels will make internal Succession Candidates difficult to identify in certain situations**.

Given the size and the flatness of the GPI organization, the identification and development of internal successors for senior roles may not be practical in certain situations. For example, [redacted]

e) **Every GPI position is critical, especially the senior roles**.

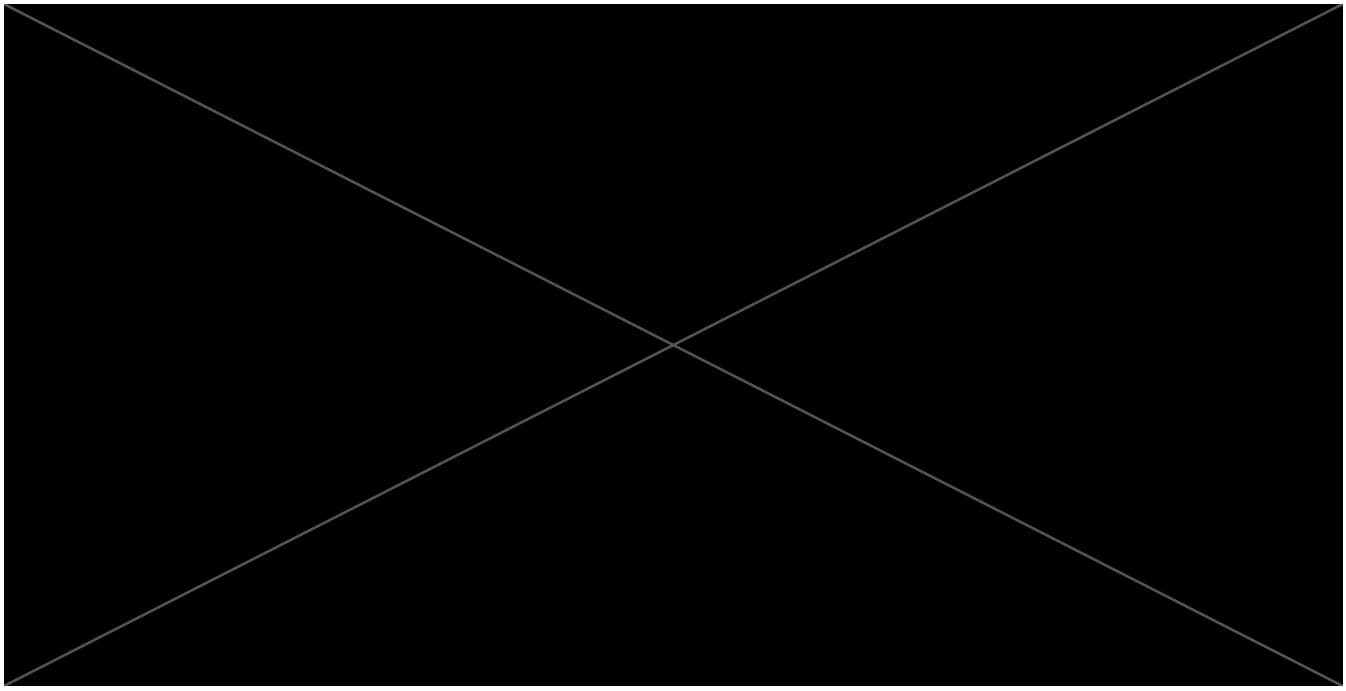
The size of GPI magnifies the importance of properly planning, selecting and developing each individual in the organization. The impact of having the wrong person in the wrong role is amplified at GPI versus a large utility and can have significant negative consequences for the future of the company.

6. Recommendations for Risk Mitigation

1) Create a long term vision of the organization, but implement changes gradually.

Recognizing the unionized environment, the size of the company, and the regulatory environment, significant changes implemented over a short span of time to the GPI organization would represent too great of a risk. Alternatively, we would recommend that a longer term [redacted] target GPI organization be developed. This target organization structure (see diagram below) can then be used as a guide to make strategic decisions that align with a future target organizational vision as changes occur (e.g. retirements) over a longer span of time.

GPI Target Organization [redacted]



2) Leverage the vacant Director of Engineering and Operations position as a building block for the longer term GPI future and reduce organizational transition risk.

We would recommend that [redacted] be a key consideration in the recruitment and selection of the next Director of Engineering and Operations. GPI should consider developing a succession plan for the Director of Engineering and Operations which would include training and development opportunities to build the capabilities of this person [redacted] If the new Director of Engineering and Operations progresses to expectations, the transition risk [redacted] would be reduced.

3) Design the organization around the capabilities and leadership potential of key staff.

We would recommend a talent retention and skills development program focused on the individuals within the company with the highest potential to move up in the organization and take on more significant roles [redacted] This could include retaining this talent by allowing them to grow into roles over time, where this would

include "promotion-in-place" advancement over time justified by a gradual increase in assigned accountabilities.

4) Target to broaden the senior leadership team (CEO and Direct Reports) in the mid-term

We recommend that be increased to possibly include With the increased responsibility, could be This would reduce the transition risk

The narrowing of would make it easier to replace with either could potentially replace This would potentially allow to continue development before taking on more accountability and moving up

5) Pursue a labour strategy to convert target union roles to professional roles.

To create more opportunities for advancement and attract appropriate talent, we would recommend to pursue the conversion of positions from the PWU to professional positions. Alternative options will need to be evaluated including potentially changing the designation of these position to Society. The positions we recommend to evaluate include

As this will require more dedicated time and higher level thinking to evaluate and produce a labour strategy, we would recommend that this could be assigned to

1-Staff-8
Customer Engagement
Ref: Exhibit 1, Tab 5, page 11 of 15

Question(s):

a) "Affordable electricity costs and value of money" was identified as one of the four key customer preferences. Please discuss any feedback provided by customers about the proposed rate impacts for the 2022 test year and how this feedback shaped the final proposal included in the application.

Response:

a) Grimsby Power balances the needs and wants of customers with providing our services at a reasonable cost. Grimsby Power communicated and met with customers from 2016 to 2019 listening to customers' expectations. In March of 2020 Grimsby Power closed its doors to the public in light of health and safety concerns for both customers and staff. In addition, Grimsby community events throughout 2020 and into 2021 were cancelled due to the pandemic and unfortunately, this eliminated the ability to meet with the public in person.

In 2019 Grimsby Power met with customers at various events as described in Exhibit 1. Those meetings included an event held at the end of November 2019 for small and large commercial customers. At that time GPI presented 2021 capital projects and rate impacts as at that time GPI was scheduled to file a rate application for 2021 rates.

During that meeting there were no concerns raised about the rate increase presented for General Service customers. Customers were focused on, education, reliability, sustainability and ways to decrease consumption.

Grimsby Power deferred its 2021 Cost of Service application filing due to the uncertainties of the pandemic.

1-Staff-9

Activity and Program-based (APB) Benchmarking
Ref: PEG Report to the OEB, revised May 11, 2021
Tables in Excel format for the PEG Report, May 11, 2021

Question(s):

a) Please explain the cost differences for the Station Maintenance O&M program between the cost data reported for the APB benchmarking and those presented in Appendix 2-JC as summarized in the table below.

Year	PEG APB Report Table 19 ($000)	Appendix 2-JC ($000)
2017	2.9	206.459
2018	133.5	241.617
2019	90.5	202.859

Response:

a) The cost differences between the APB benchmarking and those presented in Appendix 2-JC is the result the different way the calculations were done.

In 2-JC the Station Maintenance O&M program is calculated by summarizing the cost for Niagara West MTS – the transformer station and the 2 distributions stations.

The APB benchmarking calculation does not include account 5010 or 5012. A detailed calculation is provided below:

Description	2-JC			PEG Report		
	2017	2018	2019	2017	2018	2019
Transformer Station Niagara West MTS	**$206,459**	**$241,617**	**$202,859**	**$ 2,977**	**$133,498**	**$ 90,519**
5010 Load Dispatching	87,334	93,080	85,380			
5012 Stations Buildings and Fixtures Expense	20,694	15,039	26,960			
5014 Transformer Station Equipment - Operation Labour	477	13,279	5,868		13,279	5,868
5015 Transformer Station Equipment - Operation Supplies and Expense	72,412	51,367	60,874		51,367	60,874
5112 Maintenance of Transformer Station Equipment	22,325	65,898	21,117		65,898	21,117
5016 Distribution Station Equipment - Operation Labour	239					
5017 Distribution Station Equipment - Operation Supplies and Expenses	2,608	2,603	2,660	2,608	2,603	2,660
5110 Maintenance Buildings and Fixtures - Distribution Stations		17			17	
5114 Maintenance of Distribution Station Equipment	369	334		369	334	

1-SEC-1

[Ex.1] Please provide copies of all benchmarking studies, reports, and analyses that the Applicant has undertaken or participated in since its last rebasing application, that are not already included in the application.

Response:

Grimsby Power has provided all benchmarking analyses in the application with the exception of the CHEC Wage and Benefit Analysis (attached as Appendix 1 of 1-SEC-1). Grimsby Power does not partake in any other benchmarking studies outside of the PEG report. GPI uses the annual yearbook data to compare the utilities performance against other utilities. Typically GPI compares itself to other utilities in our region, utilities of the same size as well as utilities within the same PEG cohort. GPI compares distribution revenue, number of customers per FTE, SAIDI, SAIFI and OM&A per customer.

Grimsby Power has provided the 2020 comparison as Appendix 2 of 1-SEC-1.

Achievement through Collaboration

WAGE AND BENEFIT ANALYSIS:

2020

The following is CHEC's wage and benefit analysis for the year 2020. This analysis is to assist the CHEC group with personnel planning, recruitment, and compensation as well as aid in developing effective internal policies and procedures.

May 30, 2020

Cornerstone Hydro Electric Concepts Association Ltd.
www.checenergy.ca

Executive Summary:

This is the **fifth** CHEC analysis and report (previously reported in 2011, 2014, 2016, and 2018) on compensation trends for the CHEC LDC's. All CHEC LDC's were offered participation in this analysis and to date fourteen LDCs have fully participated (management and staff / union information provided), while one LDC has partially participated (union information only). This represents a 78% participation rate for the full analysis.

Confidentiality of Information:

All the information collected through this analysis has been treated with the utmost confidentiality. To preserve the confidentiality of data supplied by participating organizations, compensation details are only reported on an aggregate basis and where a minimum of four organizations are included in the sample to ensure confidentiality. In addition, every effort has been made to identify and remove anomalies within the data.

Analysis results are only being reported to those LDCs who participated and provided data for the report. All participants are asked to consider this report strictly confidential and are asked to not share the results with any entity that has not participated in the analysis.

Disclaimer:

This analysis has not been designed to cover every possible position in your organization. It is intended to cover the most common positions found in most LDCs across the CHEC group of LDCs. The selected positions are intended to be benchmarks only and should be treated accordingly.

Project Background:

The purpose of this report is to provide a general analysis to the participating CHEC LDC's that identifies information that is useful for decision making purposes. This analysis is primarily based on data provided to CHEC.

Cornerstone Hydro Electric Concept Association (CHEC) is an association of eighteen Local Distribution Companies (LDCs) that work collaboratively to meet regulatory and operational requirements. The LDC's covered under this analysis include:

CHEC MEMBERS	
Centre Wellington Hydro	ERTH Power
Fort Frances Power Corporation	Grimsby Power
InnPower	Lakefront Utilities
Lakeland Power	Niagara-on-the-lake Hydro
Orangeville Hydro	Ottawa River Power Corporation
Renfrew Hydro	Rideau St. Lawrence Distribution
Tillsonburg Hydro	Wasaga Distribution
Wellington North Power	

The major topics that make up the report are:

1. Board Analysis
2. Management Analysis
3. Staff / Union Analysis
4. Pension Analysis and
5. Conclusion

Wage Analysis (Board):

The participants were asked to indicate how Directors are compensated for participating on the Board. It was noted that Board compensation packages are comprised of diverse elements. The following summary provides an overview of some of the compensation elements for CHEC LDC Board members.

Remuneration:

Monetary remuneration is indicated as a High / Low range. Along with the low and high ranges is the group median. The group median is used in this report as unlike the group average, it is not affected by any single value being too high or too low and is therefore considered a better measure of the group mid-point.

Position	CHEC Low Range	CHEC High Range	CHEC Median
Chair	$4,000	$23,000	$7,947
Directors	$3,000	$20,000	$6,600

Per Diem Fees:

In addition to regular compensation, some Board Members are also compensated with a per diem rate ranging from $70 (low) to $400 (high). The per diem median rate is $250. Per Diem fees typically cover Board members expenses associated with attending board meetings.

Additional Expenses:

Over and above the per diem fees, a few of the LDC's also provide expense reimbursement for i.e. industry events, training/conferences, mileage, etc. Most of the LDC's that cover these expenditures reimburse for true costs, while others covered costs up to a set maximum per year.

Analysis (Management):

The respondents were asked to indicate how management is compensated within the LDC's. The compensation packages are comprised of diverse elements. The following summary provides an overview of the compensation elements for CHEC LDC Management.

Remuneration:

Monetary remuneration is indicated as a High / Low range. Along with the low and high ranges is the group median. The group median is used in this report as unlike the group average, it is not affected by any single value being too high or too low and is therefore considered a better measure of the group mid-point.

Position	CHEC Low Range	CHEC High Range	CHEC Median
President / CEO	$99,900	$232,300	$144,000
Administrative Assistant	$43,800	$79,000	$63,200
VP/CFO	$77,000	$150,000	$123,300
Controller/Treasurer	$70,000	$124,700	$92,400
Financial Analyst	$57,800	$108,700	$78,200
Finance Assistant	$52,400	$75,700	$59,600
VP/Director Operations	$83,000	$150,000	$127,600
Operations Manager	$80,600	$148,000	$103,400
Operations Supervisor	$65,400	$123,000	$95,800
Engineering Manager	$65,500	$127,700	$103,500
Distribution Engineer	$76,500	$100,000	$87,500
CS / Billing Manager	$68,100	$121,000	$91,200
CS / Billing Supervisor	$58,000	$108,700	$81,200
Regulatory Manager	$59,700	$107,000	$91,400
IS Systems Analyst	$55,000	$79,600	$57,900
HR Manager	$59,500	$107,000	$80,900
CDM Coordinator	$55,900	$85,200	$78,300

Benefits:

Benefit packages among the LDC's was comparable with no significant differences in the benefits received among the management group. Typical management level benefits reported are as follows:

Description	Benefit
Work Hours	35 – 40 hours
Overtime	Half of the participants offered some form of OT, ranging from time-in-lieu to double time
Paid Holidays	11 – 13 days per year – Includes all standard holidays
Floater Days	1 – 3 days per year
Vacation	Scaled – Most commonly starts at 2 weeks after 1 year with an additional week at approximately 3, 9, 17, and 25 years
Medical	Medical coverage is robust offering semi-private to private and prescription coverage, some form of vision and hearing aid assistance, along with some support for other professional services such as chiropractor, osteopath, podiatrist, massage therapist, naturopath, etc. See table below for low to high ranges.
Dental	Dental coverage is also robust, covering basic dental procedures and most plans providing additional coverage for major procedures and orthodontics
Life / AD&D	Typically, some form of life insurance and/or AD&D coverage is provided. Generally, 1.5 – 2 times base salary
Sick Days	In general, most employees accrue 1-1.5 days / month
ST – LT Disability	ST typically covers 100% for up to 3 months, LT covers 66 2/3% with a monthly maximum between $3,000 and $9,000
Pension	In addition to CPP, participation in OMERS is typically offered, employee contributions are matched by employer on a 1:1 basis
Bereavement	Typically, 1 – 5 days, depending on relationship to the deceased
Jury Duty	Typically, full pay less amount received from Jury Service

Notes: In some instances, there is enhanced coverage of benefits for executive level personnel.

A few of the CHEC LDCs have also indicated that they provide some assistance in other areas such as cell phones, home & auto insurance coverage, payment of professional association fees (i.e.: CPA / P.Eng.), educational assistance, and an annual clothing allowance. These benefits are not consistent among the group.

Medical	Low	Median	High
Naturopath / year	300	600	850
Chiropractic / year	300	600	850
Massage / year	300	600	850
Physiotherapist / year	500	600	5,000
Hearing Aids / 5 years	300	500	2,500
Vision / 2 years (not incl. eye exam)	350	450	550

Annual Increase in Salary:

The annual salary increase for all management positions was tracked and was estimated to be approximately 2.12% for 2019.

Analysis (Union Staff):

The respondents were asked to indicate how union staff is compensated among the LDC's. The compensation packages are comprised of diverse elements. The following summary provides an overview of the compensation elements for CHEC LDC Staff.

Remuneration:

Monetary remuneration is indicated as a High / Low range. Along with the low and high ranges is the group median. The group median is used in this report as unlike the group average, it is not affected by any single value being too high or too low and is therefore considered a better measure of the group mid-point.

Inside Staff	Low Range	High Range	CHEC Median
Accounting Clerk	$25.10	$38.30	$30.47
Regulatory Analyst	$24.39	$35.77	$30.75
Cashier	$16.37	$31.13	$24.75
Office / Billing Clerk	$19.51	$35.99	$28.86
Customer Service Rep.	$21.76	$39.59	$28.60
IT Analyst / Generalist	$28.62	$41.92	$33.78
Sr. Engineering Tech	$43.76	$49.46	$45.39
Engineering Tech	$25.45	$47.15	$37.72
GIS/CAD/Design Tech	$25.66	$39.79	$33.77

Outside Staff	Low Range	High Range	CHEC Median
Foreman	$35.27	$51.30	$45.20
Journey / Lineman	$22.33	$44.82	$34.25
Meter Technician	$20.74	$45.07	$34.33
Meter Reader	$17.54	$36.29	$24.03
Operations Coordinator	$28.02	$36.98	$33.13
Laborer/Grounds Person	$17.54	$31.56	$25.94

It should be noted that most union staff positions are based on a progressive scale and consider experience and seniority. The low range typically represents an entry level or apprentice position, while the high range typically represents a more senior individual or a fully qualified tradesperson.

Benefits:

Benefit packages among the LDC's was comparable with no significant differences in the benefits received among the unions between LDCs. Typical union level benefits reported are as follows:

Description	Benefit
Work Hours	35 – 40 hours
Overtime	Typically paid as double-time
On-Call	Typically, a minimum of 2 hours at double time – Average on-call pay is $263 / Week
Relief Pay	Generally paid at a rate of 105% - 112%
Paid Holidays	11 – 13 days per year – Includes all standard holidays
Floater Days	1 – 3 days per year
Vacation	Scaled – Most commonly starts at 2 weeks after 1 year with an additional week at approximately 3, 9, 17, and 25 years
Medical	Medical coverage is robust offering semi-private, private and prescription coverage, some form of vision and hearing aid assistance, along with some support for other professional services such as chiropractor, osteopath, podiatrist, massage therapist, naturopath, etc. See table below for low to high ranges.
Dental	Dental coverage is also robust covering most basic dental procedures with some plans providing additional coverage for major procedures and orthodontics
Life / AD&D	Typically, some form of life insurance and/or AD&D coverage is provided. Generally, 1.5 – 2 times base salary
Sick Days	In general, most employees accrue 1 – 1.5 days / month
ST – LT Disability	ST typically covers 100% for up to 3 months, LT covers 66 2/3 with a monthly maximum between $3,000 and $8,000
Pension	In addition to CPP, participation in OMERS is typically offered, employee contributions are matched by employer on a 1:1 basis
Bereavement	Typically, 1 – 5 days, depending on relationship to the deceased
Jury Duty	Typically, full pay less amount received from Jury Service
Meal Allowance	Typically, $16 / meal when applicable
Tools	Typically supplied by the LDC
Clothing	Typically, $288 per year for safety shoes, LDC typically supplies safety equipment and clothing or an allowance in lieu of clothing
Notes: A few of the CHEC LDCs have also indicated that they provide some assistance in other areas such as payment of professional association fees (i.e.: Trade License, OACETT), educational assistance, and payment of certain classes of driver's licenses. These benefits are not consistent among the group.	

Medical	Low	Median	High
Naturopath / year	300	500	850
Chiropractic / year	300	550	850
Massage / year	300	600	850
Physiotherapist / year	500	600	5,000
Custom Orthotics / year	133	350	600
Hearing Aids / 5 years	300	500	2,500
Vision / 2 years (not incl. eye exam)	350	450	550

Annual Increase in Salary:

The annual salary increase for all union positions was tracked and was estimated to be approximately 2.1% for 2019.

Analysis (Pension):

The respondents were asked to indicate how early retirees are compensated among the LDC's. The compensation packages are comprised of diverse elements. The following summary provides an overview of the common compensation elements for early retires among the CHEC group.

Benefits:

Other post-employment benefits (OPEBs) refer to the benefits, other than pensions, that an individual employee receives as part of his or her package of retirement benefits. Typically, retiree life insurance is the most significant OPEB offering, though other benefits such as medical and dental benefits are also covered under this umbrella term.

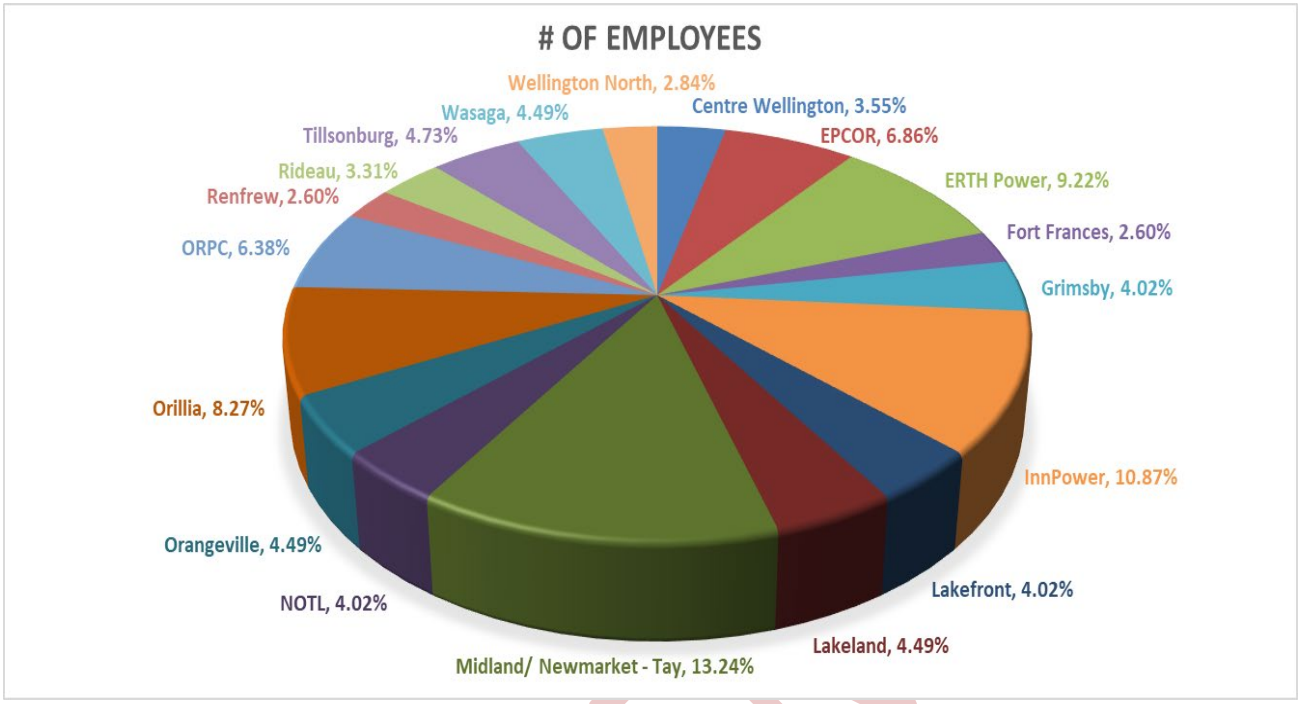
Description	Benefit
Early Retires	Typically covers the employee between the ages of 55 - 65
Pension Plan	OMERS
Other Post-Employment Benefits:	
Medical	Medical (Extended Health) coverage can be extended from retirement to the age of 65, employee typically pays 50% of the premium cost to age 65
Dental	Dental coverage can be extended from early retirement to the age of 65, employee typically pays 50% of the premium cost to age 65
AD&D	Not typically offered as a post retirement benefit
Life Insurance	Typically offered at a reduced rate of 50% of salary at retirement
Costs	Current OPEBs costs are estimated to be $6,500, per retiree, per year

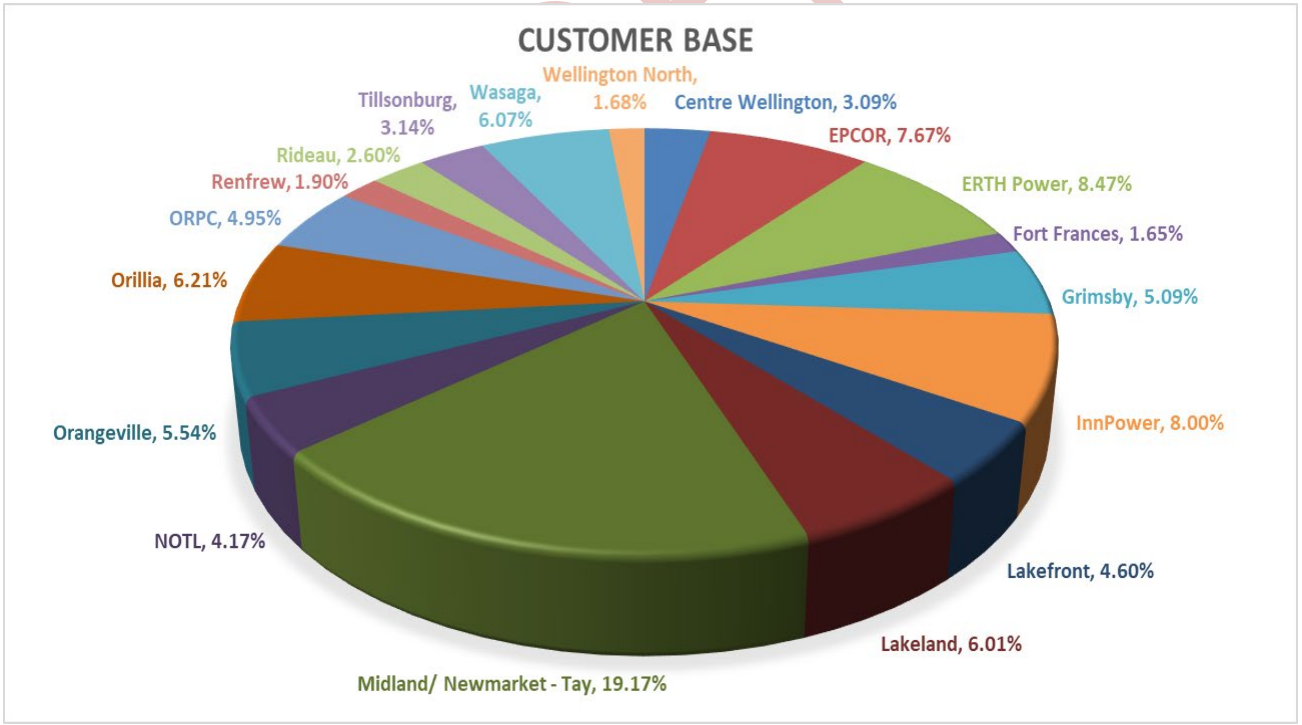
Other Post-Retirement Benefits are intended to bridge the gap between early retirement and the individual reaching the age of 65. After the age of 65, it is typically expected that various federal and provincial programs will replace OPEBs.

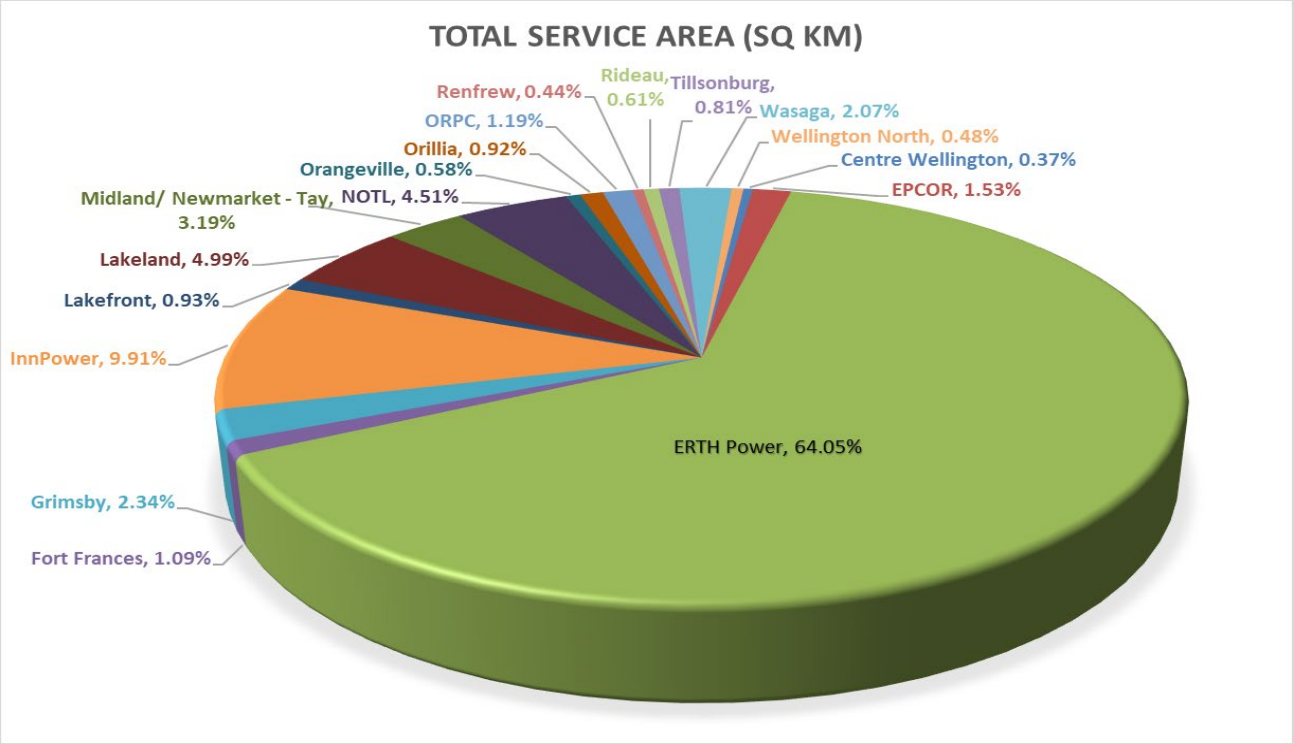
LDC Demographics:

The following is a brief comparison of demographics among the CHEC group. These demographics are provided so a basis comparison can be drawn between the number of employees in an LDC, the LDCs customer base, and the service area that those employees serve.

Utility	Employees (FTE)		Number of Customers		Service Area (Sq. km)	
Centre Wellington	15	3.55%	7,022	3.09%	11	0.37%
EPCOR	29	6.86%	17,408	7.67%	45	1.53%
ERTH Power	39	9.22%	19,238	8.47%	1,887	64.05%
Fort Frances	11	2.60%	3,745	1.65%	32	1.09%
Grimsby	17	4.02%	11,551	5.09%	69	2.34%
InnPower	46	10.87%	18,163	8.00%	292	9.91%
Lakefront	17	4.02%	10,450	4.60%	28	0.93%
Lakeland	19	4.49%	13,644	6.01%	147	4.99%
Midland/Newmarket-Tay	56	13.24%	43,524	19.17%	94	3.19%
Niagara-on-the-Lake	17	4.02%	9,461	4.17%	133	4.51%
Orangeville	19	4.49%	12,583	5.54%	17	0.58%
Orillia	35	8.27%	14,091	6.21%	27	0.92%
Ottawa River	27	6.38%	11,247	4.95%	35	1.19%
Renfrew	11	2.60%	4,312	1.90%	13	0.44%
Rideau	14	3.31%	5,909	2.60%	18	0.61%
Tillsonburg	20	4.73%	7,123	3.14%	24	0.81%
Wasaga	19	4.49%	13,789	6.07%	61	2.07%
Wellington North	12	2.84%	3,805	1.68%	14	0.48%
Total	**423**		**227,065**		**2,946**	
*The above information is from the 2018 OEB Yearbook and is as of December 31, 2018						


OF EMPLOYEES
Wellington North, 2.84%
Centre Wellington, 3.55%
Wasaga, 4.49%
EPCOR, 6.86%
Tillsonburg, 4.73%
ERTH Power, 9.22%
Rideau, 3.31%
Fort Frances, 2.60%
Renfrew, 2.60%
Grimsby, 4.02%
ORPC, 6.38%
Orillia, 8.27%
InnPower, 10.87%
Orangeville, 4.49%
Lakefront, 4.02%
NOTL, 4.02%
Lakeland, 4.49%
Midland/ Newmarket - Tay, 13.24%


CUSTOMER BASE
Wellington North, 1.68%
Tillsonburg, 3.14%
Wasaga, 6.07%
Centre Wellington, 3.09%
EPCOR, 7.67%
Rideau, 2.60%
Renfrew, 1.90%
ERTH Power, 8.47%
ORPC, 4.95%
Fort Frances, 1.65%
Orillia, 6.21%
Grimsby, 5.09%
InnPower, 8.00%
Orangeville, 5.54%
NOTL, 4.17%
Lakefront, 4.60%
Lakeland, 6.01%
Midland/ Newmarket - Tay, 19.17%



Conclusions:

As mentioned in the 2018 Wage & Benefit analysis, human resources (HR) issues commonly experienced by employers included leveraging digital technologies, managing a multigenerational workforce, employee wellness, company culture, and employee Feedback. While these issues are still valid today, when looking specifically at the utility industry, a more imminent threat is competition from the larger utilities (i.e. Alectra and Hydro One). The above wage and benefit analysis show that CHEC member LDCs are currently competitive among the group; however, larger utilities can generally offer more and often end up attracting staff from the smaller utilities.

CHEC members need to be mindful of how the larger competitors are compensating their employees so that they can remain competitive in the market, attract talent, and retain their skilled and knowledgeable staff. Therefore, later this year, CHEC will be releasing part two of the wage and benefit analysis to encompass a comprehensive analysis of the other LDC union packages (i.e. wages, benefits, etc.) to enhance the overall value of the above information, and provide a comparative basis to the entire Ontario utility sector.

LDCs must bridge the gap between the utility industry standards and their salary packages. They cannot provide compensation packages that are either less than the industry standards or are higher than current market rates.

Appendices (Position Descriptions):

The position descriptions are currently under review. We are working with the Finance Steering Committee to determine if these are relevant and required going forward. Once updated, we will be posting to the member portal so all will have access

	OM&A per Customer ($)	Customers per Employee	SAIDI	SAIFI	Total Customers	**Res Distribution Revenue per Customer ($)**	**Small Commercial Distribution Revenue per Customer ($)**	**Large Commercial Distribution Revenue per Customer ($)**
London Hydro Inc.	250.58	535.12	0.86	1.05	162,140.00	299.81	747.78	9,686.21
Elexicon Energy Inc.	257.53	687.72	2.22	1.17	169,489.00	338.19	793.62	10,691.50
Hydro Ottawa Limited	241.99	596.53	1.41	0.78	346,347.00	334.74	931.38	15,954.43
Toronto Hydro-Electric System Limited	369.87	544.28	1.03	1.50	779,176.00	475.46	1,480.05	24,731.61
Alectra Utilities Corporation	260.94	725.54	1.09	1.28	1,062,040.00	319.04	931.58	12,380.48
Hydro One Networks Inc.	416.84	305.80	13.54	3.08	1,361,102.00	905.57	1,768.82	20,346.81
Average	**299.63**	**565.83**	**3.36**	**1.48**	**646,715.67**	**445.47**	**1,108.87**	**15,631.84**
Grimsby Power Incorporated	**307.15**	**794.29**	**0.64**	**0.92**	**11,684.00**	**349.94**	**797.83**	**7,274.09**

Six Largest by Customer Count (Over 100,000)

	OM&A per Customer ($)	Customers per Employee	SAIDI	SAIFI	Total Customers	**Res Distribution Revenue per Customer ($)**	**Small Commercial Distribution Revenue per Customer ($)**	**Large Commercial Distribution Revenue per Customer ($)**
Cooperative Hydro Embrun Inc.	307.52	-	0.03	0.01	2,409.00	436.63	691.53	5,892.89
E.L.K. Energy Inc.	195.62	900.79	3.32	1.14	12,611.00	218.75	308.63	4,050.44
Halton Hills Hydro Inc.	297.91	460.49	2.81	2.09	22,564.00	341.15	674.06	10,889.06
Hearst Power Distribution Company Limited	409.28	379.86	3.25	1.24	2,659.00	299.04	396.15	6,316.61
Hydro Hawkesbury Inc.	210.59	1,094.80	5.63	2.66	5,474.00	223.34	403.59	5,260.82
Northern Ontario Wires Inc.	466.09	1,694.00	5.59	1.26	5,929.00	458.03	836.30	4,199.95
Wasaga Distribution Inc.	248.22	664.40	5.46	3.36	14,238.00	281.24	509.06	7,851.41
Welland Hydro-Electric System Corp.	284.35	670.21	2.36	2.02	24,054.00	328.69	625.11	9,924.24
Average	**302.45**	**733.07**	**3.56**	**1.72**	**11,242.25**	**323.36**	**555.55**	**6,798.18**
Grimsby Power Incorporated	**307.15**	**794.29**	**0.64**	**0.92**	**11,684.00**	**349.94**	**797.83**	**7,274.09**

Group 1 Cohort

	OM&A per Customer ($)	Customers per Employee	SAIDI	SAIFI	Total Customers	**Res Distribution Revenue per Customer ($)**	**Small Commercial Distribution Revenue per Customer ($)**	**Large Commercial Distribution Revenue per Customer ($)**
Lakefront Utilities Inc.	258.28	611.09	4.67	1.53	10,639.00	270.10	561.02	11,196.39
Ottawa River Power Corporation	301.54	-	0.56	0.53	11,442.00	298.30	560.70	6,236.71
Grimsby Power Incorporated	307.15	794.29	0.64	0.92	11,684.00	349.94	797.83	7,274.09
Algoma Power Inc.	1,113.41	205.49	6.79	2.93	12,124.00	1,682.68	-	111,398.87
E.L.K. Energy Inc.	195.62	900.79	3.32	1.14	12,611.00	218.75	308.63	4,050.44
Orangeville Hydro Limited	255.49	636.76	1.01	0.75	12,697.00	329.33	728.48	6,745.75
Lakeland Power Distribution Ltd.	389.56	726.59	5.79	1.40	13,936.00	412.53	756.07	7,985.10
Wasaga Distribution Inc.	248.22	664.40	5.46	3.36	14,238.00	281.24	509.06	7,851.41
Orillia Power Distribution Corporation	430.05	373.13	1.13	0.82	14,552.00	366.93	1,018.92	11,485.42
EPCOR Electricity Distribution Ontario Inc.	339.18	616.22	1.46	0.91	18,203.00	309.99	586.54	8,625.25
Innpower Corporation	**383.85**	**552.87**	**3.08**	**1.43**	**13,212.60**	**451.98**	**647.47**	**18,284.94**

Grimsby Power Incorporated	**307.15**	**794.29**	**0.64**	**0.92**	**11,684.00**	**349.94**	**797.83**	**7,274.09**

Utilities 10,000 - 20,000 Customers

	OM&A per Customer ($)	Customers per Employee	SAIDI	SAIFI	Total Customers	**Res Distribution Revenue per Customer ($)**	**Small Commercial Distribution Revenue per Customer ($)**	**Large Commercial Distribution Revenue per Customer ($)**
Niagara Peninsula Energy Inc.	332.41	-	2.15	2.01	56,973.00	406.31	848.96	7,530.66
Welland Hydro-Electric System Corp.	284.35	670.21	2.36	2.02	24,054.00	328.69	625.11	9,924.24
Canadian Niagara Power Inc.	323.46	341.59	5.07	2.71	29,718.00	445.18	1,135.03	20,060.78
Niagara-on-the-Lake Hydro Inc.	312.01	586.24	0.73	0.52	9,632.00	370.69	953.30	11,242.61
Hydro One Networks Inc.	416.84	305.80	13.54	3.08	1,361,102.00	905.57	1,768.82	20,346.81
Alectra Utilities Corporation	260.94	725.54	1.09	1.28	1,062,040.00	319.04	931.58	12,380.48
Average	**321.67**	**438.23**	**4.16**	**1.94**	**423,919.83**	**462.58**	**1,043.80**	**13,580.93**
Grimsby Power Incorporated	**307.15**	**794.29**	**0.64**	**0.92**	**11,684.00**	**349.94**	**797.83**	**7,274.09**

Niagara Region Utilities

1-SEC-2

[Ex.1] Please provide a copy of all documents that were provided to the Board of Directors in approving the underlying budgets contained in the Business Plan and this Application.

Response:

During the March 2021 meeting presentation, attached as Appendix 1 of 1-SEC-2, was provided to the GPI Board of Directors.

The presentation is based on the 2022 Budget and Business Plan. Following the review of the Cost of Service Summary the GPI Board approved GPI to proceed with the Cost of Service Application.

Agenda Item 6
Cost of Service – Summary

GPI Company Performance – How did we do in 2020?

In the last Five years – when measured against GPI corporate goals, the company has performed well in targeted areas that align with the GPI vision and mission.

GPI Company Performance – How did we do in 2020?

During a year of uncertainties Grimsby Power worked diligently and made improvements in key performance indices. We had to limit Capital Project investments, due to COVID-19 issues and with numerous delays with the construction of the 3rd Feeder – by NPEI

- These GPI company performance results align closely with the objective of **maximizing shareholder value** and keeping rates as low as possible for the Grimsby community without sacrificing customer satisfaction and safety.

- The ability of the **GPI management team to maximize the productivity of the resources** is reflected in GPI Regulated – Return on Equity (ROE) – over the last 5 years.

  - 2016 = 2.39%
  - 2017 = 10.92%
  - 2018 = 8.48%
  - 2019 = 10.02%
  - *2020 = 7.66% (preliminary Estimate)*

GPI Company Performance – in 2020

- In the 2020 Ontario Energy Board PEG (Pacific Economics Group) Cost Efficiency Ratings Study, GPI was rated in the top grouping (i.e. Group-1). Out of the 59 LDCs in Ontario, Group-1 represents the top 7 utilities or the top 12% in the province from an efficiency perspective.

OEB Cost Efficiency

In 2020 Grimsby Power earned the highest efficiency rating amongst all surrounding utilities and moved to Group 1.

GPI's 2015 actual costs were 17% below predicted
GPI's 2019 actual costs were 31.8% below predicted
An overall efficiency gain of 14.8% in 5 years

With the highest efficiency rating Grimsby Power received the full 2.2% increase in distribution rates for 2021.

Ontario Energy Board (OEB) – Cost Efficiency Ratings (PEG report)*

Ratings among all of the 59 Utilities in the Province

Grimsby Power is in Group 1

Grimsby Power

Welland

Alectra,
Niagara On the Lake,
Niagara Peninsula
Energy

CNP
Hydro One

Toronto Hydro

* Pacific Economics Group (PEG)

GPI Company Performance

SAIDI & SAIFI – in 2020

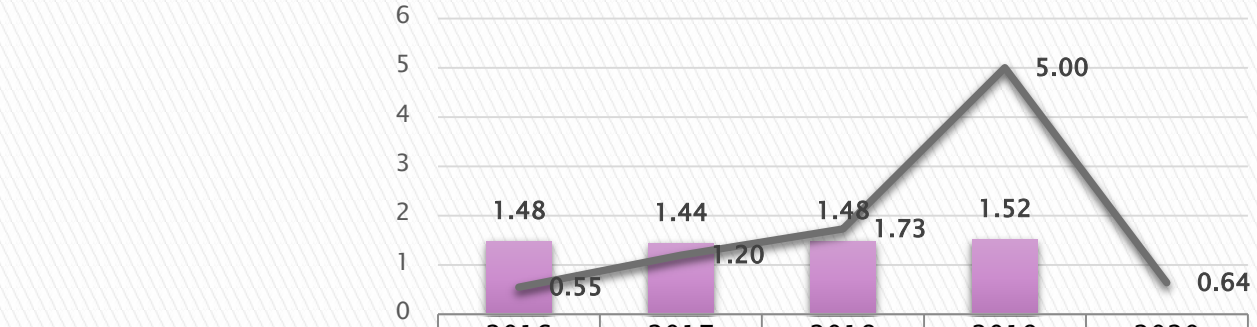
In 2019 GPI's SAIDI was 5.00 and SAIFI was 3.44.
In 2020 GPI's SAIDI was 0.64 and SAIFI was 0.92.

Continued maintenance and capital work drove down the duration of outages and less severe weather and increased maintenance reduced the frequency of outages.

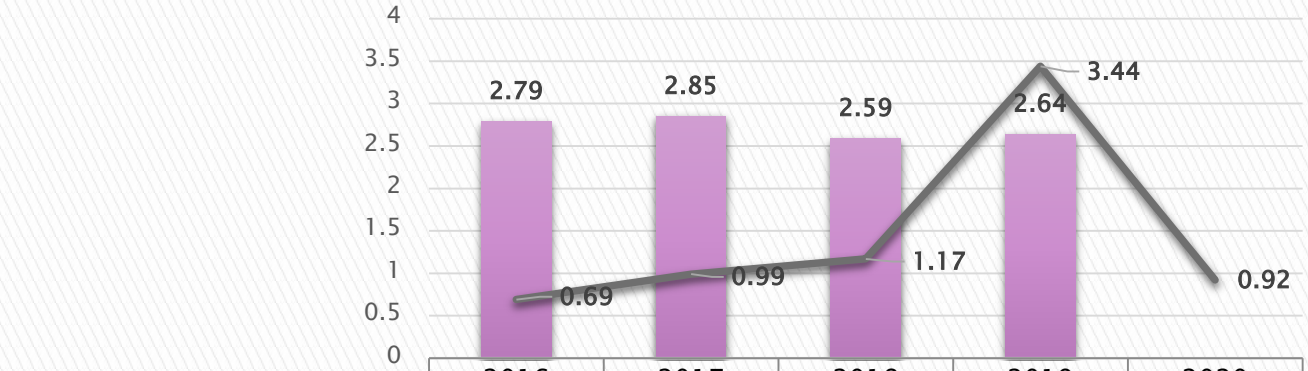
- The number of interruptions down 13% (108 to 94)
- The total number of hours of interruption are down 87% from 58,408 to 7,521 hours
- The total number of customers affected by outages is also down by 73% from 40,216 to 10,887
- In 2020 weather related events was a main contributor to outages. Over half of the total hours of interruption (4,209.80 of 7,521) and total number of customers (5,488 of 10,887) affected by outages was caused by weather.

Reliability and Restoration of Power

Outage Indices 2016-2020



	2016	2017	2018	2019	2020
Frequency Industry Average	1.48	1.44	1.48	1.52	
Frequency Grimsby Power	0.55	1.20	1.73	5.00	0.64



	2016	2017	2018	2019	2020
Duration Industry Average	2.79	2.85	2.59	2.64	
Duration Grimsby Power	0.69	0.99	1.17	3.44	0.92

2020 ADDITIONS

Description	Values	
	2020 Budget	2020 Actual
Allocation	126,550	87,549
Labour Allocation	126,550	87,549
System Access	978,075	652,234
Assumed Plant	207,780	267,031
Program - Modifications to Existing Customer Connections	69,572	135,096
Program - Transformer Station - Modifications to Support Renewable Generation	111,520	
Project - Residential Subdivision Development	271,331	15,593
Project - New Customer Connections	317,872	234,513
System Renewal	570,392	586,104
Program - Replace Defective Poles (50)	203,874	251,174
Project - Metrolinx - Pole Line Relocation Due to Road Widening at Casablanca Blvd & Livingston Ave	135,694	
Inventory - Niagara West MTS - Spare Inventory	38,500	11,705
Program - Replace Gang Operated Load Break Switch (1)	27,697	-
Program - Replace Sectionalizing Terminal (1)	15,285	31,695
Program - Replace 1 PH Pad Mounted Transformers (5)	28,625	56,740
Program - Primary Cable Testing	40,505	38,815
Program - Replace 3 PH Pad Mounted Transformer (1)	16,053	-
Project - CNR Pole Line - Phase 1 - Design Only		20,557
Project - Secondary Bus Refurbishment - Lakeside / Diana	64,160	175,417
System Service	1,221,394	361,094
Project - Third Feeder from NW-MTS	1,221,394	36,927
Program - Voltage Conversion - Kingsway Blvd		57,182
Program Voltage Conversion Centennial Park		5,000
Project Monitoring and Control Fault Indicator SCADA		82,271
Program - Rear Lot Conversion - Governors Road - Design Only		12,760
Project - Primary OH Conductor Reinforcement		166,954
Distribution Assets Total	2,896,411	1,686,981
General Plant Total	172,183	277,564
Total Additions	3,068,593	1,964,545
Contributed Capital	(651,134)	(461,764)
	2,417,459	1,502,780

GPI Company Performance – in 2020

- From a safety perspective, since 2008 GPI employees have worked **408,858 hours without a lost time incident**.

- A great achievement for all of us at GPI.

2021 Cost of Service Deferral

In 2020 Grimsby Power elected to defer the Cost of Service application for one year.

At that time:

- January 2021 would be too early for Rate Change as the customers both residential and commercial may only be recovering from the effect of COVID 19 and may **not be in a financial position to deal with an increase in rates.**
- GPI believed that deferring the rate rebasing application to the 2022 rate year is necessary during this unprecedented time to **support its customers**.
- Deferral to the 2022 rate year will allow Grimsby Power to better forecast and thus to better support the approvals being sought in GPI's next Cost of Service submission.

Now:

- By January 2022 the economy will be starting to rebound after nearly two years of restrictions due to public health concerns.
- With constant reductions in RPP rates, programs offered by the Ontario government, reduced interest and flexible payment arrangements, GPI continued to support its customers.
- Through the pandemic GPI saw a small reduction in revenue due to lost load from small and large commercial customers while revenue from residential customers remained stable.

2022 Cost of Service Implications

- A cost of service (CoS) application allows utilities to start from the ground up and rebuild rates that include the current and future capital spending, renewed OM&A amounts and a revised load forecast.

- To date the models indicate:
  - approximately **$850,077** additional distribution revenue compared to IR;
  - that would cover approximately **$3,997,248** in OM&A;
  - a regulated return on equity of **8.48%**,
  - long term interest of **2.675%,**
  - short term interest rate of **2.03%**.

- Through every cost of service application the interrogatory and settlement process works to drive down OM&A and capital expenditure. The following slide shows a comparative Income Statement and demonstrates possible scenario's and their impact on distribution revenue.

Income Statement & Scenario Analysis

Income Statement	2016 COS	2016 Actual ($)	2017 Actual ($)	2018 Actual ($)	2019 Actual ($)	2020 Draft ($)	2021 Budget ($)	2022 Budget IR ($)	2022 Budget COS ($)	Difference 2022 IR to 2022 COS ($)	Difference 2022 IR to 2022 CoS (%)
Revenue											
Sales of Electricity	$24,184,718	$22,653,104	$23,389,681	$24,586,591	$27,229,797	$33,899,106	$34,323,828	$27,273,837	$27,273,837	$ -	0.00%
Revenue from Services	5,252,850	4,983,035	5,334,264	5,473,273	5,517,717	5,801,959	5,824,496	5,938,718	6,788,795	$ 850,077	14.31%
Other Operating Income	359,385	340,195	364,537	373,397	384,945	356,518	382,822	409,226	232,891	$ (176,335)	-43.09%
Other Income/Deductions	55,600	64,019	34,493	165,918	41,724	(10,992)	32,000	8,200	8,200	$ -	0.00%
Total Revenue	29,852,552	28,040,353	29,122,974	30,599,178	33,174,183	40,046,591	40,563,146	33,629,981	34,303,723	$ 673,742	1.29%
Expenses											
Distribution Expenses - Operations	699,287	786,475	800,624	876,797	831,139	938,714	940,797	929,860	929,860	$ -	0.00%
Distribution Expenses - Maintenance	587,574	661,048	497,770	624,703	640,714	644,984	534,030	628,908	628,908	$ -	0.00%
Administrative & General Expenses	1,342,211	1,491,749	1,203,740	1,188,902	1,252,454	1,416,139	1,402,262	1,718,928	1,718,928	$ -	0.00%
Billing & Collecting	533,068	581,818	579,832	732,153	476,547	572,363	658,576	719,553	719,553	$ -	0.00%
Total Controllable Expense	3,162,140	3,521,089	3,081,966	3,422,556	3,200,855	3,572,199	3,535,665	3,997,248	3,997,248	-	0.00%
Power Supply Expenses	24,184,718	22,653,104	23,389,681	24,586,591	27,229,797	33,899,106	34,323,828	27,273,837	27,273,837	$ -	0.00%
Amortization Expenses	1,111,877	1,081,719	1,108,916	1,120,220	1,153,414	1,205,929	1,264,638	1,320,933	1,194,251	$ (126,682)	-9.59%
Interest Expenses	446,546	488,310	469,909	481,927	478,974	480,094	471,659	457,429	359,700	$ (97,728)	-21.36%
Taxes	36,311	(142,785)	114,522	195,428	(17,782)	243,736	254,866	156,655	162,333	$ 5,679	3.63%
Other Deductions	7,528	10,275	6,850	8,281	4,441	3,000	5,596	3,914	3,914	$ -	0.00%
Total Expense	28,949,119	27,611,712	28,171,844	29,815,002	32,049,699	39,404,064	39,856,253	33,210,015	32,991,284	$ (218,732)	-0.66%
Net Income	**$ 903,433**	**$ 428,641**	**$ 951,131**	**$ 784,176**	**$ 1,124,484**	**$ 642,527**	**706,893**	**419,965**	**1,312,439**	**$ 892,474**	212.51%

Income Statement & Scenario Analysis

Capital Investment	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Draft Actual	2021 Budget	2022 Budget
Distribution Capital	$ 862,427	$ 1,866,410	$ 1,397,695	$ 2,029,403	$ 1,686,981	$ 2,366,689	$ 2,835,838
General Capital	570,235	326,199	507,048	381,528	277,564	216,040	101,063
Contributions & Grants Credit	(304,022)	(723,784)	(363,406)	(214,248)	(461,764)	(344,613)	(423,426)
Total	**$ 1,128,640**	**$ 1,468,825**	**$ 1,541,337**	**$ 2,196,683**	**$ 1,502,780**	**$ 2,238,116**	**$ 2,513,475**

Revenue Requirement and Scenario Analysis

Scenario		Inputs						Revenues		
		OM&A	Capital Additions	2022 I-Factor	Return on LT Debt %	Return on ST Debt %	Return on Equity %	Annual IR Revenues	2022 COS Revenues	Difference (Increase with COS)
		+/- %	+/- %							
	Input Values	0.0%	0.0%	2.20%	2.68%	2.03%	8.48%			
	Base Case	3,997,248	2,513,465	2.20%	2.68%	2.03%	8.48%	5,938,718	6,788,795	**850,077**

	#	Scenario	OM&A	Capital Additions	2022 I-Factor	Return on LT Debt %	Return on ST Debt %	Return on Equity %	Annual IR Revenues	COS Revenues	Difference (Increase with COS)	Scenario vs. Base Case Amount	%
2022 Revenues	**1**	**Base Case**	**3,997,248**	**2,513,465**	**2.2%**	**2.68%**	**2.03%**	**8.48%**	**5,938,718**	**6,788,795**	**850,077**		
	2	-5% OM&A	3,723,975	2,513,465	1.8%	2.68%	2.03%	8.48%	5,938,718	6,590,787	**652,069**	(198,009)	-23.3%
	3	-5% Capital Additions	3,917,248	2,387,792	1.8%	2.68%	2.03%	8.48%	5,938,718	6,783,943	**845,225**	(4,852)	-0.7%
	4a	I-Factor +20bp (2.0%)	3,917,248	2,513,465	2.0%	2.68%	2.03%	8.48%	5,955,970	6,788,795	**832,826**	(17,252)	-2.0%
	4b	I-Factor -20bp (1.6%)	3,917,248	2,513,465	1.6%	2.68%	2.03%	8.48%	5,932,475	6,788,795	**856,321**	6,243	0.7%
	5a	ROE +10bp (8.58%)	3,917,248	2,513,465	1.8%	2.68%	2.03%	8.58%	5,938,718	6,800,305	**861,587**	11,509	1.3%
	5b	STD % LTD +10bp (2.13%)	3,917,248	2,513,465	1.8%	2.78%	2.13%	8.48%	5,938,718	6,806,823	**868,105**	18,028	2.1%

Scenario Analysis

- The largest impact on distribution revenue in a CoS is a reduction in OM&A.
  - A 5% reduction in OM&A drives down revenue by 23%
  - All other scenarios change revenue is +/- 2%
- Changes to Capital and Cost of Power impact rate base and the working capital allowance built into rates. The current COS figures is based on the regulated rate of return of 4.971%
- *(LT 2.675% x 56%)+(ST 2.03% x 4%)+(ROE 8.48% x 40%) = 4.971%*
- With current rates for every dollar change there is a $0.00373 impact on distribution revenue.
- *(OEB – Working Capital Allowance 7.5% x 4.971%)= $0.00373*

Other Impacts

- Disposition of Group 2 Regulatory Accounts
  - Only during a CoS can a utility dispose of balances in Group 2 accounts
  - GPI has $127,276 that can be recovered from customers
- Alignment of Low Voltage Revenue to Costs
  - With rising costs from Hydro One GPI is holding approximately $230,000 per year as a low voltage regulatory balance.
  - A CoS will allow GPI to better align current costs with revenue and reduce the regulatory balance.

Other Impacts Continued

- Deemed Interest
  - With estimated debt rates approximately $455,831 of deemed interest would be included in rates.
  - The promissory note interest would change to approximately 2.85% and reduce the annual payment by approximately $97,728 from $262,537 to $164,808.
  - Actual interest paid in 2022 would be approximately $332,720, leaving $97,728 to be spent elsewhere.
- The other impacts from a CoS, as indicated above, would free up approximately $457k in cash flow.

1-SEC-3

[Ex.1; EB-2015-0072 Decision, p.7] In the EB-2015-0072 Decision, the Board noted that "During the oral hearing, Mr. Curtiss expressed Grimsby Power's intention to search for productivity improvements and bring them "front and center" over the next 5 years. The OEB supports this commitment and will continue to monitor the OM&A per customer and related productivity measures". Please provide details of all productivity and efficiency measures the Applicant has undertaken since its last rebasing application in 2016. Please quantify the savings and explain how they were calculated.

Response:

Please refer to 1-Staff-6.

1-SEC-4

[Ex.1] Please provide details of all productivity and efficiency measures the Applicant plans to undertake in the test year. Please quantify the savings and explain how they were calculated.

Response:

Please refer to 1-Staff-6.

1-SEC-5

[Ex.1, Tab 3, Attachment 1, p.23] Please provide a revised version of Table 7 that includes 2021 year-to-date actuals, as well as at the same point in time in the year, both 2019 and 2020 year-to-actuals.

Response:

Table 7: Operating Expenses as of August 31:

	2019 YTD August	2020 YTD August	2021 YTD August
Operations	$ 538,593	$ 629,331	$ 607,012
Maintenance	$ 409,831	$ 443,393	$ 374,915
SubTotal	**$ 948,424**	**$ 1,072,724**	**$ 981,928**
%Change (year over year)	-5.1%	13.1%	-8.5%
Billing and Collecting	$ 382,894	$ 350,944	$ 371,529
Community Relations			
Administrative and General	$ 732,922	$ 764,838	$ 951,213
SubTotal	**$ 1,115,816**	**$ 1,115,782**	**$ 1,322,742**
%Change (year over year)	-3.2%	0.0%	18.5%
Total	**$ 2,064,240**	**$ 2,188,506**	**$ 2,304,670**
%Change (year over year)	-4.1%	6.0%	5.3%

1-SEC-6

[Ex.1, Tab 6, p.17] Please update Tables 1-11 to 1-14 for the 2020 OEB Scorecard information released on September 10, 2021.

Response:

Tables 1-11 to 1-14 have been updated with the 2020 OEB Scorecard information released September 10, 2021 and October 22, 2021.

Table 1-11: OEB 2020 Scorecard - Geographical Benchmarking Cohort

Distributor	New Services Connected on Time (Target: 90%)	Scheduled Appointments Met on Time (Target: 90%)	Telephone Calls Answered on Time (Target: 65%)	Billing Accuracy (Target: 98%)	SAIFI	SAIDI	Efficiency Assessment	$/Customer	$/Km of Line	ROE: Deemed	ROE: Achieved
Grimsby Power Incorporated	100	100	89.38	99.99	0.92	0.64	1	598	10,121	9.19	8.12
Canadian Niagara Power Inc.	94.91	100	79.79	99.95	2.71	5.07	4	868	16,581	8.78	5.00
Niagara Peninsula Energy Inc.	85.94	100	82.84	99.06	2.01	2.15	3	758	13,139	9.30	4.74
Niagara-on-the-Lake Hydro Inc.	99.21	100	95.61	99.87	0.52	0.73	3	750	19,566	8.98	7.80
Welland Hydro-Electric System Corp.	94.52	98.28	86.15	99.99	2.02	2.36	1	494	24,038	8.78	9.36

Table 1-12: OEB 2020 Scorecard - Similar Size Utility Benchmarking Cohort

Distributor	New Services Connected on Time (Target: 90%)	Scheduled Appointments Met on Time (Target: 90%)	Telephone Calls Answered on Time (Target: 65%)	Billing Accuracy (Target: 98%)	SAIFI	SAIDI	Efficiency Assessment	$/Customer	$/Km of Line	ROE: Deemed	ROE: Achieved
Grimsby Power Incorporated	100	100	89.38	99.99	0.92	0.64	1	598	10,121	9.19	8.12
Algoma Power Inc.	100	100	84.84	99.87	2.93	6.79	5	2,212	12,203	8.52	9.25
ERTH Power Corporation	98.59	100	95.92	99.75	0.29	0.78	3	680	36,142	9.00	8.35
Lakefront Utilities Inc.	91.17	100	82.27	99.79	1.53	4.67	2	500	24,061	8.78	5.49
Lakeland Power Distribution Ltd.	100	100	89.9	99.92	1.4	5.79	2	718	28,361	8.98	6.07
Niagara-on-the-Lake Hydro Inc.	99.21	100	95.61	99.87	0.52	0.73	3	750	19,566	8.98	7.80
Orangeville Hydro Limited	100	100	99.11	99.84	0.75	1.01	2	535	30,612	9.36	11.83
Orillia Power Distribution Corporation	100	100	98.64	99.99	0.82	1.13	3	725	43,062	9.85	2.77
Ottawa River Power Corporation	100	98.29	97.63	99.97	0.53	0.56	2	520	11,673	9.19	9.61
Tillsonburg Hydro Inc.	100	99.36	—	99.8	1.02	1.69	3	695	40,648	8.98	2.42
Wasaga Distribution Inc.	100	100	99.97	99.95	3.36	5.46	1	459	22,464	9.19	6.72

Table 1-13: OEB 2020 Yearbook - Geographical Benchmarking Cohort

Unitized & Other Statistics For the Year Ended December 31, 2020	Grimsby Power Incorporated	Canadian Niagara Power Inc.	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Welland Hydro-Electric System Corp.
OM&A per Customer ($)	307.15	323.46	332.41	312.01	284.35
Net PP&E per Customer ($)	2,556.05	4,207.53	2,685.38	3,721.43	1,419.45
Monthly Residential Service Charge 2020 ($)	28.75	36.76	33.67	29.41	28.82

Table 1-14: OEB 2020 Yearbook - Similar Size Utility Benchmarking Cohort

Unitized & Other Statistics For the Year Ended December 31, 2020	Grimsby Power Incorporated	Algoma Power Inc.	ERTH Power Corporation	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	Niagara-on-the-Lake Hydro Inc.	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Ottawa River Power Corporation	Tillsonburg Hydro Inc.	Wasaga Distribution Inc.
OM&A per Customer ($)	307.15	1,113.41	315.41	258.28	389.56	312.01	255.49	430.05	301.54	368.29	248.22
Net PP&E per Customer ($)	2,556.05	9,887.60	2,853.42	1,919.28	2,619.62	3,721.43	1,715.87	2,447.84	1,053.10	2,268.24	1,034.72
Monthly Residential Service Charge 2020 ($)	28.75	46.72	34.08	23.20	34.72	29.41	27.11	27.93	24.14	28.58	23.41

1–VECC-1

Reference: Exhibit 1, Tab 3, page 19

a) Please update the tables Total Cost per Customer and Total Cost per Km of Line to include 2020 results.

Response:

a) The tables below have been updated accordingly.

Performance Outcomes	Performance Categories	Measures	2016	2017	2018	2019	2020
Operational Effectiveness	Cost Control	Total Cost per Customer	$611	$559	$584	$594	$598

Performance Outcomes	Performance Categories	Measures	2016	2017	2018	2019	2020
Operational Effectiveness	Cost Control	Total Cost per Km of Line	$27,753	$9,383	$9,793	$10,029	$10,121

1–VECC-2

Reference: Exhibit 1, Tab 3, page 26

Table 1-5: OEB 2019 Scorecard – Geographical Benchmarking Cohort

Distributor	New Services Connected on Time (Target: 90%)	Scheduled Appointments Met on Time (Target: 90%)	Telephone Calls Answered on Time (Target: 65%)	Billing Accuracy (Tar: 98%)	SAIFI	SAIDI	Efficiency Assessment	$/Customer	$/Km of Line	ROE: Deemed	ROE: Achieved
Grimsby Power Incorporated	100.00%	100.00%	90.24%	100	3.44	5	1	594	10,029	9.19%	10.39%
Canadian Niagara Power Inc.	93.27%	100.00%	79.73%	100	2.00	3.01	4	893	16,421	8.78%	5.84%
Niagara Peninsula Energy Inc.	93.57%	99.50%	84.67%	99	1.63	2.03	3	786	13,712	9.30%	4.73%
Niagara-on-the-Lake Hydro Inc.	100.00%	100.00%	86.80%	100	0.38	0.5	3	758	19,676	8.98%	14.38%
Welland Hydro-Electric System Corp.	94.82%	93.16%	88.90%	100	2.41	1.71	2	512	24,714	8.78%	10.44%

a) GPI's SAIDI and SAFI results are significantly worse than surrounding utilities who presumably face similar weather incidents. What are the reasons for this? Specifically, has GPI compared its outages due to equipment failure to these surrounding utilities? If so please provide those results.

Response:

a) SAIDI and SAIFI results for 2019 were impacted for Grimsby Power mostly due to major adverse weather-related events. By excluding 2019 adverse weather statistic, which represented 80% of the SAIFI and 72% of the SAIDI, SAIFI would have been 0.69 and SAIDI would have been 1.39.

Weather events are inconsistent and their impacts may vary from utility to utility. There are many times when adverse weather intensity, and therefore impacts on the distribution system, vary and outcomes on system reliability are very much different from a utility to utility (i.e. there are many times when our immediate surrounding area around Town of Grimsby, which is in NPEI's service territory, is out of power and yet we have power and vice versa due to these inconsistencies on the impact of the adverse weather conditions). It is important to note that when looking at the historical period (2016-2020) Grimsby Power has very positive average SAIDI and SAIFI statistics compared to those of surrounding utilities (please see Table below).

SAIFI Avg. outage frequency (interruptions / customer) - Loss of Supply Adjusted										
	2016	**Rank**	**2017**	**Rank**	**2018**	**Rank**	**2019**	**Rank**	**2020**	**Rank**
Grimsby Power Incorporated	0.69	1	0.99	2	1.17	2	3.44	5	0.92	2
Canadian Niagara Power Inc.	2.29	5	2.33	5	2.73	5	3.08	4	2.71	5
Niagara Peninsula Energy Inc.	1.38	4	1.55	3	1.65	3	1.63	2	2.01	3
Niagara-on-the-Lake Hydro Inc.	1.03	3	0.88	1	0.48	1	0.38	1	0.52	1
Welland Hydro-Electric System Corp.	0.72	2	1.56	4	1.7	4	2.41	3	2.02	4

SAIDI Avg. outage duration (hours) - Loss of Supply Adjusted										
	2016	**Rank**	**2017**	**Rank**	**2018**	**Rank**	**2019**	**Rank**	**2020**	**Rank**
Grimsby Power Incorporated	0.55	2	1.20	2	1.73	3	5.00	4	0.64	1
Canadian Niagara Power Inc.	3.47	5	3.83	5	3.74	5	10.22	5	5.07	5
Niagara Peninsula Energy Inc.	1.52	4	1.37	3	1.98	4	2.03	3	2.15	3
Niagara-on-the-Lake Hydro Inc.	0.34	1	0.50	1	0.76	1	0.50	1	0.73	2
Welland Hydro-Electric System Corp.	0.63	3	1.83	4	1.46	2	1.71	2	2.36	4

Grimsby Power does not compare its outages caused by equipment failures to those from surrounding utilities.

1-VECC-3

Reference: Exhibit 1, Tab 3, Attachment 1, Business Plan, page 17

Preamble: *Grimsby Power will improve reliability compared to historic performance levels. These performance levels include the average number of hours and times that power to a customer is interrupted. Grimsby Power will remain below the current 1.36 with regard to the duration of outages and below 1.07 for the frequency of outages.*

a) How were the Business Plan metrics of 1.36 and 1.07 chosen?

b) What are the consequences of not meeting or exceeding these objectives?

Response:

a) Grimsby Power has aligned its Corporate Reliability Targets with those set by OEB on Grimsby Power's OEB Scorecard. Those targets are less than 1.36 for SAIDI and less than 1.07 for SAIFI.

b) Grimsby Power's reliability is one of the major Corporate Targets and therefore it is embedded in our corporate performance metrics. It is in the interest of all employees of Grimsby Power to meet and exceed our corporate targets for reliability (i.e. Grimsby Power exceeded reliability targets 3 out of 5 years over the historical period).

1–VECC-4

Reference: Exhibit 1, Tab 3, page 17 / Attachment 1, Business Plan, page 18

a) GPI was only able to achieve on average 81.6% of its planned capital expenditures (page 17). Had the Utility achieved 100% of the capital expenditures as planned would this have changed its cohort standing?

Response:

a) If GPI had achieved 100% of planned capital expenditures our cohort would remain the same. The results of the model using planned instead of actual capital spending for historical years is reproduced below for reference.

Summary of Cost Benchmarking Results - Planned Capital Additions 2016-2022

Grimsby Power Incorporated

Cost Benchmarking Summary	2016 (History)	2017 (History)	2018 (History)	2019 (History)	2020 (History)	2021 (Bridge)	2022 (Test Year)
Actual Total Cost	6,827,296	6,331,332	6,737,148	6,909,837	7,000,358	7,085,347	7,523,853
Predicted Total Cost	7,771,667	8,151,863	8,896,103	9,491,981	9,878,304	10,651,242	11,204,564
Difference	(944,372)	(1,820,531)	(2,158,955)	(2,582,144)	(2,877,946)	(3,565,895)	(3,680,711)
Percentage Difference (Cost Performance)	**-12.96%**	**-25.3%**	**-27.8%**	**-31.75%**	**-34.44%**	**-40.76%**	**-39.82%**
Three-Year Average Performance			-22.0%	-28.27%	-31.33%	-35.65%	-38.34%
Stretch Factor Cohort							
Annual Result	2	1	1	1	1	1	1
Three Year Average			2	1	1	1	1

1–VECC-5

Reference: Exhibit 1, Tab 4, Attachment 1,

a) How many customers (by customer class) does GPI currently have load limiters applied to?

Response:

a) None.

Exhibit 2 – Rate Base and Distribution System Plan

2-Staff-10
Variance of Rate Base
Ref: Exhibit 2, Tab 1, page 8 of 27

Preamble:

When discussing the variance between the 2021 bridge year and 2020 actual rate base, Grimsby Power noted a major contributor to gross fixed assets relate to a forecasted increase of $361k during 2021 in System Renewal. It was noted that this investment related to deferral of renewals along Casablanca Blvd to align with road widening project initiated by the Region.

Question(s):

a) Please provide the actual capital expenditures related to the Casablanca Blvd Road widening in System Renewal in 2020 and 2021.

b) Please provide the forecast capital expenditures related to the Casablanca Blvd Road widening in System Renewal for the 2022 test year.

c) Please explain which program(s) in System Renewal these spending fall under.

Response:

a) Actual capital expenditure related to Casablanca Blvd Road in System Access in 2020 is $0 and in 2021 is $22,390 (includes reported amount in WIP up to Aug.31, 2021).

b) Forecast capital expenditure related to the Casablanca Blvd Road widening in System Access for the 2022 test year is $134,000. Please note that Casablanca Blvd Road widening project is categorized under the System Access. To optimize capital work execution Grimsby Power has deferred some of the renewals programs (particularly some defective poles that would have been replaced under Defective Poles Replacement program) along Casablanca Blvd to align with the road widening project initiated by the Region. Those poles that were identified for replacement along Casablanca Blvd were re-assessed and placed on temporary hold in an effort to align them with the road widening project. This way Grimsby Power has eliminated the need to work on the same poles twice.

c) Casablanca Blvd Road widening project is categorized under the System Access. Replacement of Defective Poles program is categorized under System Renewal.

2-Staff-11

System Renewal
Ref: Exhibit 2, Tab 2, page 16 of 23

Preamble:

Grimsby Power stated that starting in 2022, it is increasing investments in System Renewal. OEB staff notes that the proposed capital expenditures in System Renewal for the 2022 test year is approximately 51.7% higher than the average forecast spending for 2023-2026.

Question(s):

a) Please explain if Grimsby Power has considered a more balanced pacing of its capital plan in System Renewal during the DSP period. Please include an discussion of the trade-off between increased customer bills versus the reliability or other benefits expected by undertaking these investments.

Response:

a) Grimsby Power has considered more balanced pacing of its capital plan (please refer to 2-Staff-14 that expands more on methodology used for selection of Capital plan programs/projects) not only within the System Renewal investment category but with the overall Capital Plan for the period of 2021-2026.

   In focussing only on the System Renewal investment category, one particular Program (Rear Lot Conversions – Burgess Dr.) was considered to be done in phases (Phase 1 in 2022 and Phase 2 in 2023). However due to the nature of this work (i.e. working in Customer's backyards) we have decided to try to do it in continuous flow and try to complete this as soon as we can. We are currently working on a similar project on Governors Road and customer feedback has been overwhelmingly positive as all customers welcomed rear lot conversions and were gladly receptive to the changes to their existing services.

   In 2019 Grimsby Power conducted a survey during a customer outreach event that specifically asked customers if they wanted rear lot services moved out of backyards. In the survey, 75% of respondents said they wanted the services moved out of backyards and installed underground, knowing the cost would be higher for an underground service.

All investments in System Renewal category were evaluated as per GPI Asset Management Process and benefits were high when it comes to reliability, safety and customer satisfaction.

2-Staff-12

2021 Capital Expenditures
Ref: Exhibit 2, Tab 2, Attachment 1, Appendix 2-AB
Exhibit 4, Tab 4, Table 4-27

Question(s):

a) Please confirm the 2021 planned capital expenditures is $1,921,036 as noted in Table 4-27 of Exhibit 4.

b) Please clarify the 2021 planned capital expenditures of $1,921,036 is gross or net capital expenditures.

c) Please provide variance analysis between 2021 planned and actual/forecast capital expenditures by investment category.

Response:

a) The 2021 planned capital expenditures is $2,238,116. In Table 4-27 of Exhibit 4 planned capital expenditures of $1,921,036 represents the capital expenditure amount that is within GPI's managements' control and that can be achieved.

From the planned capital expenditures of $2,238,116 the following projects that are not controlled by GPI:

- Project – Residential Subdivision development
- Project – New Customer Connections
- Program – Modifications Existing Customers Connections
- Residential Expansion

b) The 2021 planned capital expenditure of $1,921,036 is the gross capital expenditure within GPI's control.

c) The variances between 2021 planned and actual capital expenditures as August 31 are presented below:

Projects	2021 Budget	Capitalized	WIP	YTD Cost	Variance ($)	Variance (%)
System Access	317,080	97,669	81,431	179,100	(137,980)	-43.52%
Residential Expansion	153,514	55,312		55,312	(98,202)	-63.97%
Project - New Customer Connections	77,947	29,584	53,246	82,831	4,884	6.27%
Project - Residential Subdivision Development	74,738	4,385	-	4,385	(70,353)	-94.13%
Program - Modifications to Existing Customer Connections	10,881	8,388	28,184	36,573	25,692	236.12%
System Renewal	1,021,882	358,929	389,179	748,108	(273,774)	-26.79%
Program - Replace Defective Poles	286,591	183,191	12,719	195,910	(90,681)	-31.64%
Program - Replace Gang Operated Load Break Switch	30,228	45,268	-	45,268	15,040	49.75%
Program - Replace Sectionalizing Terminal	38,039	7,964	-	7,964	(30,074)	-79.06%
Program - Primary Cable Testing	23,752				(23,752)	-100.00%
Niagara West MTS - Replace Defective Battery Cells	50,000	14,520	114	14,635	(35,365)	-70.73%
Program - Replace Single Phase Pad Mounted Transformers	31,408	30,194	-	30,194	(1,213)	-3.86%
Project - CNR Pole Line (18M4 Feeder) Relocation / Rerouting	212,517	-	54,933	54,933	(157,584)	-74.15%
Project - Secondary Bus Refurbishments	66,333	19,121	-	19,121	(47,212)	-71.17%
Program - Replace Three Phase Pad Mounted Transformers	24,465	1,232	1,345	2,577	(21,888)	-89.47%
Program - Rear Lot Conversion - Governors Road	258,550	54,202	297,678	351,880	93,330	36.10%
Program - Replace Interval Meter		3,236	-	3,236	3,236	
Project - Casablanca Boulevard		-	22,390	22,390	22,390	
System Service	683,114	170,788	73,397	244,185	(438,929)	-64.25%
Project - Third Feeder from NW-MTS	599,015	-	24,879	24,879	(574,136)	-95.85%
Program - Voltage Conversion - Kingsway Blvd		157,271	-	157,271	157,271	
Program - Primary OH Conductor Reinforcements	46,589	-	3,834	3,834	(42,755)	-91.77%
Program - Primary UG Cable Reinforcements	37,509	-	12,284	12,284	(25,225)	-67.25%
Project - Monitoring & Control - Fault Indicator & SCADA		13,517	32,399	45,917	45,917	
Distribution Assets Total	2,022,076	627,386	544,007	1,171,392	(850,684)	-42.07%
General Plant						
Program - Computer Workstations	9,000	4,820		4,820	(4,180)	-46.44%
Program - Server/Network Hardware Upgrades due to Cyber Security	10,000	11,205		11,205	1,205	12.05%
Software	15,000	2,000		2,000	(13,000)	-86.67%
Project - SCADA System and Improvements	21,040	3,937		3,937	(17,103)	-81.29%
Vehicle - Trucks & Forklift	87,000	45,146		45,146	(41,854)	-48.11%
Building Upgrades	15,000			-	(15,000)	-100.00%
Office Furniture	10,000	7,174		7,174	(2,827)	-28.27%
Tools - Replacement	39,000	9,447		9,447	(29,553)	-75.78%
Communication Equipment	10,000	7,576		7,576	(2,424)	-24.24%
General Plant Total	**216,040**	**91,305**	**-**	**91,305**	**(124,735)**	**-57.74%**
TOTAL	2,238,116	718,691	544,007	1,262,698	(975,418)	-43.58%

2-Staff-13

Sources of Cost Savings
Ref: Exhibit 2, Tab 3, Attachment 1, page 13 of 678

Preamble:

Grimsby Power identified seven sources of cost savings.

Question(s):

a) Is there any quantified information associated with these identified sources of cost savings? If so, please provide savings on an annual basis for each of these sources. Please explain:

   i. Whether it's one-time saving or persistent saving.
   ii. Whether it is an avoided future cost or a reduction of current spending.
   iii. Whether its capital related or OM&A related savings or both.
   iv. Whether cost savings have been reflected in the 2022 capital/OM&A budget.
   v. How savings for each source were calculated/estimated.

b) Please identify any new productivity initiatives that are planned to be implemented for the period of 2022-2026.

Response:

a) Grimsby Power does not have any quantifiable information associated with the identified sources of cost savings. The sources of cost savings and qualitative saving opportunities are as follows:

   1) Comprehensive data collection. The saving opportunities associated with this source of cost savings would be persistent OM&A savings in regard to data entry labour and stationary expenses.

   2) Asset Condition Assessment. The saving opportunities associated with this source of cost savings would be on-going and persistent savings as more cost-effective decisions with respect to maintenance and replacements is optimized. These savings would assist in both OM&A for maintenance efforts and capital expenditures when planning future project allocations.

3) SCADA. The saving opportunities associated with this source of cost savings would be persistent OM&A savings as SCADA would allow for Grimsby Power forces to effectively identify any system issues and deploy the necessary resources.

4) Sectionalizers and Fault Detectors. The saving opportunities associated with this source of cost savings would be persistent OM&A savings as the installation of these assets would allow for Grimsby Power forces to locate issues in the system and isolate the system problems to reduce the impact of the outage.

5) Voltage Conversion. The saving opportunities associated with this source of cost savings would be persistent OM&A savings as the equipment used by Grimsby Power can be standardized and optimized throughout the system. This would result in equipment availability and minimizing spare inventory in Grimsby Power's warehouse.

6) Reclosers and Smart Faulted Circuit Indicators. The saving opportunities associated with this source of cost savings would be persistent OM&A savings as the installation of Reclosures and Smart Faulted Circuit Indicators would allow for Grimsby Power forces to effectively identify, locate, isolate and/or restore power to the affected outage areas in the system. In conjunction with the SCADA system, these assets will complement and advance the functionality of the SCADA system.

7) Outage Management System improvement. The saving opportunities associated with this source of cost savings would be persistent OM&A savings as SCADA along with smart metering and GIS information would allow for Grimsby Power forces to effectively identify any system issues and deploy the necessary resources while providing customers access to the affected area through our mapping system.

b) All productivity initiatives for the period of 2022-2026 were identified in part (a) of this question and have been accordingly reflected across forecasted period. Plan is based on the fact to have all these productivity initiatives in place by the end of the forecasted period (2022-2026).

2-Staff-14

Project Selection and Prioritization

Ref: Exhibit 2, Tab 3, Attachment 1, page 17 of 678
Exhibit 2, Tab 3, Attachment 1, page 52 of 678
Exhibit 2, Tab 3, Attachment 1, page 82 of 678

Question(s):

a) With respect to capital investment prioritization process, Grimsby Power noted that a value and risk deferral assessment of the investment is performed. Investment scores determine an initial priority of the investment for current or future budget periods. Please provide an example to show how investment scores were determined for a capital project. Please explain assumptions, data and methodology utilized in the calculation.

b) Please explain how Grimsby Power defines mandatory and non-mandatory projects or programs. Please identify which projects included in Appendix 2-AA are mandatory for the 2022 test year. Also, please indicate if the mandatory classification applies to the entire spend or only in part.

c) Please explain how Grimsby Power determined/selected the preferred technical alternative for an investment need. Is there a quantitative approach to determine a preferred alternative? If so, please provide an example to show assumptions, data and methodology utilized.

d) Please provide the list of capital projects and associated capital expenditures in Appendix 2-AA format in Excel for the 2022 test year, resulting from each of the following steps noted as part of Grimsby Power's asset management process.

- Identify Needs
- Develop Business Cases to support Preferred Technical Alternatives
- Prioritize and Select Investments
- Draft Capital Investment Plan
- Recommendation by Operations Committee
- Recommendation by Audit Committee
- Approval by GPI Board

Response:

a) Investment scores are determined by combining the results of the value matrix and the risk matrix for each project. The value and risk matrix respectively consists of categories including Safety, Reliability, Customer, Finance, Regulatory Compliance and Regional and Municipal requirements (if required). Each category is considered and taken into the evaluation. The projects/options are scored respectively to determine the order of capital investment. For a specific example please see Appendix 1 of 2-Staff-14. This file was created by Grimsby Power to evaluate various design options for Project – Third Feeder from NW-MTS.

b) Typically projects that are comprised of a higher Safety and Reliability priority would be considered as mandatory. System Access project such as development and municipal pole relocation projects are mandatory in nature and budgeted and scheduled to meet the timing needs of external agencies. System Renewal projects are usually non-mandatory in nature as well as System Service projects unless supported by emerging data (i.e. asset inspections, ACA, indicators for imminent failures,). General Plant is typically non-mandatory in nature. Please see the table below showing the Mandatory and Non Mandatory projects for 2022.

Projects	2022 Test Year
	Mandatory
System Access	
Residential Expansion	Yes
Project - New Customer Connections	Yes
Project - Residential Subdivision Development	Yes
Program - Modifications to Existing Customer Connections	Yes
Project - Metrolinx - Pole Line Relocation Due to Road Widening	Yes
Sub-Total	
System Renewal	
Program - Replace Defective Poles	Yes
Program - Secondary Bus Refurbishments	Yes
Program - Replace Sectionalizing Terminal	Yes
Program - Replace Gang Operated Load Break Switch	Yes
Program - Primary Cable Testing	No
Program - Replace Pad Mounted Transformers	Yes
Program - Rear Lot Conversion	No
Program - Niagara West MTS - Relay Changeout	Yes
Project - CNR Pole Line (18M4 Feeder) Relocation / Rerouting	No

Sub-Total	
System Service	
Program - Primary OH Conductor and UG Cable Reinforcements	No
Sub-Total	
General Plant	
Program - Computer Workstations	No
Program - Server/Network Hardware Upgrades due to Cyber Security	Yes
Project - SCADA System and Improvements	No
Building Upgrades	No

c) Grimsby Power reviews the technical alternative for a given project and assesses the Efficiency, Safety Customer Value, Reliability and Cost to ensure that the preferred technical alternative is selected. For instance, the alternative approach for the rear lot conversion would be to install new overhead in the front lot or keep the pole line in the rear lot which is the existing location (please refer to 2-Staff-23 for more detailed example that shows assumptions, data and methodology used for Real Lot Conversion program). Although these technical alternatives would be less cost, the safety, reliability, customer value and consistency with the current Grimsby Power standards for subdivisions resulted in placing the infrastructure underground in the front lot.

d) During the GPI Special meeting on March 18, 2021 a detailed presentation was provided to the GPI Board of Directors (a copy of the presentation is filed as attachment to 1-SEC-2). The presentation is based on the 2022 Budget and Business Plan. Following the review of the Cost of Service Summary the GPI Board approved GPI to proceed with the Cost of Service Application.

Each of the listed projects and capital expenditures has followed Grimsby Power's project prioritization process (i.e. GPI Asset Management Process Exh.2, Tab 3, Page 52 of 678) which was reviewed and approved by Grimsby Power's Board. Grimsby Power's project prioritization process starts with various drivers (External Drivers, Strategic Investments and Internal Drivers). From those drivers project needs are identified. Once the needs are identified the process goes through considerations of various items such as determination of technical options, preferred technical alternatives and investment requirements. Once prioritization and selection of investments is complete last step in the process is to obtain recommendations and required approvals.

Please see the table below showing the list of capital projects and associated capital expenditures in Appendix 2-AA format in Excel for the 2022 test year.

Projects	2022 Test Year
Reporting Basis	**MIFRS**
System Access	
Residential Expansion	660,249
Project - New Customer Connections	46,154
Project - Residential Subdivision Development	30,194
Program - Modifications to Existing Customer Connections	12,286
Project - Metrolinx - Pole Line Relocation Due to Road Widening	134,000
Sub-Total	**882,883**
System Renewal	
Program - Replace Defective Poles	521,019
Program - Secondary Bus Refurbishments	65,676
Program - Replace Sectionalizing Terminal	37,686
Program - Replace Gang Operated Load Break Switch	29,220
Program - Primary Cable Testing	27,732
Program - Replace Pad Mounted Transformers	56,521
Program - Rear Lot Conversion	598,550
Program - Niagara West MTS	100,000
Project - CNR Pole Line (18M4 Feeder) Relocation / Rerouting	435,000
Sub-Total	**1,871,404**
System Service	
Program - Primary OH Conductor and UG Cable Reinforcements	81,541
Sub-Total	**81,541**
General Plant	
Program - Computer Workstations	10,000
Program - Server/Network Hardware Upgrades due to Cyber Security	10,000
Project - SCADA System and Improvements	1,063
Building Upgrades	80,000
Sub-Total	**101,063**
Miscellaneous	
Total	**2,936,891**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*	
Total	**2,936,891**
Deferred Revenue (Capital Contribution)	**(423,426)**
Total	**2,513,465**

Project Status Report – 2508M8 – Proposed Options Extract

Mar 2021

grimsbypower

your local power provider

Filed: October 28, 2021
EB-2021-0027 Grimsby Power Inc. 2022 Cost of Service Application
2-Staff-14 Appendix 1

Proposed Options

grimsbypower
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Option 1

- Grimsby Rd 12 (North) / Young St (East) / South Grimsby Rd 6

Option 2

- Grimsby Rd 12 (North) to Mud St

Option 3

- Grimsby Rd 12 (North) / Young St (West) / Grassie Rd RR8 (North)

Option 4

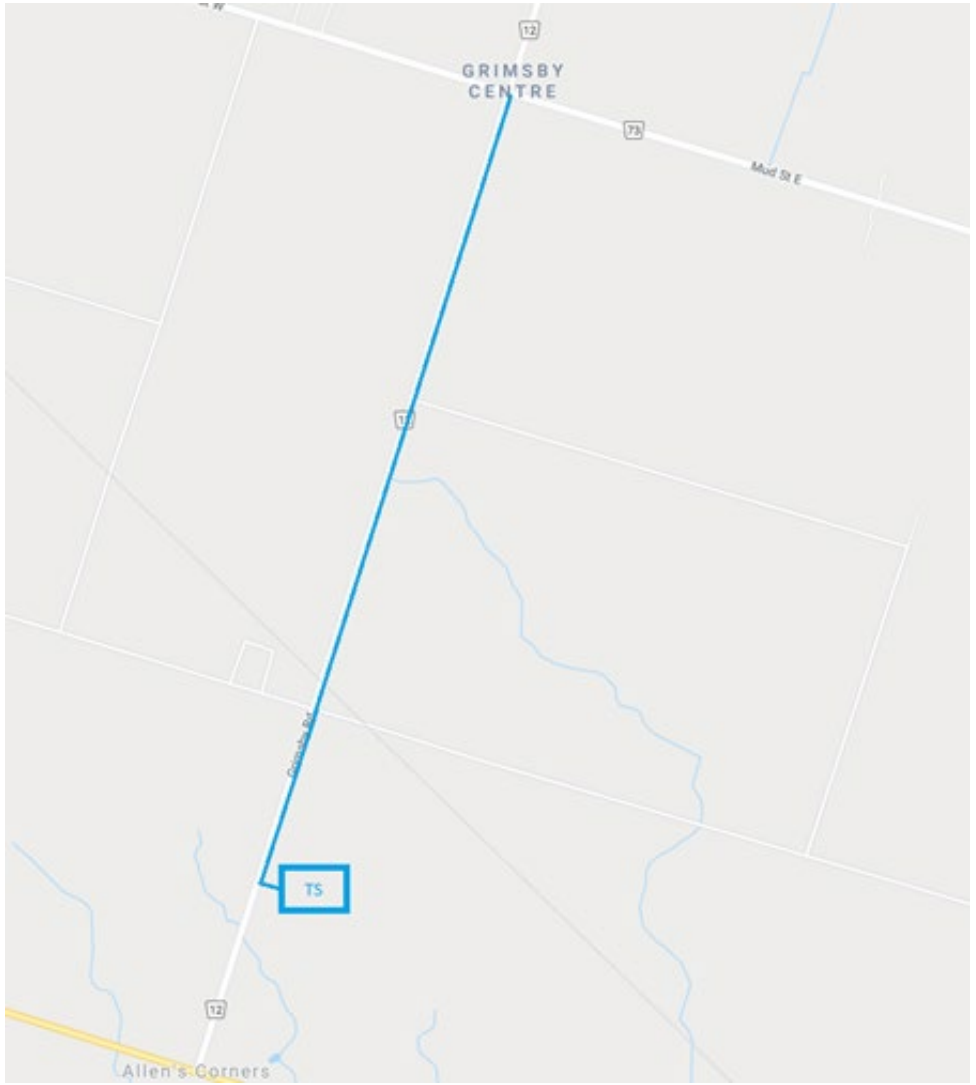
- Grimsby Rd 12 (North) / Young St (West) / South Grimsby Rd 10 (North)

Option 1

Highlights:

- ~ 5.0km feeder length
- ~ 100 New poles
- CP Rail Crossing
- 3 Underground sections along Young St
- Adjacent to 115kV power lines
- Estimated $1.2 million
- Service connection to Grimsby Power system on east end of jurisdiction

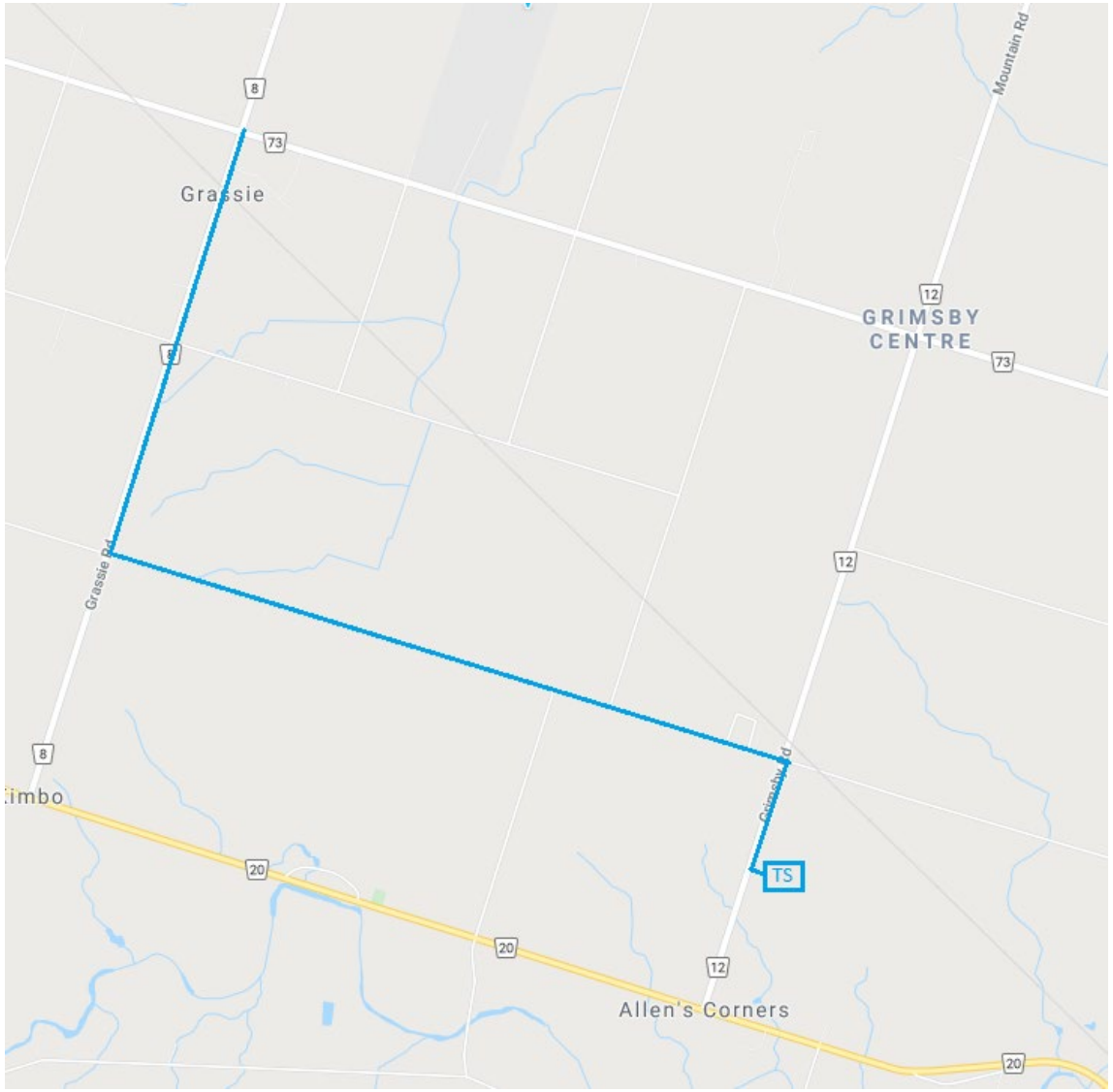
Option 2



Highlights:

- ~ 2.5km feeder length
- ~ 56 New poles
- CP Rail Crossing
- 1 Underground section on Grimsby Rd 12
- Double pole Line along RR 12
- 2 km guard rail required along RR 12
- Estimated $ 950,000
- Service connection to Grimsby Power system in centre of jurisdiction

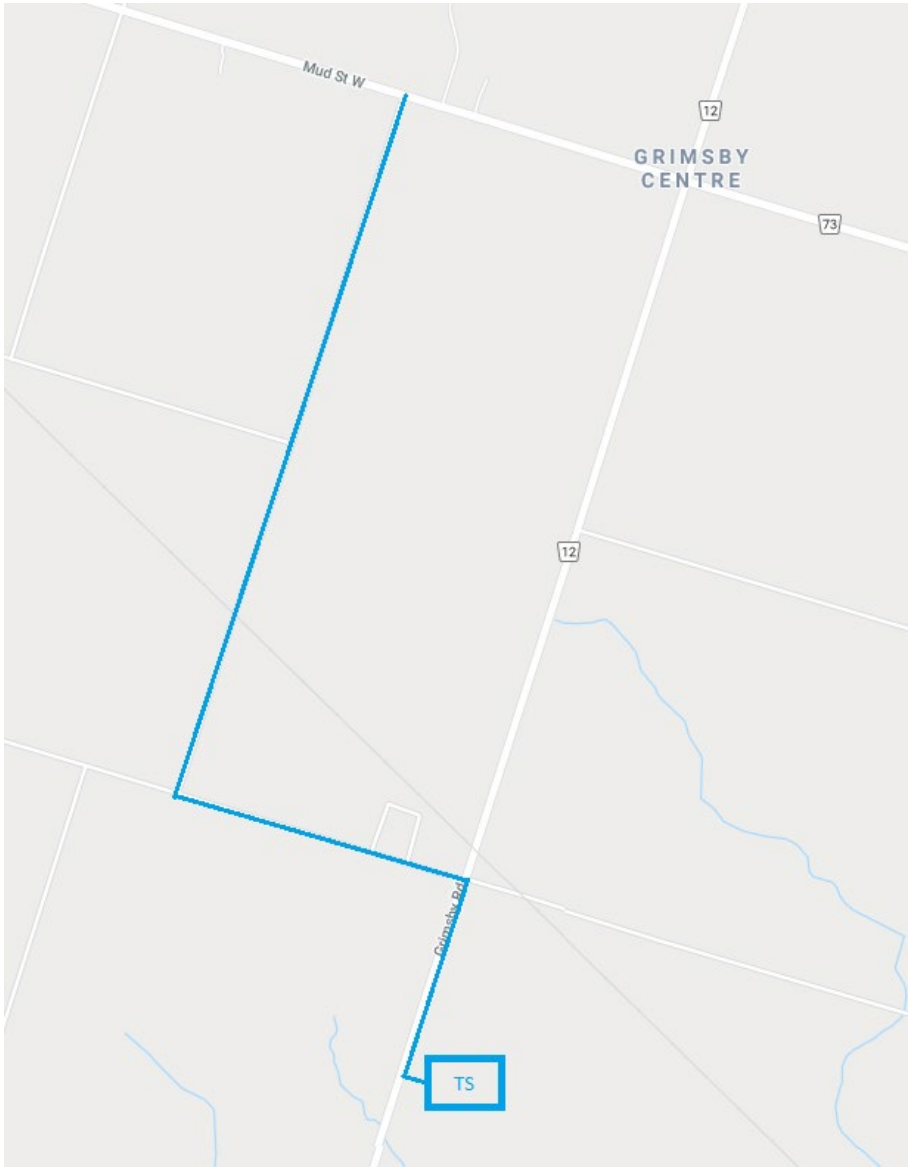
Option 3



Highlights:

- **~ 5.8km feeder length**
- **~ 110 New poles**
- **CP Rail Crossing**
- **Double pole Line along RR 12**
- **Potential 2 km guard rail required along RR 8**
- **Most expensive option**
- **Service connection to Grimsby Power system in west end of jurisdiction**

Option 4



Highlights:

- **~ 3.3km feeder length**
- **~ 65 New poles**
- **CP Rail Crossing**
- **Estimated $ 650,000**
- **Service connection to Grimsby Power system in centre of jurisdiction**

Recommendation & Conclusion

Based on the discussions held with Niagara Region, NPEI and GPI representatives and further discussions following the meeting, the preferred proposal is **Option 4** with the following taken into consideration:

- Option 4 avoids the requirement for a guard rail installation along Grimsby Rd 12 which is preferred from all parties
- Option 4 allows the system connection to be centered along the GPI jurisdiction without extensive distances as well as current and future load considerations being realized
- Option 4 pole line allows for steamlined construction horizon due to reduced involvement of existing feeders
- West Lincoln will need to be engaged for consent, however do not forsee any conflict based on existing pole location defined on Young St / South Grimsby Rd 10

GPI is requesting that Niagara Region please review the Option 4 proposal and provide verbal consent in order to proceed with the detailed design and encroachment permit submission

2-Staff-15
Meter Re-Verification
Ref: Exhibit 2, Tab 3, Attachment 1, page 19 of 678

Preamble:

Grimsby Power provided its planned meter re-verification testing for each year over the DSP period.

Question(s):

a) Please explain why meters planned to be tested in 2022 is approximately 248% higher than the average amount planned for 2023-2026.

b) Please explain how the potential replacement cost was derived.

c) Please explain why meter re-verification testing plan is considered as a contingent aspect of the DSP.

d) Please explain which capital program(s) this meter re-verification testing falls under. Please reconcile the budget of $193,440 with capital program/project presented in Appendix 2-AA.

Response:

a) The driving factor for meter reverification testing is the Meter Seal Expiry date of the meter group. Meter group that is due for a reverification in 2022 is one of the largest meter groups that Grimsby Power has in our service territory hence such a high number of meters whose seals need to be verified in 2022.

b) Cost was derived by multiplying number of meters in this meter group with the unit cost per meter install within this meter group.

c) Grimsby Power added meter re-verification testing as a contingent aspect of the DSP as this work activity depends on the outcome of the future event (i.e. success of the re-verification test).

d) The need for meter replacement of these meters is dependent on the success of the re-verification test which is in the future meter testing years so Grimsby Power did not include cost of this program in our Capital Program budgets and hence included this in the contingent aspect of the DSP.

2-Staff-16

System Renewal
Ref: EB-2015-0072, Exhibit 2, Appendix 2-A DSP, page 91

Preamble:

In its last DSP, Grimsby Power provided a table summarized its system renewal programs by asset category.

Question(s):

a) Please provide a table in the same format in Excel to summarize the actual program cost, quantities of work, and unit cost by asset category for each year over 2016-2021.

b) Please provide a table in the same format in Excel to summarize the forecast program cost, quantities of work, and unit cost by asset category for each year over 2022-2026.

Response:

a) Please see table below.

		Level		2016	2017	2018	2019	2020	
Wood Poles		181	Units (Actuals)	14	16	26	50	75	
	Unit Cost	$4,304	Unit Cost w/Brdn	$ 6,117	$ 5,912	$ 5,240	$ 5,861	$ 3,744	
	Burden	$615	Program Cost (Actuals)	$ 67,972	$ 81,748	$ 119,410	$ 258,744	$ 251,174	
			Total Burden	$ 17,671	$ 12,844	$ 16,829	$ 34,295	$ 29,653	
Concrete Poles		0	Units (Actuals)	0	0	0	0	0	No concrete poles were replaced in the historical period
	Unit Cost	N/A	Unit Cost w/Brdn						
	Burden		Program Cost (Actuals)						
Pole Mounted Transformers		10	Units (Actuals)	4	3	1	2	0	
	Unit Cost	$2,779	Unit Cost w/Brdn	$ 2,366	$ 4,042	$ 2,560	$ 3,869		
	Burden	$410	Program Cost (Actuals)	$ 7,504	$ 11,177	$ 2,310	$ 6,800		
			Total Burden	$ 1,960	$ 950	$ 250	$ 937		
Pad Mounted Transformers		57	Units (Actuals)	8	13	11	16	9	Pad mounts include 1ph and 3ph, hence annual unit costs have high oscillations year over year as it depends on the amount of 1ph vs 3ph transformers replaced during any given year
(includes 1ph and 3ph)	Unit Cost	$7,403	Unit Cost w/Brdn	$ 4,420	$ 6,251	$ 10,954	$ 9,172	$ 6,619	
	Burden	$377	Program Cost (Actuals)	$ 32,807	$ 78,218	$ 114,166	$ 140,011	$ 56,740	
			Total Burden	$ 2,553	$ 3,039	$ 6,332	$ 6,743	$ 2,832	
Meters		38	Units (Actuals)	16	0	22	0	0	
(Remaining GS>50 Meters)	Unit Cost	$1,398	Unit Cost w/Brdn	$ 2,032		$ 1,104			OH switches include 1ph and 3ph, hence annual unit costs have high oscillations year over year as it depends on the amount of 1ph vs 3ph transformers replaced during any given year
	Burden	$96	Program Cost (Actuals)	$ 28,991.63		$ 24,145.42			
			Total Burden	$ 3,519		$ 141			
Overhead Switches		6	Units (Actuals)	2	0	1	2	1	
(includes 1ph and 3ph)	Unit Cost	$25,601	Unit Cost w/Brdn	$ 27,578		$ 39,360	$ 23,999	$ 31,706	
	Burden	$3,436	Program Cost (Actuals)	$ 45,704		$ 33,832	$ 44,438	$ 29,629	Padmounted switches include MAN and AUTO, hence annual unit costs have high oscillations year over year as it depends on the amount of MAN vs AUTO switches replaced during any given year
			Total Burden	$ 9,451		$ 5,528	$ 3,560	$ 2,077	
Padmount Switches		2	Units (Actuals)	0	1	0	1	0	
(includes MANUAL and AUTO)	Unit Cost	$78,541	Unit Cost w/Brdn		$ 56,344		$ 111,629		
	Burden	$5,445	Program Cost (Actuals)		$ 53,635		$ 103,447		
			Total Burden		$ 2,709		$ 8,182		
UG Cable		3190	Units (Actuals)	750	0	340	2100	0	UG Cable costs includes installations that required civil rebuilts and those where civil infrastructure was reused hence annual unit costs have high oscillations year over year
(includes total runs)	Unit Cost	$55	Unit Cost w/Brdn	$ 32		$ 252	$ 40		
	Burden	$5	Program Cost (Actuals)	$ 20,740		$ 78,459	$ 77,118		
			Total Burden	$ 3,487		$ 7,105	$ 6,100		

b) Please see table below.

		Level		2021	2022	2023	2024	2025	2026	
Wood Poles		645	Units (Forecasted)	100	109	109	109	109	109	
	Unit Cost	$4,819	Unit Cost w/Brdn	$ 3,470	$ 5,384	$ 5,725	$ 5,827	$ 5,932	$ 6,038	
	Burden	$604	Program Cost (Budget)	$ 286,591	$ 521,019	$ 558,190	$ 569,353	$ 580,741	$ 592,355	
			Total Burden	$ 35,910	$65,284	$ 69,942	$ 71,341	$ 72,767	$ 74,223	
Concrete Poles		0	Units (Forecasted)	$ -	$ -	$ -	$ -	$ -	$ -	Zero forecasted for replacement as we had no inspection data that would indicate concrete poles to be replaced
	Unit Cost	N/A	Unit Cost w/Brdn							
	Burden		Program Cost (Budget)							
			Total Burden							
Pole Mounted Transformers		12	Units (Forecasted)	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	
	Unit Cost	$2,779	Unit Cost w/Brdn	$ 3,162	$ 3,162	$ 3,162	$ 3,162	$ 3,162	$ 3,162	
	Burden	$383	Program Cost (Budget)	$ 5,558	$ 5,558	$ 5,558	$ 5,558	$ 5,558	$ 5,558	
			Total Burden	$ 766	$ 766	$ 766	$ 766	$ 766	$ 766	
Pad Mounted Transformers		36	Units (Forecasted)	$ 6	$ 6	$ 6	$ 6	$ 6	$ 6	
(includes 1ph and 3ph)	Unit Cost	$9,997	Unit Cost w/Brdn	$ 10,487	$ 10,487	$ 10,487	$ 10,487	$ 10,487	$ 10,487	
	Burden	$490	Program Cost (Budget)	$ 55,872	$ 56,521	$ 60,047	$ 61,248	$ 62,473	$ 63,722	
			Total Burden	$ 2,740	$ 2,772	$ 2,945	$ 3,003	$ 3,063	$ 3,125	
Overhead Switches		6	Units (Forecasted)	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	
(includes 1ph and 3ph)	Unit Cost	$31,112	Unit Cost w/Brdn	$ 33,449	$ 33,449	$ 33,449	$ 33,449	$ 33,449	$ 33,449	
	Burden	$2,337	Program Cost (Budget)	$ 30,228	$ 29,220	$ 30,868	$ 31,485	$ 32,115	$ 32,757	
			Total Burden	$ 2,270	$ 2,195	$ 2,318	$ 2,365	$ 2,412	$ 2,460	
Padmount Switches		0	Units (Forecasted)	$ -	$ -	$ -	$ -	$ -	$ -	Zero forecasted for replacement as we had no inspection data that would indicate padmount sw to be replaced
(includes MANUAL and AUTO)	Unit Cost	N/A	Unit Cost w/Brdn							
	Burden		Program Cost (Budget)							
			Total Burden							
UG Cable		0	Units (Forecasted)	$ -	$ -	$ -	$ -	$ -	$ -	Zero forecasted for replacement as cable testing reports not received in time for budgeting purposes
(includes total runs)	Unit Cost	N/A	Unit Cost w/Brdn							
	Burden		Program Cost (Budget)							
			Total Burden							

2-Staff-17

Pole Line Relocation due to Road Widening
Ref: Exhibit 2, Tab 3, Attachment 1, page 114 of 678

Preamble:

This project is pole line relocation due to a Metrolinx new Go train station. OEB staff notes that in 2018, a change in the delivery process was announced that a third-party agreement is required for the design and construction of the Go station, rather than Metrolinx as originally planned.

Question(s):

a) Please explain if the Region of Niagara has announced any updates on the securing of a third-party partner.

b) Please discuss if the uncertainty exists in the construction timeline of the new Go train station has any impacts on Grimsby Power's forecast for the pole line relocation project.

Response

a) Region of Niagara has secured Associated Engineering as their third party partner to design and coordinate the road widening efforts.

b) Grimsby Power is aligned with the construction timeline for the road widening efforts in conjunction with the Go train station which is now projected for a 2022 construction start.

2-Staff-18

Pad Mounted Transformers
Ref: Exhibit 2, Tab 3, Attachment 1, page 121 of 678

Question(s):

a) In the material investment summary for the replace pad mounted transformers project, Grimsby Power stated that it is planning to replace 5 single-phase and 1 three-phase pad mounted transformers per year over the forecast period. The Flagged for Action Plan produced by Kinectrics recommended 1 single-phase and 0 three-phase pad mounted transformers per year over the forecast period. Please provide the rationale of deviating from the Flagged for Action Plan.

Response:

a) For the Replace Pad Mounted Transformer Program, Grimsby Power based the volume of transformers replacements on the age and/or inadequate operating conditions. Transformers that are past useful life and were discovered to have inadequate operating conditions were replaced under this program. All pad mount transformers that were replaced under this program and yet were above ACA recommended replacement numbers have had operational failure detected or have failed Grimsby Power's Distribution Maintenance and Inspections process. Grimsby Power conducts visual inspections of pad-mounted transformers in accordance with the Distribution System Maintenance and Inspection program (Exhibit 2, Tab 3, Attachment 1, page 310 of 678). Furthermore, as part of Distribution System and Inspection program GPI has also implemented thermographic imaging as part of the inspections to determine if there are any abnormalities present which require attention.

2-Staff-19

Variance Analysis of Capital Expenditures
Ref: Exhibit 2, Tab 2, page 8 of 23

Preamble:

When comparing the planned vs. actual net capital expenditures over the 2016-2020 period, there was an overall underspending of approximately $1,656k (17.4%).

Question(s):

a) Please explain the overall variance between planned vs. actual capital expenditures by investment category (i.e., System Access, System Renewal, System Service, and General Plant) over the 2016-2020 period.

b) Please describe any actions Grimsby Power plans to take to minimize future variances between planned and actual capital expenditures over the forecast period.

c) Please identify if any material System Service and System Renewal projects planned for the historical period (2016-2020) were not completed, and the reasons why the associated projects were not completed.

d) Regarding the 2021 net capital expenditures of $2,238k, please explain how many months are actual vs. forecast. Does Grimsby Power have updated 2021 capital expenditures based on latest information? If so, please provide them in Appendix 2-AB format and indicate how many months are actual vs. forecast.

Response:

a) For variance analysis between planned vs actual for 2016 please see Exb 2, Tab 3, Pg 89 of 678
For variance analysis between planned vs actual for 2017 please see Exb 2, Tab 3, Pg 90 of 678
For variance analysis between planned vs actual for 2018 please see Exb 2, Tab 3, Pg 91 of 678
For variance analysis between planned vs actual for 2019 please see Exb 2, Tab 3, Pg 92 of 678
For variance analysis between planned vs actual for 2020 please see Exb 2, Tab 3, Pg 93 of 678

b) Grimsby Power has made strategic staffing re-alignment on staffing accountabilities across all lines of businesses (in particular within Eng&Ops) to make sure that capital work is delivered as planned. Replacement of full time staff in Eng&Ops has taken place (i.e. appointed Director of Eng&Ops, hired Eng Tech). Long term contracts with external service providers have also been put in place. Regular progress reporting on Capital Projects execution is in effect. Success of Grimsby Power's current focus on Capital Programs work delivery is observed in the latest financial results as of Aug.31, 2021 (provided in 2-Staff-12-c).

c) Please refer to answer above 2-Staff-19 (a) where there is a reference to appropriate section of the application that address variances over the historical period (2016-2020).

d) The 2021 net capital expenditures of $2,238k is 12 months of forecast.

Appendix 2-AB actual vs. budget (forecast)

CATEGORY		2021			
	Budget 12 months	Actual 8 months	Forecast 4 months	2021 Actual plus Forecast	Var
		$ '000			%
System Access	662	98	212	310	46.9%
System Renewal	1,022	359	802	1,161	113.6%
System Service	683	171	692	863	126.4%
General Plant	216	91	55	146	67.7%
TOTAL EXPENDITURE	2,583	719	1,762	2,481	96.1%
Capital Contributions	(345)	(31)	(323)	(354)	102.7%
Net Capital Expenditures	2,238	688	1,439	2,127	95.0%
System O&M	$ 1,475	$ 982	$ 491	$ 1,473	99.9%

There are several projects included in the forecast figures that are scheduled to be in service by December 31, 2021. Some of the major projects in System Renewal scheduled for completion in 2021 include Defective Pole replacement ($100,878), CNR Pole Line Relocation ($238,843) and the Rear Lot Conversions ($332,866). Major projects schedule for completion in 2021 for System Service include the Third Feeder from NWMTS ($564,276) and the Primary UG Cable Reinforcements ($91,884).

Overall increased focus on overall capital project delivery is brining Grimsby Power in line with budgeted capital expenditures.

2-Staff-20

System Access
Ref: Exhibit 2, Tab 3, Attachment 1, page 89 of 678

Preamble:

Table 30 indicates that there was an underspend in System Access expenditures over the historical period, most of which is related to planned connections not materializing.

Question(s):

a) Does the total underspend in System Access over the historical period represent a backlog of customer connections that will take place during the forecast period? (For example, was expected subdivision growth simply delayed rather than foregone?) If so, is this backlog accounted for in the planned expenditures for the forecast period?

b) Please clarify on what basis certain System Access projects require capital contributions from customers and others do not.

c) Please describe any actions Grimsby Power plans to take to minimize future variances between planned and actual system access expenditures over the forecast period.

Response:

a) Total underspend in System Access is dependent on external factors that cannot be controlled by Grimsby Power. Grimsby Power works closely with local Municipal Authorities and Developers to plan work in this investment category. Grimsby Power can confirm only those customer connections that were planned in historical period to materialize in the forecasted period for which Grimsby Power has signed agreements in place. Grimsby Power has accounted for all planned expenditures in the forecasted period. Based on the data known to Grimsby Power we do not foresee backlog of work within this investment category.

b) The projects that require capital contributions from customers are related to Residential Expansion. It includes the jobs for which the cost is fully covered by the customers and the assumed plant.

c) Grimsby Power will continue to work closely with all Municipal Authorities that are involved with the review and approval process for any new developments within

the Town of Grimsby. Grimsby Power also regularly attends any meetings and sharing of information requests about servicing and work planning with the Developers, in effort to minimize future variations between planned and actual System Access expenditures over the forecasted period.

2-Staff-21

Residential Expansion
Ref: Exhibit 2, Tab 3, Attachment 1, page 111 of 678

Question(s):

a) Grimsby Power provided the planned customer attachments and load for each year over the DSP period. Please provide the agreements between Grimsby Power and the developer(s)/builder(s).

b) Grimsby Power stated that "The main driver for this project is customer service requests. The Developer/Builder is building a new subdivision or townhouse complex requiring the installation of service. Infills have also been included as part of the Residential Expansions project." Please explain how the forecast budget of $660,249 for the 2022 test year was derived. Please provide all assumptions, data, and methodology. Please also distinguish the forecast costs on new subdivision/townhouse vs. infills.

c) Appendix B of the Distribution System Code describes the methodology to determine capital contribution a distributor shall charge a customer to construct an expansion. Please explain how Grimsby Power calculate capital contributions from developers/builders. Please provide an example in Excel.

Response:

a) Signed agreements YTD are attached as Appendix 1 of 2-Staff-21. Please note that the agreements for subdivision developments at 8 Lake St and 314 Main St E are being reviewed and are in the final stages of being approved. Others listed are still in various contract development stages with the Developers.

b) Grimsby Power has used available data from developers, builders and Town of Grimsby that was available at that time to come up with final forecasted residential numbers. Some of the subdivision projects were in planning stages and have not completely materialized yet. Final forecasted residential numbers were used to come up with forecasted budget. Please see table below for more details on data and methodology used.

Description	2022
Residential Expansion	
Assumed Plant	226,085
Customer Work Orders	271,643
GPI	162,521
Total	**660,249**
Capital Contribution	
Capital Contribution - Assumed Plant	(164,835)
Capital Contribution - Customer Work Orders	(258,591)
Total	**(423,426)**

The 2022 Assumed plant – is calculated by multiplying the average cost per connection for the last 7 years (2015-2020 actual plus 2021 forecast) with the forecasted number of connections for 2022.

The Capital Contribution - Assumed plant is calculated by using the same methodology by multiplying the average contributed capital per connection for the last 7 years (2015-2021) with the forecasted number of connections for 2022.

The Customer Work Orders is calculated as an average of the last 4 (2018-2020 actual plus 2021 forecast) years actual capital expenditures requested and paid by the customers.

The Capital Contribution – Customer Work Orders is equal with the capital expenditures as the customers are paying in full the cost.

c) Grimsby Power only uses the alternative bid or developer installed method. GPI calculates capital contributions from developers in its economic evaluation model. The capital contribution looks at the net present value of the assets compared to the revenue expected from customer connections. Grimsby Power does not physically receive a payment of contributed capital but instead reduces the transfer price by the contributed capital amount and then books the net payment to the developer as a liability. An example in Excel has been provided as 2-Staff-21 Economic Evaluation Model - Sample.

Grimsby Power Incorporated

Residential Subdivision Development Agreement

Corporate Name of Developer:	Phelps Homes Ltd.	
Name of Development	Johnathan	
Approximate Location of Development:	27 John St, N/W corner of John Street and Robinson Street North	
Number of Electrical Connections	41	
Type and Number of Dwellings	Single Detached Units Stacked Townhomes Semi-Detached Units	 40
Date:	August 10, 2021	

Development & Subdivision Agreement between Grimsby Power Incorporated and Phelps Homes Ltd.

IN WITNESS WHEREOF the said parties hereto have executed *The Agreement*.

For *The Developer*

Signature: DocuSigned by: David Samis D75CB36117D94FD..

Print Name: David Samis

Title: President

Signature of Witness: DocuSigned by: CAD 1FF4ACBB0E684F2..

Print Name of Witness: Chris Drakos

Title of Witness: CFO

Date of Endorsement: August 20, 2021

For *Grimsby Power Incorporated*

Signature: Sinisa Grkovic Digitally signed by Sinisa Grkovic Date: 2021.09.08 15:13:59 -04'00'

Print Name: Sinisa Grkovic, MEng, PEng

Title: Director of Engineering & Operations

Signature: R. Fernandes

Print Name: Remy Fernandes

Title: Chief Executive Officer

Date of Endorsement: Sep 15/2021

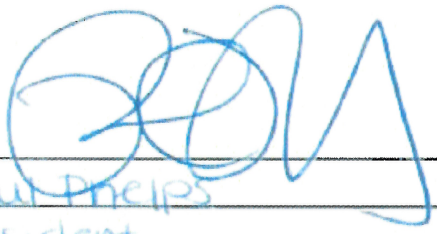
Grimsby Power Incorporated

Residential Subdivision Development Agreement

Corporate Name of Developer:	Phelps Homes LTD.	
Name of Development	211, 229 and 265 CENTRAL AVENUE (LEGACY)	
Approximate Location of Development:	North side of Central Ave between Park Road and Baker Road	
Number of Electrical Connections	94	
Type and Number of Dwellings	Single Detached Units Row House Units Semi-Detached Units	 93
Date:	January 2, 2019	

IN WITNESS WHEREOF the said parties hereto have executed *The Agreement*.

For *The Developer*

Signature: 

Print Name: Paul Phelps

Title: President

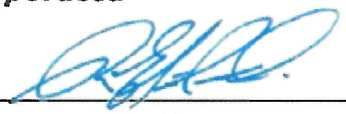
Signature of Witness: KRitchie

Print Name of Witness: Katie Ritchie

Title of Witness: Executive Assistant to Paul Phelps

Date of Endorsement: January 9, 2019

For *Grimsby Power Incorporated*

Signature: 

Print Name: Rosso Parra, P.Eng.

Title: Engineering Supervisor

Signature: R. Fernandes

Print Name: Remy Fernandes

Title: Chief Executive Officer

Date of Endorsement: January 29th, 2019

2-Staff-22

Defective Pole Replacements
Ref: Exhibit 2, Tab 3, Attachment 1, pp. 124-125 of 678

Preamble:

In the material investment summary for the defective pole replacements project, it was stated that:

> On average, GPI estimates to replace approximately 109 poles per year over the forecast period.

Grimsby Power also noted that:

> In the past 5 years, GPI has replaced approximately 20 poles, or 0.5%, of the total number of poles per year and it is targeting to increase that number to 75 poles, or 2.0%, of the total number of poles per year as per Asset Condition Assessment completed in Jan. 2019.

Question(s):

a) Please explain the discrepancy between the target of 109 poles vs. 75 poles per year over the forecast period.

b) Please explain how the forecast cost for the defective pole replacement program was derived (e.g., Did Grimsby Power rely on the historical unit cost information?).

c) Does Grimsby Power plan to maintain or improve its reliability objectives with the implementation of its DSP?

Response:

a) Statement on page 125 of 678 should be corrected to state 36 vs approximately 20 poles and 109 vs 75 poles. Full statement with the two corrections should read ‘In the past 5 years, GPI has replaced 36 poles per year on average and it is targeting to increase that number to 109 per year on average as required by the recommendations made in the ACA issued in Jan.2019.Table below demonstrates Grimsby Power’s asset replacement plan for Defective Poles (Wood) which was reflected in the current COS Application

Asset Conditions Assessment Summary (Table 3 of ACA submitted in 2018; Issued in 2019)		2019	2020	2021	**2022**	**2023**	**2024**	**2025**	**2026**	2027	2028	DSP 2022 - 2026		GPI 2019 - 2028	ACA 2019 - 2028
												Total	Avg	Total Avg	Total Avg
Defective Pole Replacement - Wood	ACA	143	109	109	109	109	109	109	109	43	545	109	109	993 113	993 99
	Plan	50	75	100	115	125	120	95	90	90	85	545	109	945 96	945 95
	Actual	50	75	NA	NA	NA	NA	NA	NA	NA	NA				

b) Historical unit cost information for pole replacement program was considered as one of the contributing factors in the development of the forecast cost for the defective pole replacement program. Additional contributing factors that were not considered are type of soil (i.e. rock vs sand), amount of circuits on the poles (i.e. single vs double circuits), amount of additional equipment on the poles (i.e. poles that contain switching devices), etc. All these items are contributing factors that were not considered in the past for unit costs forecasts of this replacement program.

c) Grimsby Power's strategic objective is to build and maintain a reliable cost-effective distribution system with the implementation of its DSP. Completing Defective Pole Replacement program along with completing all other Capital Programs/Projects as per ACA will enable Grimsby Power to at least maintain (and in some cases improve) its' existing reliability.

2-Staff-23

Rear Lot Supply Relocation
Ref: Exhibit 2, Tab 3, Attachment 1, page 133 of 678

Question(s):

a) In the material investment summary for the rear lot supply relocation project, Grimsby Power stated that there are no equivalent projects/programs over the historical period. Please explain how the forecast budgets of $598,550 for 2022, $298,000 for 2025 and $315,000 for 2016 were derived. Please explain all assumptions, data and methodology utilized in the forecast.

b) In Grimsby Power's service area, approximately how many houses/customers are currently served by rear lot overhead supply?

c) Please explain the role that customer requests play in the decision to implement rear lot supply relocation projects.

d) How many houses/customers will be transitioned to front-side underground supply in each of the years over the forecast period? How many houses/customers will remain on rear lot supply at the end of the forecast period, if any?

e) Please explain the rationale for replacing rear lot overhead supply with underground supply instead of overhead supply.

f) In the proposed relocation projects, are there any assets being replaced earlier than would otherwise be warranted by their conditions?

g) Over the historical period (2016-2020), how many interruptions have been associated with existing rear lot supply infrastructure?

h) Grimsby Power stated that "Operational costs (trouble calls, rear lot line clearing, plant replacement) are also expected to decrease with underground front yard supply." Is there any way to quantify the expected operational cost savings?

Response:

a) There are numerous disadvantages associated with rear lot systems:
- Increased safety hazards associated with:
  - Falling trees and branches

- Tight work spaces
- Poor visibility at night
- Lack of ability to use standard equipment such as bucket trucks. Poles typically require use of cranes over residences.
- Need to climb deteriorated poles
- Assets used are obsolete and designed to legacy standards

- Reduced reliability associated with:
- Areas tend to be heavily treed and suffer from frequent tree brush contact and damage from falling trees
- Difficult for crews to reach for maintenance and outage restoration
- Fault detection and isolation issues associated with lack of remotely operated switches, reclosers, and fault indicators
- Trees and fences significantly increase difficulty for crews to troubleshoot outages and locate faults.
- Increased interactions with residents as a result of requiring backyard access hence increasing outage restoration duration.
- The location and condition of the infrastructure significantly reduces resiliency to climate change including storms and severe weather events

GPI considered 3 options for rebuilding the rear lot projects:

Option 1: Relocate to front lot using overhead distribution

Scope of work includes removal of existing rear lot hydro owned equipment and supplying customers from the front of the lots using overhead hydro infrastructure.

Considering the telecommunication lines are located in the rear lot, the existing pole line in the backyards would have to remain in service. New pole lines would have to be installed complete with associated assets including primary/secondary conductors, guying/anchoring, and pole mounted transformers. In addition, extensive tree trimming and tree removals would be required to ensure minimum clearances from overhead hydro infrastructure is maintained.

This option does not align with GPI's design practices for supplying residential developments (i.e. subdivisions) and does not align with the Town of Grimsby's preference. This option is also not favorable to customers as it harms the aesthetic value of the front lots in their neighborhoods, with high probability of complaints that could trigger project postponement or redesign and ultimately increasing the cost and duration of the projects. Furthermore, because communication lines are typically supplied through the rear, there will be an increased amount of overhead lines in the neighborhoods.

Option 2: Relocate to front lot using underground distribution

Scope of work includes removal of existing rear lot hydro owned equipment and supplying customers from the front of the lots using underground hydro

infrastructure. This would entail installation of underground primary and secondary duct structure with cables, pad mounted transformers and kiosks.

This option aligns with GPIs practices to supply new subdivision developments using underground infrastructure. This also aligns with Town of Grimsby's preference and with previously completed conversion project east of the forecasted projects. Moreover, this option yields reliability benefits from faults associated with animal contact, tree contact, and damage from falling tree branches during severe weather storms.

Option 3: Maintain same location of rear lot pole lines

Scope of work includes replacement of aging and non-standard equipment. This would involve installing new poles, transformers, and conductors. Extensive tree trimming would also be required to meet minimum clearances between vegetation and hydro infrastructure.

This option could reduce the number of outages experienced and would mitigate issues related to deteriorated assets, but it would not address the remaining safety hazards and reliability issues associated with prolonged restoration and accessibility issues.

Conclusion

There are 2 projects (Burgess and Nassau) proposed for execution between 2022 and 2026. The aggregate high level cost estimate to complete the rear lot conversion projects using the 3 options are listed below:

Option	High Level Estimate
Option 1: Relocate to front lot using OH distribution	$ 1,065,671
Option 2: Relocate to front lot using UG distribution	$ 1,211,550
Option 3: Maintain same location of rear lot pole lines	$ 747,307

Option 2 was selected because it aligns with current standard design practices and increases the safety and reliability of the system. It reduces the time and effort required to respond to power outages in the area and maintains neighborhood aesthetics. This option also aligns with previously completed conversion project just east of the forecasted projects, and going with an overhead supply will lead to resident complaints that could trigger project postponement or redesign and ultimately increasing the cost and duration of the projects.

Cost for Option 2 of $1,211,550 is budgeted costs for these projects (Burgess and Nassau) and it has been reflected in Grimsby Power's budgets over the forecasted period ($598,550 for 2022, $298,000 for 2025 and $315,000 for 2026).

For the detailed breakdown of High Level Estimate costs for the selected Option 2 please see the table below with detailed estimate breakdown.

Description	QTY				Labour	Material	Total	
	Burgess	Nelles	Nassau	Total				
Option 1: Relocate to front lot using OH distribution								Post Estimating Note: Nelles area to be done as part of Burgess and Nassau. (i.e. Nelles's units broken down and added to Burgess and Nassau units).
House Conversions	45	39	32	116	$ 5,000		$ 580,000	
Pole Installation	15	13	13	41	$ 2,000	$ 1,500	$ 143,500	
Anchor	7	4	4	15	$ 800	$ 400	$ 18,000	
Downguys	14	7	8	29	$ 300	$ 120	$ 12,180	
OH Tx	5	3	2	10	$ 2,630	$ 3,000	$ 56,300	
OH Primary	900	500	915	2315	$ 15	$ 4	$ 44,242	
OH Secondary Bus	900	560	1050	2510	$ 15	$ 4	$ 47,690	
OH Secondary Service	1300	1000	810	3110	$ 15	$ 4	$ 59,090	
OH Secondary Service for S/L servicing	150	130	130	410	$ 15	$ 4	$ 7,790	
Design and Execution (10%)							$ 96,879	
							$ 1,065,671	
Option 2: Relocate to front lot using UG distribution								
Amount in DSP	598550	613000					$ 1,211,550	
Option 3: Maintain same location of rear lot pole lines								
Estimate proposed poles (Including Removal of Existing)	25	7	16	48	$ 8,500	$ 1,500	$ 480,000	
OH Tx	5	3	2	10	$ 2,630	$ 3,000	$ 56,300	
OH Primary	380	300	1025	1705	$ 15	$ 4	$ 32,395	
OH Secondary Bus	1550	830	610	2990	$ 15	$ 4	$ 56,810	
OH Secondary Service	1155	930	750	2835	$ 15	$ 4	$ 53,865	
Design and Execution (10%)							$ 67,937	
							$ 747,307	

b) In Grimsby Power's service territory list of all customers that are currently served by rear lot overhead supply are:

Governors Rd – approximately 50 services
Burgess Dr – approximately 67 services
Nassau Dr – approximately 48 services
Lakeside Dr/Rodney Ave/Cottage Ave/Stanley Ave – approximately 44 services

Please note that the arrangement/size of homes and existing rear lot overhead lines are different from area to area so in some areas cost of the removal of rear lots supplies are different and not directly related to the number of homes (i.e. distance of overhead lines in Burgess Dr areas are longer than those in Governors Rd area).

c) Grimsby Power values customer feedback and hence actively seeks for customer feedback via Customer Satisfaction Surveys. More specifically for real lot conversion projects all affected customers were contacted prior to Grimsby Power initiating any work activities (please see below sample of the letter that each affected customer has received). All of the customers for Governors Rd project were very supportive and willing to participate with the Grimsby Power rear lot conversion project at this location.

d) Grimsby Power plans to transition all homes at Burgess Dr (67 services) in 2022 (test year) and all homes at Nassau Dr (48 services) in 2026. Please note that planned budget for this program at Nassau Dr in 2025 is related to work associated with underground supply portion only. At the end of the forecast

period there will be approximately 44 services in Lakeside Dr/Rodney Ave/Cottage Ave/Stanley Ave area that will remain on the rear lot supply.

Finally, please note that services at Lakeside Dr/Rodney Ave/Cottage Ave/Stanley Ave have different layouts (i.e. newer area with larger access points) and there is room to convert them to front overhead supply. This work will be planned to be completed outside of the forecasted period. For detailed view of services converted by year please see table below.

	Year of Conversions / Approximate amount of services converted				
Area of Rear Lot Conversions	2022 Test Year	2023	2024	2025	2026
Burgess Dr	67				
Nassau Dr					48

e) During planning activities for this program Grimsby Power considered various options (one of them being replacing the existing rear lot overhead supply with the front lot overhead supply). For this design solution new pole lines would have to be installed complete with associated assets including primary/secondary conductors, guying/anchoring, and pole mounted transformers. In addition, extensive tree trimming and tree removals would be required to ensure minimum clearances from the overhead hydro infrastructure is maintained as these areas have many mature trees. This design option also does not align with Grimsby Power's design practices for supplying residential developments (i.e. subdivisions) and does not align with the Town of Grimsby's preference for subdivisions. This option is also not favorable to customers as it harms the aesthetic value of the front lots in their neighborhoods, with high probability of complaints that could trigger project postponement or redesign and ultimately increasing the cost and duration of the project.

f) The majority of assets being replaced are past their useful life as the electrical supply in this area was installed in 1950s and 1970s. Any assets (i.e. like some pole mounted transformers) that may have still have useful life remaining will be evaluated and refurbished if possible.

g) During the historical period (2016-2020) Grimsby Power had 9 interruptions associated with the failures of existing rear lot supply infrastructure in these 3 areas. If these assets were underground such failures would not occur. It is relevant to note that out of 28 poles in the Governors Rd area, 17 poles are listed as potential poles that need to be replaced. Similarly, out of 21 poles in the Burgess Dr area, 8 poles are listed as the potential poles that need to be replaced (along with 5 poles owned by Bell) and finally out of 18 poles in the Nassau Dr area, 5 poles are listed as the potential poles that need to be replaced as per our ACA (along with 7 poles owned by Bell that also need replacement).

h) Grimsby Power's costs to replace such equipment in the rear lots is much higher when compared to the costs to replace same equipment where access is not an issue. Also please note that Grimsby Power's restoration time is also longer for the outages in these areas as getting an access is much harder in these areas. Please see the table below that compares these costs and outage duration times.

EVENT	YEAR	LOCATION	CODE DESCRIPTION	CODE	DURATION (HOURS DECIMAL)	COST TO REPAIR	AVE. COST TO REPAIR SIMILAR CAUSE AT TYPICAL LOCATION - NOT A REAR LOT LOCATION	AVE. DURATION OF OUTAGE IN OTHER TYPICAL LOCATION - NOT A REAR LOT LOCATION
1	2016	7 Naussau / Nelles S	Defective Equipment	5	1.28	$ 677.58	$ 150.91	0.50
2	2017	17 McNab	Unknown/Other	0	2	$1,341.28	$ 575.73	1.00
3	2018	87 Dorchester	Defective Equipment	5	2.67	$ 718.57	$ 185.69	1.00
4	2018	4 Nelles Rd	Defective Equipment	5	2	$1,291.73	$ 148.94	0.50
5	2019	Nelles Rd South	Defective Equipment	5	2.38	$ 539.71	$ 112.86	1.00
6	2019	16 McNab Dr	Defective Equipment	5	1.58	$ 563.23	$ 144.80	1.00
7	2020	15 McNab	Defective Equipment	5	3	$ 553.88	$ 153.37	1.00
					14.91	$5,685.98	$ 1,472.31	6.00

From the table above it is noticeable that the opportunity cost savings for Grimsby Power are significant once this supply gets converted from the overhead rear lot supply to the underground front supply. One of the main drivers for the execution of this program is the Safety of the general public. Grimsby Power does not want to be in the situation when some of this rear lot supply infrastructure starts to fail prematurely. In many instances we have our rear lot infrastructure in these areas over customers' pools and seated areas. Rear lot conversions will ultimately result in the safer designs, faster restorations and less service calls to these areas.

Grimsby Power Inc.
Tel: (905) 945-5437
Fax: (905) 945-9933
231 Roberts Road
Grimsby, Ontario, L3M 5N2
www.grimsbypower.com

Memorandum

To: Residents on Governors Road & Dorchester Drive

From: Kevin Robins, Operation Supervisor (E.T.)

Date: December 10, 2020

Re: Notification of Commencement of Underground Utility Conduits Installation on Governors Road and Dorchester Drive for Grimsby Power – Phase I - Town of Grimsby

Dear Resident:

Please be advised that the construction for the required ducts for the above noted is scheduled to start on December 14, 2020. The installation of ducts will be along Governors Rd & Units 44-94 along Dorchester Dr. The installation method shall be by “Directional Boring” (Figure 1) which will minimize the impact on existing driveways. In case where driveways are required to be accessed, the restoration of these locations will be completed by Grimsby Power at Grimsby Power’s expense. Grimsby Power has retained Wiens Underground Electric Ltd. Group to complete these works on their behalf. The work is expected to be completed by mid-February 2021.

You will be contacted in the event of any foreseen interruptions to you during this time. There is no expected power outage required for the mentioned construction efforts. Construction activity will be between the working hours to of 7:00am to 7:00pm.

If you have any questions or concerns regarding the work being carried out, please direct them to the contractor or this office at:

Grimsby Power Inc. (Operation Supervisor)	attn: Kevin Robins	905-945-5437 Ext. 227
Wiens Underground Electric Ltd.	attn: Carl Braun	905-682-5060

If you require additional information, please contact the Town of Grimsby at 905-945-5437

In case of an emergency after hours, please contact the Operation Supervisor, **Kevin Robins at 905-945-5437 Ext. 227**.

Yours truly,
Kevin Robins, C.E.T. – Grimsby Power Inc.

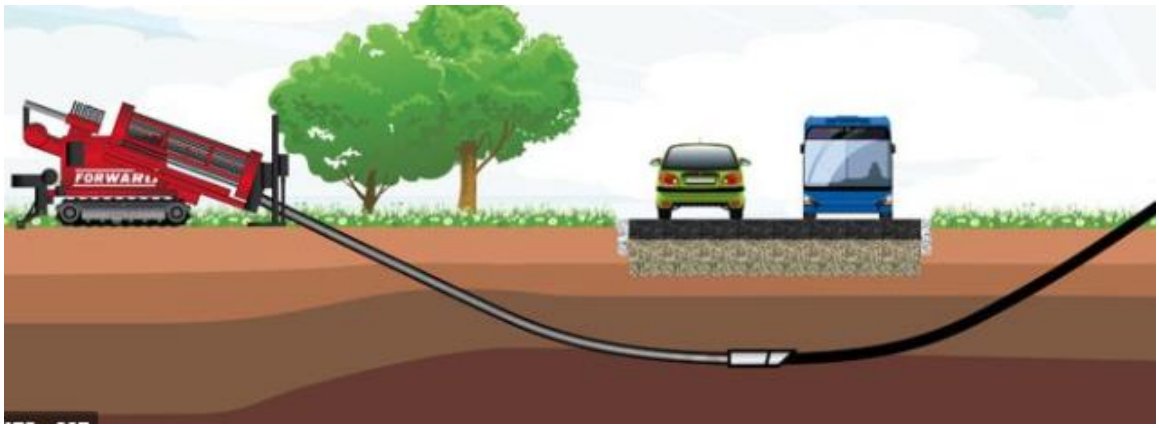


Figure 1: Directional Boring Method

2-Staff-24

Health Index Results
Ref: Exhibit 2, Tab 3, Attachment 1, page 59 of 678

Preamble:

Grimsby Power provided its health index results summary in Table 19.

Question(s):

a) Please indicate what steps are being taken to improve the low data availability indicator for the pad-mounted switchgear asset class.

b) Please indicate what steps are being taken to address the data gaps at the component-level for pole mounted transformers, overhead lines and overhead switches and underground cables.

c) Considering there is no component-level data for all the overhead asset groups and underground cables, please explain to what extent Grimsby Power relied on the condition assessment results on these asset groups for forecasting the associated renewal expenditures.

Response:

a) Grimsby Power conducts visual inspections of pad-mounted switchgears in accordance with the Distribution System Maintenance and Inspection program (Exhibit 2, Tab 3, Attachment 1, page 310 of 678). Furthermore, as part of Distribution System and Inspection program GPI has also implemented infrared thermographic imaging as part of the inspections to determine if there are any abnormalities present which require attention. With the introduction of infrared thermography Grimsby Power is planning to improve data availability indicators for the pad mounted switchgear. For the same reason Grimsby Power has also added a feature of ultrasound analysis to be used in the situations when thermography provides limited results.

b) As referenced above, Grimsby Power does visual inspections of the overhead pole-mounted transformers, overhead switches and overhead lines in accordance with the Distribution System Maintenance and Inspection program (Exhibit 2, Tab 3, Attachment 1, page 310 of 678). Thermographic imaging of overhead transformers and overhead switches is also being incorporated to further identify any hot spots or loose connections at these locations. For

underground cables, Grimsby Power secures a third-party firm to conduct cable testing to determine the integrity of the underground cables. A final report prepared by Metsco in 2019 (Exhibit 2, Tab 3, Attachment 1, page 341 of 678) outlines the methodology and results of their testing. The results demonstrated that the underground cables within the study set yielded acceptable levels with no imminent cable replacement required.

c) Grimsby Power's plan is to cover all of the component level data for all of the overhead asset groups via consistent execution of Grimsby Power's Distribution System Maintenance and Inspection Program (Exhibit 2, Tab 3, Attachment 1, page 310 of 678) and Thermographic Imaging for overhead equipment. For underground cables Grimsby Power has a plan in place to continue third-party cable testing in effort to cover all component level data for this underground asset group.

2-SEC-7

[Ex.2, Tab 1, p.2; Ex.2 Tab 2, p.7] Please provide a revised version of Tables 2-1 and 2-19 that include 2021 year-to-date actuals, as well as at the same point in time in the year, both 2019 and 2020 year-to-actuals.

Response:

Please find the updated tables below:

Updated Table 2-1

Fixed Assets Description	August 2019	August 2020	August 2021
Gross Fixed Assets, Opening Balance	31,790,298	33,913,829	35,408,506
Gross Fixed Assets, Closing Balance	32,091,784	34,324,092	36,086,195
Average Gross Fixed Assets	**31,941,041**	**34,118,960**	**35,747,351**
Accumulated Depreciation, Opening Balance	8,474,431	9,519,127	10,657,751
Accumulated Depreciation, Closing Balance	9,483,108	10,645,836	11,825,265
Average Accumulated Depreciation	**8,978,769**	**10,082,482**	**11,241,508**
Average Net Book Value	**22,962,272**	**24,036,479**	**24,505,843**

Eligible Working Capital Expenses	August 2019	August 2020	August 2021
Cost of Power	17,807,588	22,865,468	21,708,325
Operations	538,593	629,331	607,012
Maintenance	409,831	443,393	374,915
Billing & Collecting	389,742	360,083	380,293
Admin & General Expense	732,922	764,838	951,213
Donations - LEAP	6,303	6,303	6,303
Property Taxes	22,667	24,988	26,410
Total Eligible Working Capital Expenses	**19,907,646**	**25,094,405**	**24,054,473**
Working Capital Allowance (%)	7.50%	7.50%	7.50%
Working Capital Allowance	**1,493,073**	**1,882,080**	**1,804,085**
Rate Base	**24,455,345**	**25,918,559**	**26,309,928**

Updated Table 2-19:

	As August 31		
	2019	**2020**	**2021**
CATEGORY	**Actual**	**Actual**	**Actual**
System Access	75	349	98
Sustem Renewal	280	148	359
System Service	7	30	171
General Plant	55	124	91
TOTAL EXPENDITURES	418	651	719
Capital Contribution	(42)	(194)	(39)
Net Capital Expenditures	376	457	680
System O&M	948	1071	982

2-SEC-8

[Ex.2, Tab 1, p.7] Please provide cost details and anticipated completion time of projects that contribute to the increase in gross fixed assets in-service of $1,809,104 in 2020 in comparison to 2019.

Response:

Please see tables below that show cost details of all projects that contribute towards the increase in gross fixed assets in-service for 2019 and 2020. All those programs/projects have been completed except for Project – Third Feeder from NW MTS which has in-service target date Nov.30th, 2021 and Project- CNR Pole Line (18M4) relocation/rerouting which has in-service target date in 2025.

Projects	2019	2020
System Access		
Residential Expansion	274,825	627,134
Project - New Customer Connections	76,580	65,127
Project - Residential Subdivision Development	43,717	7,064
Program - Modifications to Existing Customer Connections	82,504	40,458
Sub-Total	477,626	739,783
System Renewal		
Program - Replace Defective Poles	258,744	251,174
Program - Secondary Bus Refurbishments		175,417
Program - Replace Sectionalizing Terminal	13,917	31,695
Program - Replace Gang Operated Load Break Switch	44,438	
Program - Primary Cable Testing	125,739	
Program - Replace Pad Mounted Transformers	168,694	56,740
Program - Primary Cable Silicon Injection		38,815
Program - Rear Lot Conversion		12,760
Program - Niagara West MTS	33,398	11,705
Program - Voltage Conversion	424,387	62,182
Project - CNR Pole Line (18M4 Feeder) Relocation / Rerouting		20,557
Sub-Total	1,069,317	661,046
System Service		
Program - Primary OH Conductor and UG Cable Reinforcements		166,954
Project - Third Feeder from NW-MTS	99,969	36,927
Project - NWTS Automation & Improvements	45,770	82,271
Project - Replace Manually Operated Pad Mounted Switchgear with an Automated/Remote Controlle	103,447	
Project - Pole Line Upgrade	233,275	
Sub-Total	482,460	286,152
General Plant		
Program - Computer Workstations	14,380	23,428
Program - Server/Network Hardware Upgrades due to Cyber Security	36,301	22,796
Software		39,370
Project - SCADA System and Improvements	65,044	26,636
Vehicle - Trucks & Forklift	198,425	123,960
Building Upgrades	10,399	17,819
NWTS - Upgrades	280	
Tools - Replacement	49,998	15,009
Communication Equipment	3,200	6,573
Miscellaneous	3,501	1,973
Sub-Total	381,528	277,564
Total	**2,410,931**	**1,964,545**
Total	**2,410,931**	**1,964,545**
Deferred Revenue (Capital Contribution)	**(214,248)**	**(461,764)**
Total Additions	**2,196,683**	**1,502,780**

	2019	2020	Variance
Opening Balance	31,790,290	33,913,821	**2,123,531**
Additions	2,196,683	1,502,780	**(693,903)**
Dispositions	(73,152)	(8,103)	**65,049**
Closing Balance	33,913,821	35,408,498	**1,494,677**
Average Gross Fixed Assets	**32,852,056**	**34,661,160**	**1,809,104**

2-SEC-9

[Ex.2, Tab 1, p.8] Please provide anticipated completion time of the referenced System Renewal and System Service projects.

Response:

Major projects that are part of the approved budget under System Renewal for Bridge Year 2021 are Program – Replace Defective Poles 2021, Program Rear Lot Conversion – Governors Rd and Project 18M4 Feeder Relocations – Phase 1 (these 3 projects/programs account for approximately 74% of total approved budget for System Renewal in 2021). Anticipated completion date for Program – Replace Defective Poles 2021 and Program Rear Lot Conversion – Governors Rd is Dec.24th, 2021 (as originally planned). Project 18M4 Feeder Relocations – Phase 1 is slightly behind planned schedule due to COVID pandemic caused delays, but we will increase construction efforts in the last quarter of the year to bring this project back on schedule and get it in service by year end, as per our original plan.

One major project that is part of the approved budget under System Service for Bridge Year 2021 is the project Third Feeder for NW MTS (this project accounts for approximately 88% of total approved budget for System Service in 2021). Target in service date for this project is Nov.30th, 2021 (as originally planned).

2-SEC-10

[Ex.2 Tab 1, p.9] The variance between the 2022 Test Year and the 2021 Bridge Year rate base is the highest since GPI's last application in 2016. Please provide a table showing evenly paced increase in capital expenditure during the period from 2016 to 2026.

Response:

For a table showing historical variance analysis of capital expenditures and capital expenditures over forecasted period please see Appendix 2-AB (Exhibit 2, Tab 2, Attachment 1).

2-SEC-11

[Ex.2, Tab 2, p.7] Please provide explanations to the underspent in capital expenditures in each year from 2016 to 2019.

Response:

For the explanation of variances (which includes underspent) of capital expenditures over historical period (2016 – 2020) please see Exhibit 2, Tab 3, Pages 89-95.

2-SEC-12

[Ex.2 Tab 2, Attachment 1, p.1] Please provide a revised version of Appendix 2-AB that includes as the 2021 'Plan' amount, the Applicant's internal forecast expenditures approved at the beginning of the year.

Response:

In Appendix 2-AB the "Plan" columns from 2016 to 2020 represents the 2016 Board Approved Capital Expenditures. The 2016 Board Approved Capital Expenditures was for the next five years and did not have the figures for 2021.

The "Actual" column contains the 2021 budgeted amounts as approved by the GPI Board.

2-SEC-13

[Ex.2, Tab 2, p.10] Please provide cost details of the Casablanca Blvd project, including cost forecast of the project and actual capital expenditures incurred to date. Pleas also provide anticipated completion time of the project.

Response:

For answers to this question please refer to answers to 2-Staff-10.

2-SEC-14

[Ex.2, Tab 2, p.10] Please provide cost details for the additional 3rd feeder from NW MTS. Please confirm 2022 Test Year forecast does not include cost related to the additional 3rd feeder.

Response:

Please see below cost details for the additional 3rd Feeder from NW MTS. This Estimate Cost breakdown was used as a basis of Grimsby Power and NPEI's Cost Sharing Agreement (issued Feb.24, 2021) for the addition of Grimsby Power's Third Feeder at NW MTS. Please note that highlighted amount of $735,911.39 is the budgeted amount that can be seen for this project at Appendix 2-AA (Exhibit 2, Tab 3, Attachment 1, Page 88 of 678).

2022 Test Year Forecast does not include costs related to the additional 3rd feeder. Target in service date for the Third Feeder at NW MTS is Nov.30th, 2021.

2020-008 Grimsby Power M8 Feeder Estimate Breakdown - Dec 07, 2020	
45' Pole Build Estimate	
Item	Total (Without HST)
Equipment	$154,440.00
Labour	$515,727.28
Material	$201,057.12
Accounts Payable (Vac/Traffic/Civil)	$232,654.00
Sub Total	*$1,103,878.40*
45' Poles, 50 Percent Estimate	*$551,939.20*
Full Height Build Estimate	
Equipment	$154,581.75
Labour	$516,808.73
Material	$336,556.11
Accounts Payable (Vac/Traffic/Civil)	$279,904.00
Sub Total	*$1,287,850.59*

Estimated Cost Difference	
45' Estimate	$1,103,878.40
Full Height Estimate	$1,287,850.59
Estimated Cost Difference	*$183,972.19*

Grimsby Power Portion	
45' Poles, 50 Percent Estimate	$551,939.20
Estimated Cost Difference	$183,972.19
Sub Total	*$735,911.39*
HST	*$95,668.48*
Total Estimated Cost	*$831,579.87*

Removal of Station Egress, Cable and Civil	
Material	$14,770.25
Labour	$11,943.28
Equipment	$7,120.00
Civil(Material/Labout/Equipment)	$14,350.00
Sub Total	*$48,183.53*
50% of Sub Total	*$24,091.77*

Adjusted Grimsby Power Portion Feb 23, 2021	
Removal of Station Egress	$24,091.77
Dec 2020 Estimate	$735,911.39
Sub Total	*$711,819.63*
HST	*$92,536.55*
Total Estimated Cost	*$804,356.18*

2-SEC-15

[Ex.2, Tab 3, Attachment 1, p.87, Table 28] The Applicant has provided forecast capital expenditures by category between 2023 and 2026 in Appendix 2-AB. Please provide a revised version of Appendix 2-AA that includes planned expenditures between 2023 to 2026.

Response:

Appendix 2-AA between 2023 and 2026

Projects	2023	2024	2025	2026
System Access				
Residential Expansion	483,278	479,430	519,458	527,204
Project - New Customer Connections	22,400	17,150	31,500	28,000
Project - Residential Subdivision Development	45,266	39,250	40,035	40,836
Program - Modifications to Existing Customer Connections	13,893	14,171	14,454	14,743
Project - Metrolinx - Pole Line Relocation Due to Road Widening at Casablanca Blvd & Livingston Ave.	87,750			
Project - Main Street Road Widening from Casablanca to Oakes	60,000			
Sub-Total	**712,587**	**550,001**	**605,447**	**610,783**
System Renewal				
Program - Replace Defective Poles	558,190	569,353	580,741	592,355
Program - Secondary Bus Refurbishments	68,072	69,433	70,822	72,238
Program - Replace Sectionalizing Terminal	39,925	40,723	41,538	42,369
Program - Replace Gang Operated Load Break Switch	30,868	31,485	32,115	32,757
Program - Primary Cable Testing	32,353	33,000	33,660	34,333
Program - Replace Pad Mounted Transformers	60,047	61,248	62,473	63,722
Program - Rear Lot Conversion			298,000	315,000
Program - Niagara West MTS	102,000	104,040	106,121	
Program - Voltage Conversion				290,000
Project - CNR Pole Line (18M4 Feeder) Relocation / Rerouting		395,000	70,000	
Sub-Total	**891,453**	**1,304,282**	**1,295,468**	**1,442,774**
System Service				
Program - Primary OH Conductor and UG Cable Reinforcements	47,396	48,344	49,311	50,297
Program - Primary UG Cable Reinforcements	38,361	39,128	39,911	40,709
Project - Monitoring and Control - Fault Indicators Installation and SCADA Integration			85,600	96,300
Project - Additional Feeder from NW-TS (2508-M7)	887,300	397,600		
Project - Adding two (2) phases of underground cable at Bal Harbour			144,000	
Project - Automate Primary 3 Phase Switches - Install Reclosures	165,008	126,231	42,919	43,777
Sub-Total	**1,138,065**	**611,303**	**361,740**	**231,083**
General Plant				
Program - Computer Workstations	10,200	10,404	10,612	10,824
Program - Server/Network Hardware Upgrades due to Cyber Security	1,040			
Software		30,000	70,000	
Project - SCADA System and Improvements	80,000	81,040	216,040	
Building Upgrades - Parking			100,000	
Building Upgrades - Elevetor/Wheelchair lifting device	300,000			
Building Upgrades - Replace existing HVAC System				385,000
NWTS - Upgrades		75,000		
Tools - Replacement		8,000		
Sub-Total	**391,240**	**204,444**	**396,652**	**395,824**
Total	**3,133,346**	**2,670,031**	**2,659,307**	**2,680,464**
Deferred Revenue (Capital Contribution)	**(326,917)**	**(322,453)**	**(347,292)**	**(354,238)**
Total	**2,806,429**	**2,347,578**	**2,312,015**	**2,326,227**

2-SEC-16

[Ex. 2, Tab 3, Attachment 1, p.61] Using the same asset categories as provided in Table 21, please provide the number of assets replaced or planned to be replaced for each year between 2016 to 2026.

Response:

Please see table below. Note that asset counts for years 2016 to 2021 (up to Aug.31st, 2021) are actuals and asset counts for 2022-2026 are forecasted values.

Asset Category	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Station Transformers	0	0	0	0	0	0	0	0	0	0	0
Station Circuit Breakers	0	0	0	0	0	0	0	0	0	0	0
Wood Poles	14	16	26	50	75	75	109	109	109	109	109
Concrete Poles	0	0	0	0	0	0	0	0	0	0	0
1Ph Pole Mounted Transformer	4	3	1	2	0	2	2	2	2	2	2
2Ph Pole Mounted Transformer	0	0	0	0	0	0	0	0	0	0	0
3Ph Pole Mounted Transformer	0	0	0	0	0	0	0	0	0	0	0
1Ph OH Lines	0	0	0	0	2.8	1	1	1	1	1	1
2Ph OH Lines	0	0	0	0	0	0	0	0	0	0	0
3Ph OH Lines	0	0	0	0	0	0	0	0	0	0	0
1Ph OH Switches	0	0	0	0	0	0	0	0	0	0	0
3Ph OH Switches	2	0	1	2	1	1	1	1	1	1	1
1Ph Pad Mounted Transformers	8	11	10	13	8	5	5	5	5	5	5
3Ph Pad Mounted Transformers	0	2	1	3	1	1	1	1	1	1	1
Pad Mounted Switchgear	0	1	0	1	0	0	0	0	0	0	0
1Ph Underground Cables	0	0	340	0	0	0	0	0	0	0	0
2Ph Underground Cables	0	0	0	0	0	0	0	0	0	0	0
3Ph Underground Cables	250/ph	0	0	700/ph	0	0	0	0	0	0	0

2-SEC-17

[Ex.2, Appendix 2-AA] For each system renewal, program included Appendix 2-AA, please provide a table that shows the number of assets replaced or planned to be replaced in each year between 2016 to 2022. Please provide the response in excel format.

Response:

Please see table below. Note that asset counts for years 2016 to 2021 (up to Aug.31st, 2021) are actuals and asset counts for 2022-2026 are forecasted values.

2-SEC-18

[Ex. 2, Tab 3, Attachment 1, p.111] With respect to the Residential Expansions:

a. The Applicant states: "New subdivisions/developments subject to economic evaluation. A subdivision/development will have a capital contribution from the developer that considers 25 years of operating revenue." Yet, the Applicant has not forecast any capital contributions related to its Residential Expansion Program between 2022 and 2026. Please reconcile.
b. For each year between 2016 and 2021, please provide the total capital contributions that Applicant has received regarding its Residential Expansion Program.

Response:

a. 2022-2026 forecasted Capital Contribution related to the Residential Expansion Program:

Description	2022	2023	2024	2025	2026
Residential Expansion					
Assumed Plant	226,085	95,383	57,957	100,234	102,239
Customer Work Orders	271,643	274,928	290,449	287,081	292,822
GPI	162,521	112,967	131,024	132,143	132,143
Total	**660,249**	**483,278**	**479,430**	**519,458**	**527,204**
Capital Contribution					
Capital Contribution - Assumed Plant	(164,835)	(51,988)	(32,005)	(60,211)	(73,213)
Capital Contribution - Customer Work Orders	(258,591)	(274,928)	(290,449)	(287,081)	(281,025)
Total	**(423,426)**	**(326,917)**	**(322,453)**	**(347,292)**	**(354,238)**

b. 2016-2021 Capital Contribution related to the Residential Expansion Program:

Description	2016	2017	2018	2019	2020	2021
Residential Expansion						
Assumed Plant	84,685	470,326	307,789	31,977	267,031	128,741
Customer Work Orders	248,900	469,816	258,573	200,917	272,553	300,241
GPI	115,703	129,239	56,644	41,931	87,549	69,145
Total	**449,288**	**1,069,380**	**623,006**	**274,825**	**627,134**	**498,127**
Capital Contribution						
Capital Contribution - Assumed Plant	(55,122)	(253,968)	(104,833)	(13,331)	(189,211)	(44,372)
Capital Contribution - Customer Work Orders	(248,900)	(469,816)	(258,573)	(200,917)	(272,553)	(300,241)
Total	**(304,022)**	**(723,784)**	**(363,406)**	**(214,248)**	**(461,764)**	**(344,613)**

2–VECC-6

Reference: Exhibit 2, Appendix 2-AB/ pages 4-

a) GPI's actual capital spending between the years 2016 and 2020 was over 18% lower than that projected in the prior distribution system plan (DSP). It is only by the end of 2021 that GPI will have spent the monies projected in the 2016-2020 DSP.
   i. Please outline which projects were not undertaken as anticipated during that period and the reasons why they were not completed.
   ii. Please describe what were the repercussions for Utility management in both failing to meet capital spending objectives and having a decline in reliability as measured by SAIDI and SAIFI over the rate plan.

b) Over the prior rate period, including 2021, Grimsby spent (or will have spent) an average of $2.081 million per year. For both 2022 and the remaining years of the new DSP the Utility spending on capital will be significantly in excess of this amount at $2.8 million.
   i. Please explain why there is a significant increase in annual spending and the major driver for this annual increase
   ii. Given the Utility's past performance showing it unable or unwilling to complete spending projected in the prior DSP what changes have been made that would indicate that the current plan proposals will be achieved?

Response:

a) i. Grimsby Power capital spending during the historical period was underspent for each of the historical years (2016-2020). Below is a detailed explanation that states reasons for such underspend.

2016

$377k underspend in System Access investment portfolio was primarily associated with residential expansion which contains Assumed Plant, Customer Work Order, and Residential subdivisions. GPI energized 22 connections in 2016, which was significantly lower than forecasted plan. GPI works closely with all applicable agencies to forecast approximate number of connections annually, but the actual timing of the connections is dependent on the external factors that cannot be controlled by GPI, such as development construction progress. The underspend variance in System Service portfolio was primarily associated with the deferral of NW MTS automation improvements, as well as reclosure installations that carried over to 2017. Finally, the underspend of $141k in General Plant portfolio was primarily associated with deferred purchasing of SCADA system equipment from 2016 to 2017.

2017
Underspend in System Renewal portfolio can be accredited to underspend in Pole Replacement Program (note that ACA did not get published yet at the time), no activity on 18M4 CNR Feeder Relocation (it was budgeted at $155k and nothing was spent), and miscellaneous deferrals of some renewal projects such as switchgear replacements.

2018
The underspend of $205k in System Access investment portfolio was primarily associated with the forecast for suite metering project (Lakehouse at 10 and 40 Esplanade Lane) which did materialize in 2018. Similar to 2017, underspend in System Renewal portfolio can be accredited to underspend in Pole Replacement Program (note that ACA was just being conducted but not yet officially issued at the time), reduced spending on 18M4 CNR Feeder Relocation (it was budgeted at $59k and spent $28k) and miscellaneous deferrals of some renewal project such as 3ph pad mounts replacements.

2019
The underspend of $428k in System Access investment portfolio was primarily associated with residential expansion which contains Assumed Plant, Customer Work Order, and Residential subdivisions. The number of connections that materialized in 2019 was significantly lower than the forecasted number. As mentioned in the 2016 variance analysis, GPI works closely with all applicable agencies to forecast the approximate number of connections annually, but the actual timing of the connections is dependent on the external factors that cannot be controlled by GPI such as development construction progress and changes to the occupancy dates.

2020
The underspend of $99k in System Access investment portfolio was primarily associated with residential subdivision development which slowed down due to Covid-19. The underspend variance in System Service investment portfolio was primarily associated with the deferral of the planned work for adding 3rd feeder from NW MTS. This deferral was due to the design changes required to satisfy requirements of both GPI, NPEI and local Municipal and Regional Authorities.

ii. Grimsby Power's Management has done their best to meet all of Grimsby Power's Corporate targets which amongst others contain

Variance in the Actual Capital Expense vs Budget and % Change in Corporate Reliability Targets. It is relevant to note that Grimsby Power had various weather events in 2019 which represented 80% of the SAIFI and 72% of the SAIDI for that year. For all other years Grimsby Power remains to be a leader (i.e. Top 2 in rankings) in the reliability when compared to other LDCs in the region. Please see table below that demonstrates this point.

SAIFI Avg. outage frequency (interruptions / customer) - Loss of Supply Adjusted										
	2016	**Rank**	**2017**	**Rank**	**2018**	**Rank**	**2019**	**Rank**	**2020**	**Rank**
Grimsby Power Incorporated	0.69	1	0.99	2	1.17	2	3.44	5	0.92	2
Canadian Niagara Power Inc.	2.29	5	2.33	5	2.73	5	3.08	4	2.71	5
Niagara Peninsula Energy Inc.	1.38	4	1.55	3	1.65	3	1.63	2	2.01	3
Niagara-on-the-Lake Hydro Inc.	1.03	3	0.88	1	0.48	1	0.38	1	0.52	1
Welland Hydro-Electric System Corp.	0.72	2	1.56	4	1.7	4	2.41	3	2.02	4

SAIDI Avg. outage duration (hours) - Loss of Supply Adjusted										
	2016	**Rank**	**2017**	**Rank**	**2018**	**Rank**	**2019**	**Rank**	**2020**	**Rank**
Grimsby Power Incorporated	0.55	2	1.20	2	1.73	3	5.00	4	0.64	1
Canadian Niagara Power Inc.	3.47	5	3.83	5	3.74	5	10.22	5	5.07	5
Niagara Peninsula Energy Inc.	1.52	4	1.37	3	1.98	4	2.03	3	2.15	3
Niagara-on-the-Lake Hydro Inc.	0.34	1	0.50	1	0.76	1	0.50	1	0.73	2
Welland Hydro-Electric System Corp.	0.63	3	1.83	4	1.46	2	1.71	2	2.36	4

b) i. Major driver to the increase in capital spending for 2021 is addition of the new feeder (i.e. Project – Third Feeder from NW MTS – M8) which was a direct outcome of performed Capacity Planning Study. Another major contributor to the increase in capital spending for 2021 is related to the increase in System Renewals investment category as Grimsby Power has aligned its' business plan with the recommendations of ACA when it comes to asset replacements. Major contributors to the capital spend over forecast years remain to be major projects that deal with ensuring adequate capacity levels are in service (i.e. Project Additional Feeder from NW MTS – M7 which is scheduled for 2023/24) and increase in System Renewal spending over all forecasted years (i.e. plan to align with ACA recommendations for asset replacements with the ultimate goal to sustain adequate system reliability levels).

ii. Grimsby Power recognizes past challenges in meeting approved capital budgets over the historical period. Grimsby Power has adjusted accordingly and is moving forward with the adjustments put in place (for a list of items that Grimsby Power has introduced in effort to meet the approved capital budgets please see answers to OEB Interrogatory 2-Staff-19b). Grimsby Power's capital spend actuals in 2021 (up to August 31, 2021 – please see OEB Interrogatory 2-Staff-19d) are a proof that Grimsby Power is managing to deliver on capital spending as per the approved levels.

2–VECC-7

Reference: Exhibit 2, Tab 1, page 19

a) Please update Appendix 2-BA 2021 Fixed Asset Continuity Schedule to show actual 2021 additions to date.

Response:

a) Appendix 2-BA 2021 Fixed Assets Continuity Schedule as of August 31, 2021:

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year YTD August 2021

			Cost				Accumulated Depreciation				
CCA Class	OEB Account	Description	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 882,928	$ 13,205.00		$ 896,133	$ (816,379)	$ (24,453.83)		$ (840,833)	$ 55,300
N/A	1805	Land	$ 149,992			$ 149,992				$ -	$ 149,992
47	1808	Buildings	$ 1,256,185			$ 1,256,185	$ (422,339)	$ (25,123.70)		$ (447,463)	$ 808,722
47	1808	Buildings	$ 15,279			$ 15,279	$ (1,748)	$ (611.17)		$ (2,359)	$ 12,920
47	1815	Transformer Station Equipment >50 kV (10)	$ 103,188	$ 67.73		$ 103,256	$ (41,338)	$ (10,322.21)		$ (51,661)	$ 51,595
47	1815	Transformer Station Equipment >50 kV (20)	$ 921,519	$ 11,907.55		$ 933,427	$ (564,138)	$ (72,348.53)		$ (636,487)	$ 296,940
47	1815	Transformer Station Equipment >50 kV (40)	$ 3,457,574	$ 3,039.80		$ 3,460,614	$ (1,088,048)	$ (86,266.01)		$ (1,174,314)	$ 2,286,299
47	1815	Transformer Station Equipment >50 kV (45)	$ 2,682,922			$ 2,682,922	$ (1,093,701)	$ (56,757.88)		$ (1,150,459)	$ 1,532,463
47	1815	Transformer Station Equipment >50 kV (50)	$ 77,279			$ 77,279	$ (30,383)	$ (1,421.08)		$ (31,804)	$ 45,475
47	1815	Transformer Station Equipment >50 kV (55)	$ 643,777			$ 643,777	$ (245,933)	$ (10,469.58)		$ (256,402)	$ 387,375
47	1830	Poles, Towers & Fixtures	$ 5,371,787	$ 226,755.03		$ 5,598,542	$ (1,113,522)	$ (143,838.45)		$ (1,257,360)	$ 4,341,182
47	1835	Overhead Conductors & Devices	$ 4,238,719	$ 216,910.75	$ (1,133)	$ 4,454,496	$ (511,250)	$ (74,893.82)	$ 1,133	$ (585,011)	$ 3,869,486
47	1840	Underground Conduit	$ 3,486,021	$ 2,340.45		$ 3,488,361	$ (623,879)	$ (82,329.22)		$ (706,208)	$ 2,782,153
47	1845	Underground Conductors & Devices	$ 3,432,387	$ 15,801.99		$ 3,448,189	$ (719,930)	$ (119,710.91)		$ (839,641)	$ 2,608,548
47	1850	Line Transformers	$ 5,975,868	$ 110,957.13		$ 6,086,825	$ (1,312,179)	$ (175,990.76)		$ (1,488,170)	$ 4,598,655
47	1855	Services - Overhead	$ 291,118	$ 12,857.99		$ 303,976	$ (35,717)	$ (5,121.13)		$ (40,838)	$ 263,139
47	1855	Services Underground	$ 1,998,481	$ 12,649.48		$ 2,011,130	$ (368,558)	$ (57,585.41)		$ (426,144)	$ 1,584,986
47	1860	Meters 15yrs	$ 2,123,071	$ 7,729.30		$ 2,130,800	$ (1,153,837)	$ (142,217.40)		$ (1,296,055)	$ 834,746
47	1860	Meters >50	$ 425,408	$ 5,039.48		$ 430,447	$ (130,541)	$ (18,699.42)		$ (149,240)	$ 281,207
47	1860	Meters CT's & PT's	$ 232,595	$ 195.85		$ 232,791	$ (42,926)	$ (6,888.34)		$ (49,814)	$ 182,977
N/A	1905	Land	$ 111,556			$ 111,556				$ -	$ 111,556
47	1908	Buildings and Fixtures (50)	$ 311,426			$ 311,426	$ (105,885)	$ (6,228.52)		$ (112,113)	$ 199,313
47	1908	Buildings and Fixtures (40)	$ 57,147			$ 57,147	$ (15,607)	$ (1,428.67)		$ (17,036)	$ 40,111
47	1908	Buildings and Fixtures (25)	$ 420,943	$ 7,724.40		$ 428,668	$ (112,266)	$ (16,966.15)		$ (129,232)	$ 299,436
8	1915	Office Furniture & Equipment (10 years)	$ 144,178			$ 144,178	$ (91,304)	$ (13,891.41)		$ (105,195)	$ 38,983
10	1920	Computer Equipment - Hardware	$ 202,248	$ 6,884.32		$ 209,133	$ (130,578)	$ (21,159.48)		$ (151,738)	$ 57,395
10	1930	Transportation Equipment (8)	$ 107,853	$ 45,521.00		$ 153,374	$ (46,533)	$ (11,557.46)		$ (58,090)	$ 95,284
10	1930	Transportation Equipment (15)	$ 1,235,422			$ 1,235,422	$ (384,110)	$ (83,686.64)		$ (467,797)	$ 767,625
8	1935	Stores Equipment	$ 135,923			$ 135,923	$ (9,515)	$ (9,460.26)		$ (18,975)	$ 116,947
8	1940	Tools, Shop & Garage Equipment	$ 267,118	$ 8,332.44		$ 275,450	$ (151,754)	$ (21,588.67)		$ (173,343)	$ 102,107
8	1945	Measurement & Testing Equipment	$ 45,372			$ 45,372	$ (42,203)	$ (1,718.11)		$ (43,922)	$ 1,451
8	1955	Communications Equipment	$ 79,405	$ 7,576.24		$ 86,981	$ (61,583)	$ (8,171.25)		$ (69,754)	$ 17,227
8	1960	Miscellaneous Equipment	$ 5,474	$ 189.05		$ 5,663	$ (646)	$ (547.35)		$ (1,193)	$ 4,469
47	1970	Load Management Controls Customer Premises	$ 16,439			$ 16,439	$ (10,401)	$ (1,643.88)		$ (12,045)	$ 4,394
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ 357,196	$ 1,872.95		$ 359,069	$ (47,830)	$ (17,077.31)		$ (64,907)	$ 294,162
47	2440	Deferred Revenue	$ (5,855,288)	$ (38,735)		$ (5,894,024)	$ 868,810	$ 161,526.84		$ 1,030,337	$ (4,863,687)
		Sub-Total	**$ 35,408,506**	**$ 678,822.48**	**$ (1,133)**	**$ 36,086,195**	**$(10,657,751)**	**$ (1,168,647)**	**$ 1,133**	**$(11,825,265)**	**$ 24,260,930**
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 35,408,506**	**$ 678,822**	**$ (1,133)**	**$ 36,086,195**	**$(10,657,751)**	**$ (1,168,647)**	**$ 1,133**	**$(11,825,265)**	**$ 24,260,930**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable									
		Total						**$ (1,168,647)**			

			Less: Fully Allocated Depreciation	
10		Transportation	Transportation	$ (95,244)
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 161,527
			Net Depreciation	$(1,234,930)

2–VECC-8

Reference: Exhibit 2, Appendix 2-AA

a) Please update Appendix 2-AA to show the 3rd quarter results for both 2020 and 2021.

Response:

a) GPI has completed only 8 months of 2021 financial statements. The table below shows Appendix 2-AA for 2020 and 2021 as of August 31:

Projects	2021	2020
System Access	97,669	348,520
Residential Expansion	55,312	53,606
Project - New Customer Connections	29,584	196,611
Project - Residential Subdivision Development	4,385	15,593
Program - Modifications to Existing Customer Connections	8,388	82,710
System Renewal	358,929	148,386
Program - Replace Defective Poles	183,191	125,315
Program - Replace Gang Operated Load Break Switch	45,268	
Program - Replace Sectionalizing Terminal	7,964	
Niagara West MTS - Replace Defective Battery Cells	14,520	
Program - Replace Single Phase Pad Mounted Transformers	30,194	23,071
Project - Secondary Bus Refurbishments	19,121	
Program - Replace Three Phase Pad Mounted Transformers	1,232	
Program - Rear Lot Conversion - Governors Road	54,202	
Program - Replace Interval Meter	3,236	
System Service	170,788	30,235
Project - Third Feeder from NW-MTS	-	4,459
Program - Voltage Conversion	157,271	5,000
Program - Primary OH Conductor Reinforcements	-	20,776
Project - Monitoring & Control - Fault Indicator & SCADA	13,517	
Distribution Assets Total	627,386	527,141
General Plant		
Program - Computer Workstations	4,820	37,804
Program - Server/Network Hardware Upgrades due to Cyber Security	11,205	34,270
Software	2,000	
Project - SCADA System and Improvements	3,937	14,338
Vehicle - Trucks & Forklift	45,146	24,792
Building Upgrades		2,980
Office Furniture	7,174	
Tools - Replacement	9,447	9,957
Communication Equipment	7,576	
General Plant Total	**91,305**	**124,140**
TOTAL	718,691	651,281

2–VECC-9

Reference: Exhibit 2, Appendix 2-AA

a) Please explain how the capital contribution forecast of 423k was calculated.
b) Please provide the forecast capital contribution for each of the projects listed under System Access (Appendix 2-AA) in 2022.

Response:

a) Please refer to 2-SEC-18 a)

b) The Capital Contribution is related to the Residential Expansion only as presented below:

Projects	2022 Test Year
System Access	
Residential Expansion	660,249
Capital Contribution - Assumed Plant	(164,835)
Capital Contribution - Customer Work Orders	(258,591)
Sub-Total - Residential Expension	**236,823**
Project - New Customer Connections	46,154
Project - Residential Subdivision Development	30,194
Program - Modifications to Existing Customer Connections	12,286
Project - Metrolinx - Pole Line Relocation	134,000
TOTAL	**$ 459,457**

2–VECC-10

Reference: Exhibit 2, Tab2, page 20

	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Bridge Year	2022 Test Year
Lineman's Expenses	$ 187,584	$ 211,392	$ 208,068	$ 197,992	$ 197,696	$ 236,646
Truck Expenses	$ 98,872	$ 142,765	$ 149,032	$ 173,812	$ 189,497	$ 192,610
Total OM&A Before Capitalization (B)	$ 286,456	$ 354,157	$ 357,100	$ 371,805	$ 387,193	$ 429,256

Capitalized OM&A	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Bridge Year	2022 Test Year	Directly Attributable?
Employee Benefits	$ 62,924	$ 94,217	$ 109,137	$ 83,672	$ 79,296	$ 113,722	Yes
Fleet Cost	$ 51,483	$ 71,675	$ 85,335	$ 68,255	$ 71,146	$ 58,498	Yes
Total Capitalized OM&A (A)	$ 114,406	$ 165,892	$ 194,473	$ 151,927	$ 150,442	$ 172,220	
% of Capitalized OM&A (=A/B)	39.94%	46.84%	54.46%	40.86%	38.85%	40.12%	

a) Please update Tables 2-26 and 2-27 to include the 2016 historical year.

Response:

a) Updated Table 2-26:

OM&A Before Capitalization	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Bridge Year	2022 Test Year
Lineman's Expenses	$212,056	$187,584	$211,392	$208,068	$197,992	$197,696	$236,646
Truck Expenses	$149,862	$ 98,872	$142,765	$149,032	$173,812	$189,497	$192,610
Total OM&A Before Capitalization (B)	$361,918	$286,456	$354,157	$357,100	$371,805	$387,193	$429,256

Updated Table 2-27:

Capitalized OM&A	2016 Historical Year	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Bridge Year	2022 Test Year
Employee Benefits	$102,400	$ 62,924	$ 94,217	$109,137	$ 83,672	$ 79,296	$113,722
Fleet Cost	$ 36,418	$ 51,483	$ 71,675	$ 85,335	$ 68,255	$ 71,146	$ 58,498
Total Capitalized OM&A (A)	$138,818	$114,406	$165,892	$194,473	$151,927	$150,442	$172,220
% of Capitalized OM&A (=A/B)	38.36%	39.94%	46.84%	54.46%	40.86%	38.85%	40.12%

2–VECC-11

Reference: Exhibit 2, Attachment 1, DSP, page 59

a) Please show the forecasted (or DSP objective goal) Average Health Index i.e., Table 19/Figure 18) at the end of the proposed DSP.
b) Please explain why GPI does not use a health index outcome measure as a metric of the success (or failure) of its DSP.

Response:

a) Grimsby Power's DSP objective goal is to effectively eliminate those assets that have been classified with 'very poor' conditions within the ACA. Asset categories with highest percentage of assets with 'very poor' conditions are Poles (Wood) and OH Lines (1-Phase and 3-Phase) and hence Grimsby Power's DSP is focused on those asset groups. Grimsby Power has structured its business plan to address this issue over the forecasted period and align with ACA recommendations for asset replacements. Table below demonstrates Grimsby Power's asset replacement plan for Defective Poles (Wood) which was reflected in the current COS Application.

Asset Conditions Assessment Summary (Table 3 of ACA submitted in 2018; Issued in 2019)		2019	2020	2021	**2022**	**2023**	**2024**	**2025**	**2026**	2027	2028
Defective Pole Replacement - Wood	ACA	143	109	109	109	109	109	109	109	43	545
	Plan	50	75	100	115	125	120	95	90	90	85
	Actual	50	75	NA	NA	NA	NA	NA	NA	NA	NA

Asset Conditions Assessment Summary (Table 3 of ACA submitted in 2018; Issued in 2019)		DSP 2022 - 2026		GPI 2019 - 2028	ACA 2019 - 2028
		Total	Avg	Total Avg	Total Avg
Defective Pole Replacement - Wood	ACA	109	109	993 113	993 99
	Plan	545	109	945 96	945 95
	Actual				

Note: this question and answer is aligned with 2-Staff-22

b) For some asset categories, Health Index outcome measure is based on the age of the equipment only. We have many assets that are past their service age and yet they are fully operational as they satisfy maintenance inspections criteria. Therefore, using a Health Index outcome measure as a metric of success (or failure) of DSP would not necessarily be adequate.

2–VECC-12

Reference: Exhibit 2, Attachment 1, DSP, page 67

a) Are the costs of the Distribution System Plant Inspections and Ground Level Maintenance inspections expensed or capitalized (or a combination of both)?

b) Are the Off-Road High Voltage Line Inspections costs capitalized or expensed (or a combination of both)?

Response:

a) All costs associated with Distribution System Plant Inspections and Ground Level Maintenance for existing assets are expensed by Grimsby Power.

b) All costs associated with Off-Road Distribution Line Inspections are expensed by Grimsby Power.

2–VECC-13

Reference: Exhibit 2, Appendix 2-AA

a) GPI forecast spending $258,550 on rear lot conversion in 2021. How much has been spent to date on these conversions.

b) Please identify the location of these conversions and the number of customers who service line has been converted.

Response:

a) As of August 31st, 2021 Grimsby Power forecast spending is at $351,880 (includes reported amount in WIP up to Aug.31, 2021) on rear lot conversions. Reasons for the forecasted overspend for this project are: additional surveying costs, extra excavations due to the locations of the gas lines, material delivery delays due to the Covid - negative impact on the crew mobilizations, etc.)

b) As of August 31st, 2021 no customers have officially been converted yet as the program is in it's last steps of construction for 2021 project (i.e. Governors Road). Please note that all directional drilling construction work activities related to the primary feed have been completed this year. Also completed are pad mount transformer installations. Currently Grimsby Power is working on secondary connections. Transfer of services and pole removals/cuts are the last remaining tasks. For more information on the amount of services and customers affected by this program please see response to OEB Interrogatory question 2-Staff-23.

2–VECC-14

Reference: Exhibit 2, Attachment 1, DSP, page 45, 133

a) GPI proposes to embark on significant spending (in excess of $1 million) for rear-lot plant replacements over the term of the DSP. Yet the main body of the DSP provides no background or details for this program. Please provide the following:
   i. The location and number of customers affected in each year of the replacement program.
   ii. The cost-benefit analysis supporting overhead to underground replacement showing the cost differential and expected reliability benefits as between the two types of plant replacement.
   iii. Correspondence showing that GPI has sought from the local municipal authority permission to move its plant to either overhead or underground. Specifically, please provide the correspondence which shows GPI is prohibited from providing overhead service and if prohibited what appeal process there is to that decision.
   iv. Please provide the customer engagement which was undertaken both showing the cost differential in different types of plant replacement and the areas/customers who would be affected.
   v. Please provide the outage history for the planned back-yard replacement areas for the past five years.
   vi. Please provide the reference in the Kinectrics 2018 Asset Condition Assessment which supports or recommends the replacement of rear lot plant.
   vii. Please provide the specific metric or measure that will be used to assess the level of success of this program.

Response:

a) i. Please see answer to OEB Interrogatory 2-Staff-23 (b)

   ii. Please see answer to OEB Interrogatory 2-Staff-23 (a)

   iii. Grimsby Power has not received any restrictions from the local municipality to move its plant to overhead installations. Overhead installation was one of the Options considered for this rear lot conversion project. For full cost benefit analysis for rear lot conversion projects please see OEB Interrogatory 2-Staff-23 (a).

   iv. In November of 2019 Grimsby Power conducted a customer engagement presentation wherein Grimsby Power provided the details of this project (along with other major initiatives) to customers. Customers had an opportunity to ask questions and discuss details about this and other projects. No negative feedback was received about

rear lot conversion projects. Grimsby Power has also contacted each affected customer for Governors Rd Lot Conversion Project and has not received a single customer complaint. To the contrary, all of the affected customers welcomed this initiative and were willing participants of this project (please see OEB 2-Staff-23 (c) for sample of Customer Letters). Furthermore, it is relevant to note that in the latest Customer Satisfaction survey that was conducted by Grimsby Power in 2021, 60% of verbatim commentaries received, that were related to Capital Work plans, were explicit in their comments asking Grimsby Power to focus on converting overhead to underground supplies within the Town of Grimsby.

v. Please see answers provided to OEB Interrogatory 2-Staff-23 (g).

vi. Please see answers provided to OEB Interrogatory 2-Staff-23 (g).

vii. Grimsby Power has 3 locations in the Town of Grimsby where there are plans to convert O/H rear lot supplies to U/G front supplies. There are various operational complexities of conducting such work. There are operational challenges as this is the first project with rear lot conversions for Grimsby Power. Once the first of three locations is converted Grimsby Power is planning to do a customer survey with those affected customers to receive feedback and utilize feedback for the remaining two locations. Success of the program will be measured in completing the work safely, on time, within budget and with few or no customer complaints.

2–VECC-15

Reference: Exhibit 2, Attachment 1, DSP, page 45, 133

a) GPI proposes to embark on a significant spending in pole replacements over the course of the rate plan period. The body of the DSP contains no rationale for this project and no specific details.

   i. Is the significant increase in "defective pole" replacement based on finding in the Kinectrics 2018 Asset Condition? If yes, please explain how this asset condition differed from the last ones and what accounts for the extraordinary high degradation rate over the past 5 years in pole condition.

   ii. Is this project the replacement of single poles, multiple poles in a single location or complete circuits/lines?

   iii. Please show the number of poles replaced in each year under the Plan for (a) singular replacement; (b) multiple poles replaced in a single location; (c) line or circuit replacement with fully dressed poles.

   iv. Please provide the specific metric that will be used to judge the level of success of this program at the end of the rate plan period.

Response:

a) For detailed Material Investment sheet for Defective Pole Replacement program please refer to Exhibit 2, Tab 3 Pages 124-126.
For additional information on this program please see answers provided to 2-Staff-22.

   i. The increase in the defective pole program was attributed to the ACA issued by Kinetrics in 2019. Grimsby Power did not have an independent ACA in the past. Grimsby Power notes, however, that it does not solely rely on ACA data for defective pole replacements but also on asset inspections and testing that is prescribed in Distribution System Maintenance and Inspection Program (Exhibit 2, Tab 3, Pages 310-340). Grimsby Power's Maintenance and Inspection Program for Wood Poles consists of visual inspection and pole testing (i.e. Resistograph Testing).

   ii. Defective Pole Replacement program is for replacement of all those poles that are classified with "very poor' and 'poor' conditions within ACA and/or fail pole inspections (pole testing) as per Grimsby Power's Distribution System Maintenance and Inspection Program (Exhibit 2, Tab 3, Pages 310-340).

   iii. Over the historical period Grimsby Power replaced only singular

poles under Defective Pole Replacement Program. For the actual number of poles replaced under this program please see answers provided to OEB Interrogatory 2-Staff-16.

iv. Grimsby Power has budgeted for specific number of poles to be replaced each year based on the ACA data. Grimsby Power's goal is to replace poles that have been classified in the ACA as poles with 'very poor' and 'poor' conditions and/or fail pole inspections (i.e. Resistograph Testing) criteria. Grimsby Power's goal is to align with the ACA's recommendation for a 10-year average amount per year pole replacements. Please see table below for more details on ACA and DSP Plans for Defective Pole Programs.

Asset Conditions Assessment Summary (Table 3 of ACA submitted in 2018; Issued in 2019)		2019	2020	2021	**2022**	**2023**	**2024**	**2025**	**2026**	2027	2028
Defective Pole Replacement - Wood	ACA	143	109	109	109	109	109	109	109	43	44
	Plan	50	75	100	115	125	120	95	90	90	85
	Actual	50	75	NA	NA	NA	NA	NA	NA	NA	NA

Asset Conditions Assessment Summary (Table 3 of ACA submitted in 2018; Issued in 2019)		DSP 2022 - 2026		GPI 2019 - 2028		ACA 2019 - 2028	
		Total	Avg	Total	Avg	Total	Avg
Defective Pole Replacement - Wood	ACA	545	109	993	113	993	99
	Plan	545	109	945	96	945	95
	Actual						

2–VECC-16

Reference: Exhibit 2, Appendix 2-AA / Tab 3, Attachment 1, page 111

a) Please explain why residential expansions do not attract a contribution in aid of construction from developers?

b) Please explain how the number of infill services (25) was calculated.

c) Please explain what "Legacy" services refers to.

d) For the following projects shown in Project ID SA-001 please provide an update of their construction status:

i. 27 John Street townhouse development;

ii. 3 & 84 Slessor Blvd;

iii. 709-721 Winston Rd,

Specifically, address whether all municipal approvals have been provided and whether the developer has begun construction or pre-construction work.

Response:

a) Residential expansions do attract a contribution in aid of construction however those amounts are not identified in the table, Exhibit 2, Tab 3 Attachment 1, page 111. The table in 2-VECC-9 shows residential expansions with contributed capital.

b) Infill services amounts are calculated based on the average amount of new unplanned services that were added year over year within the historical period. Grimsby Power is adjusting this amount as needed so for the forecasted period Grimsby Power has adjusted that amount from 25 to 10 in effort to closer to the latest estimated values for the Infills.

c) Legacy is the name of a Subdivision in the Town of Grimsby. For the copy of the signed agreement for Legacy Subdivision please see answer to OEB 2-Staff-21.

d) Subdivision agreements for developments at 8 Lake St and 314 Main St E are being reviewed and are in the final stages of approval.

i. Grimsby Power signed a subdivision agreement with this developer for this address and construction is per plan. Copy of signed subdivision agreement has been attached within answer to OEB Interrogatory 2-Staff- 21(a).

ii. Development at these addresses was delayed for various reasons provided by the Developer. This delay will most likely have an impact for Grimsby Power as servicing of these customers may not occur in 2022.

iii. At this point of time this development is still early planning stages.

2–VECC-17

Reference: Exhibit 2, Attachment 1, DSP, page 45, 133

a) For the CNR Pole Line Replacement please clarify the length of line that is being replaced and its start and end location by crossroad or geographic (e.g., Casablanca to Kerman etc.).

b) Does this line lie within the transmission corridor of Hydro One? Please explain more specifically where the line is being relocated to.

Response

a) The length of overhead lines that is being replaced is approximately 550m with the remaining existing 2,117m of overhead lines being removed and relocated. The start location is Iroquois Trail/CNR Right-Of-Way and the end location is Nelles Rd N/CNR Right-of Way.

b) The existing overhead line resides in the CNR corridor which is directly adjacent to the Hydro One Transmission Corridor. The overhead lines that are being relocated will be installed along Central Ave from Book Rd to Park Ave N and along Central Ave from Baker Rd N to Nelles Rd N.

2–VECC-18

Reference: Exhibit 2, Tab 3, Attachment 1 2018 Kinectrics ACA, page 237

Table 3 Ten Year Flagged for Action Plan

Asset Category		Flagged for Action Plan by Year									
		1	2	3	4	5	6	7	8	9	10
Station Transformers		0	0	0	0	0	0	0	0	0	0
Station Circuit Breakers		0	0	0	0	0	0	0	0	0	0
Poles	Wood	143	109	109	109	109	109	109	109	43	44
	Concrete	3	3	3	2	2	2	2	1	1	1
Pole Mounted Transformers	1 Phase	3	3	4	4	4	5	5	5	6	6
	2 Phase	0	0	0	0	0	0	0	0	0	0
	3 Phase	0	0	0	0	0	0	0	0	0	0
OH Lines *	1 Phase	4	3.7	3.4	3.3	3	2.6	2.5	2.4	2.3	1.9
	2 Phase	0	0	0	0	0	0	0	0	0	0
	3 Phase	3	2.7	2.6	2.4	2.3	2	1.6	1.6	1.6	1.2
OH Switches	1 Phase	0	0	0	0	0	0	0	0	0	0
	3 Phase	4	3	4	4	4	4	4	4	4	3
Pad Mounted Transformers	1 Phase	2	2	2	2	1	1	1	1	1	1
	3 Phase	0	0	0	0	0	0	0	0	0	0
Pad Mounted Switchgear		0	0	0	0	0	0	0	0	0	0
Underground Cables *	1 Phase	2.1	1.8	1.7	1.8	1.5	1.3	2	2	1.9	2
	2 Phase	0	0	0	0	0	0	0	0	0	0
	3 Phase	0	0	0	0	0	0	0	0	0	0

* by length (km)
* Year 0 = 2018, year 1 = 2019, year 2 = 2020 … etc.

a) With reference to the above table shown in the Kinectrics 2018 ACA please show the actual (columns 1-3), test year in progress (column 4); and forecast DSP plan (columns 5-8) GPI asset replacements.

Response:

a) Please see table below. Note that asset counts for years 2016 to 2021 (up to Aug.31st, 2021) are actuals and asset counts for 2022-2026 are forecasted values.

Asset Category	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Station Transformers	0	0	0	0	0	0	0	0	0	0	0
Station Circuit Breakers	0	0	0	0	0	0	0	0	0	0	0
Wood Poles	14	16	26	50	75	75	109	109	109	109	109
Concrete Poles	0	0	0	0	0	0	0	0	0	0	0
1Ph Pole Mounted Transformer	4	3	1	2	0	2	2	2	2	2	2
2Ph Pole Mounted Transformer	0	0	0	0	0	0	0	0	0	0	0
3Ph Pole Mounted Transformer	0	0	0	0	0	0	0	0	0	0	0
1Ph OH Lines	0	0	0	0	2.8	1	1	1	1	1	1
2Ph OH Lines	0	0	0	0	0	0	0	0	0	0	0
3Ph OH Lines	0	0	0	0	0	0	0	0	0	0	0
1Ph OH Switches	0	0	0	0	0	0	0	0	0	0	0
3Ph OH Switches	2	0	1	2	1	1	1	1	1	1	1
1Ph Pad Mounted Transformers	8	11	10	13	8	5	5	5	5	5	5
3Ph Pad Mounted Transformers	0	2	1	3	1	1	1	1	1	1	1
Pad Mounted Switchgear	0	1	0	1	0	0	0	0	0	0	0
1Ph Underground Cables	0	0	340	0	0	0	0	0	0	0	0
2Ph Underground Cables	0	0	0	0	0	0	0	0	0	0	0
3Ph Underground Cables	250/ph	0	0	700/ph	0	0	0	0	0	0	0

2–VECC-19

Reference: Exhibit 2, Tab 1, pages 24-25
Exhibit 8, Tab 3, pages 3-4

a) With respect to the determination of the Low Voltage costs included in the Working Capital calculation, please explain why the 2022 LV rates for the various rate classes used in Exhibit 2 do not match those proposed in Exhibit 8.

b) With respect to the determination of the Low Voltage costs included in the Working Capital Calculation, please explain why the 2022 LV rates used in Exhibit 2 for the GS 50-4,999 and Street Light classes are different for RPP vs. non-RPP customers.

c) Please confirm (per the Bill Impact Model) that the LV billing determinants are not adjusted for losses when determining a customer's bill.

d) With respect to the determination of the Low Voltage costs included in the Working Capital Calculation, please explain why the total 2022 Residential kWh used in Exhibit 2 do not match those used in Exhibit 8.

e) With respect to the determination of the Low Voltage costs included in the Working Capital Calculation, please explain why the total costs used in Exhibit 2 ($530,623) do not match those used in Exhibit 8 $478,224).

Response:

a,b,d,e) On September 8, 2021 GPI submitted responses to clarifying questions from OEB staff. Question 1 and Question 8 were related to the low voltage charges being different in Exhibit 2 and Exhibit 8. The responses to Question 1 and Question 8 from the clarification questions are below and provide a response to questions a, b, d and e above.

c) GPI confirms that the low voltage billing determinants are not adjusted for losses when determining a customer's bill.

2-Staff Clarification Question-1 September 8, 2021

The 2022 cost of power is shown as $29,756,512 in Table 2-18 in Exhibit 1, Tab 1, page 25 of 27, and calculated as $29,774,890 in Appendix 2-ZB.

Response:

In comparing Table 2-18 and Appendix 2-ZB the calculated value of $29,774,890 in Appendix 2-ZB is incorrect. Tab 2-ZB of the Chapter 2 Appendices as filed July 30, 2021 is missing the allocation of Transmission Network and Transmission Connection and Low Voltage to RPP for the GS>50 rate class. A formula that was allocating a portion of the kWh to RPP was removed in error this caused the non RPP portion to be too high and reduced the OER.

A total of $54,498 should have been allocated to RPP for Transmission Network (17,381kWh*$3.1354=$54,498) and a total of $25,761 should have been allocated to RPP for Transmission Connection (17,381kWh*$1.4821=$25,761). A total of $16,997 should have been allocated to RPP for Low Voltage. The missing allocation changed the OER credit applied by $18,381. The OER as filed was $3,024,743 and should have been $3,043,124 ($3,024,743-$3,043,124=$18,378).

The change in OER brings the total filed of $29,774,891 to $29,756,513. Table 1 below highlights the differences.

Table 1

	2-ZB As Filed July 30, 2021			Table 2-18 Exhibit 2 Tab 1			Difference		
	RPP	non-RPP	Total	RPP	non-RPP	Total	RPP	non-RPP	Total
Electricity Commodity	13,621,134	2,629,989	16,251,123	13,621,134	2,629,989	16,251,123	-	-	-
Global Adjustment non-RPP		11,531,445	11,531,445		11,531,445	11,531,445	-	-	-
Transmission Network	1,027,265	1,426,524	2,453,789	1,081,763	1,372,026	2,453,789	54,498	- 54,498	-
Transmission Connection	459,260	447,470	906,730	485,021	421,709	906,730	25,761	- 25,761	-
Wholesale Market Service	394,282	409,868	804,151	394,282	409,868	804,151	-	-	-
Class A CBR		5,850	5,850		5,850	5,850	-	-	-
Class B CBR	52,571	46,849	99,420	52,571	46,849	99,420	-	-	-
RRRP	65,714	68,311	134,025	65,714	68,311	134,025	-	-	-
Low Voltage	301,225	229,395	530,619	318,222	212,401	530,623	16,997	- 16,994	4
Smart Meter Entity Charge	82,480		82,480	82,480		82,480	-	-	-
Sub Total	**16,003,931**	**16,795,702**	**32,799,634**	**16,101,188**	**16,698,450**	**32,799,637**	**97,256**	**- 97,253**	**4**
OER Credit 18.9%	- 3,024,743		- 3,024,743	- 3,043,124		- 3,043,124	- 18,381	-	- 18,381
Total	**12,979,188**	**16,795,702**	**29,774,891**	**13,058,063**	**16,698,450**	**29,756,513**	**78,875**	**- 97,253**	**- 18,378**

Furthermore, when reviewing 2-ZB and Question 8 Grimsby Power noticed that the Low Voltage rates in 2-ZB were incorrect.

The Low Voltage rates in 2-ZB should match the rates indicated in Table 8-11 of Exhibit 8, Tab 3, Page 4 of 4 below.

Rate Class	Billing Determinants		Allocated Low Voltage Charges	Low Voltage Charge Rates	
	Annualized kWh or kW	Unit of Measure		Low Voltage $/kWh	Low Voltage $/kW
Residential	98,116,964	kWh	$232,197	$0.0024	
General Service <50 kW	22,618,334	kWh	$48,037	$0.0021	
General Service 50 to 4,999 kW	223,982	kW	$196,018		$0.8751
Street Lighting	2,087	kW	$1,340		$0.6421
Unmetered Scattered Load	311,198	kWh	$632	$0.0020	
Embedded Distributor					
Total			$478,224		

Grimsby Power has updated 2-ZB to include the allocation of Transmission Network, Transmission Connection and Low Voltage to RPP for the GS>50 rate class and corrected the Low Voltage rates. The updates are highlighted in yellow in 2-ZB (Table 3). The updates change the total Cost of Power from $29,756,513 to $29,712,018. Table 2 below provides the variances between Table 2-18 from Exhibit 2 and the corrected Cost of Power in 2-ZB.

Table 2

	Table 2-18 Exhibit 2 Tab 1			Corrected 2-ZB			Difference		
	RPP	non-RPP	Total	RPP	non-RPP	Total	RPP	non-RPP	Total
Electricity Commodity	13,621,134	2,629,989	16,251,123	13,621,134	2,629,989	16,251,123	-	-	-
Global Adjustment non-RPP	-	11,531,445	11,531,445		11,531,445	11,531,445	-	-	-
Transmission Network	1,081,763	1,372,026	2,453,789	1,081,763	1,372,026	2,453,789	-	-	-
Transmission Connection	485,021	421,709	906,730	485,021	421,709	906,730	-	-	-
Wholesale Market Service	394,282	409,868	804,151	394,282	409,868	804,151	-	-	-
Class A CBR	-	5,850	5,850	-	5,850	5,850	-	-	-
Class B CBR	52,571	46,849	99,420	52,571	46,849	99,420	-	-	-
RRRP	65,714	68,311	134,025	65,714	68,311	134,025	-	-	-
Low Voltage	318,222	212,401	530,623	290,818	190,130	480,949	- 27,404	- 22,271	- 49,674
Smart Meter Entity Charge	82,480	-	82,480	82,480	-	82,480	-	-	-
Sub Total	**16,101,188**	**16,698,450**	**32,799,637**	**16,073,784**	**16,676,179**	**32,749,963**	**- 27,404**	**- 22,271**	**- 49,674**
OER Credit 18.9%	- 3,043,124		- 3,043,124	- 3,037,945		- 3,037,945	5,179	-	5,179
Total	**13,058,063**	**16,698,450**	**29,756,513**	**13,035,839**	**16,676,179**	**29,712,018**	**- 22,224**	**- 22,271**	**- 44,495**

Table 3 below shows the updated 2-ZB and an updated Table 2-18.

Table 3

		2022 Test Year	RPP		2022 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast				-				
Residential	kWh	100,933,789		10,460,777.94	1,656,369		31,885	
GS<50kW	kWh	21,572,392		2,235,763	2,077,122		39,985	
GS>50 - 4,999 kW	kWh	8,606,314		891,958	73,432,418		1,413,574	
Streetlights	kWh	-		-	786,065		15,132	
Unmetered Scattered Load	kWh	314,890		32,635	10,496		202	
Embedded Distributor	kWh	-		-	58,660,344		1,129,212	
SUB-TOTAL		131,427,386		13,621,134	136,622,814		2,629,989	$ 16,251,123

Global Adjustment non-RPP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh			$ -			141,089.5	
GS<50kW	kWh			0			176,929.2	
GS>50 - 4,999 kW	kWh			0			6,148,887.5	
Streetlights	kWh			0			66,957.0	
Unmetered Scattered Load	kWh			0			894.1	
Embedded Distributor	kWh			0			4,996,688.1	
SUB-TOTAL		0		0			11,531,445	$ 11,531,445

Transmission - Network	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	100,933,789	0.0085	854,780	1,656,369	0.0085	14,027	
GS<50kW	kWh	21,572,392	0.0079	170,004	2,077,122	0.0079	16,369	
GS>50 - 4,999 kW	kW	17,381	3.1354	54,498	206,601	3.1354	647,782	
Streetlights	kW		2.3348	-	2,087	2.3348	4,873	
Unmetered Scattered Load	kWh	314,890	0.0079	2,482	10,496	0.0079	83	
Embedded Distributor	kW		4.1472	-	166,110	4.1472	688,892	
SUB-TOTAL				1,081,763			1,372,026	2,453,789

Transmission - Connection	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	100,933,789	0.0038	384,266	1,656,369	0.0038	6,306	
GS<50kW	kWh	21,572,392	0.0034	73,916	2,077,122	0.0034	7,117	
GS>50 - 4,999 kW	kW	17,381	1.4821	25,761	206,601	1.4821	306,205	
Streetlights	kW	-	1.0870	-	2,087	1.0870	2,269	
Unmetered Scattered Load	kWh	314,890	0.0034	1,079	10,496	0.0034	36	
Embedded Distributor	kW	-	0.6007	-	166,110	0.6007	99,777	
SUB-TOTAL				485,021			421,709	906,730

Wholesale Market Service	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	100,933,789	0.0030	302,801	1,656,369	0.0030	4,969	
GS<50kW	kWh	21,572,392	0.0030	64,717	2,077,122	0.0030	6,231	
GS>50 - 4,999 kW	kWh	8,606,314	0.0030	25,819	73,432,418	0.0030	220,297	
Streetlights	kWh	-	0.0030	-	786,065	0.0030	2,358	
Unmetered Scattered Load	kWh	314,890	0.0030	945	10,496	0.0030	31	
Embedded Distributor	kWh	-	0.0030	-	58,660,344	0.0030	175,981	
SUB-TOTAL				394,282			409,868	804,151

Class A CBR	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate[4]	$	Total
Residential				-			-	
GS<50kW				-			-	
GS>50 - 4,999 kW	kWh			-	19,499,514	0.0003	5,850	
Streetlights				-			-	
Unmetered Scattered Load				-			-	
Embedded Distributor				-			-	
SUB-TOTAL				-			5,850	5,850

Class B CBR	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	100,933,789	0.0004	40,374	1,656,369	0.0004	663	
GS<50kW	kWh	21,572,392	0.0004	8,629	2,077,122	0.0004	831	
GS>50 - 4,999 kW	kWh	8,606,314	0.0004	3,443	53,932,904	0.0004	21,573	
Streetlights	kWh	-	0.0004	-	786,065	0.0004	314	
Unmetered Scattered Load	kWh	314,890	0.0004	126	10,496	0.0004	4	
Embedded Distributor	kWh	-	0.0004	-	58,660,344	0.0004	23,464	
SUB-TOTAL				52,571			46,849	99,420

RRRP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	100,933,789	0.0005	50,467	1,656,369	0.0005	828	
GS<50kW	kWh	21,572,392	0.0005	10,786	2,077,122	0.0005	1,039	
GS>50 - 4,999 kW	kWh	8,606,314	0.0005	4,303	73,432,418	0.0005	36,716	
Streetlights	kWh	-	0.0005	-	786,065	0.0005	393	
Unmetered Scattered Load	kWh	314,890	0.0005	157	10,496	0.0005	5	
Embedded Distributor	kWh	-	0.0005	-	58,660,344	0.0005	29,330	
SUB-TOTAL				65,714			68,311	134,025

Low Voltage - No TLF adjustme	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential		96,532,817.16	$ 0.0024	231,679	1,584,146.96	0.0024	3,802	
GS<50kW		20,631,780.47	$ 0.0021	43,327	1,986,553.83	0.0021	4,172	
GS>50 - 4,999 kW		17,381	$ 0.8751	15,210	206,601	0.8751	180,797	
Streetlights			$ 0.6421	-	2,087	0.6421	1,340	
Unmetered Scattered Load		301,159.77	$ 0.0020	602	10,038.66	0.0020	20	
Embedded Distributor				-			-	
SUB-TOTAL				290,818			190,130	480,949

Smart Meter Entity Charge								
Class per Load Forecast		Customers	Rate	$	Customers	Rate	$	Total
Residential		11,213	0.57	76,699			-	
GS<50kW		845	0.57	5,782			-	
SUB-TOTAL				82,480			-	82,480
SUB- TOTAL				16,073,784			16,676,179	32,749,963
OER CREDIT[3]	18.90%			(3,037,945)			0	(3,037,945)
TOTAL				**13,035,839**			**16,676,179**	**29,712,018**

The change in the Cost of Power changes the revenue requirement. Grimsby Power has filed updated versions of Chapter 2 Appendices (updated 2-ZB and 2-OA), updated Revenue Requirement Workform, updated Cost Allocation Model, updated Tariff Schedule and Bill Impacts and an updated PILs model to reflect the updated Cost of Power amount.

2-Staff Clarification Question-2 September 8, 2021

The low voltages charges for the General Service greater than 50 kW rate class and Street Light rate classes are $0.8751 and $0.6421 per Table 8-11 of Exhibit 8 but are entered as $0.8752 and $0.6419 on the tariff of rates and charges.

Response:

The correct low voltage charges are $0.8751 and $0.6421 as per Table 8-11 of Exhibit 8. GPI has updated the tariff of rates and charges accordingly.

Exhibit 3 – Operating Revenue

3-Staff-25
Load Forecast
Ref: Load Forecast Model, Sheet: Power Purchase Model
Preamble:

Grimsby Power has included 2010 to 2020 historic data in is load forecasting model. The regression model was forecast using 2011 to 2020 historic data.

Question(s):

a) Did Grimsby Power consider using the 2010 data in its load forecasting as an 11th historic year? If so, what were the results, if not, why not?

Response:

a) Grimsby Power did not consider using 2010 to 2020 data. Ten years of data was selected to provide a sufficient dataset without including older years that may not reflect current consumption levels and trends.

3-Staff-26
Load Forecast
Ref: Exhibit 3, page 28
Load Forecast Model, Sheet: Power Purchase Model
Preamble:

Grimsby Power has a forecast for the embedded distributor in cells R165:R176 at the referenced worksheet. This forecast is used to adjust both the predicted wholesale purchases and forecast the rate class consumption.

Question(s):

a) Does this forecast include losses or exclude losses for the embedded distributor?

b) Please explain why it is appropriate to use the same figure, either inclusive or exclusive of losses for both the rate class forecast, and its contribution to wholesale purchases.

c) Please provide the consumption of the embedded distributor, both with, and without losses.

Response:

a) b) & c) The Embedded Distributor does not have attributable losses as all power is measured at the station itself from the primary metering.

3-Staff-27
Embedded Distributor Forecast
Ref: Exhibit 3, page 28
Load Forecast Model, Sheet: Embedded Distributor
Preamble:

An Annual Growth Rate of 0.5% is used for both energy and demand. In addition, there is a Gross Up difference in demand between metered and billed. This has been decreasing each year from 2018 to 2020, both in absolute kW and in percentage.

Question(s):

a) Please provide the rationale for the forecasted 0.5% growth rate in energy and demand.

b) Please identify the cause of the gross up, and explain whether it would normally be related to overall embedded distributor demand.

Response:

a) NPEI, Grimsby Power's Embedded Distributor customer, provided a forecast of low growth and high growth scenarios. The 0.5% forecast growth is the average of the low growth and high growth scenarios.

b) NPEI has two large generators installed on the NWMTS. As per the revised settlement agreement dated July 28, 2016 there is an agreement to charge the distribution revenue on a grossed up basis.

Section 3.1 Complete Settlement: The Parties accept the evidence of Grimsby Power that the customer forecast, loss factors, CDM adjustments and the resulting billing determinants are appropriate and are an appropriate reflection of the energy and demand requirements of the Applicant's customers. The load forecast for the Embedded Distributor has been adjusted to account for gross billing. The load forecast of 139,279 kW formed the billing determinant for the Embedded Distributor. The 139,279 kW was derived from the sum of the actual 2015 demand supplied from the Niagara West MTS to NPEI plus the demand supplied to NPEI from embedded generation (i.e. gross load) on the circuit supplying NPEI. This information has been supplied to Grimsby Power from NPEI. The following Table 6 sets out the agreed to load forecast for all of the rate classes except the Embedded Distributor rate class which has been adjusted as noted above.

Section 3.3 Complete Settlement: The Parties accept the evidence of Grimsby Power, subject to the adjustment identified below, that Grimsby Power's proposal for rate 1 design, including the proposed fixed/variable splits is appropriate. The rate design for residential class reflects the OEB's New Distribution Rate Design for Residential Electricity Customers (EB-2014-0210). The following Table 9 sets out Grimsby Power's proposed fixed/variable rates subject to OEB determination on OM&A and PILS.

a) Grimsby Power agrees to a fixed/variable revenue proportion of 50% fixed and 50% variable for the Embedded Distributor class. As noted above the Embedded Distributor forecast is based upon the gross load on the circuits from the Niagara West MTS serving NPEI. The variable portion of this revenue is highly influenced by embedded generation and therefore the following policy will provide Grimsby Power with sufficient certainty of revenue.

i) The monthly billing demand for the variable rate is defined as the highest Non- Coincident peak demand (kW) which occurs in any hour of the month. The monthly billing demand will be the highest demand that occurs in any hour in the month from the sum of (a) the demand supplied from the Niagara West MTS to the customer plus (b) the demand that is supplied to the customer from embedded generation which have installed capacity of 2MW or more for renewable generation and 1MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, biomass, bio-oil, bio-gas, landfill gas, or water.

ii) The revenue generated from this variable rate in any calendar year will be trued up such that:

- If the sum of the billed demand for each month is less than the threshold of 117,500kW per year the difference between the threshold (117,500kW) and the actual demand billed (lower than 117,500kW) will be multiplied by the current variable rate and owed by the Embedded Distributor to Grimsby Power (a true-up). This provides Grimsby Power assurance its revenue from the Embedded Distributor class will meet or exceed approximately 84% of forecast gross demand (139,279) for the class. The 16% difference allows for reductions in demand within the Embedded Distributors customer base (supplied from Niagara West MTS) related to CDM programs, loss of customer load, impacts of generation below 1 the 1MW and 2MW capacities noted in (i) above, and potential transfers of load by NPEI to other facilities.

- This true up, if necessary, will begin based on demands starting on January 1, 2017. The value of the true-up will be calculated in the first quarter of each year from 2018 to 2021 which covers the rate rebasing period except 2016.

3-Staff-28
Load Forecast adjustment
Ref: Exhibit 3, page 20
Load Forecast Model, Sheet: Customer Count
Preamble:

An adjustment for subdivisions is made consisting of 42 additional residential customers in 2021 and 337 additional residential, 2 additional GS < 50 and 2 additional GS > 50 connections in 2022.

Question(s):

a) Please indicate how many connections were added each year due to subdivisions from 2016-2020, and so far in 2021.

Response:

a) The table below shows the number of subdivision connections each year from 2016 to present 2021.

	2016	2017	2018	2019	2020	2021
Nubmer of Connections	19	163	107	71	44	5

3-Staff-29
Load Forecast
Ref: Load Forecast Model, Sheet: Purchases
Load Forecast Model, Sheet: Purchased Power Model
Preamble:

Grimsby Power indicates a quantity of power used by Wholesale Market Participants on the load forecast model, purchases worksheet. The quantity of energy purchased, without adjustment for wholesale market participants is used on the Purchased Power model worksheet.

Question(s):

a) Does the energy on the Purchased Power Model, column D include energy purchased by wholesale market participants (except for energy purchased by the embedded distributor)?

b) Does the resulting forecasted delivered energy by rate class include energy delivered for wholesale market participants? If so, which rate classes?

c) Does Grimsby Power purchase power from embedded generators including FIT and microFIT? If so, is this energy included in the amount in the Purchased Power Model, column D?

Response:

a) Yes column D includes energy purchased by wholesale market participants (WMP).

b) Yes the resulting forecasted delivered energy includes energy delivered to the WMP, one customer in the GS 50 to 4,999 kW class is a wholesale market participant.

c) Yes, Grimsby Power does purchase power from embedded generators, which is included in column D of the Purchased Power Model.

3-SEC-19

[Ex.3, Tab 2, p.1] Please provide a revised version of Table 3-24 that includes 2021 year-to-date actuals, as well as at the same point in time during the year, both 2019 and 2020 year-to-actuals.

Response:

The table provided below shows year to date actuals for 2019-2021 from January to August.

January - August			
Residential	**2019**	**2020**	**2021**
# of Customers	10,675	10,769	10,964
kWh	64,672,203	72,112,369	71,718,495
Variance # of Customers		0.88%	1.81%
Variance kWh		11.50%	-0.55%

GS<50	**2019**	**2020**	**2021**
# of Customers	794	799	797
kWh	13,288,823	12,899,777	13,162,625
Variance # of Customers		0.63%	-0.25%
Variance kWh		-2.93%	2.04%

GS>50	**2019**	**2020**	**2021**
# of Customers	107	108	111
kWh	41,519,651	40,458,932	48,612,907
kW	118,941	112,466	138,802
Variance # of Customers		0.93%	2.78%
Variance kWh		-2.55%	20.15%
Variance kW		-5.44%	23.42%

Street Lighting	**2019**	**2020**	**2021**
# of Customers	2	2	2
kWh	459,336	461,350	456,520
kW	1,375	1,344	1,196
Variance # of Customers		0.00%	0.00%
Variance kWh		0.44%	-1.05%
Variance kW		-2.21%	-11.03%

Unmetered Scattered Load	**2019**	**2020**	**2021**
# of Customers	66	62	62
kWh	224,877	219,893	215,947
Variance # of Customers		-6.06%	0.00%
Variance kWh		-2.22%	-1.79%

Embedded Distributor	**2019**	**2020**	**2021**
# of Customers	1	1	1
kWh	31,680,901	41,597,120	46,436,781
kW	90,722	116,069	114,978
Variance # of Customers		0.00%	0.00%
Variance kWh		31.30%	11.63%
Variance kW		27.94%	-0.94%

3–VECC-20

Reference: Exhibit 3, Tab 1, page 4

Preamble: "*Grimsby Power is proposing a modification to the definitions of a General Service < 50 kW and General Service 50 to 4,999 kW rate classes such that customers are considered General Service <50 kW if their average peak demand is less than 50 kW. Under the current definition, customers that exceed 50 kW in any month are classified as General Service 50 to 4,999 kW customers*."

a) Please clarify how the average peak demand will be determined (e.g., is the averages based on a calendar year, is it based on a rolling 12 months, or calculated in some other manner?).

b) Over the period 2011-2020 how many customers in either the GS<50 or GS 50-4,999 classes were reclassified to the alternate GS class and then reclassified back to their original class – based on the current definitions.

c) If the proposed definition had been in place starting in 2011 how many customers in either the GS<50 or GS 50-4,999 classes would have been reclassified to the alternate GS class and then reclassified back to their original class over the 2011-2020 period?

Response:

a) The average peak demand would be determined based on a calendar 12 months.
b) From 2011 – 2020 no customers were reclassified to an alternate GS rate class then reclassified back.
c) GPI's CIS system does not have the ability to track data in parallel for the same customer. The system does not capture TOU readings and usage and demand readings for the same customer. Our CIS system also does not capture demand data for GS<50 customers.

3–VECC-21

Reference: Exhibit 3, Tab 1, pages 4 and 8

Preamble: The Application states (page 4): *"For the purposes of developing the load forecast, historic customer, load, and demand data for the customers that were General Service 50 to 4,999 kW customers but will be General Service < 50 kW customers in the future have been restated as if those customers were General Service < 50 kW customers since 2011*."

The Application states (page 8): "*The increase in consumption per General Service < 50 kW customer has increased as a result of the change in the definition of the rate classes. The increase in consumption per General Service 50 to 4,999 kW customer is a result of the addition of two large customers in the bridge year and the rate class definitions*."

a) With respect to the referenced statement from page 8, what are the points comparison that GPI is using when referring to an increase in consumption per GS<50 customer?

b) How can the change in definition of the rate classes be the reason for the GS<50 per customer increase when, per page 4, the same definition has been used for all of the historic years and forecast years?

c) Similarly, with respect to the referenced statement from page 8, what points of comparison is GPI using when referring to an increase in consumption per GS 50-4,999 customer?

d) How can the change in definition of the rate classes be a reason for the GS 50-4,999 per customer increase when, per page 4, the same definition has been used for all of the historic years and forecast years?

Response:

a) The reference to the increase is in relation to the consumption per GS<50 kW customer with the proposed reclassification and consumption per GS<50 kW customer prior to the proposed reclassification.

b) Forecast consumption per GS<50 customer has increased relative to GS<50 consumption per customer prior to the reclassification. When the historic consumption is reclassified, forecast GS<50 consumption per customer is in line with historic class consumption. For clarity, Table 3-6 on page 8 above the referenced text displays reclassified consumption.

c) The reference to the increase is in relation to the consumption per GS 50 to 4,999 kW customer with the proposed reclassification and consumption per GS 50 to 4,999 kW customer prior to the proposed reclassification.

d) Please see response to part b). Forecast consumption per GS 50 to 4,999 kW customer would be in line with reclassified historic consumption per customer, however, the two large customers with materially increasing consumption cause an increase in consumption per customer.

3–VECC-22

Reference: Exhibit 3, Tab 1, page 10
Load Forecast Model, Purchases Tab
Exhibit 2, page 24

Preamble: The Application states: "The dependent variable is system purchases, excluding embedded distributor purchases, plus cumulative CDM. Cumulative CDM is then removed from predicted purchases."

a) Please confirm that the system purchases values used as the dependent variable also include purchases for local generators and the requirements of any wholesale market participants served by GPI, with the later adjusted for losses.

b) Is the Embedded Distributor a wholesale market participant?

c) Excluding the Embedded Distributor how many wholesale market participants does GPI serve and what rate class(es) are they in? As part of the response, please indicate if any of the new GS customers (per page 20) are expected to be wholesale market participant.

d) If any of GPI's customers (including the Embedded Distributor) are wholesale market participants, please explain how the cost of power calculation in Exhibit 2 has been adjusted to exclude their electricity requirements.

Response:

a) Confirmed.

b) The Embedded Distributor is not a wholesale market participant. Grimsby Power is charged by the IESO for the full load to the NWMTS.

c) Grimsby Power has one wholesale market participant. No new customers are expected to become wholesale market participants.

d) The one wholesale market participant is in the GS 50 to 4,999 kW class. Consumption for this customer, approximately 3 GWh, has been removed from GS 50 to 4,999 kW volumes in Exhibit 2 (see Table 2-18).

3–VECC-23

Reference: Exhibit 3, Tab 1, page 11

Preamble: The Application states: "*Grimsby Power considered a range of HDD and CDD base temperatures from 10°C to 20°C to analyze the weather variables that most closely predict total system purchases. HDD and CDD variables with a base of 16°C were found to be the most predictive*."

a) Were the appropriate base values for HDD and CDD tested separately or did the analysis assume that HDD and CDD would have the same "base value"?

Response:

a) HDD and CDD base values were considered separately. It is appropriate to consider separate base values since heating load and cooling load may not necessarily begin at the same average daily value. In this case HDD and CDD at 16°C were each found to be the most predictive.

3–VECC-24

Reference: Exhibit 3, Tab 1, page 12
Load Forecast Model, Economic Tab, Purchase Power Model Tab and Purchase Power Model (WN) Tab

a) The Economic Tab of the Load Forecast Model sets out a number of economic-related variables, none of which are used as an independent variable in the proposed load forecast model. Did GPI test the impact of including any of these variables in the load forecast model? If yes, which ones and why were they rejected for inclusion in the final model?

b) There does not appear to be any variable included in the load forecast model to account for the impact of the economic downturn in 2020 due to the COVID-19 pandemic. Did GPI consider the need for such a variable and, if yes, why was one not included?

c) Why is the Embedded Distributor included in the customer count variable when Embedded Distributor usage is excluded from the dependent variable?

Response:

a) Each of the economic variables included in the 'Economic' tab were considered. The economic variables were typically statistically significant on a standalone basis (excluding certain selected variables) but performed poorly when the 'Customer Counts' variable was included. There is an overall upward trend in system purchases so any variable that increases over time will be correlated to system purchases. However, system purchases increased in 2020 while economic variables decreased so the correlation is somewhat weaker than customer counts, which continued to increase.

b) The economic downturn would have been reflected in economic variables, which were considered. Grimsby Power's system purchases (excluding Embedded) were higher in 2020 than in any other year so the COVID pandemic did not have a negative impact on Grimsby's total purchases, though individual classes were impacted differently. Instead, interaction COVID-Degree Days variables were used to account for higher than forecast consumption. Additionally, a COVID variable, equal to 0 until February 2020 and equal to 1 in March 2020 and each month thereafter, was considered but not found to be statistically significant.

c) The Embedded Distributor should not be included in the customer count figures. Grimsby Power will not provide a revised forecast at this time since the correction is not material. The correction will be made in future load forecasts filed in this proceeding (if required).

3–VECC-25

Reference: Exhibit 3, Tab 1, page 18
Load Forecast Model, Rate Class Energy Model Tab

a) The Application states that the historical class for the period 2016-2020 of 4.56% was used to determine billed load. However, in the Load Forecast Model it appears a value of 4.43% was used. Please reconcile and indicate what GPI considers to be the appropriate value.

b) What was the average historic loss factor for the 2011-2020 period?

Response:

a) The 4.56% loss factor is the appropriate value. The Load Forecast Model filed with interrogatories has been revised with the appropriate 4.56% loss factor.

b) The average historic loss factor for the 2011-2020 period is 4.54%.

3–VECC-26

Reference: Exhibit 3, Tab 1, pages 19-20
Load Forecast Model, Customer Count Tab

Preamble: The Application states: "*Generally, the factor resulting from the geometric mean analysis from 2011 to 2020 is applied to the 2020 customer/connection numbers to determine the forecast of customer/connections in 2021*".

a) In the Customer Count Tab, the geometric mean analysis from 2011-2020 is used for all customer classes except Residential where the analysis is based on 2015-2020. Please explain why a different period is used for the Residential Class.

Response:

a) A few years prior to 2015 had higher-than-normal Residential customer growth due to new housing developments. The shorter period was selected to reflect normal growth, with consideration that new housing developments are known and manually added. With the manual additions the growth rate in 2022 is 2.9%, which is materially greater than the geometric mean from 2011 to 2020 of 1.6%.

3–VECC-27

Reference: Exhibit 3, Tab 1, pages 20 and 23-24
Load Forecast Model, Customer Count Tab

Preamble: The Application states (page 20): "*The subdivision is forecast to add 42 Residential customers in 2021, 337 Residential customers in 2022, 2 General Service < 50 kW customers in 2022, and 2 General Service 50 to 4,999 kW customers in 2022*".

The Application states (page 23): "*One of the two new large customers completed construction in 2021 and has had relatively steady consumption in 2021"*.

a) Please provide the customer/connection counts for each class as of the end of June 2021 and July 2021. As part of the response please indicate how many of the customers are associated with the new subdivision.

b) Please provide an update as to the expected overall number of Residential customer additions in 2021 and expectations for 2022 as a result of the new subdivision.

c) With respect to the two new large industrial customers, the 2022 customer count for the GS 50-4,999 class has been increased by 1.1 (Table 3-18). This number was calculated (see Load Forecast model) by assuming that both customers are added in 2022. However, according the Application, one of them came into service in 2021 and will be part of the customer count for all of the months in 2022. Wouldn't this result in a higher increase in the class' customer count for 2022 than 1.1?

Response:

a)

	Total Customers	
	Jun-21	**Jul-21**
Residential	10,963	10,963
GS<50	797	797
GS>50	111	111
Embedded Distributor	1	1
Streetlights	2	2
USL	62	62
	11,936	**11,936**

b) Grimsby Power has added 180 residential and 1 GS>50 from January to August 2021. We expect to add another 15 customers in 2021 and 230 in 2022.

The initial forecast of 341 (*337 Residential customers in 2022, 2 General Service < 50 kW customers in 2022, and 2 General Service 50 to 4,999 kW)* additions in 2022 was brought in line with current planning estimations from the Town of Grimsby (226 *Residential customers in 2022, 2 General Service < 50 kW customers in 2022, and 2 General Service 50 to 4,999 kW)*. The load forecast for 2022 was changed accordingly.

c) The application refers to two sets of “two new customers”: the two new customers from the new subdivision, and two cannabis industry customers which have recently purchased existing facilities in Grimsby and are expanding operations and capacity. The first two are new customers. The two cannabis industry customers are new customers to Grimsby Power, but they are not incremental customer accounts.

The customer referenced in the excerpt from page 23 is labeled as a “new customer” but is one of the cannabis industry customers that is replacing an old customer, so it should not count as an additional customer.

3-VECC -28

Reference: Exhibit 3, Tab 1, pages 21 and 23-24

Load Forecast Model, Rate Class Energy Model Tab and New >50 Customers Tab

Preamble: The Application states (page 21): *"The most recent consumption per customer volumes are used as a first approximation of forecast consumption per customer in 2021 and 2022, however, consumption in 2020 is not typical for some rate classes due to the COVID-19 pandemic so consumption per customer volumes in 2019 are used as the starting point for the Residential, General Service < 50 kW and General Service 50 to 4,999 kW rate classes. The volumes used are provided in Table 3 - 14".*

The Application states (page 23): *"The additional growth has been added from two sources: new developments and two large General Service 50 to 4,999 kW customers that are materially increasing consumption demand in the test and bridge years. The forecast of consumption from the new developments is calculated by multiplying Forecast Annual Consumption per customer from Table 3-14 by the average number of customers added from the class".*

The Application states (pages 23-24): *"One of the two new large customers completed construction in 2021 and has had relatively steady consumption in 2021. Consumption and demand for the remaining months of 2021 and all of 2022 are assumed to be equal to average consumption and demand from January to June 2021. A certain level of consumption is included in the purchases forecast, so the amount of consumption and demand added is net of the customer's typical historic consumption."*

a) With respect to the referenced statement from page 21, please confirm that 2019 consumption per customer/connection was also used as the "starting point" for the other customer classes.

b) Please confirm that for the Residential and GS<50 customers added due to the new developments the consumption per customer was based on actual 2019 usage and was not weather normalized.

c) With respect to the one new customer that completed construction in 2021, the Application states that "consumption and demand for the remaining months of 2021 and all of 2022 are assumed to be equal to average consumption and demand from January to June 2021". However, in the Load Forecast model the monthly usage post June 2021 is calculated as a rolling average of the values for the previous 6 months. Please reconcile and indicate which of the two approaches GPI proposes to use.

d) Please explain why GPI considers that there is already a certain level of consumption for the each of the new GS 50-4,999 customers built into the purchase power forecast.

Response:

a) As stated, 2019 consumption per customer is used as the starting point for Residential, General Service < 50 kW, and General Service 50 to 4,999 kW. Consumption per customer/connection in 2020 is used as the starting point for Street Lights, Unmetered Load, and the Embedded Distributor

b) Confirmed.

c) The volumes in each month should be equal to the average from January to July 2021. This correction results in a 533,137 kWh increase to the GS 50 to 4,999 kW class and no change to any other classes or the kW demand forecast since the demand of the customers is forecast separately. This correction has been incorporated into the revised load forecast.

d) As described in 3-VECC-27 part c), the “new customer” referenced on page 23 is a customer that has taken over previously existing facilities. The customer itself is new to Grimsby Power, but the facilities are not. The built-in consumption and demand that is removed reflects the consumption and demand of the previous customer in those facilities.

3–VECC-29

Reference: Exhibit 3, Tab 1, page 30

a) Are the historical Embedded Distributor kW values used to calculate the forecast demand actual or weather normalized values?

b) If actual, what would be the resulting forecast if based on weather normalized values calculated by applying the actual kW/kWh ratio to the weather normalized kWh values for each year?

Response:

a) Historical kW values are actual.

b) The described methodology is similar to the methodology used to forecast the Embedded Distributor kW demand and result in the same forecast figure.

	NPEI kWh	NPEI kWh Weather Normal	NPEI kW	kW/kWh Ratio	Weather-Normal Demand	
	A	B	C	D=C/A	E=B*D	
2017	29,983,391	30,868,410	115,729	0.3860%	119,144	
2018	43,380,634	41,797,869	144,421	0.3329%	139,152	
2019	49,068,645	50,714,842	143,708	0.2929%	148,530	
2020	59,182,120	58,078,111	167,588	0.2832%	164,461	
2021					*165,284*	= 2020 * 100.5%
2022					*166,110*	= 2021 * 100.5%

Demand in 2022 is forecast by first applying an annual 0.5% increase to weather-normalized 2020 kWh consumption, then multiplying this figure by the 2020 kW/kWh ratio. The described methodology follows the same steps in a different order, assuming the 2020 kWh/kW ratio and 0.5% annual growth rate are used.

3–VECC-30

Reference: Exhibit 3, Tab 3, pages 2 and 6

Preamble: The Application states (page 6): "*The increase in revenue in the 2022 Test year is primarily due to an increase in revenue for pole rentals and Government and Other Assistance Directly Credited to Income*."

The Application also states (page 6): "*In the 2022 Test Year there is also $7,000 higher revenue from late payment charges as the impact of the COVID-19 pandemic starts to subside*".

a) It is noted that the forecast 2022 revenue from late payment charges is still lower than that received in the years prior to 2020. Please provide more details on the basis for the 2022 forecast.

b) What is the reason for the increase in 2022 revenue from Government and Other Assistance Directly Credited to Income?

Response:

a) Year to date for 2021 GPI has collect $17, 014 in late payment charges. GPI does not believe it will reach the budgeted revenue of $26,000 in 2021 and believes the 2022 budget of $20,000 is in line with current collection processes and the extended use of lenient payment arrangements.

b) The increase in revenue from Government and Other Assistance Directly Credited to income is the result of an increase in deferred revenue due to the amount of forecast residential expansion in 2022.

Exhibit 4 – Operating Costs

4-Staff-30
2021 Actual
Ref: Appendix 2-JC

Question(s):

a) Please provide the updated year to date actual OM&A costs for 2021 bridge year in Appendix 2-JC format. Please specify how many months are actual vs. forecast.

Response:

a) The Appendix 2-JC with the actual OM&A costs (8 months) for 2021 is below:

Programs	August 2021
CUSTOMER FOCUS	
Customer Service and Billing	319,107
Bad Debts and Collections	8,507
Sub-Total	327,614
OPERATIONAL EFFECTIVENESS	
Supervision & Engineering	245,897
Transformer Station Niagara West MTS	120,501
Meter Reading and Operation	204,882
Overhead Services	159,743
Underground Services	114,347
Vegetation Maintenance	66,896
Administration and Financial	636,765
Building Maintenace and Utilities	64,315
Sub-Total	1,613,347
PUBLIC AND REGULATORY RESPONSIVENESS	
Professional Services	122,191
Information Technology	107,800
General Expenses and Advertising	93,297
Regulatory Costs	21,758
Insurance	27,427
Sub-Total	372,474
Total OM&A	**$ 2,313,434**

4-Staff-31
2016 Actual
Ref: Appendix 2-JC

Question(s):

a) Please provide a variance analysis between the 2016 OEB-approved OM&A and the 2016 actuals.

Response:

a) The table below shows the variance between the 2016 OEB-approved OM&A and the 2016 actuals.

Programs	2016 Approved	2016 Actuals	Variance
CUSTOMER FOCUS			
Customer Service and Billing	421,148	483,121	61,974
Bad Debts and Collections	43,776	45,726	1,949
Sub-Total	464,924	528,847	63,923
OPERATIONAL EFFECTIVENESS			
Supervision & Engineering	443,516	418,551	(24,965)
Transformer Station Niagara West MTS	201,983	267,810	65,827
Meter Reading and Operation	221,951	273,438	51,487
Overhead Services	189,110	224,802	35,692
Underground Services	122,634	136,552	13,919
Vegetation Maintenance	66,137	128,629	62,492
Administration and Financial	871,123	911,383	40,260
Building Maintenace and Utilities	75,741	97,518	21,777
Sub-Total	2,192,194	2,458,683	266,489
PUBLIC AND REGULATORY RESPONSIVENESS			
Professional Services	108,654	146,738	38,085
Information Technology	78,711	86,133	7,422
General Expenses and Advertising	163,844	141,676	(22,168)
Regulatory Costs	95,922	110,367	14,445
Insurance	30,297	31,568	1,270
Sub-Total	477,427	516,482	39,054
Total OM&A	**3,134,545**	**3,504,012**	**369,467**

The large variances are in the following programs:

- Customer Service and Billing is due to underestimated labour costs in the application and higher that forecasted CIS and postage costs;

- Transformer Station Niagara West MTS to cover the cost for the implementation of 2 transfer trips from the FIT generator DG to the Niagara West Breaker and to the Recloser;

- Meter Reading and Operation – unexpected work to replace a primary metering unit, due to a lightning storm;

- Vegetation Maintenance – in 2016 GPI completed the tree trimming work planned for 2015 and 2016;

4-Staff-32
Pension Plan
Ref: Exhibit 4, Tab 4, page 21 of 22

Question(s):

a) Grimsby Power mentioned its employees are members of the Ontario Municipal Employees Retirement System under a contributory defined benefit pension plan. Please provide the contribution percentage from the employer and employees.

b) Please discuss if Grimsby Power has explored any options that would result in a lower cost pension plan.

Response:

a) The employee contribution is equal with the employer contribution and is calculated as follows:

- 9% for earnings that do not exceed the Year's Maximum Pensionable Earnings (YMPE) (in 2021 it was $61,600)

- 14.6% for earnings that exceed the Year's Maximum Pensionable Earnings (YMPE)

b) GPI had not explored any other option for the pension plan.

4-Staff-33
COVID-19 Impact
Ref: Exhibit 4, Tab 1, page 1 of 9

Question(s):

a) Please confirm that Grimsby Power has not made any assumptions or inclusions for expenses related to COVID-19 in its 2021 and 2022 OM&A budgets. If not, please specify the impacts.

b) Please confirm that Grimsby Power has not made any assumptions or inclusions for expenses related to COVID-19 in its 2021 and 2022 capital budgets. If not, please specify the impacts.

Response:

a) GPI confirms that no assumptions or inclusions were made for expenses related to COVID-19 in its 2021 and 2022 OM&A budgets. Any cost related to COVID 19, defined as expenses being temporarily borne because of COVID related measures are kept in the regulatory account 1509.

b) GPI confirms that no assumptions or inclusions were made for expenses related to COVID-19 in its 2021 and 2022 capital budgets. Any cost related to COVID 19 are kept in the regulatory account 1509.

4-Staff-34
Review and Approval of Annual Budget
Ref: Exhibit 4, Tab 1, page 1 of 9

Question(s):

a) Please specify if any changes were made to 2022 capital and OM&A budgets after management review.

b) Please specify if any changes were made to 2022 capital and OM&A budgets after Board of Directors review.

Response:

a) No changes were made after management review.

b) Based on the input received from the HR/Audit Committee the following changes were made:

- Small adjustments to the Distribution Capital (6K) and General Plant (1.6K);
- Elimination of the Engineering Supervisor position;
- Increase in pay rate for the Director of Engineering position;
- Reduce consulting expenses;
- Adjustments to the allocation and tax expenses as result of the above changes;

After GPI's Board review of the budget the IT System & Communication Specialist position was added to the 2022 expenses.

4-Staff-35
Human Resource Requirements
Ref: Exhibit 4, Tab 2, page 8 of 16

Preamble:

Grimsby Power explained the need and costs related to four positions (Accounting Supervisor, Senior Customer Service Representative, Journeyman Lineman Apprentice, IT System & Communication Specialist) when describing OM&A cost drivers.

Question(s):

a) Please clarify if any of these four positions is a temporary position. If so, please specify the planned term for the position.

b) Please clarify when Grimsby Power has filled/planned to file each of these four positions.

Response:

a) The four positions (Accounting Supervisor, Senior Customer Service Representative, Journeyman Lineman Apprentice, and IT System & Communication Specialist) are not temporary positions.

b) The Accounting Supervisor position was filled as of September 2021. For the Senior Customer Representative GPI is working closely with a recruitment agency. GPI plans on filling the IT System & Communication Specialist and the Journeyman Lineman Apprentice 2022.

4-Staff-36
Customer Service and Billing
Ref: Exhibit 4, Tab 3, page 11 of 17

Preamble:

In comparing the 2022 test year with 2020 actuals, Grimsby Power identified an increase of $73,316 in labour costs in Customer Service and Billing.

Question(s):

a) Please specify the increase in labour costs due to increases in wages.

Response:

a) In comparing the 2022 Test year with the 2020 actuals, the increase of $73,316 in labour costs is mainly attributed to:

- Increase relative to vacancies - $59,172:
  - The Senior Customer Account Representative
    - The position being vacant for a portion of 2020. There was a vacancy in the position in 2020 as a result of hiring limitations due to Covid-19.
    - Moving from a part-time to full-time position in 2022 added.
  - One of the Customer Accounts Representative was off for most of the year 2020.
- The remaining increase in labour, $14,144, is due to increases in wages with positions moving to their full allotment due to the number of years in the position and inflationary wage and benefit increases.

4-Staff-37
Maintenance Poles, Towers and Fixture
Ref: Exhibit 4, Tab 3, page 15 of 17

Question(s):

a) Please explain how the budget of $138,259 in the maintenance poles, towers and fixture program for the 2022 test year was derived. Please provide assumptions, data and methodology utilized in the forecast.

b) Please provide actual spending in the maintenance poles, towers and fixture program for each year over the 2016-2019 period.

c) Compared to the 2016 OEB-approved level, Grimsby Power proposed an increase of approximately 351% in the poles, towers and fixture maintenance program for the 2022 test year, and an increase of approximately 664% in the pole replacement capital program. Please explain how Grimsby Power justified the trade-offs between capital and O&M.

Response:

a) Historical data on labour hours and materials was used to estimate this budget for the 2022 test year. Budget of $138,259 was derived based on the historical amounts used for pole maintenance activities (including emergency response and pole removals) and pole inspections for the area that needs to be inspected in 2022. Cost for labour (includes labour of Linemen, Foreman, Eng Techs) was budgeted at $109,534, total equipment was budgeted at $20,925, cost of material used was budgeted at $1,200 and cost for sub-contractor cost was budgeted at $6,600.

b) Please see the table extract below for the actual spending for this work activity over the historical period.

	2016	2017	2018	2019
Maintenance_of_Poles_Towers_and_Fixtures_	**42,253.67**	**32,807.65**	**47,888.18**	**75,843.31**
Wages and Benefits	**30,806.96**	**10,792.30**	**32,716.55**	**71,708.71**
Emergency Response	978.59	2,591.87	2,381.84	
Pole Inspections	8,964.39	11,334.37	8,157.52	1,385.26
Remove Poles (various WOs)	1,254.34	5,705.89	4,632.27	2,749.34
Vehicle Accident	249.39	2,383.22		

c) In 2019 Grimsby Power has received ACA for all distribution assets. ACA has indicated the need for significant investments in the System Renewals category (particularly Defective Poles Replacement Program). Grimsby Power has embedded ACA recommendations in its overall work execution plans and created an investment plan within its COS application to address ACA recommendations. Such plan requires increase in Grimsby Power's Capital Program (particularly for Defective Poles Replacement Program). At the same time Grimsby Power is continuing its pole inspections as per Grimsby Power's Maintenance and Inspection Program for wood poles. Grimsby Power's Maintenance and Inspection Program for wood poles consists of visual inspections and pole testing (i.e. Resistograph Testing). Since more wood poles are recommended by ACA for replacement over the forecasted period, there is also a higher level of resistograph testing required to confirm that all those ACA recommended poles require replacements.

4-Staff-38
Administration and Financial
Ref: Exhibit 4, Tab 3, page 16 of 17

Preamble:

In comparing the 2022 test year with 2020 actuals, Grimsby Power identified an increase of $384,962 in labour costs in Administration and Financial.

Question(s):

a) Please specify the increase in labour costs due to changes in staffing level.

b) Please specify the increase in labour costs due to increases in wages.

Response:

a) Increase labour costs due to the staffing level in 2022 Test year compared to the 2020 Actuals is approximately $353,600 and is attributable to the combined effect of the new positions of Director of Engineering and Operations and Accounting Supervisor added in 2021 and vacancies relating to the Executive Assistant and Accounting Assistant in 2020; while Grimsby Power has further detail with respect to the costs of these drivers on a position by position basis it believes it cannot disclose this information as it relates to the personal compensation information for individual employees.

b) The increase in labour costs due to increase in wages is $31,362.

4-Staff-39
Summary of Positions
Ref: Exhibit 4, Tab 4, page 11 of 22

Question(s):

a) There is a net increase of two FTEs from the 2016 OEB-approved level to the 2022 forecast in the Engineering department, please explain the need and cost for these two positions.

b) Please explain why the net increase of approximately six FTEs from 2020 actuals to the 2022 forecast are reasonable.

Response:

a) In 2016 the Engineering Department had only 1 FTE – Engineering Technician due to a vacancy of one Engineering Technician. GPI has always had two staff in the Engineering department.

In 2017 GPI filled the vacant position, hiring a new Engineering Technician.

In 2022 GPI is planning to hire a new IT Systems & Communication Specialist due to the:

- increased need for IT support as there is minimal support for IT implementation.
- optimize the various IT systems and increase productivity across all lines of business
- increased IT related threats;
- increased risk of cyber-attacks;
- effective communication, especially during unplanned power outages
- increased presence and expansion of utility related messaging on social media networks (i.e. Twitter) and corporate web site

Grimsby Power does not believe it can provide information on the record with respect to each of these positions as it would require the disclosure of personal information relating to the compensation of specific employees.

b) The increase of the FTEs from 2020 to the 2022 forecast is related to :

- 2020 Vacant positions and hiring process on hold due to the COVID 19;
- 2022 New positions.

The table below illustrates the variances.

Position	2020	2022	Variance due to:	
			Vacancy	New
President and CEO	1.00	1.00		
Director of Finance	1.00	1.00		
Director of Operations and Engineering		1.00	1.00	
Operations Supervisor	1.00	1.00		
Engineering Supervisor	0.19		(0.19)	
Regulatory and Customer Accounts Supervisor	1.00	1.00		
Accounting Supervisor		1.00		1.00
Executive Assistant	0.46	1.00	0.54	
Foreman	1.00	1.00		
Journeyman Lineman	3.00	4.00		1.00
Engineering Technician	1.56	2.00	0.44	
It System and Communication Specialist		1.00		1.00
Accounting Assistant	0.81	1.00	0.19	
Accounting and Settlement Clerk	1.00	1.00		
Senior Customer Representative	0.47	1.00		0.53
Customer Representative	1.22	2.00	0.78	
Storekkeper	1.00	1.00		
TOTAL	**14.71**	**21.00**	**2.76**	**3.53**

The increase relative to the approved FTE head count in 2016 is 4 FTEs.

The increase relative to the actual FTEs in 2016 the increase is 3 FTEs.

The gaps in the years between 2016 and 2022 relating to vacancies have since been filled.

The addition of 3 FTEs to the existing complement of 18 FTES relates to the currently vacant positions:

- Journeyman Linemen Apprentice
- IT Systems & Communication Specialist
- Senior Customer Representative

The additions of these positions are critical to the operation of GPI as they support customers' needs.

In the case of the Journeyman Linemen Apprentice, by having a new Journeyman Lineman Apprentice position the company would operate effectively and efficiently and directly support customers' requests. By hiring a Journeyman Lineman Apprentice GPI will have an ability to optimize its work execution, as it will have enough Linemen to consistently have two crews at all times and in the same time have an ability to have one Lineman on the Service Truck when needed. With the current Linemen complement whenever there is an unplanned event, GPI needs to break down the crews and interrupt progress of the capital work. Being able to have a dedicated crew for execution of the capital work is a benefit that GPI plans to utilize with an addition of this new employee.

In the case of the IT System & Communication Specialist presently most of the functions with regards to IT Infrastructure and Cybersecurity are outsourced and we would like to bring these functions in house. This position also would support GPI's needs to expand the communication to the customers.

With respect to the Senior Customer Representative, this position will assist with addressing constant changes in the billing system and regulations related to customer services that stretched GPI's ability to provide the level of customer service required by its customers.

4-Staff-40
Salary and Benefits
Ref: Exhibit 4, Tab 4, page 15 of 22

Question(s):

a) Please specify the wage and benefit increase assumptions used for management staff for the 2021 and 2022 budgets.

b) Please specify wage and benefit increase assumptions used for union staff for the 2021 and 2022 budgets.

Response:

a) The wage and benefits increase assumptions for management are as follows:

- 2021: 1.64% as a general wage increase, an overall increase of 4.79% due to the change in the position pay rate and 2.9% for the benefits.
- 2022: 2.2% for the wages and 3% for benefits.

b) The wage and benefits increase assumptions for union employees are as follows:

- 2021: 2.2% as a general wage increase, an overall increase of 5.52% due to the wage and step movements and 2.9% for the benefits.
- 2022: 2.2% for the wages and 3% for benefits.

4-Staff-41
Corporate Performance Measures and Metrics
Ref: Exhibit 4, Tab 4, page 20 of 22

Question(s):

a) Please provide the corporate objectives for the 2022 test year and actual performance results for each year over the 2016-2020 period.

b) Regarding the "% Weighted Completion of Budgeted Capital Projects Items" measure, please explain whether it is a measure based on quantity of work or capital expenditures.

c) Please provide an example to explain how the "% Weighted Completion of Budgeted Capital Projects Items" measure is calculated.

d) In light of the OEB's Activity and Program Based Benchmarking Initiative, has Grimsby Power considered including cost efficiency and effectiveness measures to track unit cost information for its main OM&A and capital programs/projects?

Response:

a) The Corporate objectives of each year are based on the annual budget and are approved by the GPI Board. The annual budget for the next fiscal year is presented and approved by the GPI board during the month of December. At this point in time the 2022 corporate objectives are not available.

Below are the results for the period 2016-2020:

2016 Performance Measures for the Corporation

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Result	Weighted Result
Financial	30	% Variance in Actual OM&A Expense vs. Budget	Less Than or Equal to 110% of Budget	Plus or Minus 5.0% of Budget	Less Than 95% of Budget - Justify Budget Execution and Savings Achieved	5,266,107	100%	30%
			Less Than or Equal to $5,788,479	Between $4,999,141 and $5,525,367 (Revised Budget $ 5,262,254)	Less Than $4,999,141			
Financial	15	% Variance in Actual Capital Expense vs. Budget	Plus or Minus 20.0% of Budget	Plus or Minus 10.0% of Budget	Plus or Minus 5.0% of Budget	1,114,476	100%	15.0%
			Between $939,174 and $1,408,760	Between $1,056,570 and 1,291,364 (Revised Budget	Between 1,115,269 and $1,232,665			
Financial	15	% Weighted Completion of Budgeted Capital Projects & Items	Greater Than or Equal to 80.0% but Less Than 90.0%	Greater Than or Equal to 90.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	82.4%	50%	8%
Customer Service	3	% of General Telephone Calls Answered within Minimum Standard	Greater Than or Equal to 75.0% but Less Than 85.0%	Greater Than or Equal to 85.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	71.0%	0%	0%
Customer Service	2	% of Written Responses Met within Standard	Greater Than or Equal to 97% but Less Than 100%	Equal to 100%	Subjective	100%	100%	2%
Customer Service	3	First Contact Resolution	No More Than 4 per Month on Average	No More Than 2 per Month on Average	No More Than 1 per Month on Average	99.94%	150%	5%
Customer Service	2	Billing Accuracy	98% or More	99 % or More	99.8% or More	99.98%	150%	3%
Safety	10	# of Lost time Incidents & H&S Program	1	0	Subjective	-	100%	10%
Safety	10	# of Field Audits vs. Target	Greater Than or Equal to 80% but Less Than 95%	Plus or Minus 5.0% of Budget	Greater Than 105% but Less Than or Equal to 120%	36	50%	5%
			Greater Than or Equal to 34 but Less Than 40	Greater Than or Equal to 40 but Less Than or Equal to 44 (Base is	Greater Than 44 but Less Than or Equal to 50			
Reliability	5	% Change in 3 Year Rolling Average - SAIDI	Greater Than 5.0% but Less Than or Equal to 15.0%	Plus or Minus 5.0%	Better Than Negative 5.0%	0.933	150%	8%
			Greater Than 1.3986 but Less Than or Equal to 1.5318 (2015 - 1.3320)	Between 1.2654 and 1.3986 (2015 - 1.3320)	Better Than 1.2654 (2015 - 1.3320)			
Reliability	5	% Change in 3 Year Rolling Average - SAIFI	Greater Than 10.0% but Less Than or Equal To 20.0%	Plus or Minus 10.0% of Budget	Better Than Negative 10.0%	0.847	150%	8%
			Greater Than 1.0406 but Less Than or Equal To 1.1352 (2015 - 0.9460)	Between 0.8514 and 1.0406 (2015 - 0.9460)	Better Than 0.8514 (2015 - 0.9460)			
	100					**Total Weighted Result**		**92.0**

Performance Measures for 2017 - Corporate

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Result	Weighted Result
Financial	25	% Variance in Actual OM&A Controllable Expense vs. Budget	Less Than or Equal to 110% of Budget	Plus or Minus 5.0% of Budget	Less Than 95% of Budget - Justify Budget Execution and Savings Achieved	$ 3,072,257	150%	37.5%
			Less Than or Equal to $3,889,260	Between $3,358,906 and $3,712,476(Budget $ 3,535,691)	Less Than $3,358,906			
Financial	15	% Variance in Actual Capital Expense vs.. Budget	Plus or Minus 20.0% of Budget	Plus or Minus 10.0% of Budget	Plus or Minus 5.0% of Budget	$ 1,227,697	50%	7.5%
			Between $1,101,063 and $1,651,595	Between $1,238,696 and 1,513,962 (Budget $1,376,329)	Between 1,307,513 and $1,445,145			
Financial	5	Find Cost Savings of $35,000 through expense reduction or gained efficiencies	Greater Than or Equal 70% but Less Than 85%	Greater Than or Equal to 85.0% but Less Than 91.0% of Budget	Greater Than or Equal to 91%	$ 19,020	0%	0.0%
			Find cost savings between $24,500 and $29,750	Find cost savings between $29,750 and $31,850	Between $ 31,850 and $35,000			
Financial	15	% Weighted Completion of Budgeted Capital Projects & Items	Greater Than or Equal to 80.0% but Less Than 90.0%	Greater Than or Equal to 90.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	78.8%	0%	0%
Customer Service	5	Customer Engagement	Take Part in Externally hosted engagement events to promote Grimsby Power	Host a Workshop with GPI Customers "Understanding Your Bill"	Host a Workshop with GPI Customers "Understanding Your Bill" and take part in externally hosted events. Utilize other means of customer engagement to meet the requirements of the RRFE.	Target	100%	5.0%
Customer Service	5	% of General Telephone Calls Answered within Minimum Standard	Greater Than or Equal to 75.0% but Less Than 85.0%	Greater Than or Equal to 85.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	75.4%	50%	2.5%
Customer Service	3	First Contact Resolution	No More Than 4 per Month on Average	No More Than 2 per Month on Average	No More Than 1 per Month on Average	0.1667	150%	4.5%
Customer Service	2	Billing Accuracy	98% or More	99 % or More	99.8% or More	99.97%	150%	3.0%
Safety	5	# of Lost time Incidents & H&S Program	1	0	Subjective	Target	100%	5%
Safety	10	# of Field Audits vs. Target	Greater Than or Equal to 80% but Less Than 95%	Plus or Minus 5.0% of Budget	Greater Than 105% but Less Than or Equal to 120%	48	150%	15.00%
			Greater Than or Equal to 36 but Less Than 43	Greater Than or Equal to 43 but Less Than or Equal to 47 (Base is	Greater Than 47 but Less Than or Equal to 54			
Reliability	5	% Change in 5 Year Rolling Average - SAIDI	Greater Than 5.0% but Less Than or Equal to 15.0%	Plus or Minus 5.0%	Better Than Negative 5.0%	1.2146	150%	7.50%
			Greater Than 1.3986 but Less Than or Equal to 1.5318 (2015 - 1.3320)	Between 1.2654 and 1.3986 (2015 - 1.3320)	Better Than 1.2654 (2015 - 1.3320)			
Reliability	5	% Change in 5 Year Rolling Average - SAIFI	Greater Than 10.0% but Less Than or Equal To 20.0%	Plus or Minus 10.0% of Budget	Better Than Negative 10.0%	1.0208	100%	5.00%
			Greater Than 1.0406 but Less Than or Equal To 1.1352 (2015 - 0.9460)	Between 0.8514 and 1.0406 (2015 - 0.9460)	Better Than 0.8514 (2015 - 0.9460)			
	100					**Total Weighted Result**		**92.5**

Performance Measures for 2018 - Corporate

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Result	Weighted Result
Financial	25	% Variance in Actual OM&A Controllable Expense vs. Budget	Less Than or Equal to 110% of Budget	Plus or Minus 5.0% of Budget	Less Than 95% of Budget - Justify Budget Execution and Savings Achieved	$ 3,385,533	100%	25.0%
			Less Than or Equal to $3,815,996	Between $3,295,633 and $3,642,541(Budget $ 3,469,087)	Less Than $3,295,633			
Financial	15	% Variance in Actual Capital Expense vs. Budget	Plus or Minus 20.0% of Budget	Plus or Minus 10.0% of Budget	Plus or Minus 5.0% of Budget	$ 1,356,311	0%	0.0%
			Between $1,438,977 and $ 2,158,465	Between $1,618,849 and 1,978,721 (Budget $1,798,721)	Between 1,708,785 and $1,888,657			
Financial	5	Find Cost Savings of $35,000 through expense reduction or gained efficiencies	Greater Than or Equal 70% but Less Than 85%	Greater Than or Equal to 85.0% but Less Than 91.0% of Budget	Greater Than or Equal to 91%	$ 17,425	0%	0.0%
			Find cost savings between $24,500 and $29,750	Find cost savings between $29,750 and $31,850	Between $ 31,850 and $35,000			
Financial	10	% Weighted Completion of Budgeted Capital Projects & Items	Greater Than or Equal to 80.0% but Less Than 90.0%	Greater Than or Equal to 90.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	74.4%	0%	0%
Customer Service	10	Customer Engagement	Take Part in Externally hosted engagement events to promote CDM and Grimsby Power	Host events promoting awareness of Grimsby Power	Host Engagement Workshops with customers to provide feedback on issues surrounding electricity rates and projects	Target	100%	10.0%
Customer Service	5	% of General Telephone Calls Answered within Minimum Standard	Greater Than or Equal to 75.0% but Less Than 85.0%	Greater Than or Equal to 85.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	88.5%	100%	5.0%
Customer Service	3	First Contact Resolution	No More Than 4 per Month on Average	No More Than 2 per Month on Average	No More Than 1 per Month on Average	1	150%	4.5%
Customer Service	2	Billing Accuracy	98% or More	99 % or More	99.8% or More	99.87%	150%	3.0%
Safety	5	# of Lost time Incidents & H&S Program	1	0	Subjective	0	150%	8%
Safety	10	# of Field Audits vs. Target	Greater Than or Equal to 80% but Less Than 95%	Plus or Minus 5.0% of Budget	Greater Than 105% but Less Than or Equal to 120%	50	150%	15.00%
			Greater Than or Equal to 36 but Less Than 43	Greater Than or Equal to 43 but Less Than or Equal to 47 (Base is	Greater Than 47 but Less Than or Equal to 54			
Reliability	5	% Change in 5 Year Rolling Average - SAIDI	Greater Than 5.0% but Less Than or Equal to 15.0%	Plus or Minus 5.0%	Better Than Negative 5.0%	1.1645%	150%	7.50%
			Greater Than 1.3986 but Less Than or Equal to 1.5318 (2015 - 1.3320)	Between 1.2654 and 1.3986 (2015 - 1.3320)	Better Than 1.2654 (2015 - 1.3320)			
Reliability	5	% Change in 5 Year Rolling Average - SAIFI	Greater Than 10.0% but Less Than or Equal To 20.0%	Plus or Minus 10.0% of Budget	Better Than Negative 10.0%	0.9694%	100%	5.00%
			Greater Than 1.0406 but Less Than or Equal To 1.1352 (2015 - 0.9460)	Between 0.8514 and 1.0406 (2015 - 0.9460)	Better Than 0.8514 (2015 - 0.9460)			
	100					**Total Weighted Result**		**82.5**

Performance Measures for 2019 - Corporate

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Result	Weighted Result
Financial	15	% Variance in Actual OM&A Controllable Expense vs. Budget	Less Than or Equal to 110% of Budget	Plus or Minus 5.0% of Budget	Less Than 95% of Budget - Justify Budget Execution and Savings Achieved	$3,194,551	150%	22.5%
			Less Than or Equal to $3,816,328	Between $3,295,920 and $3,642,858(Budget $ 3,469,389)	Less Than $3,295,920			
Financial	15	% Variance in Actual Capital Expense vs. Budget	Plus or Minus 20.0% of Budget	Plus or Minus 10.0% of Budget	Plus or Minus 5.0% of Budget	$1,980,556	50%	7.5%
			Between $1,837,510 and $ 2,756,263	Between $2,067,199 and 2,526,577 (Budget $2,296,888)	Between 2,182,044 and $2,411,732			
Financial	15	Strategic Planning	Subjective - Plan is substantially complete but not issued	Subjective - Plan is complete and issued	Subjective - Plan is issued and best of breed	Target	50%	7.5%
Financial	5	Find Cost Savings of $35,000 through expense reduction or gained efficiencies	Greater Than or Equal 70% but Less Than 85%	Greater Than or Equal to 85.0% but Less Than 91.0% of Budget	Greater Than or Equal to 91%	$ 12,762	0%	0.0%
			Find cost savings between $24,500 and $29,750	Find cost savings between $29,750 and $31,850	Between $ 31,850 and $35,000			
Financial	5	% Weighted Completion of Budgeted Capital Projects & Items	Greater Than or Equal to 80.0% but Less Than 90.0%	Greater Than or Equal to 90.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	74.2%	0%	0%
Customer Service	10	Customer Engagement	Take Part in Externally hosted engagement events to promote CDM and Grimsby Power	Host events promoting awareness of Grimsby Power	Host Engagement Workshops with customers to provide feedback on issues surrounding electricity rates and projects	Max	150%	15.0%
Customer Service	5	% of General Telephone Calls Answered within Minimum Standard	Greater Than or Equal to 75.0% but Less Than 85.0%	Greater Than or Equal to 85.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	90.2%	100%	5.0%
Customer Service	3	First Contact Resolution	No More Than 4 per Month on Average	No More Than 2 per Month on Average	No More Than 1 per Month on Average	0.92	150%	4.5%
Customer Service	2	Billing Accuracy	98% or More	99 % or More	99.8% or More	99.98%	150%	3.0%
Safety	5	# of Lost time Incidents & H&S Program	1	0	Subjective	0	150%	7.5%
Safety	10	# of Field Audits vs. Target	Greater Than or Equal to 80% but Less Than 95%	Plus or Minus 5.0% of Budget	Greater Than 105% but Less Than or Equal to 120%	50	150%	15.0%
			Greater Than or Equal to 36 but Less Than 43	Greater Than or Equal to 43 but Less Than or Equal to 47 (Base is 45)	Greater Than 47 but Less Than or Equal to 54			
Reliability	5	% Change in 5 Year Rolling Average - SAIDI	Greater Than 5.0% but Less Than or Equal to 15.0%	Plus or Minus 5.0%	Better Than Negative 5.0%	1.7685	0%	0.0%
			Greater Than 0.95928 but Less Than or Equal to 1.05065 (2018 - 0.9136)	Between 0.86792 and 0.95928(2018 - 0.9136)	Better Than 0.86792(2018 - 0.9136)			
Reliability	5	% Change in 5 Year Rolling Average - SAIFI	Greater Than 10.0% but Less Than or Equal To 20.0%	Plus or Minus 10.0% of Budget	Better Than Negative 10.0%	1.2924	0%	0.0%
			Greater Than 0.77782 but Less Than or Equal To 0.84853 (2018 - 0.70711)	Between 0.63640 and 0.77782 (2018 - 0.70711)	Better Than 0.63640 (2018 - 0.70711)			
	100					**Total Weighted Result**		**87.5**

Performance Measures for 2020 - Corporate

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Result	Weighted Result
Financial	15	% Variance in Actual OM&A Controllable Expense vs. Budget	Less Than or Equal to 110% of Budget	Plus or Minus 5.0% of Budget	Less Than 95% of Budget - Justify Budget Execution and Savings Achieved	$ 3,539,965	100%	15.0%
			Less Than or Equal to $4,026,661	Between $3,477,571 and $3,843,631(Budget $ 3,660,601)	Less Than $3,477,571			
Financial	15	% Variance in Actual Capital Expense vs. Budget	Plus or Minus 20.0% of Budget	Plus or Minus 10.0% of Budget	Plus or Minus 5.0% of Budget	$ 1,494,678	0%	0.0%
			Between $1,745,411 and $ 2,618,117	Between $1,963,587 and 2,399,940 (Budget $2,181,764)	Between 2,072,676 and $2,399,940			
Financial	15	COS Application	Subjective - Plan Fails OEB Initial Submission Review but is Rectified with Only Minor Changes	Subjective - Plan Meets OEB Initial Submission Review with Only Minor Non-Conformance Issues	Subjective - Plan Meets OEB Initial Submission Requirements with No Non-Conformance Issues	Target	100%	15.0%
Financial	5	Find Cost Savings of $35,000 through expense reduction or gained efficiencies	Greater Than or Equal 70% but Less Than 85%	Greater Than or Equal to 85.0% but Less Than 91.0% of Budget	Greater Than or Equal to 91%	$ 6,200	0%	0.0%
			Find cost savings between $24,500 and $29,750	Find cost savings between $29,750 and $31,850	Between $ 31,850 and $35,000			
Financial	5	% Weighted Completion of Budgeted Capital Projects & Items	Greater Than or Equal to 80.0% but Less Than 90.0%	Greater Than or Equal to 90.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	67.6%	0%	0%
Customer Service	5	Customer Engagement	Take Part in Externally hosted engagement events to promote CDM and Grimsby Power	Host events promoting awareness of Grimsby Power	Host Engagement Workshops with customers to provide feedback on issues surrounding electricity rates and projects	Target	100%	5.0%
Customer Service	5	% of General Telephone Calls Answered within Minimum Standard	Greater Than or Equal to 75.0% but Less Than 85.0%	Greater Than or Equal to 85.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	89.4%	100%	5.0%
Customer Service	5	First Contact Resolution	No More Than 4 per Month on Average	No More Than 2 per Month on Average	No More Than 1 per Month on Average	0.667	150%	7.5%
Customer Service	5	Billing Accuracy	98% or More	99 % or More	99.8% or More	99.99%	150%	7.5%
Safety	5	# of Lost time Incidents & H&S	1	0	Subjective	0	150%	7.5%
Safety	10	# of Field Audits vs. Target	Greater Than or Equal to 80% but Less Than 95%	Plus or Minus 5.0% of Budget	Greater Than 105% but Less Than or Equal to 120%	34	100%	10.0%
			Greater Than or Equal to 36 but Less Than 43	Greater Than or Equal to 43 but Less Than or Equal to 47 (Base is 45)	Greater Than 47 but Less Than or Equal to 54			
Reliability	5	% Change in 5 Year Rolling Average - SAIDI	Greater Than 5.0% but Less Than or Equal to 15.0%	Plus or Minus 5.0%	Better Than Negative 5.0%	0.92	150%	7.5%
			Greater Than 1.292 but Less Than or Equal to 1.564 (GPI - 1.36)	Between 1.292 and 1.428(GPI - 1.36)	Better Than1.156(GPI - 1.36)			
Reliability	5	% Change in 5 Year Rolling Average - SAIFI	Greater Than 10.0% but Less Than or Equal To 20.0%	Plus or Minus 10.0%	Better Than Negative 10.0%	0.64	150%	7.5%
			Greater Than 1.496 but Less Than or Equal To 1.632 (GPI - 1.07)	Between 1.224 and 1.496 (GPI - 1.07)	Better Than 1.2240 (GPI - 1.07)			
	100					**Total Weighted Result**		**87.5**

b) "% Weighted Completion of Budgeted Capital Projects Items" - the purpose of this metric is to promote the completion of projects/purchases as a percentage of completion in the field. The more projects/purchases that are 100% completed against budget the better.

The weighted percentage is calculated by multiplying the percentage of each project/program value in the total budgeted capital expenditures of the year with the percentage of completion for that specific project/program.

c) Below is the 2019 % Weighted Completion of Budgeted Capital Projects Items calculation:

			Corporate			
	Total Budgeted Cost	Total Actual Cost	Adjustments	% of Total	% Complete	Weighted %
Capital Distribution Plant	**$ 2,077,431**	**$1,601,637**	**1,953,288**	**94.80%**		**71.93%**
System Access	**$ 242,896**	**$ 49,859**				
Project - Residential Subdivision Development	67,965					0.00%
Project - New Customer Connections	38,592					0.00%
Program - Modifications to Existing Customer Connections	17,586					0.00%
Project - New Customer Connections	101,504	49,859	1	5.20%	60.0%	3.12%
Program - Transformer Station - Modifications to Support Renewable Generation	17,250		1	0.88%	0.0%	0.00%
System Renewal	**$ 1,369,609**	**$1,069,317**				
Program - Primary Cable Silicon Injection	64,458	125,739	1	3.30%	100.0%	3.30%
Program - Replace 1 PH Pad Mounted Transformers	57,734	69,877	1	2.96%	140.0%	4.14%
Program - 2019 System Renewal - Primary Cable Testing	37,982	28,683	1	1.94%	100.0%	1.94%
Project - Niagara West MTS - iFIX Upgrades due to Cybersecurity	31,383	33,398	1	1.61%	100.0%	1.61%
Program - Replace Sectionalizing Terminal	12,388	13,917	1	0.63%	100.0%	0.63%
Program - Replace Defective Poles	176,356	258,744	1	9.03%	100.0%	9.03%
Project - Voltage Conversion - Maple Estates (phase 2)	245,363	233,358	1	12.56%	100.0%	12.56%
Program - Voltage Conversion - Kingsway Blvd	218,678	2,664	1	11.20%	5.0%	0.56%
Program - Voltage Conversion - Parkwood Drive	214,945	188,365	1	11.00%	100.0%	11.00%
Project - Metrolinx - Pole Line Relocation Due to Road Widening at Casablanca Blvd & Livingsto	135,291		1	6.93%	0.0%	0.00%
Program - Replace Gang Operated Load Break Switch	91,995	44,438	1	4.71%	100.0%	4.71%
Program - Replace 3 PH Pad Mounted Transformer	83,039	70,134	1	4.25%	96.5%	4.10%
System Service	**$ 464,926**	**$ 482,460**				
Project - Pole Line Upgrade at Central Ave. Between Park Rd. and Baker Rd.	155,767	233,275	1	7.97%	100.0%	7.97%
Project - Monitoring and Control - Fault Indicators Installation and SCADA Integration	133,008	45,770	1	6.81%	85.0%	5.79%
Program - Convert Radial Feed Customers to Loop	86,679		1	4.44%	0.0%	0.00%
Project - Replace Manually Operated Pad Mounted Switchgear with an Automated/Remote Co	65,089	103,447	1	3.33%	100.0%	3.33%
Niagara West MTS - Feeders F60 Standard Protection & Overall Integrated System	24,382	99,969	1	1.25%	100.0%	1.25%
Capital General Plant	**$ 219,458**	**$ 378,920**	**$ 219,458**	**100.00%**		**95.44%**
Program - Computer Workstations	6,800	14,380	1	3.10%	100.0%	3.10%
Program - Server/Network Hardware Upgrades due to Cyber Security	25,000	36,301	1	11.39%	100.0%	11.39%
Software	10,000		1	4.56%	0.0%	0.00%
Project - SCADA System and Improvements	34,457	65,044	1	15.70%	100.0%	15.70%
Vehicle - Trucks & Forklift	50,750	195,817	1	23.13%	100.0%	23.13%
Building Upgrades	13,000	10,399	1	5.92%	100.0%	5.92%
NWTS - Upgrades		280	1	0.00%	100.0%	0.00%
Tools - Replacement	79,451	49,998	1	36.20%	100.0%	36.20%
Communication Equipment		3,200	1	0.00%	100.0%	0.00%
Miscellaneous		3,501	1	0.00%	100.0%	0.00%
Grand Total	**$ 2,296,888**	**$ 1,980,556**	**$ 2,172,746**			**74.18%**

4-Staff-42
Wages Benchmarking
Ref: Exhibit 4, Tab 4, page 21 of 22

Preamble:

Grimsby Power stated that it has utilized the annual MEARIE Group-Management Salary Survey of local distribution companies for the management wages calculation.

Question(s):

a) Please explain which positions were reviewed in the survey.

b) Please provide Grimsby Power's benchmarking results for each of the reviewed positions.

c) Please explain why job rates are established to target the P50th percentile for small utilities with less than 20,000 customers.

Response:

a) For the 2021 management wages calculation GPI used the 2020 Management Salary Survey. The following positions were reviewed:

- President and CEO
- Director of Engineering and Operations
- Director of Finance
- Operations Supervisors
- Regulatory and Customer Accounts Supervisor
- Executive Assistant

b) GPI cannot provide the requested information as it would require the disclosure of personal information relating to individual employees; GPI can advise that the average percentage (calculated by comparing GPI wages with Mearie P50 survey for each position) is 1.07% higher.

c) GPI decided to use the P50th percentile for small utilities with less than 20,000 customers as this category best represents the size of the utility.

Salary levels which are consistent with the utility industry will support:

- The retention of staff who may consider job offers at other utilities – a more competitive wage makes changing jobs less attractive;

- The attraction of new staff to fill vacancies in a utility job market which will become increasingly competitive as “boomer retirements” accelerate in future years;

- The retention of valuable experienced staff who are eligible for retirement – OMER’s pensions are based on the best 60 consecutive months of service and pensions can be maximized with higher earnings;

4-Staff-43
System O&M
Ref: Appendix 2-AB

Question(s):

a) Please explain drivers for the consistent underspending in System O&M over the 2017-2020 period.

b) Please describe any actions Grimsby Power plans to take to minimize future variances between planned and actual system OM&A expenditures over the forecast period.

Response:

a) Grimsby Power estimated System O&M to be 4% higher (fixed factor) year over year in the period from 2017-2020 compared to the 2016 value. The values from 2017-2020 were based on a 4% increase was based on the original O&M filed in GPI's 2016 CoS application ($1,642,996). Please note that when the forecast was created in 2016 there was no specific plan cost breakdown for years beyond the 2016 test year.

The main drivers for consistent underspending in System O&M over the 2017-2020 period compared to planned is related with the fact that our planned values for System O&M were based on a 4% increase to Grimsby Power's original planned, $1,642,996 and the high fixed factor of 4%. These two drivers drove the planned values for System O&M higher and increased the variance in the underspent amount over the historical period (2017-2020).

Grimsby Power adjusted that fixed factor in 2021 to 2% in effort to lower the estimate for forecasted values for System O&M and therefore to be more in line with the actuals for those activities

b) Grimsby Power will continue to improve on budgeting for System O&M. Grimsby Power will specifically review its budgeting practices (i.e. using fixed factor for System O&M budget for year over year budget calculations) and revise it accordingly if necessary. Grimsby Power also adjusted the inflation factor in the forecast period to 2% compared to 4% used previously.

4-Staff-44
Customer Service Expenses
Ref: Appendix 2-JB

Question(s):

a) There is an increase of $51,430 in Customer Service Expenses in 2022 budget from 2016 OEB-approved level, please explain drivers for the increase.

Response:

a) The drivers for the increase in Customer Service Expenses in 2022 budget compared to 2016 OEB approved level are:
   - Postage - $16,000
   - Customer Information System - $16,403
   - Third Party Services $7,444
   - Miscellaneous (Office Supplies, Communication Services etc.) $11,583.

4-Staff-45
Wages and Benefits
Ref: Appendix 2-JB

Question(s):

a) Please provide the cost of wages and benefits included in the 2016 OEB-approved OM&A of $3,134,546.

b) Please provide the cost of wages and benefits included in the 2020 actual OM&A of $3,539,965.

Response:

a) In the 2016 OEB approved OM&A of $3,134,546 the total labour cost (wages and benefits) is $1,581,331.

b) In the 2020 actual OM&A of $3,539,965 the total labour cost (wages and befits) is $1,584,372.

4-Staff-46
Customers/FTEs
Ref: Appendix 2-L

Preamble:

When comparing the number of customers and FTEs between the 2020 actuals and the 2022 test year, OEB staff notes a forecasted increase of 3.6% in the number of customers while an increase of 40% in the number of FTEs.

Question(s):

a) Please discuss how Grimsby Power justifies the misalignment in the forecasted increases between number of customers and number of FTEs.

b) Please discuss how customers can benefit from the proposed increases in FTEs.

Response:

a) Due to the COVID 19, the year 2020 was a unique year with vacant positions and hiring process on hold. From the FTE perspective 2020 is not a sustainable year that can be used for comparison to 2022.

If the comparison is used 2016 Actual to 2022 test year, the variances are:

	2016 Actuals	2022 Test Year	Variance	
			Amount	%
Number of Customers	13,858	14,945	1,087	8%
Number of FTEs	18	21	3	17%

Even the increase in number of customer is 8% compared to the increase in FTE of 17%, for a small organization like GPI any new FTE has a large percentage value compared with medium and large utilities.

GPI did not add any new position since 2011 (Accounting Assistant). GPI identified the need for the additional positions required to meet the business objectives. In response to efficiency, the organization needs to increase its staff complement to meet future challenges.

Also, it is equally important to compare the Customer/FTE between GPI and the industry average. Based on the 2020 yearbook information, the industry average is 533, GPI's proposed 2022 Customer/FTE is 712.

b) GPI utilized third party services to assist us in Operations, Engineering, IT and SCADA and Administration. Due to the insufficient FTEs GPI relied more in the last three years on these third party services.

GPI proposal for the new positions (Accounting Supervisor, Senior Customer Service Representative, Journeyman Lineman Apprentice, and IT System & Communication Specialist) will impact the customers as follows:

- Allowing the management staff to focus more on strategic functions that can deliver overall true value to GPI's customers; actively review customer feedback and perceptions via surveys to improve customer satisfaction and performance metrics;

- Work on additional cost reductions by spending more time working on key strategic, planning and budgeting areas and focus on reducing costs while improving efficiency;

- Accurately track costs and make accounting system improvements to ensure spending is within budget and departmental processes and run more efficiently, which keeps costs lower for the rate payer;

- Provide accurate and timely data and reports to facilitate organizational decision making that strengthens GPI's ability to provide better service to customers;

- Make process and community outreach recommendations to enhance transparency and communication with customers;

- More focus on customer driven initiatives (e-billing, consumption monitoring, Green Button etc) through increased communication in a variety of formats, more comprehensive data collection for reporting to see were customer needs aren't being met or possible future initiatives, increased community involvement and allow the company to continue focus on phone call and written responses. The full time hours would also provide much needed back up during vacation times of other Customer Accounts staff;

- The increased hours for the Senior Customer Representative would also provide for better communication and work flow between the Customer

Accounts department and the Engineering/Operations department. The position would be the first point of contact by customers - for general inquiries to the Engineering and Operations department. This would allow for a smoother and quicker response to customer inquiries that can be tracked to ensure all customer inquires are fulfilled. Providing a single initial point of contact would also allow for consistent information to customers and allow Engineering and Operations staff to focus on technical work for customers;

- Better collection activities outside of the disconnection process – from November to April;
- Additional work to track final collection notices and act as a help-desk to those customers using the billing and consumption portal products;
- Improve quality of communication to the customers by spending adequate time to listen and to respond quickly to customers inquires - increase use of social media to build connections and relationships;
- Use of social media and corporate web site for promotion of H&S related items and customer preparedness during unplanned outages, stormy weather, etc.
- Focus on both the annual Capital Work and to complete the maintenance work. Improve the efficiency of the operations group by optimizing the field work execution and have the ability to have a Lineman available for unplanned event and not to interrupt work on completing capital work. Ensure the capital work does not suffer due to conflicts in responding to unplanned maintenance or emergency calls;
- Provide ongoing and effective communication, including more social media communications to the customers especially during unplanned outages;
- More consistent and effective communication with the customers so that it is more effective, regular and impactful.
- By having adequate number of Lineman optimize work execution more effectively and efficiently while maintaining safety at all times;
- Increase ability to find faults faster during unplanned outages.

4-Staff-47
LRAMVA
Ref: Tab 1 of LRAMVA Workform
DVA Continuity Schedule

Preamble:

The total LRAMVA balance in the LRAMVA workform is a debit balance of $105,501. The total claim amount for LRAMVA balance in the DVA Continuity Schedule is a debit balance of $105,995.

Question(s):

a) Please confirm the LRAMVA disposition requested in this application is a total balance of $105,501, comprised of $99,683 (principal) and $5,818 (carrying charges) as calculated in the LRAMVA workform.

b) If necessary, please update the evidence to ensure that the LRAMVA balance and resulting rate riders reflect the balance calculated in the LRAMVA workform.

Response:

a) & b) Grimsby Power confirms that the LRAMVA disposition requested in this application is a total of $105,501. The amount is comprised of $99,683 in principal and $5,818 in carrying charges.

The variance between $105,501 in the LRAMVA workform and the $105,995 in the DVA Continuity Schedule is $494. The $494 amount was added to the DVA Continuity Schedule in cell BQ88 of tab 2b in error as the carrying charges for 2021 were already calculated in the LRAMVA workform.

Grimsby Power has removed the $494 from Tab 2b cell BQ88 of the DVA Continuity Schedule. The total claim of $105,501 in the DVA Continuity Schedule now matches the LRAMVA workform.

The change reduces the LRAMVA rate rider for the General Service 50 to 4,999kW from 0.1242 to 0.1236. Grimsby Power has adjusted the Tariff Schedule and Bill Impact model accordingly.

4-SEC-20

[Ex.4, Appendix 2-JB] Please provide a corrected version of Appendix 2-JB that shows OM&A cost drivers between each year from 2016 and 2022.

Response:

The Appendix 2-JB, Ex.4, Tab 2, p.5 shows the year over year changes in cost drivers from 2016 to 2022.

GPI identified all the cost drivers from 2016 to 2022 and showed the change in each year from 2016 to 2022, even though in some years the costs were cost decreases.

4-SEC-21

[Ex.4, Tab 1, p.6] Please provide justifications to GPI's selection of the benchmarking group.

Response:

Table 4-4 is an extract from the PEG Report (dated August 2020) with no specific selection other than arranged in an alphabetical order. The table shows GPI Cost Benchmarking Results history from 2015-2019.

4-SEC-22

[Ex.4, Tab 3, p.15] Please provide cost details related to the Utilismart, including any one-time cost and any incremental cost actually incurred or forecasted for each year since 2018.

Response:

2018-2020 Cost Details related to the Utilismart:

Cost Details	2018	2019	2020	2021 (8 months)
Data Collection	12,150	16,200	16,200	10,800
Settlement Services	34,800	42,000	42,000	28,000
C&I Energy Manager	10,800	14,664	14,400	9,752
Cellular Services	3,733	5,497	5,514	3,858
Bundled Service Discount	(15,255)	(20,340)	(20,340)	(13,560)
TOTAL	**$ 46,228**	**$ 58,021**	**$ 57,774**	**$ 38,850**

4-SEC-23

[Ex.4,Tab 3, p.2] Please provide a revised version of Appendix 2-JC that includes 2021 year-to-date actuals, as well as at the same point in time during the year, both 2019 and 2020 year-to-actuals.

Response:

Revised Appendix 2-JC as of August for 2019, 2020 and 2021:

Programs	August 2019	August 2020	August 2021
CUSTOMER FOCUS			
Customer Service and Billing	322,955	311,737	319,107
Bad Debts and Collections	15,793	2,147	8,507
Sub-Total	338,748	313,884	327,614
OPERATIONAL EFFECTIVENESS			
Supervision & Engineering	343,472	261,605	245,897
Transformer Station Niagara West M	137,249	170,359	120,501
Meter Reading and Operation	153,060	197,184	204,882
Overhead Services	166,353	193,748	159,743
Underground Services	69,605	122,245	114,347
Vegetation Maintenance	51,047	65,790	66,896
Administration and Financial	504,620	495,104	636,765
Building Maintenace and Utilities	69,069	72,651	64,315
Sub-Total	1,494,475	1,578,686	1,613,347
PUBLIC AND REGULATORY RESPONSIVENESS			
Professional Services	65,420	66,139	122,191
Information Technology	43,738	101,246	107,800
General Expenses and Advertising	85,991	93,296	93,297
Regulatory Costs	20,741	19,543	21,758
Insurance	21,911	24,852	27,427
Sub-Total	237,801	305,076	372,474
Total OM&A	**$ 2,071,023**	**$ 2,197,646**	**$ 2,313,434**

4-SEC-24

[Ex.4, Tab 3, p.15] With respect to the maintenance cost of poles, towers, and fixture:

1. Please provide a revised version of Table 4-16 including 2021 year-to-date actuals, as well as at the same point in time during the year, both 2019 and 2020 year to actuals.
2. Please provide forecast amount for each year of the Application period.

Response:

1. Revised version of Table 4-16 year-to-date actuals 2019, 2020 and 2021:

Programs	Details	August 2019	August 2020	August 2021
OPERATIONAL EFFECTIVENESS				
Overhead Services	**Maintenance Poles, Towers and Fixture**	54,349	73,445	39,719
	OH Lines and Feeders	50,731	66,301	58,540
	OH Transformers	7,657	8,415	9,748
	OH Conductors and Devices	38,347	32,349	31,380
	OH Services	15,269	13,237	20,356
Sub-Total		**$ 166,353**	**$ 193,748**	**$ 159,743**

2. Budgeted amount for each of the following years: 2019, 2020 and 2021

Programs	Details	Budget 2019	Budget 2020	Budget 2021
OPERATIONAL EFFECTIVENESS				
Overhead Services	**Maintenance Poles, Towers and Fixture**	33,614	148,754	112,958
	OH Lines and Feeders	58,691	91,552	82,121
	OH Transformers	52,715	27,434	20,384
	OH Conductors and Devices	50,554	57,286	54,244
	OH Services	28,803	30,145	28,110
Sub-Total		**$ 224,376**	**$ 355,170**	**$ 297,816**

4-SEC-25

[Ex.4, Tab 3, p.16] Please provide Administration and Financial Cost (Labour) Actuals in each year from 2016 to 2020

Response:

Administration and Financial Cost (Labour) Actuals in each year from 2016 to 2020:

Programs		2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals
OPERATIONAL EFFECTIVENESS						
Administration and Financial						
	Labour	894,533	682,646	691,994	709,093	773,577

4-SEC-26

[Ex.4, Tab 4, p.10] Please provide a revised Table 4-22 / Appendix 2-K including 2021 year-to-date actuals, as well as at the same point in time during the year, both 2019 and 2020 year to actuals.

Response:

Table 4-22/ 2-K year to date actuals 2019, 2020 and 2021:

FTE Category	August 2019	August 2020	August 2021
Number of Employees (FTEs including Part-Time)[1]			
Management (including executive)	5.92	4.71	5.55
Non-Management (union and non-union)	11.15	9.14	10.17
Total	17.08	13.84	15.72
Total Salary and Wages including ovetime and incentive pay			
Management (including executive)	$ 485,682	$ 430,691	$ 510,509
Non-Management (union and non-union)	$ 564,108	$ 538,373	$ 553,906
Total	$1,049,790	$ 969,064	$1,064,414
Total Benefits (Current + Accrued)			
Management (including executive)	$ 121,858	$ 110,019	$ 123,036
Non-Management (union and non-union)	$ 156,535	$ 151,150	$ 146,650
Total	$ 278,393	$ 261,169	$ 269,686
Total Compensation (Salary, Wages, & Benefits)			
Management (including executive)	$ 607,540	$ 540,711	$ 633,545
Non-Management (union and non-union)	$ 720,643	$ 689,522	$ 700,556
Total	$1,328,183	$1,230,233	$1,334,100

4-SEC-27

[Ex.4, Tab 4, p.20] For each year between to 2016 and 2020, please provide the annual Corporate Performance Measures and Metrics used for incentive pay, and the actual end of year results for measure and metric.

Response:

Please refer to 4-Staff-41 a).

4-SEC-28

[Ex. 4, Tab 6, Attachment 1] With respect to regulatory costs:

1. Please provide a breakdown of (one-time) consultants' cost.
2. Please confirm that all application-related one-time costs are not included in 2017 to 2021 historic/bridge year OM&A costs.

Response:

1. In compliance with the Filling Requirements, One-Time costs associated with this Cost of Service application are being amortized over a five-year period. The total cost is set-up as a pre-paid expense and one fifth of this amount is amortized each year.

   The breakdown calculation for the total consultants' cost incurred in the 2016 Cost of Service application is shown below:

	Cost	**1/5**
Engineering Consultant	107,724	21,545
Tax Consultant	38,470	7,694
TOTAL	**146,194**	**29,239**

2. The 2016 Cost of Service application consultants' cost of $146,194 was expensed one fifth each year starting 2016 until 2020.

4-SEC-29

[Ex.4, Appendix 2-K] Please provide a revised version of Appendix 2-K that includes two additional rows showing total compensation amounts allocated to capital and OM&A.

Response:

Updated Appendix 2-K with allocation amounts:

	Last Rebasing Year (2016 OEB Approved)	Last Rebasing Year (2016 Actuals)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Bridge Year	2022 Test Year
Number of Employees (FTEs including Part-Time)1								
Management (including executive)	8	8	6	6	6	5	6	8
Non-Management (union and non-union)	9	10	10	11	11	10	12	13
Total	17	18	16	17	17	15	18	21
Total Salary and Wages including ovetime and incentive pay								
Management (including executive)	$ 808,122	$ 883,393	$ 650,477	$ 684,383	$ 689,311	$ 614,818	$ 759,423	$ 973,337
Non-Management (union and non-union)	$ 674,588	$ 739,786	$ 784,802	$ 849,618	$ 869,015	$ 849,110	$ 867,740	$ 949,561
Total	$1,482,711	$1,623,179	$1,435,279	$1,534,001	$1,558,326	$1,463,928	$1,627,163	$1,922,898
Total Benefits (Current + Accrued)								
Management (including executive)	$ 199,079	$ 195,304	$ 164,136	$ 171,645	$ 167,579	$ 164,703	$ 190,730	$ 235,269
Non-Management (union and non-union)	$ 185,692	$ 190,892	$ 208,673	$ 224,933	$ 222,191	$ 193,991	$ 253,803	$ 288,891
Total	$ 384,771	$ 386,196	$ 372,809	$ 396,578	$ 389,770	$ 358,693	$ 444,533	$ 524,160
Total Compensation (Salary, Wages, & Benefits)								
Management (including executive)	$1,007,201	$1,078,697	$ 814,613	$ 856,028	$ 856,890	$ 779,521	$ 950,154	$1,208,606
Non-Management (union and non-union)	$ 860,280	$ 930,678	$ 993,475	$1,074,552	$1,091,206	$1,043,101	$1,121,543	$1,238,452
Total	$1,867,481	$2,009,375	$1,808,087	$1,930,579	$1,948,096	$1,822,621	$2,071,696	$2,447,058
Compensation allocated to Capital	$ 136,191	$ 102,400	$ 62,924	$ 94,217	$ 109,137	$ 83,672	$ 79,296	$ 113,722
Compensation allocated to OM&A	$1,731,290	$1,906,975	$1,745,164	$1,836,362	$1,838,959	$1,738,949	$1,992,400	$2,333,336

4-SEC-30

[Ex. 4, Tab 9, p.9] With respect to Accelerated CCA:

1. Please provide the supporting calculations for 2018.
2. Please provide a forecast of the 2021 calculations.

Response:

1. 2018 Accelerated CCA Supporting Calculation:

2018 No AIIP

Class No. [200]	2 UCC BOY [201]	3 Additions [203]	5 Proceeds* [207]	6 UCC	7 1/2 of [203] - [207] [211]	8 Reduced UCC	9 Rate % [212]	10 Recapture [213]	11 Terminal Loss [215]	12 CCA [217]	13 UCC EOY [220]	CCA As Filed	Difference
1	$ 11,311,974	$ 81,578		$ 11,393,552	$ 40,789	$ 11,352,763	4	$ -	$ -	$ 454,111	$ 10,939,441	$ 454,111	$ (0)
8	$ 419,143	$ 74,721		$ 493,864	$ 37,361	$ 456,503	20	$ -	$ -	$ 91,301	$ 402,563	$ 104,311	$ (13,010)
10	$ 301,430	373,868	$ (5,000)	$ 670,298	$ 184,434	$ 485,864	30	$ -	$ -	$ 145,759	$ 524,539	$ 145,759	$ 0
2	$ 314,257	$ -		$ 314,257	$ -	$ 314,257	6	$ -	$ -	$ 18,855	$ 295,402	$ 18,855	$ 0
45	$ 38	$ -		$ 38	$ -	$ 38	45	$ -	$ -	$ 17	$ 21	$ 17	$ 0
47	$ 8,972,190	$ 982,105		$ 9,954,295	$ 491,053	$ 9,463,242	8	$ -	$ -	$ 757,059	$ 9,197,236	$ 822,721	$ (65,662)
50	$ 18,477	$ 3,695		$ 22,172	$ 1,848	$ 20,324	55	$ -	$ -	$ 11,178	$ 10,994	$ 11,178	$ 0
12	$ 18,130	$ 25,371		$ 43,501	$ 12,686	$ 30,815	100	$ -	$ -	$ 30,816	$ 12,686	$ 31,065	$ (250)
6	$ 16,070	$ -		$ 16,070	$ -	$ 16,070	10	$ -	$ -	$ 1,607	$ 14,463	$ 1,607	$ -
95	$ -			$ -	$ -	$ -	0	$ -	$ -	$ -	$ -	$ -	$ -
	$ 21,371,709	$ 1,541,338	$ (5,000)	$ 22,908,047	$ 768,171	$ 22,139,876		$ -	$ -	**$ 1,510,703**	$ 21,397,344	$ 1,589,624	$ (78,921)
												Tax Impact	$ (20,914)
												Grossed-up	**$ (28,454)**

2. 2021 Accelerated CCA Supporting Calculation:

2021 Rolled with NO Accelerated CCA Applied

Class No. [200]	2 UCC BOY [201]	3 Additions [203]	5 Proceeds* [207]	6 UCC	7 1/2 of [203] - [207] [211]	8 Reduced UCC	9 Rate % [212]	10 Recapture [213]	11 Terminal Loss [215]	12 CCA [217]	13 UCC EOY [220]	CCA w/ AIIP	Difference
1	$ 10,081,789			$ 10,081,789	$ -	$ 10,081,789	4	$ -	$ -	**$ 403,272**	**$ 9,678,518**	$ 403,272	$ (0)
1b	$ 25,132	$ 20,000		$ 45,132	$ 10,000	$ 35,132	6	$ -	$ -	**$ 2,108**	**$ 43,024**	$ 3,215	$ (1,107)
8	$ 487,206	$ 44,000		$ 531,206	$ 22,000	$ 509,206	20	$ -	$ -	**$ 101,841**	**$ 429,365**	$ 98,773	$ 3,068
10	$ 349,930	87,000		$ 436,930	$ 43,500	$ 393,430	30	$ -	$ -	**$ 118,029**	**$ 318,901**	$ 134,292	$ (16,263)
2	$ 261,017			$ 261,017	$ -	$ 261,017	6	$ -	$ -	**$ 15,661**	**$ 245,356**	$ 15,661	$ 0
17	$ 1,939			$ 1,939	$ -	$ 1,939	8	$ -	$ -	**$ 155**	**$ 1,784**	$ 142	$ 13
45	$ 6			$ 6	$ -	$ 6	45	$ -	$ -	**$ 3**	**$ 3**	$ 3	$ (0)
47	$ 10,339,713	$ 1,908,845		$ 12,248,558	$ 954,423	$ 11,294,135	8	$ -	$ -	**$ 903,531**	**$ 11,345,027**	$ 1,034,988	$ (131,457)
50	$ 79,503	$ 45,040		$ 124,543	$ 22,520	$ 102,023	55	$ -	$ -	**$ 56,112**	$ 68,430	$ 48,642	$ 7,470
12	$ 24,011	$ 20,000		$ 44,011	$ 10,000	$ 34,011	100	$ -	$ -	**$ 34,011**	$ 10,000	$ 20,000	$ 14,011
6	$ 11,715			$ 11,715	$ -	$ 11,715	10	$ -	$ -	**$ 1,172**	$ 10,544	$ 1,172	$ (0)
54	$ 20,227			$ 20,227	$ -	$ 20,227	30	$ -	$ -	**$ 6,068**	$ 14,159		$ 6,068
95	$ -			$ -	$ -	$ -	0	$ -	$ -	$ -	$ -	$ -	
	$ 21,682,188	$ 2,124,885	$ -	$ 23,807,073	$ 1,062,443	$ 22,744,630		$ -	$ -	**$ 1,641,962**	**$ 22,165,111**	**$ 1,760,160**	$ (118,198)
												Tax Rate	$ (31,322)
												Grossed-up	**$ (42,616)**

4–VECC-31

Reference: Exhibit 4, Tab 4, page 11

a) Please clarify the increase in positions in Engineering from 2 to 3 between 2021 and 2022 and the increase in Executives as between 2020 and 2021. Specifically, which one of these positions is Director of Engineering and Operations and what is the title of the other position?

Response:

a) The Engineering Department has 2 Engineering Technician positions. The 2022 increase from 2 to 3 FTE in the Engineering Department is due to the IT System and Communication Specialist.

The increase in Executives from 2 FTEs in 2020 to 3 FTEs in 2021 is due to the hiring of the Director of Engineering and Operations in 2021.

4–VECC-32

Reference: Exhibit 4, Tab 2, pages 13- /9-

a) Please clarify if the IT System and Communication Specialist is being hired to implement GPI's Cyber Security plans.

b) Has this position been hired?

c) Please provide the job description for this position.

d) Please provide the total (including labour) incremental annual costs (as compared to 2016) for the new cyber security protocols.

Response:

a) One of the accountabilities for this position is ensuring that Cyber Security plans are in place and such risks are mitigated effectively.

b) GPI is planning to hire the IT System and Communication Specialist in 2022.

c) Draft version of Job description is provided as Appendix 1 of 4-VECC-32.

d) The Cost related to the Cybersecurity :

2016	2017	2018	2019	2020	2021	2022	Total Annual Spend for 2022
		4,037	15,963	- 14,141	9,000	9,360	24,219

JOB DESCRIPTION

POSITION: **IT SYSTEMS AND COMMUNICATION SPECIALIST**

WORK GROUP: **Management/Supervisory**

The IT Systems and Communication Specialist:

- Directing the maintenance, design and integrity of the overall network infrastructure including installation, configuration, maintenance, monitoring, and support of all network resources including software, firewalls, routers, switches, wireless access points, phone VOIP systems, and network related components.
- Directing communications functions of the utility including corporate web site changes/upgrades c/w all analytics, updates to corporate social networks (i.e. Twitter) and coordinating all communications and engagement material presented to customers.

ORGANIZATIONAL RELATIONSHIP:

- Director of Engineering and Operations
- Works closely with departmental managers and third party service providers

RESPONSIBILITIES:

Information Technology

- Business systems development and support by maintaining a good working knowledge of application software and ensure most efficient use of end-user applications and data based on corporate requirements and business processes;
- Provide subject matter expertise to the Company on its IT systems
- Recommend and implement appropriate security controls to protect the Company's information
- Provide cybersecurity expertise and mitigate risks
- Support and oversee requests, incidents, and IT issues, manage, and coordinate the support of issues

- Perform regularly scheduled vulnerability assessments, recommend, and implement effective monitoring, establish baselines for subsequent effectivity assessment
- Update and report on the security status to the OEB Security Framework
- Develop and maintain Business Continuity Plan/Disaster Recovery Plan
- Maintain a good working knowledge of databases, query reporting solutions and high-end report writing tools to maximize value of corporate data;
- Consult with internal stakeholders to determine operational requirements, optimal business solutions using available technologies, and make recommendations regarding the benefits of new and emerging technologies;
- Take lead role in the research, selection, and acquisition of new technologies and business solutions;
- Support to IT Staff on the configuration, deployment, and support of all clients, servers, network devices, and applications;
- Define, develop, and document business requirements for hardware and software including objectives, deliverables, and specifications on a project by project basis in collaboration with internal users;
- Work towards achieving total system integration based on knowledge of continuing developments in information technology;
- Define, implement and manage standards, policies, and procedures with relation to information technology;
- Provide project management for the delivery and support of information technology solutions;
- Be responsible for the preparation and management of the capital and operating budgets related to information technology.

Corporate Communications

- Design and distribute annual reports, quarterly newsletters, bill inserts and timely press releases.
- Prepare Board reports quarterly that reflect engagement and communication activities.
- Coordinate with Managers to broadcast prompt information ensuring customer disruption notices are expeditious. These activities include remote work afterhours and weekends.
- Create and post updates on company social media platforms in line with Social Media Strategy.
- Maintain company website, mobile application, and other communication channels with up-to-date information and ensure accuracy of posted information.

- Work with internal staff to market Customer Service portals, paperless billing, and other customer service offerings to reach departmental goals.
- Develop communication strategies to engage customers and channel partners.
- Coordinate internal communications and materials for staff to support external promotions.
- Track, record and measure communication and engagement programs.
- Support all departments in communication activities and requirements.
- Complete other job duties, as necessary.

General

- Administers corporate policies, procedures, and collective agreement;
- Provide support to ensure staff receive necessary training as required;
- Complete other projects and duties as required.

QUALIFICATIONS:

- Minimum 5 years of progressive information technology and customer care experience (utility experience would be an asset);
- Strong project management, communication, vendor management, business analyst, conceptual modelling solution architecture, and customer care skills;
- Process improvement and system integration experience with new technologies;
- Ability to analyze processes and articulate recommendations for improvements;
- Excellent communication skills, including oral, written and interpersonal;
- Demonstrated experience managing social media platforms for business is an asset;
- Demonstrated proficiency in the use of personal computers with Windows based operating environment including Microsoft applications such as Outlook, Excel, & Word;
- Demonstrated proficiency in project management software is an asset.

EDUCATION REQUIRED:

- Bachelor in a related field such as Information Technology, Business Administration, Commerce, Computer Science or equivalent education and;
- Continuing educational courses in Information Technology and/or Communication Systems are an asset.

LICENCES OR SPECIAL REQUIREMENTS:

- Valid Class G drivers license with a clean abstract.

WORKING ENVIRONMENT:

- Typical office workstation;
- Occasional outdoor environment;

TYPE OF CANDIDATE:

The ideal candidate is one who enjoys the satisfaction of providing excellent customer service through effective communication with customers and through the technical solutions provided to customers. If you aspire to lead the development of IT and Communication activities through the use of technology by maximizing leadership skills, utilizing computer applications, and are effective communicator, organized, detail oriented, and results focused then this position should be one of interest.

4–VECC-33

Reference: Exhibit 4, Tab 3, pages 4-

Preamble: Operations with respect to NW MTS are currently contracted to third-party service providers. GPI's intent is to slowly migrate some of these services to GPI staff as training and knowledge of the station is increased.

Table 4-14

Summary of Transformer Station Niagara West MTS 2016 OEB

Approved to 2022 Test Year

Programs	Details	Last Rebasing Year (2016 OEB-Approved)	2020 Actuals	2022 Test Year	Variance (Test Year vs. 2020 Actuals)	Variance (Test Year vs. Last Rebasing Year (2016 OEB-Approved)
OPERATIONAL EFFECTIVENESS						
Transformer Station	Load Dispatching	71,671	104,237	90,060	(14,177)	18,389
	Operating Expenses	52,122	73,738	84,683	10,945	32,561
	Maintenance Expense	45,690	55,042	63,526	8,484	17,836
	Insurance	25,000	24,165	28,387	4,222	3,387
	Property Tax	7,500	9,459	10,092	632	2,592
Sub-Total		201,983	266,641	276,748	10,107	74,764

a) Are any FTE's included in Appendix 2-K for the service providers contracted to maintain NW MTS? If yes, please provide the number of FTEs.

b) Has GPI developed a business plan to bring MTS service in-house? If yes, what are the expected savings (or costs) for that change.

Response:

a) No FTE is included in Appendix 2-K for the service providers contracted to maintain NW MTS. Since 2018 GPI has migrated MTS weekly inspections to the existing FTEs.

b) At this point Grimsby Power has a long term contract with Station Service Contractor that specializes in Station Maintenance and has trained staff and acquired tools to conduct such work. In the forecasted period Grimsby Power has no provisions to increase its internal FTEs for full station maintenance services for Grimsby Power owned MTS.

4–VECC-34

Reference: Exhibit 4, Tab 3, page 11

a) Please breakdown the $167,804 in incremental Customer Service and Billing costs into labour related and non-labour related components.

Response:

a) Table 4-12 – Customer Service and Billing costs:

Expense	Last Rebasing Year (2016 OEB-Approved)	2022 Test Year	Variance (Test Year vs. Last Rebasing Year (2016 OEB-Approved)
Labour	$ 183,144	$ 296,599	$ 113,455
Non-Labour	$ 281,780	$ 336,129	$ 54,349
TOTAL	$ 464,924	$ 632,728	$ 167,804

4–VECC-35

Reference: Exhibit 4, Tab 3, pages 15

Preamble: *The 2022 Test Year balance of $321,026 is $131,916 higher than 2016 Board Approved amount of $189,110. The primary driver for higher costs relates to pole maintenance and costs associated with the maintenance of OH Conductors and Devices.*

a) GPI proposes a significant increase in pole replacement as part of its 5-year DSP. At the same time, the Utility is projecting a significant increase in pole and line maintenance costs. Please explain why pole and line maintenance are not decreasing if the stock of assets is being significantly renewed over the next 5 years.

Response:

a) For detailed explanation on justification for increase in Replacement of Defective poles over the 5-year DSP please see answers to 2-VECC-15.
For detailed explanation on justification for increase System O&M (which includes pole and lines maintenance costs) over the 5-year DSP please see answers to OEB Interrogatory 4-Staff-37.

4–VECC-36

Reference: Exhibit 4, Tab 4, page 19

Table 4-26 /Short Term Incentive Split

GPI's Position Description	Corporate Performance %	Individual Performance %
President and CEO	75	25
Director of Engineering and Operations	50	50
Director of Finance	50	50
Operations Supervisor	50	50
Regulatory and Customer Accounts Supervisor	50	50
Accounting Supervisor	50	50
IT/Communication Specialist	25	75
Executive Assistant	25	75

a) Are the eight positions listed in this table the same 8 positions listed in Appendix 2-K as Management (including executive)?

b) Are all these positions currently filled?

Response:

a) GPI confirms that the eight positions listed in this table are the same eight positions listed in Appendix 2-K as Management (including executive).

b) Yes the positions are filled with one exception - the IT/Communication Specialist

4–VECC-37

Reference: Exhibit 4, Tab 6, page 2

a) Table 4-38 does not indicate the procurement method for MEARIE products. Please clarify the services and products provided and the procurement method used to purchase those services.
b) When was the last time GPI tendered for any of these insurance services?
c) Please provide the MEARIE related premiums for each of 2016 through 2022 (forecast).

Response:

a) The procurement method for MEARIE products is based on the historical experience of most of Electrical Utilities.

MEARIE Group provides the following products to GPI:

- Employee Benefit Programs:
  - Life Insurance
  - Disability Insurance
  - Health Care
  - Employee Assistance Program
  - Virtual Care

- Insurance for the following:
  - General Liability
  - Enhanced Directors Endorsement Liability
  - Privacy, Cyber and Network Security
  - Fleet/Vehicle

b) GPI's last tender for any insurance services was in 2003. Since 2003 GPI moved the following insurance services to a local insurance firm – Duliban Insurance Brokers LTD:
   - Property Coverage
   - Board Members Accident
   - Equipment

c) 2016 – 2022 MEARIE related premiums:

Description	2016	2017	2018	2019	2020	2021	2022
Comprehensive Liability :	**27,699**	**27,677**	**26,259**	**26,726**	**29,504**	**29,319**	**29,189**
General Liability	19,045	18,391	17,676	19,090	21,074	21,102	21,389
Enhanced Directors Endorsement Liability	4,327	4,643	4,291	3,818	4,215	4,108	3,900
Privacy, Cyber & Network Security	4,327	4,643	4,291	3,818	4,215	4,108	3,900
Fleet/Vehicles:	**7,777**	**8,477**	**9,851**	**10,296**	**8,462**	**12,385**	**13,200**
Property (NW MTS)		**23,060**	**21,147**	**22,296**	**24,165**	**30,548**	**34,800**
TOTAL	**$35,476**	**$59,214**	**$57,257**	**$59,318**	**$62,131**	**$72,253**	**$ 77,189**

4–VECC-38

Reference: Exhibit 4, Tab 6, page 2

a) Is GPI a member of the Electricity Distributors Association? If yes, please provide the annual association fees for 2016 through 2022.

Response:

a) GPI is not a member of the Electricity Distributors Association.

4–VECC-39

Reference: Exhibit 4, Tab 6, page 4

Table 4-39

Regulatory Costs specific to the 2022 Cost of Service

Cost of Service Expense	Amount
Legal	$ 40,000
Customer Engagement	$ 12,676
Consultant	$ 150,000
DSP	$ 75,000
Intervenor and OEB Cost	$ 120,000
Miscellaneous	$ 2,324
TOTAL	**$ 400,000**
Amortized over 5 Years	**$ 80,000**

a) Please provide the amounts incurred to date for these one-time application related costs.

b) Are any of the application costs shown in the table included as costs in the 2020 or 2021 OM&A costs shown in Appendices 2-JA or 2-JC?

c) Is the 80k included as part of 2022 OM&A costs in Appendices 2-JA and (under Regulatory Costs) in 2-JC.

d) Please clarify what the 150k in consulting cost relates to.

e) Is the 80,oooIs GPI a member of the Electricity Distributors Association? If yes, please provide the annual association fees for 2016 through 2022.

Response:

a) The amounts incurred to date for these one-time application costs is in the table below:

Cost of Service Expense As of September 30, 2021	Amount
Legal	$ 19,711
Customer Engagement	$ 13,038
Consultant	$145,575
DSP	$ 77,042
Intervenor and OEB Cost	
Miscellaneous	
TOTAL	**$255,366**
Amortized over 5 Years	**$ 51,073**

b) All the application costs are kept in a prepaid account and are not included as costs in any of the 2020 or 2021 OM&A costs in Appendices 2-JA or 2-JC.

c) The 80K is included in the 2022 OM&A costs in Appendices 2-JA under Regulatory Costs.

d) The Consultant Costs is related to the :

Application Consultant - $140,075
Tax Consultant - $5,500

e) GPI is not a member of the Electricity Distributors Association.

Exhibit 5 – Cost of Capital and Capital Structure

5-Staff-48
Long-term Debt
Ref: Exhibit 5, Tab 1, page 7 of 10

Preamble:

Grimsby Power stated that it is requesting to recover the cost of long-term debt at a rate of 2.68% for the 2022 test year.

Question(s):

a) Please confirm the requested long-term debt rate was 2.73% per Table 5-5.

b) Please confirm the debt rate for the promissory note will be updated in accordance with the OEB-issued long-term debt rate for 2022 rates.

Response:

a) GPI confirms that the requested long term debt rate is 2.73%.

b) GPI confirms that debt rate for the promissory note will be updated in accordance with OEB issued long-term debt rate for 2022 rates.

5–VECC-40

Reference: Exhibit 5, Tab 1, page 2

Preamble: *In order to maintain the flexibility for the future, GPI maintained a reasonable debt. Operating with a reasonable debt/equity will provide GPI's flexibility to access the credit facility in case it is needed for a large investment*.

a) Interest rates are at historically low values. GPI is underleveraged. Why is it not the most prudent course of action to borrow long-term now to finance the larger capital program anticipated in the DSP?

b) What is the current long-term interest rate that GPI believes it could borrow $3-4 million?

Response:

a) GPI assumes that the assertion that GPI is "under leveraged" with respect to its long term debt burden is based on a comparison of GPI's actual long term debt against the OEB's deemed capital structure. On an operating basis GPI does not agree that it is under-leveraged; GPI manages its funding requirements not covered by long term debt instruments using its credit facilities on a short term basis, which it in turn manages in the normal course using its cash flow from rates. From a ratemaking perspective the notional gap between GPI's actual long term debt and the level of debt in its deemed capital structure attracts the weighted average cost of its actual debt, which already reflects the low OEB deemed Long Term Debt rate on GPI's affiliate debt and the low rate on GPI's 3rd party debt instruments.

b) Current interest rate that GPI could borrow long-term form the bank is in the range 2.5% to 3%.

5–VECC-41

Reference: Exhibit 5, Tab 1,

Performance Outcomes	Performance Categories	Measures	2016	2017	2018	2019
Financial Performance	Financial Ratios	ROE: Deemed (included in rates)	9.19%	9.19%	9.19%	9.19%
		ROE: Achieved	2.39%	10.92%	8.45%	10.39%

a) Please provide GPI's return on equity for 2020.

Response:

a) Grimsby Power's regulated ROE for 2020 was 8.12%.

Exhibit 7 – Cost Allocation

7-Staff-49
Weighting Factors
Ref: Exhibit 7, pages 1-2
Cost Allocation Model, sheet I9 Direct Allocation

Preamble:

The services weighting factor for the GS < 50 kW rate class has been set at 3.14 (reflecting a cost 3.14 times as much as Residential). Grimsby power has provided explanations as to why this cost is higher for GS < 50 than Residential.

Grimsby power has provided explanations for the Services weighting factors.

The direct allocation for the Embedded Distributor includes a direct allocation for Account 5315.

Question(s):

a) Please provide the derivation of the 3.14 weighting factor or explain how this number was arrived at.

b) Please provide the derivation of the services weighting factors.

c) Please detail which costs are included in the direct allocation of Account 5315 to the Embedded Distributor, which are included in the derivation of the services weighting factor for this rate class, and confirm that there is no double counting of costs.

Response:

a) The weighting factors provided in the cost allocation model were the same weighting factors used in GPI's EB-2015-072 2016 Cost of Service application. GPI reviewed the calculation and determined that the weighting factor for the GS<50 rate category was too high. The 3.14 was initially determined by using 2015 costs divided by the number of work orders however the number of work orders used was overstated for the residential rate class lowering the cost per service and therefore increasing the weight for a GS<50 service.

   GPI has updated the services weighting factor as indicated in the table below.

	Residential	GS <50	GS 50 to 4,999 kW	Street Light	Unmetered Scattered Load	Embedded Distributor
Insert Weighting Factor for Services Account 1855	1	0.91	0	0	0	0

The revised weighting was calculated by taking the costs for services added in each year from 2016 to 2020 and dividing that by the number of customers (or service addresses instead of work orders). An average residential service was calculated to be $1,181 and a GS<50 was calculated to be $1076.10. The cost for a GS<50 customer is lower compared to a residential as most GS<50 services are overhead.

b) Please see the response to a) above.

c) The cost that is directly allocated to the Embedded Distributor from account 5315 is the cost associated with a vendor producing a calculation that splits the IESO invoice between NPEI and GPI. Grimsby Power did not include this cost in the derivation of the Billing and Collecting weighting factor or the Services weighting factor.

7-Staff-50

Load Profiles
Ref: Exhibit 7, Tab 1, page 5

Preamble:

Grimsby Power indicates that it has based its load profiles on the same information provided by Hydro One that it has used in its previous rate applications, and not updated its load profiles to reflect recent smart meter and interval meter information.

Grimsby notes that it intends to follow the OEB's guidance on acceptable methodologies for updating cost allocation load profiles.

OEB staff notes that it's not clear how prescriptive any filing requirements will be regarding approved methodologies.

Question(s):

a) Please confirm that Grimsby Power will begin to collect smart meter and interval meter data either now, or shortly after the conclusion of this proceeding so that it has the data available to implement whatever methodology it determines most appropriate at the time of its next rebasing application.

b) Please confirm that Grimsby Power will update its load profiles at the next rebasing application whether that takes the form of following filing requirements, a methodology used by other distributors, or one of its own design.

Response:

a) Grimsby Power will begin to collect smart meter and interval data after the conclusion of the proceeding to have data available to implement a methodology that we see as most appropriate for the next rebasing.

b) Grimsby Power confirms that is will update load profiles for the next rebasing application.

7-SEC-31

[Ex.7, Tab 1, p.3] Please provide the breakdown of and justifications to the 7.4 weighting factors attributed to GS 50-4,999 kW class.

Response:

Please see 7-Staff-49.

7-VECC-42

Reference: Exhibit 7, Tab 1, pages 6-8
Cost Allocation Model, Tabs I7.1 and I7.2
EB-2015-0072, Responses to 7-Staff-42 and 7-EP-44

Preamble: The Application states: "*Grimsby Power proposes to apply the same methodology used in the 2016 Settlement Agreement in this application. The allocation includes 40% of costs related to the Niagara West MTS to the Embedded Distributor class, a direct allocation of a very small portion of billing & collecting associated with invoicing the Embedded Distributor and an allocation of expenses that are allocated by the O&M allocator*".

a) Please describe the GPI owned assets used to service the Embedded Distributor (including the relevant USOA they are included in).

b) Please confirm that the meter ownership and reading responsibilities continue to be as outlined in 7-Energy Probe-44 from EB-2015-0072.

c) Please confirm that the assignment of the capacity of the Niagara West MTS continues to be as set out in the response to 7-Staff-42 from EB-2015-0072.

d) Please itemize the USOA accounts for which Miscellaneous Revenues are allocated to the Embedded Distributor and explain why it is reasonable for the Embedded Distributor to be allocated a share of these revenues.

e) Given the Embedded Distributor is allocated a portion of the General and Administrative expenses, would it not be appropriate to allocate the Embedded Distributor a portion General Plant as this provides the infrastructure supporting the staff whose costs are included in General and Administrative expenses?

Response:

a) The GPI owned assets used to service the Embedded Distributor are inclusive of the Niagara West Transformation station. A description of the assets is further noted in the connection agreement between GPI and NPEI. The connection agreement between NPEI and GPI is attached as Appendix 1 of 7-VECC-42.

b) Grimsby Power now owns all metering at the Niagara West MTS. In March of 2017 GPI installed revenue meters on the two 230kV circuits supplying the station.

c) The assigned capacity of the Niagara West MTS is still based on the evaluation by NWTC in the April 2014 report as noted in 7-Staff-42 from EB-2015-0072.

d) The Embedded Distributor receives a share of the Miscellaneous Revenues that are allocated by the O&M, OM&A, CCA, or CWNB allocators. Incurred costs associated with these Miscellaneous Revenues are generally allocated by the same allocators, effectively offsetting the shared cost that is allocated to classes. As the Embedded Distributor is receiving a share of costs, it is reasonable for the class to also receive a proportionate share of the offsetting revenues.

GL Account		O1 Grouping	Embedded Distributor	Allocator
4082	Retail Services Revenues	mi	-$342	OM&A
4084	Service Transaction Requests (STR) Revenues	mi	-$5	OM&A
4086	SSS Admin Charge	mi	-$2	CCA
4235-01	Account Set Up Charges	mi	-$62	CWNB
4235-90	Miscellaneous Service Revenues - Residual	mi	-$1,014	OM&A
4245	Government Assistance Directly Credited to Income	mi	-$4,212	OM&A
4375	Revenues from Non-Utility Operations	mi	-$60	O&M
4390	Miscellaneous Non-Operating Income	mi	-$155	OM&A
4405	Interest and Dividend Income	mi	-$478	OM&A
		Total	**-$6,330**	

e) In Grimsby Power's 2016 COS application the Embedded Distributor received an allocation of General Plant, however, the allocation was subsequently removed in the final cost allocation model. Grimsby Power elected to follow the methodology agreed upon in the 2016 Settlement Agreement in which the Embedded Distributor does not receive a share of general plant.

CONNECTION AGREEMENT FOR AN EMBEDDED DISTRIBUTOR

THIS CONNECTION AGREEMENT is made this 23rd day of March, 2021,

BETWEEN

GRIMSBY POWER INC. (the "**Distributor**")

AND

NIAGARA PENINSULA ENERGY INC. (the "**Customer**")

(each a "**Party**" and collectively the "**Parties**")

RECITALS:

WHEREAS the Distributor is the owner of the distribution system serving the service area described in electricity distribution license number ED-2002-0554 (the "License") issued to Grimsby Power Inc. (GPI) (the "**Distributor's Distribution System**").

AND WHEREAS the Customer owns or operates a distribution system serving the service area described in electricity distribution license number ***ED-2007-0749*** *issued to Niagara Peninsula Energy Inc. (NPEI)* which is connected to the Distributor's distribution system at the Demarcation Point(s) specified herein;

AND WHEREAS in accordance with its License and the Distribution System Code (DSC) issued by the Ontario Energy Board, the Distributor has agreed to offer, and the Customer has agreed to accept, distribution service to Customer Equipment.

NOW THEREFORE in consideration of the foregoing, and of the mutual covenants, agreements, terms and conditions herein contained, the Parties, intending to be legally bound, hereby agree as follows:

1. Definitions and Schedules

1.1. Words and phrases contained in this Agreement (whether capitalized or not) that are not defined in this Agreement have the meanings given to them in the *Electricity Act, 1998,* the *Ontario Energy Board Act, 1998,* any regulations made under either of those *Acts,* the DSC or the Distributor's Conditions of Service.

1.2. The following schedules form part of this Agreement:

Schedule A - Contacts for Notice

Schedule B - Billing and Settlement Procedures

Schedule C - Dispute Resolution

Schedule D - Details of Specific Operation

Schedule E - Where the Customer is Financed by a Lender

Where a schedule is to be completed by the Parties, the Parties may not include in that schedule a provision that would be contrary to or inconsistent with the DSC.

1.3. Acronyms

DSC	Distribution System Code
GPI	Grimsby Power Inc.
NPEI	Niagara Peninsula Energy Inc.
NWTS	Niagara West Transformer Station, 3021 Grimsby Rd., West Lincoln.
OEB	Ontario Energy Board

1.4. Definitions

Embedded Generation Facility has the meaning as described in the Distribution System Code.

2. Customer Information

2.1. Schedule D lists the equipment ownership of each Party and includes the following information:

(a) a single line diagram; and

(b) a diagram of the metering installations applicable to the Customer.

3. Incorporation of Code and Application of Conditions of Service and Other Contracts

3.1. The DSC, as it may be amended from time to time, is hereby incorporated in its entirety by reference into, and forms part of, this Agreement. Unless the context otherwise requires, all references to "this Agreement" include a reference to the DSC.

3.2. The Distributor hereby agrees to be bound by and at all times to comply with the DSC, and the Customer acknowledges and agrees that the Distributor is bound at all times to comply with the DSC in addition to complying with the provisions of this Agreement.

3.3. In addition to this Agreement, the relationship between the Distributor and the Customer will be governed by the Distributor's Conditions of Service that are in effect at the relevant time. In the event of a conflict or an inconsistency between a provision of this Agreement and a provision of the Distributor's Conditions of Service, the provision of this Agreement shall govern.

4. Customer Equipment Standards

4.1. The Customer shall ensure that all electrical and mechanical equipment that is owned by the Customer and is used by the Customer and all equipment connected to all electrical and mechanical equipment used by the Customer or by the Customer's load or generation customers (collectively, the "Customer Equipment"):

(a) conforms to all applicable industry standards including, but not limited to, those of the Canadian Standards Association ("CSA"), the Institute of Electrical and Electronic Engineers, the American National Standards Institute and the International Electrotechnical Commission;

(b) is installed, constructed, operated and maintained in accordance with this Agreement, the Distributor's offer to connect, the requirements of the Reg. 22/04, any agreements made between the Customer and the Distributor with respect to the connection of Customer Equipment to the Distributor's distribution system, all applicable reliability standards and good utility practice; and

(c) meets the technical and operating requirements set out in Schedule D. These requirements shall not exceed any technical or operating requirements set out in the DSC unless the Customer agrees.

5. Charges, Settlement and Billing

5.1. The Customer shall pay the Distributor such charges as may be approved by the OEB in relation to the connection of, and the provision of distribution service to, the Customer.

5.2. Billing and settlement activities will be conducted in accordance with the procedures set out in Schedule B.

6. Representations and Warranties

6.1. The Customer represents and warrants to the Distributor as follows, and acknowledges that the Distributor is relying on such representations and warranties without independent inquiry in entering into this Agreement:

(a) the Customer Equipment is in compliance with all applicable technical requirements and laws;

(b) the Customer has been given warranty information and operation manuals for the Customer Equipment;

(c) the Customer has been adequately instructed in the operation and maintenance of the Customer Equipment and the Customer has developed and implemented an operation and maintenance plan based on those instructions;

(d) if the Customer is a corporation or other form of business entity, the Customer is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(e) the Customer has all necessary power, authority and capacity to enter into this Agreement and to perform its obligations under this Agreement;

(f) this Agreement constitutes a legal and binding obligation on the Customer, enforceable against the Customer in accordance with its terms;

(g) the Customer holds all permits, licenses and other authorizations that may be necessary to enable it to own and operate the Customer Equipment; and

(h) any individual signing this Agreement on behalf of the Customer has been duly authorized by the Customer to sign this Agreement and has the full power and authority to bind the Customer.

6.2. The Distributor represents and warrants to the Customer as follows, and acknowledges that the Customer is relying on such representations and warranties without independent inquiry in entering into this Agreement:

(a) the Distributor is duly incorporated under the laws of Ontario;

(b) the Distributor has all necessary power, authority and capacity to enter into this Agreement and to perform its obligations under this Agreement;

(c) this Agreement constitutes a legal and binding obligation on the Distributor, enforceable against the Distributor in accordance with its terms; and

(d) any individual signing this Agreement on behalf of the Distributor has been duly authorized by the Distributor to sign this Agreement and has the full power and authority to bind the Distributor.

7. Disconnection Device at the Ownership Demarcation Point

7.1. The Customer shall furnish, install and maintain a suitable disconnecting device at the Demarcation Point(s) with the Distributor's feeder. The disconnecting device shall provide a visual break in the main current-carrying path. The disconnection switch at the Ownership Demarcation Point shall be rated for the voltage and fault current requirements of the Customer Equipment, and shall meet all applicable CSA standards, ESA requirements, and all other applicable laws. The switch enclosure, if applicable, shall be properly grounded. The disconnection switch at the Ownership Demarcation Point shall be accessible at all times, located for ease of access to the Distributor's personnel, and shall be capable of being locked in the open position. The Customer shall follow the Distributor's procedures for switching, clearance, tagging, and locking.

8. Modifications to the Customer Equipment and Connection of Generation Equipment

8.1. The Customer shall not modify its connection assets or the Customer Equipment except in accordance with this section. The Customer shall give the Distributor no less than 30 working days' notice prior to the date on which the modification will be completed.

8.2. The Customer shall not install Emergency Backup Generation and/or Energy Storage without the notification of, and approval from, the Distributor.

8.3. The Customer shall not install an Embedded Generation Facility without the notification of, and approval from, the Distributor.

8.4. The Customer shall not connect or permit a third party to connect an Embedded Generation Facility to their Distribution System without notifying the Distributor of the intended connection, and completing a Connection Impact Assessment study where applicable.

9. Insurance

9.1. NPEI shall, during the term of this Agreement and any renewals thereof, maintain a policy or policies of general liability insurance in which GPI is named as additional insured in the amount of $5,000,000 per occurrence and the policy or policies shall contain cross-liability clause and severability of interest clauses, against legal liability arising from the negligence of NPEI and those over whom it is responsible in law due to damage to the property of GPI or any other person or persons including third parties, and against liability due to injury to, or death of, any person or persons, including third parties, in any one instance. GPI shall not be responsible for the payment of any premium with respect to any such insurance, which is the sole responsibility of NPEI.

9.2. GPI shall, during the term of this Agreement and any renewals thereof, maintain a policy or policies of general liability insurance in which NPEI is named as additional insured in the amount of $5,000,000 per occurrence and the policy or policies shall contain cross-liability clause and severability of interest clauses, against legal liability arising from the negligence of GPI and those over whom it is responsible in law due to damage to the property of NPEI or any other person or persons including third parties, and against liability due to injury to, or death of, any person or persons, including third parties, in any one instance. NPEI shall not be responsible for the payment of any premium with respect to any such insurance, which is the sole responsibility of GPI.

9.3. Both parties will provide the other with a certificate, or certificates, of insurance evidencing continuity and compliance with the insurance requirements set forth in this, Section 9, not less than thirty (30) days prior to the expiration of the then-current policy, and shall deposit promptly with the other, insurance certificates for every policy of and renewal certificates for such insurance (or a certified copy thereof).

9.4. The insurance certificates will provide that the other party will receive thirty (30) days' prior written notice from the insurer of any termination of material reduction in the amount or scope of coverage.

9.5. The parties will review the above insurance requirements every five (5) years to confirm that they continue to be adequate for the purposes of this agreement, and will take steps to amend the requirements as necessary.

10. Liability and Force Majeure

10.1. The liability provisions of section 2.2 of the DSC apply to this Agreement and are hereby incorporated by reference into, and form part of, this Agreement.

10.2. A Party shall have a duty to mitigate any losses relating to any claim for indemnification from the other Party that may be made in relation to that other Party. Nothing in this section shall require the mitigating Party to mitigate or alleviate the effects of any strike, lockout, restrictive work practice or other labour dispute.

10.3. A Party shall give prompt notice to the other Party of any claim with respect to which indemnification is being or may be sought under this Agreement.

10.4. The force majeure provisions of section 2.3 of the DSC apply to this Agreement and are hereby incorporated by reference into, and form part of, this Agreement.

11. Customer Equipment Commissioning and Testing

11.1. The Customer shall give the Distributor at least fifteen days advance written notice of the date(s) and time(s) on which the Customer Equipment will be commissioned and tested prior to connection. The Customer shall give the Distributor the same notice in relation to the commissioning and testing of any material modification to the Customer's connection assets or Customer Equipment that occurs after connection.

11.2. The Distributor shall have the right to witness the commissioning and testing activities referred to in Section 11.1.

12. Notice

12.1. Any notice, demand, consent, request or other communication required or permitted to be given or made under or in relation to this Agreement shall be given or made: by courier or other personal form of delivery; by registered mail; by facsimile; or by electronic mail. Notices shall be addressed to the applicable representative of the Party identified in Schedule A.

12.2. A notice, demand, consent, request or other communication referred to in Section 12.1 shall be deemed to have been made as follows:

(a) where given or made by courier or other form of personal delivery, on the date of receipt;

(b) where given or made by registered mail, on the sixth day following the date of mailing;

(c) where given or made by facsimile, on the day and at the time of transmission as indicated on the sender's facsimile transmission report; and

(d) where given or made by electronic mail, on the day and at the time when the notice, demand, consent, request or other communication is recorded by the sender's electronic communications system as having been received at the electronic mail destination.

13. Access to Customer Equipment

13.1. Each Party shall ensure that its facilities are secured at all times.

13.2. The Customer shall permit and, if the land on which any of the Customer's Equipment is located is not owned by Customer, cause such landowner to permit, the Distributor's employees and agents to enter the property on which the Customer Equipment is located at any reasonable time. Such access shall be provided for the purposes of inspecting and/or testing the Customer's Equipment as and when permitted by this Agreement, the DSC or the Distributor's Conditions of Service or as required to ensure the continued safe and satisfactory operation of the Customer's Equipment, to ensure the accuracy of the Distributor's meters, to establish work protection, or to perform work.

13.3. Any inspecting and/or testing referred to in section 13.2 shall not relieve the Customer from its obligation to operate and maintain the Customer's Equipment and any related equipment owned by the Customer in a safe and satisfactory operating condition and in accordance with this Agreement.

13.4. The Distributor shall have the right to witness any testing done by the Customer of the Customer's Equipment and, to that end, the Customer shall provide the Distributor with at least fifteen working days advance notice of the testing.

13.5. Notwithstanding section 10.1, where the Distributor causes damage to the Customer's property as part of this access, the Distributor shall pay to the Customer the Customer's reasonable costs of repairing such property or, if such property cannot be repaired, replacing such property.

13.6. Notwithstanding section 10.1, if the Customer has been given access to the Distributor's property, and if the Customer causes damage to the Distributor's property as part of that access, the Customer shall pay to the Distributor the Distributor's reasonable costs of repairing such property or, if such property cannot be repaired, replacing such property.

14. Disconnection of Customer Equipment to Permit Maintenance and Repairs

14.1. If the Customer requests it, the Distributor will provide the Customer with reasonable notice of any planned equipment outages in the Distributor's distribution system that occur on or after the date of the Customer's request which will impact Customer Equipment or system (as applicable) or its connection.

14.2. The Distributor will make reasonable efforts to ensure that the outages referred to in section 14.1 will be of minimal duration and cause minimal inconvenience to the Customer.

14.3. In connection with any planned equipment outage, either Party may disconnect or isolate, or require the disconnection or isolation of, its equipment or system (as applicable) from the other Party's equipment or system (as applicable) so that the employees, contractors or agents of the Party may construct, maintain, repair, replace, remove, investigate or inspect its own equipment or system (as applicable) in accordance with the terms of this Agreement and good utility practice.

14.4. Where practical, the Customer shall notify the Distributor prior to temporarily isolating or disconnecting the Customer Equipment from the Distributor's distribution system.

15. Disconnection of Customer's Equipment for Other Reasons

15.1. The Customer shall discontinue operation of the Customer's Equipment or system (as applicable) and the Distributor may isolate or disconnect the Customer's Equipment or system (as applicable) from the Distributor's distribution system, upon any of the following:

(a) termination of this Agreement in accordance with section 19;

(b) if the Customer's connection assets or Customer Equipment are modified by the Customer in a manner contrary to section 8.1;

(c) during an emergency or where necessary to prevent or minimize the effects of an emergency;

(d) in accordance with section 31, 31.1 or 40(5) of the Electricity Act, 1998, other applicable law, the DSC, the Distributor's License or the Distributor's Conditions of Service; or

(e) where required to comply with a decision or order of an arbitrator or court made or given under Schedule C.

15.2. In the event of disconnection under section 15.1(b), the Customer's Equipment or system (as applicable) shall remain isolated or disconnected from the Distributor's distribution system until the connection process referred to in section 8.1 has been completed.

15.3. In the event of disconnection under section 15.1(c), the Distributor shall reconnect, or permit the reconnection of, Customer Equipment or system (as applicable) to the Distributor's distribution system when it is reasonably satisfied that the emergency has ceased and that all other requirements of this Agreement are met.

15.4. In the event of disconnection under section 15.1(d) or 15.1(e), the Distributor shall reconnect, or permit the reconnection of, Customer Equipment or system (as applicable) to the Distributor's distribution system when the Distributor is reasonably satisfied that the reason for the disconnection no longer exists, the Customer agrees to pay all Board-approved reconnection costs charged by the Distributor, and the Distributor is reasonably satisfied of the following, where applicable:

(a) the Customer has taken all necessary steps to prevent the circumstances that caused the disconnection from recurring and has delivered binding undertakings to the Distributor that such circumstances shall not recur; and

(b) any decision or order of a court or arbitrator made or given under Schedule C that requires a Party to take action to ensure that such circumstances shall not recur has been implemented and/or assurances have been given to the satisfaction of the affected Party that such decision or order will be implemented.

15.5. Where Customer Equipment or system (as applicable) has been isolated or disconnected, each Party shall be entitled to decommission and remove its assets associated with the

connection. Each Party shall, for that purpose, ensure that the other Party has all necessary access to its site at all reasonable times.

15.6. The Customer shall continue to pay for distribution services provided up to the time of isolation or disconnection of its Customer Equipment or system (as applicable).

15.7. The Customer shall pay all reasonable costs including, but not limited to, the costs of removing any of the Distributor's equipment from the Customer's site, that are directly attributable to the isolation or disconnection of Customer Equipment and, where applicable, the subsequent decommissioning of Customer's Equipment. The Distributor shall not require the removal of the protection and control wiring on the Customer's site.

15.8. While Customer Equipment or system (as applicable) is isolated or disconnected, the Distributor shall not be required to convey electricity to or from Customer Equipment or system (as applicable).

16. Dispute Resolution

16.1. Any dispute between the Customer and the Distributor arising under or in relation to this Agreement will be resolved in accordance with Schedule C. The Parties shall comply with the procedure set out in Schedule C before taking any civil or other proceeding in relation to the dispute, provided that nothing shall prevent a Party from seeking urgent or interlocutory relief from a court of competent jurisdiction in the Province of Ontario in relation to any dispute arising under or in relation to this Agreement.

17. Amendments

17.1. Any amendment to this Agreement shall be made in writing and duly executed by both Parties.

17.2. No amendment shall be contrary to or inconsistent with the DSC or the remainder of this Agreement.

17.3. The Parties shall amend this Agreement in such manner as may be required by the OEB.

18. Waiver

18.1. A waiver of any default, breach or non-compliance under this Agreement is not effective unless in writing and signed by the Party to be bound by the waiver. The waiver by a Party of any default, breach or non-compliance under this Agreement shall not operate as a waiver of that Party's rights under this Agreement in respect of any continuing or subsequent default, breach or non-compliance, whether of the same or any other nature.

19. Term of Agreement and Termination

19.1. This Agreement shall become effective upon execution by the Parties, and shall continue in effect until terminated in accordance with section 19.2 or 19.3.

19.2. The Customer may, if it is not then in default under this Agreement, terminate this Agreement at any time by giving the Distributor thirty days prior written notice setting out the termination date.

19.3. Except as set out in Schedule E, the Distributor may terminate this Agreement upon any material breach of this Agreement by the Customer (a "Default"), if the Customer fails to remedy the Default within the applicable cure period referred to in section 19.4 after receipt of written notice of the Default from the Distributor.

19.4. The Customer shall cure a Default within the applicable cure period specified in the DSC or the Distributor's Conditions of Service. If no such cure period is specified in relation to a given Default, the cure period shall be sixty working days.

19.5. Termination of this Agreement for any reason shall not affect:

(a) the liabilities of either Party that were incurred or arose under this Agreement prior to the time of termination; or

(b) the provisions that expressly apply in relation to disconnection of the Customer's facilities following termination of this Agreement.

19.6. Termination of this Agreement for any reason shall be without prejudice to the right of the terminating Party to pursue all legal and equitable remedies that may be available to it including, but not limited to, injunctive relief.

19.7. The rights and remedies set out in this Agreement are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to a Party at law or in equity. Nothing in this section 19.7 shall be interpreted as affecting the limitations of liability arising from section 10.1 or the obligation of a Party to comply with section 16 while this Agreement is in force.

19.8. Sections 19.5 to 19.7 shall survive termination of this Agreement.

20. Exchange and Confidentiality of Information

20.1. Confidential information in respect of a Party means (i) information disclosed by that Party to the other Party under this Agreement that is in its nature confidential, proprietary or commercially sensitive and (ii) information derived from the information referred to in (i), but excludes the following:

(a) information that is in the public domain; or

(b) information that is, at the lime of the disclosure, in the possession of the receiving Party, provided that it was lawfully obtained from a person under no obligation of confidence in relation to the information.

20.2. Subject to section 20.3, each Party shall treat all confidential information disclosed to it by the other Party as confidential and shall not, without the written consent of that other Party:

(a) disclose that confidential information to any other person; or

(b) use that confidential information for any purpose other than the purpose for which it was disclosed or another applicable purpose contemplated in this Agreement.

Where a Party with the written consent of the other Party, discloses confidential information of that other Party to another person, the Party shall take such steps as may be required to ensure that the other person complies with the confidentiality provisions of this Agreement.

20.3. Nothing in section 20.2 shall prevent the disclosure of confidential information:

(a) where required or permitted under this Agreement, the DSC, the Market Rules or the Distributor's License;

(b) where required by law or regulatory requirements;

(c) where required by order of a government, government agency, regulatory body or regulatory agency having jurisdiction;

(d) if required in connection with legal proceedings, arbitration or any expert determination relating to the subject matter of this Agreement, or for the purpose of advising a Party in relation thereto;

(e) as may be required to enable the Distributor to fulfill its obligations to any reliability organization; or

(f) as may be required during an emergency or to prevent or minimize the effects of an emergency.

20.4. Notwithstanding section 10.1, a Party that breaches section 20.2 shall be liable to the other Party for any and all losses of the other Party arising out of such breach.

20.5. The Parties agree that the exchange of information, including, but not limited to, confidential information, under this Agreement is necessary for maintaining the reliable

operation of the Distributor's distribution system. The Parties further agree that all information, including, but not limited to, confidential information, exchanged between them shall be prepared, given and used in good faith and shall be provided in a timely and cooperative manner.

20.6. Each Party shall provide the other with such information as the other may reasonably require to be able to perform its obligations under this Agreement.

20.7. Each Party shall, as soon as practicable, notify the other Party upon becoming aware of a material change or error in any information previously disclosed to the other Party under this Agreement and, in the case of the Customer, in any information contained in its Application. The Party shall provide updated or corrected information as required to ensure that information provided to the other Party is up to date and correct.

21. Assignment, Successors and Assigns

21.1. Except as set out in Schedule E, the Customer shall not assign its rights or obligations under this Agreement in whole or in part without the prior written consent of the Distributor, which consent shall not be unreasonably withheld or unduly delayed. The Distributor may withhold its consent to any proposed assignment until the proposed assignee assumes, in writing, all of the Customer's obligations contained in this Agreement.

21.2. The Distributor shall have the right to assign this Agreement in whole upon written notification to the Customer.

21.3. This Agreement shall be binding upon and endure to the benefit of the Parties and their respective successors and permitted assigns.

22. Governing Law

22.1. This Agreement shall be governed by the laws of the Province of Ontario and the federal laws of Canada applicable therein.

23. Entire Agreement

23.1. Except as expressly provided herein, this Agreement constitutes the entire agreement between the Parties with respect to the subject-matter hereof and supersedes all prior oral or written representations and agreements of any kind whatsoever with respect to the subject-matter hereof.

24. Joint Use Arrangements

24.1. The Customer and the Distributor acknowledge and agree that this Agreement does not permit either Party to affix or attach its Equipment to the other Party's distribution plant. Should either Party wish to attach its Equipment on the other Party's distribution plant, the Parties must execute an appropriate Joint Use Agreement before either Party can be permitted to affix or attach its Equipment to the other Party's distribution plant.

IN WITNESS WHEREOF, the Parties hereto, intending to be legally bound, have caused this Agreement to be executed by their duly authorized representatives.

GRIMSBY POWER INC.

Signature: R. Fernandes

Name: Remy Fernandes

Title: President & CEO

Date: March 24/2021

NIAGARA PENINSULA ENERGY INC.

Signature:

Name: Brian Wilkie

Title: President & CEO

Date: March 24, 2021

SCHEDULE A – CONTACTS FOR NOTICE

Either Party has the right to change the position designations and telephone numbers listed below with immediate effect at any time by notice in writing delivered to the other Party by fax or other telegraphic means. Any employee of a Party with apparent authority may deliver such a notice to the other Party.

CUSTOMER

Main Contact

Company Name:	Niagara Peninsula Energy Inc.
Street Address:	***7447 Pin Oak Drive, Box 120***
Location:	Niagara Falls, ON, L2E 6S9
Name:	Brian Wilkie
Position:	President & CEO
Work Phone:	905-356-2681 Ext. 6000
Cell Phone:	
Fax:	905-356-2831
Email:	brian.wilkie@npei.ca

Alternate Contact

Company Name:	Niagara Peninsula Energy Inc.
Street Address:	***7447 Pin Oak Drive, Box 120***
Location:	Niagara Falls, ON, L2E 6S9
Name:	Suzanne Wilson
Position:	Sr. V.P. Finance
Work Phone:	905-356-2681 Ext. 6004
Cell Phone:	
Fax:	905-356-2831
Email:	Suzanne.wilson@npei.ca

DISTRIBUTOR

Main Contact

Company Name:	Grimsby Power Inc.
Street Address:	231 Roberts Road
Location:	Grimsby, ON L3M 5N2
Name:	Remy Fernandes
Position:	President & CEO
Work Phone:	(905) 945-5437 x 221
Cell Phone:	(905) 516-0324
Fax:	
Email:	remyf@grimsbypower.com

Alternate Contact

Company Name:	Grimsby Power Inc.
Street Address:	231 Roberts Road
Location:	Grimsby, ON L3M 5N2
Name:	Mioara Domokos
Position:	Director of Finance
Work Phone:	(905) 945-5437 x232
Cell Phone:	
Fax:	
Email:	mioarad@grimsbypower.com

SCHEDULE B – BILLING AND SETTLEMENT PROCEDURES

The following provisions apply to billing and settlement in relation to the Customer:

B.1. Settlement Terms for Embedded Load Customers

B.1.1. *Arranging for Distribution* Services: The Customer or its representative shall not have access to Distribution Services until it has met all the applicable requirements of the DSC, GPI's Conditions of Service and terms of this Agreement and any other agreement made between the parties with respect to the work to be performed on the Distributor's distribution system for the Customer's connection to the Distributor's satisfaction, including, without limitation, the installation of all equipment required to connect the Customer to the Distribution System and to meter the provision of the Distribution Service for the purpose of billing and settlement as per the relevant distribution Rate Orders approved by the OEB. All revenue meters and associated equipment required for billing and settlement shall meet the requirements of the Distributor and the DSC.

B.1.2. The metering for the Customer shall conform to Measurement Canada standards and the Distributor's Retail Metering Standards except for IESO registered meters. ~~As a registered Wholesale Market Participant, the Customer must provide metering facilities that comply with the Markel Rules issued by the IESO.~~ The Distributor will be responsible for the ownership, installation and maintenance of the meter and contracting the services of a Registered Meter Service Provider (MSP).

B.1.3. Disputes between the Distributor and the Customer shall be dealt with in accordance with the dispute resolution process specified in Schedule C (Dispute Resolution).

B.2. Sale of Power by the Distributor

B.2.1.1. The terms and conditions under which the Embedded Distributor Customer accepts Standard Supply Service from the Distributor are described in the Distributor's Conditions of Service except for IESO registered points of delivery. IESO registered points of delivery must comply with the Market Rules for delivery charges for power withdrawn from the distribution system.

B.2.1.2. *Application of Distribution Rates by Point of Supply:* For applicable tariffs and charges per Point of Supply and connection points, please refer to the Rate Order, Retail Settlement Code, Distribution System Code and where applicable the Retail Settlement Totalization Table that is available from the Distributor upon request.

The Retail Settlement Totalization Table will be updated by the Distributor from time to time as required to reflect any changes to the Customer's connection(s) to the Distributor's distribution system.

B.2.1.3. Settlement of sale of power by the Distributor shall occur monthly. Settlement payments shall be issued by the Customer within 21 days after the end of a calendar month. Unless otherwise agreed to by the parties, any invoice is subject to adjustment for errors in arithmetic, computation, meter reading corrections and estimates. Any adjustments for

errors will be made in the month following the month in which the error was first detected by the Distributor or first brought to the attention of the Distributor.

B.2.1.4. All electronic payments made by the Customer to the Distributor shall be sent to the Distributor's designated Canadian bank account with a statement to the Customer's address, by first class mail delivery, by facsimile to the Customer's facsimile number or by electronic mail. The Distributor may change the Canadian bank account to which payments are to be made upon thirty (30) business days' written notice to the Distributor, unless the parties agree otherwise.

B.2.1.5. Unless expressly provided otherwise in this Section, the parties agree that the Distributor's effective late payment charge rate shall be applied to any overdue settlement payments not issued by the Customer within twenty-one (21) Business Days after month end above. These payments shall accrue interest on the unpaid balance from the due date until payment is issued.

B.2.1.6. Where billing errors are identified by either the Distributor or the Customer, the provisions outlined in the Retail Settlement Code will be used for settlement dispute resolution.

B.2.2. Purchase of Power by the Distributor from the Customer where the Customer is an Embedded Distributor

Where the Customer is an Embedded Distributor with embedded retail generation that displaces the load to the point where power is injected into the Distributor's distribution system (i.e., reverse power flow at the point of delivery), the Distributor shall pay the Customer energy and global adjustment charges where the metering data at the affected point of delivery is reflecting the power injection. The Distributor will create and maintain a Retail Totalization Table to capture the settlement arrangement for the payment to the Customer by the Distributor.

B.2.2.1. Settlement of power purchase payments for electrical energy delivered as outlined in B.2.2 shall occur monthly. Settlement payments shall be issued by the Distributor within twenty-one (21) business days after the end of a calendar month during which there was reverse power flow at the Customer's point(s) of delivery. Unless otherwise agreed to by the parties, any invoice is subject to adjustment for errors in arithmetic, computation, meter reading corrections and estimates. Any adjustments for errors will be made in the month following the month in which the error was first detected by the Distributor or first brought to the attention of the Distributor.

B.2.2.2. All electronic payments made by the Distributor to the Customer shall be sent to the Customer's designated Canadian bank account with a statement to the Customer's address, by first class mail delivery or by facsimile to the Customer's facsimile number. The Customer may change the Canadian bank account to which payments are to be made or the address to which the generation statements are to be sent hereunder upon thirty (30) business days' written notice to the Distributor, unless the parties agree otherwise.

B.2.2.3. Unless expressly provided otherwise in this Section, the parties agree that the Distributor's effective late payment charge rate shall be applied to any overdue settlement payments not issued by the Distributor within twenty-one (21) Business Days after month end above. These payments shall accrue interest on the unpaid balance from the due date until payment is issued.

B.3. Method of Payment

All payments made shall be made by Electronic Funds Transfer (EFT). An AUTHORIZATION OF ELECTRONIC FUNDS TRANSFER form will be available upon request.

B.4. Meter Service Provider

As a Wholesale Market Participant, the Distributor is responsible for contracting the services of a Registered Meter Service Provider.

B.4.1. Meter Service Provider Information for Delivery Points that are registered with the IESO

The MSP referred to here is the on-going operational provider not the design and installation provider.

Company Name:	Peterborough Utilities Inc.
Street Address:	2245 Keene Rd
Location:	Peterborough, ON K9J 6Z6
Name:	Terry McConnell
Position:	Manager, Metering Services
Work Phone:	(705)748-9300 x 1279
Cell Phone:	
Fax:	(705) 743-5988
Email:	TMcConnell@puc.org

B.4.2. Metering Information

The latest Meter Information Form is available from the Distributor upon request.

B.4.3. Meter Service Provider Information for Delivery Points that are not registered with the IESO

The MSP referred to here is the on-going operational provider not the design and installation provider.

Company Name:	Peterborough Utilities Inc.
Street Address:	2245 Keene Rd
Location:	Peterborough, ON K9J 6Z6
Name:	Terry McConnell
Position:	Manager, Metering Services
Work Phone:	(705)748-9300 x 1279
Cell Phone:	
Fax:	(705) 743-5988
Email:	TMcConnell@puc.org

B.4.4. Metering Information

The latest Meter Information Form is available from the Distributor upon request.

SCHEDULE C – DISPUTE RESOLUTION

C.1. The Party claiming a dispute will provide written notice to the other Party. The Parties will make reasonable efforts through or by their respective senior executives to resolve any dispute within sixty days of receipt of such notice.

C.2. If a dispute is settled by the senior executives of the Parties, the Parties shall prepare and execute minutes setting forth the terms of the settlement. Such terms shall bind the Parties. The subject-matter of the dispute shall not thereafter be the subject of any civil or other proceeding, other than in relation to the enforcement of the terms of the settlement. If a Party fails to comply with the terms of settlement, the other Party may submit the matter to arbitration under section C.3. A copy of the minutes referred to in this section from which all confidential information has been expunged shall be made available to the public by the Distributor upon request.

C.3. If the senior executives of the Parties cannot resolve the dispute within the time period set out in section C.1 or such longer or shorter period as the Parties may agree, either Party may submit the dispute to binding arbitration under sections C.4 to C.8 by notice to the other Party.

C.4. The Parties shall use good faith efforts to appoint a single arbitrator for purposes of the arbitration of the dispute. If the Parties fail to agree upon a single arbitrator within ten working days of the date of the notice referred to in section C.3, each Party shall within five working days thereafter choose one arbitrator. The two arbitrators so chosen shall within fifteen working days select a third arbitrator.

C.5. Where a Party has failed to choose an arbitrator under section C.4 within the time allowed, the other Party may apply to a court to appoint a single arbitrator to resolve the dispute.

C.6. A person may be appointed as an arbitrator if that person:

(a) is independent of the Parties;

(b) has no current or past substantial business or financial relationship with either Party, except for prior arbitration; and

(c) is qualified by education or experience to resolve the dispute.

C.7. The arbitrator(s) shall provide each of the Parties with an opportunity to be heard orally and/or in writing, as may be appropriate to the nature of the dispute.

C.8. The *Arbitration Act,* 1991 (Ontario) shall apply to an arbitration conducted under this Schedule C.

C.9. The decision of the arbitrator(s) shall be final and binding on the Parties and may be enforced in accordance with the provisions of the *Arbitration Act,* 1991(0ntario). The Party against which the decision is enforced shall bear all costs and expenses

reasonably incurred by the other Party in enforcing the decision.

C.10. A copy of the decision of the arbitrator(s) from which any confidential information has been expunged shall be made available to the public by the Distributor upon request.

C.11. Subject to section C.12, each Party shall be responsible for its own costs and expenses incurred in the arbitration of a dispute and for the costs and expenses of the arbitrator(s) if appointed to resolve the dispute.

C.12. The arbitrator(s) may, if the arbitrator(s) consider it just and reasonable to do so, make an award of costs against or in favor of a Party to the dispute. Such an award of costs may relate to either or both the costs and expenses of the arbitrator(s) and the costs and expenses of the Parties to the dispute.

C.13. If a dispute is settled by the Parties during the course of an arbitration, the Parties shall prepare and execute minutes setting forth the terms of the settlement. Such terms shall bind the Parties, and either Party may request that the arbitrator(s) record the settlement in the form of an award under section 36 of the *Arbitration Act, 1991* (Ontario). The subject-matter of the dispute shall not thereafter be the subject of any civil or other proceeding, other than in relation to the enforcement of the terms of the settlement.

C.14. If a Party fails to comply with the terms of settlement referred to in section C.13, the other Party may submit the matter to arbitration under section C.3 if the settlement has not been recorded in the form of an award under section 36 of the *Arbitration Act, 1991* (Ontario).

C.15. A copy of the minutes referred to in section C.13 from which all confidential information has been expunged shall be made available to the public by the Distributor upon request.

C.16. The Parties may not, by means of the settlement of a dispute under section C.2 or section C.13, agree to terms or conditions that are inconsistent with or contrary to the DSC or this Agreement.

SCHEDULE D – DETAILS OF SPECIFIC OPERATION

Note: For changes to this schedule please contact the Day-to-Day Operating contact listed below

D.1. Contacts

Either Party has the right to change the position designations and telephone numbers listed below with immediate effect at any time by notice in writing delivered to the other Party by fax or other telegraphic means. Any employee of a Party with apparent authority may deliver such a notice to the other Party.

D.1.1. Day-to-Day Operation

For the operation of **GRIMSBY POWER INC.**, **(Distributor)** Distribution Network **Operating Contacts (Real Time)**

	DISTRIBUTOR	CUSTOMER
Company Name:	Grimsby Power Inc.	Niagara Peninsula Energy Inc.
Street Address:	231 Roberts Road	7447 Pin Oak Drive
Location:	Grimsby, ON L3M 5N2	Niagara Falls, ON L2E 6S9
Name (Operator):	OGCC	Control Room
Position:	Various Operators	Various Operators
Phone Number:	866-384-4743+Access Code 40547# + reason code# + station code#	905-353-6024
Name (Supervisor):	Kevin Robins	Hayret Muhtar
Position:	Operations Supervisor	Supervisor, GIS & Control Room
Work Phone:	(905) 945-5437 x 227	905-356-2681 Ext. 6025
Cell Phone:	(905) 975-3353	289-241-6252
Email:	kevinr@grimsbypower.com	control@npei.ca
Emergency #1:	(905) 945-5437 x 227	905-358-6661
Emergency #2:	(905) 975-3353	
Emergency Operations (Primary)	(905) 945-2638 [Direct Line]	
Emergency Operations (Secondary)	(905) 522-0922 [24Hr 7Day #]	

Operating Manager

	DISTRIBUTOR	CUSTOMER
Company Name:	Grimsby Power Inc.	Niagara Peninsula Energy Inc.
Street Address:	231 Roberts Rd.	7447 Pin Oak Drive
Location:	Grimsby, ON L3M 5N2	Niagara Falls, ON L2E 6S9
Name:	(vacant)	Ron Campaigne
Position:	Director of Engineering & Operations	Director of Operations
Work Phone:	(905) 945-5437	905-356-2681
Cell Phone:		905-658-5188
Fax:		
Email:		ron.campaigne@npei.ca

D.1.2. Contractual Matters and Formal Notice

	DISTRIBUTOR	CUSTOMER
Company Name:	Grimsby Power Inc.	Niagara Peninsula Energy Inc.
Street Address:	231 Roberts Road	7447 Pin Oak Drive, Box 120
Location:	Grimsby, ON L3M 5N2	Niagara Falls, ON L2E 6S9
Name:	Remy Fernandes	Shanon Wilson
Position:	President & CEO	Sr. V.P. Asset Management
Work Phone:	(905) 945-5437 x 221	905-356-2681 Ext. 6015
Cell Phone:	(905) 516-0325	905-321-3481
Fax:		905-356-2831
Email:	remyf@grimsbypower.com	shanon.wilson@npei.ca

D.1.3. Distribution Planning and Engineering

	DISTRIBUTOR	CUSTOMER
Company Name:	Grimsby Power Inc.	Niagara Peninsula Energy Inc.
Street Address:	231 Roberts Rd.	7447 Pin Oak Drive, Box 120
Location:	Grimsby, ON L3M 5N2	Niagara Falls, ON L2E 6S9
Name:	(vacant)	Jim Sorley
Position:	Director of Engineering & Operations	Director of Engineering
Work Phone:	(905) 945-5437	905-356-2681 Ext. 6224
Cell Phone:		905-327-1782
Fax:		905-356-2831
Email:		jim.sorley@npei.ca

D.2. Description of Facilities

The Customer Distribution Facilities covered by this agreement are located in the Town of Lincoln and the Town of West Lincoln, Ontario.

In the context of this document, the description of feeders will be limited to feeders exiting Niagara West TS.

D.2.1. Dedicated Feeders

Dedicated Feeders are feeders that exit Niagara West TS and supply only customers of one utility, either GPI or NPEI.

GPI has Operating Control of the NWTS circuit breakers. The Utility to which a feeder is dedicated has Operating Control of that feeder.

D.2.2. Express Feeders

Express Feeders are Dedicated Feeders to GPI that cross NPEI service territory between Niagara West TS and GPI territory are considered. Express feeders do not supply NPEI customers.

D.2.3. Shared Feeders

Shared Feeders are feeders that supply both GPI and NPEI customers. Shared Feeders supply predominantly GPI customers, but also supply NPEI customers and NPEI laterals located along the right-of-way as they cross NPEI service territory.

Shared Feeders provide a cost-effective supply to these NPEI customers and avoid the construction of additional dedicated NPEI facilities.

GPI has Operating Control of the NWTS circuit breaker supplying the feeder.

NPEI has Operating Control of the feeder located within the NPEI service area.

GPI has Operating Control of the feeder located within the GPI service area.

D.2.4. Ownership and Controlling Authority

Grimsby Power Inc. is the Controlling Authority of the Distributor's Facilities and Equipment listed below, except where otherwise indicated.

The Customer's Controlling Authority has control over all Customer Equipment except where otherwise indicated.

A Party may change its designated Controlling Authority set out below at any time during the term of the Agreement, subject to the following conditions:

(a) Either Party shall notify the other in writing of any change in its designated Controlling Authority at least ten Business Days before implementing a change.

(b) Notification of any changes to the designated Controlling Authority shall be made to the respective Contact for Contractual Manners and Formal Notice.

Niagara West TS (NA2508)

Distributor owns the following:	**Customer** owns the following:
Niagara West TS Entire station including all feeder breakers.	**Niagara West TS** None
Feeders	**Feeders**
M1 – Current limiting reactor All	M1 – Current limiting reactor None
M2 – NPEI Dedicated Feeder Up to the bolted cable connections on the load side of the M2 circuit breaker.	M2 – NPEI Dedicated Feeder From the bolted cable connections on the load side of the M2 circuit breaker.
M3 – Express Feeder Feeder exit cable and main feeder conductor from station to the GPI border, all equipment within GPI territory.	M3 – Express Feeder Supporting poles and framing hardware from the station to the GPI border.
M4 – Shared Feeder Feeder exit cable to the riser pole switch, all equipment within GPI territory.	M4 – Shared Feeder Supporting poles, framing hardware, riser pole switch and main feeder conductor from the station to the GPI border, distribution transformers and primary laterals within NPEI territory.
M5 – NPEI Dedicated Feeder Up to the bolted cable connections on the load side of the M5 circuit breaker.	M5 – NPEI Dedicated Feeder From the bolted cable connections on the load side of the M5 circuit breaker.
M6 – Current limiting reactor. All	M6 – Current limiting reactor none
M7 – (spare position)	M7 – (spare position)
M8 – Shared Feeder Feeder exit cable to the riser pole switch, all equipment within GPI territory.	M8 – Shared Feeder Supporting poles, framing hardware, riser pole switch and main feeder conductor from the station to the GPI border, distribution transformers and primary laterals within NPEI territory.

Metering Equipment 230kV Station Total Metering 27.6kV Station Service Metering 27.6kV M3 PME 27.6kV M4 PME	**Metering Equipment** None
Protection Systems All	**Protection Systems** None
Telecommunications All Niagara West TS terminal equipment including Transfer Trip Protections to Embedded Generators connected to NPEI feeders.	**Telecommunications** None

D.3. Joint Use

Where equipment is affixed or attached on the other parties' plant, the parties shall ensure that an appropriate Joint Use Agreement is in effect prior to permitting the joint use.

D.4. Single Line Diagram

The Distributor agrees to provide the Customer with a copy of its Single Line Diagram detailing the Customer's connection point to the Distributor. Where the Distributor's Single Line Diagram contains connection information for more than one Customer, the Customer authorizes the Distributor to provide the information contained on the Single Line Diagram to the Distributor's other customers shown on the said document.

Drawing Owner	Drawing Number
GPI	NW1-100

D.5. Metering Facilities Diagram

Drawing Owner	Drawing Number
GPI	MSP-B000539

D.6. Normal Operations

This schedule shall include Customer-specific information during normal operations. If none exists, no additional information is required.

D.6.1. Hold-off Procedures

A hold-off is used to restrict the operation of the device(s) to previously agreed limits, except with the holder's consent.

Hold-offs are most commonly used to block the auto reclosing and the manual re-energization of a line following an automatic trip.

Under no circumstances shall a hold-off be used in place of a work protection.

If remote control is lost to devices under a hold-off, the holder must be notified that the hold-off is no longer in effect until the integrity of the hold-off is confirmed.

When a hold-off is in effect on a line or other apparatus, it shall not be re-energized following an automatic trip until communication is established with the holder and his/her consent is obtained. It is a basic requirement of hold-off procedures that satisfactory communication be established and maintained with the holder of the hold-off.

D.6.2. Switching

The Customer must comply with the DSC when performing all switching operations.

A Customer with an installed capacity of 1 MW or above must contact Distributor's Controlling Authority before connecting / reconnecting to the Distribution System.

D.6.3. Load Transfers

The Day-to-Day Operating Contact shall be notified of all planned or unplanned Customer Load Transfers involving Niagara West TS feeders to ensure that the transfer will not have adverse effects on the system. This notification will also allow coordination of station equipment outages (i.e. Bus outages).

Feeders with GPI Customers

Load and/or Generation Transfers: The Day-to-Day Operating Contact is accountable for assessing and approving transfers on distribution feeders that have GPI embedded generation and/or load customers connected to them.

Feeders without GPI Customers

Load Transfers: If the Customer's load is being transferred to an alternate Customer supply feeder (i.e., back-to-back), the Customer is accountable for the assessment of the transfer. The Customer shall notify the GPI Operating Manager of the transfer.

Generation Transfers: If an Embedded Generator is connected to a Customer feeder or to the Customer portion of a feeder shared with GPI, the Customer shall be accountable for assessing the generation transfer. The Customer shall notify the GPI Operating Manager of the transfer.

D.6.4. Phase Balancing

The Customer shall endeavor to maintain phase balance within generally acceptable industry standards.

D.6.5. Voltage Regulation

Voltage regulation is performed via the On-Load Tap Changers on the main power transformers at Niagara West TS.

The Distributor will maintain supply voltage within generally acceptable industry standards and will provide voltage regulation settings and information upon request to the Customer.

D.6.6. Power Quality

The Distributor and the Customer shall follow good utility practice in managing the Power Quality of the distribution system.

The Customer shall take reasonable steps to investigate all power quality complaints and report to the Distributor on the results of the investigation.

The Distributor shall assist in Power Quality investigations by providing copies of recorded data, event records, etc. on request.

D.7. Emergency Operations

This Schedule includes Customer specific information during Emergency operations.

D.7.1. Unplanned Outages

This section assigns authority and defines responsibilities for the restoration of load when equipment failure, inclement weather or foreign contact causes protective relaying to trip faulted equipment out of service.

D.7.2. Conditions of Restoration

When a Customer feeder, or shared feeder, has been automatically removed from service then:

(a) One attempt to energize the feeder shall be made after one (1) minute.

(b) When the first attempt is unsuccessful, the Distributor’s Controlling Authority shall contact the Customer’s Controlling Authority directly to obtain direction.

(c) Any further attempts to energize the feeder will be made after consultation with, and at the discretion of, the Distributor's Controlling Authority.

D.7.3. Equipment Repairs affecting the Other Party

This section assigns authority and defines responsibility for repairs to distribution equipment that affect supply to the Other Party and/or their customers.

D.7.4. Restoration of Supply

When distribution equipment owned by the Distributor is unavailable due to damage or failure and causes an unplanned outage to Customer load, the Distributor shall:

(a) Inform the Customer of the situation through the contacts listed in Section D.1.

(b) Assist the Customer to restore supply in an efficient and timely manner and in accordance with typical utility practices.

When distribution equipment owned by the Customer is unavailable due to damage or failure and causes an unplanned outage to Distributor load, the Customer shall:

(c) Inform the Distributor of the situation through the contacts listed in Section D.1.

(d) Assist the Distributor to restore supply in an efficient and timely manner and in accordance with typical utility practices.

D.8. Load Shedding

This section assigns authority and defines responsibilities for manual primary Load Shedding that may be required to correct abnormal conditions on the IESO Controlled Grid or Distributor's Facilities and Equipment. Procedures are also outlined for conducting simulation of rotational Load Shedding.

D.8.1. Information

From time to time the IESO-controlled grid or Distributor's Facilities and Equipment may experience abnormal conditions. To minimize their impact, and to restore and maintain security of operations, prompt control action must be taken. The control actions are numerous and vary according to the abnormal condition.

In extreme situations, the only way to correct abnormal conditions may be to shed primary firm load. Recognizing the impact on the Customer, this control action must be pre-planned as much in advance as possible.

Rotational Load Shedding of primary firm load provides assurance that the abnormal condition will be quickly corrected while allowing for Customer selectivity. The Rotational Load Shedding schedule shall comply with the IESO's rules, procedures and policies in effect at the relevant time.

D.8.2. Under-Frequency Load Shedding

Under-Frequency Load Shedding (UFLS) includes blocks of load connected to UFLS relays that automatically shed the load when under-frequency thresholds are met.

Under-Frequency Load Shedding plans shall meet the requirements of the IESO.

D.8.3. Emergency Load Shedding

Emergency Load Shedding schedules shall identify where 100 MW, 200 MW, etc., of load can be shed at any given time. Because of the varying load profiles, each Distributor's Controlling Authority is responsible to ascertain where load can be shed on a shift-by-shift basis.

Since it is likely that Emergency Load Shedding will evolve into Rotational Load Shedding, consideration should be given to selecting load that is from a part of the Rotational Load Shedding schedule which would be cut later in the rotation, rather than at the anticipated starting point on the Rotational Load Shedding schedule. This is to avoid the load being cut for an extended period of time.

D.8.4. Rotational Load Shedding

Rotational Load Shedding schedules shall outline the primary firm load under the control of the Distributor's Controlling Authority identified in Section 3, arranged in relatively equal Megawatt (MW) blocks representing a percentage of the load under their control.

D.9. Load Forecasting

The Distributor is responsible for capacity planning for the Niagara West TS.

The Customer shall provide load and load forecast information to the Distributor on request to support the planning process.

The Customer shall notify the Distributor of any proposed new load connections 1MW or greater, including both single customer and multi-unit developments, that have not been identified in the most recently submitted load forecast.

D.10. Protection Settings

D.10.1. Fault Levels

The Distributor will provide fault current levels at the point of supply to Customer connections upon request.

D.10.2. Dedicated Feeders

The Customer will be responsible for creating feeder relay settings for feeders that are dedicated to Customer supply.

The Customer will provide a copy of the feeder relay settings, signed by a P.Eng., to the Distributor. The Distributor will apply the relay settings and provide confirmation to the Customer of the applied settings.

D.10.3. Shared Feeders

The Distributor will be responsible for creating and applying feeder relay settings for feeders that are shared between the Distributor and the Customer.

The Distributor will provide copies of the relay settings to the Customer on request.

D.10.4. Re-Verification Schedules for Protection and Control

The Customer shall re-verify its protections and control systems that can impact on the Distribution System. Maintenance intervals for protection groups are to follow the scope and frequencies of the Reliability Standard (NERC PRC-005 *Protection System*

Maintenance) that are in effect.

All tests must be coordinated and approved ahead of time through the normal outage planning process.

D.11. Telecommunications for Protection and Control

D.11.1. Types of Telecommunication Channels

(a) Number of Blocking Channels = (0)

(b) Number of Transfer Trip Channels = (3)

(c) Number of generation/load rejection trip channels = (0)

(d) Number of Direct/Remote Trip Channels = (0)

The telecommunication channels shall be monitored in order to assess equipment and channel readiness.

D.11.2. Telecommunication Medium

Refer to Embedded Generator connection details in Section D.12.4.

D.11.3. Ownership of Telecommunication Terminal Equipment

The terminal equipment located at the Transformer Station are owned by Distributor.

The terminal equipment located at the remote site are owned by the Generator.

The communication medium is considered to be owned by Generator.

D.11.4. Responsibility for Work and Costs Associated with Breakdown and Routine Maintenance

If maintenance or repair is required on terminal equipment owned by the Distributor, the Distributor will bear all incurred costs.

If maintenance is required on terminal equipment or communications channels owned by the Customer, the Customer will bear all incurred costs.

This clause does not extend to capital replacement at equipment end of life.

D.11.5. Re-verification Schedule

Routine Maintenance on communication equipment and the communication channels must be performed as per Section 8 above.

D.11.6. Inventory of Communication Equipment

The provision of spare communication equipment is the Customer's responsibility and will be located at their site.

D.11.7. Failure of Communication Equipment

There is no tele-protection communication equipment directly between the Distributor and the Customer.

If tele-protection communication equipment between the Distributor and an Embedded Generator connected to the Customer's distribution system fails, the generation shall be disconnected until the failure is resolved.

D.11.8. Mean Time for Repairs

The mean time for repairs will be within two Business Days, dependent on the availability of staff of the Communication Service Provider and the Distributor.

D.12. Embedded Generation

D.12.1. Reporting Requirements

All Embedded Generators will be required to keep a written log.

This log will record the date, time and a description any incidents. The incidents recorded, must include, but are not limited to those in the table below.

Distributor will have the right to review this log. The Embedded Generator must make the log, or a copy of the log, available for Distributor's review upon request, within five business days of that request.

The Generator will provide reports to the Distributor either on a requested basis, or for specific types on incidents that require reports as per the table within five business days of the incident.

The report must include, but is not limited to:

(a) Embedded Generator Name Supply Feeder

(b) Date and time of incident

(c) General description of the incident, including cause, if known

(d) Did the Generators equipment trip correctly?

(e) Voltage (if available)

(f) Frequency (if available)

(g) Which relays operated (targets & description)

(h) Corrective actions taken

These are the incident types to be recorded:

Note: The Distributor may modify the incidents to be logged or recorded in the table below, based on those relevant to the Distribution System specific to this Connection.

Incident	Logged	Report Required
Protection System Malfunction or Failure at the Generator's facility		

Trip from the Generator's Relay Operation		
Electrical failure / incident at the Generator's facility		
Mechanical Failure/ incident at the Generator's facility		
Trip from Feeder incident		

D.12.2. Embedded Generation Facilities within Embedded Distributor

Where an Embedded Distributor has Embedded Generation Facilities connected to their distribution system that could impact the GPI Distribution System, this section describes the obligations of the Embedded Distributor with respect to its arrangement with such Embedded Generators. Should the terms of any arrangements with the Embedded Generators be modified in any way, the Embedded Distributor shall immediately provide details of such modifications to the Distributor and the Parties shall revise this Appendix accordingly.

In the event that the Embedded Distributor connects additional Embedded Generation Facilities or expansions are made to existing Generation Facilities after the date upon this Agreement was executed, the Embedded Distributor shall expeditiously without delay, provide details of such connections and expansions to the Distributor.

Where an Embedded Distributor has Embedded Generation Facilities connected to their distribution system that could impact the GPI Distribution System, they shall ensure that:

(a) No switching operations are performed that parallel the supply feeder with any other Embedded Distributor feeder unless the Embedded Generation Facility is shutdown; and

(b) The Embedded Generation Facility is to be separated from the Distribution System any time there is a loss of the Transfer Trip Protection.

INFORMATION (only customer generation that satisfies the Connection Impact Assessment requirement for monitoring and/or Teleprotection are listed below)

* Note: Legacy (or Grandfathered) connections are exempted from the above-mentioned requirements, as their governing Connection Impact Assessment did not stipulate a requirement for monitoring and/or Teleprotection.

D.12.3. Generation Connection Capacity

There is a technical limit to the amount of generation that can be connected to a Transformer Station or to a distribution feeder.

The Distributor will determine the Station Capacity for Embedded Generation Connections, based on the thermal and short circuit capacities, and will maintain a record of the Embedded Generators connected to the station.

The Distributor will determine the Feeder Capacities for Embedded Generation

Connections, based on the feeder loading, and will maintain a record of the Embedded Generators connected to each feeder.

The Distributor will provide a copy of the station and feeder capacities and list of connected generators to the Customer on request.

D.12.4. Existing Embedded Generator Connections

Following is a list of the existing Embedded Generators connected to the Customer's Distribution System.

Operating Designation:	*HAF Wind*
Generator:	HAF Wind Energy Project
Size:	9.9 MW
Connection Date:	
Monitoring:	SCADA
Teleprotection (TT/RT):	Transfer Trip via 900MHz unlicensed radio (FreeWave)
Supply Feeder	M2

Operating Designation:	*Ravensbergen*
Generator:	Ravensbergen
Size:	2.5 MW
Connection Date:	
Monitoring:	SCADA
Teleprotection (TT/RT):	Transfer Trip via 900MHz unlicensed radio (FreeWave)
Supply Feeder	M2

Operating Designation:	*Stanpac*
Generator:	Stanpac

Size:	1.0 MW
Connection Date:	
Monitoring:	SCADA
Teleprotection (TT/RT):	Transfer Trip via 900MHz unlicensed radio (FreeWave)
Supply Feeder	M5

Other specific information on Embedded Generators in Embedded Distributor System as required.

D.12.5. Active and Reactive Power Deliveries from Embedded Retail Generators

Maximum Allowed to the GPI Distribution System (to be completed where applicable)

Maximum Permissible Amount for Delivery (kW): (n/a)

Maximum kVAR (lag): (n/a)

Maximum kVAR (lead): (n/a)

SCHEDULE E – PROVISIONS APPLICABLE IF CUSTOMER FINANCED BY A LENDER

E.1. For the purposes of this Schedule, "lender" means a bank or other entity whose principal business in that of a financial institution and that is financing or refinancing the Customer Equipment or system (as applicable).

E.2. Where notice of a Default has been served on the Customer under section 19.3, an agent or trustee for and on behalf of a lender ("Security Trustee") or a receiver appointed by the Security Trustee ("Receiver") shall upon notice to the Distributor be entitled (but not obligated) to exercise all of the rights and obligations of the Customer under this Agreement and shall be entitled to remedy the Default specified in the notice within the applicable cure period referred to in section 19.4. The Distributor shall accept performance of the Customer's obligations under this Agreement by the Security Trustee or Receiver in lieu of the Customer's performance of such obligations, and will not exercise any right to terminate this Agreement under section 19.3 due to a Default if the Security Trustee, its nominee or transferee, or the Receiver acknowledges its intention to be bound by the terms of this Agreement and such acknowledgment is received within 30 days of the date of receipt by the Customer of the notice of Default.

E.3. The Customer may, without the prior written consent of the Distributor, assign by way of security only all or any part of its rights or obligations under this Agreement to a lender. The Customer shall promptly notify the Distributor upon making any such assignment.

E.4. The Customer may disclose confidential information of the Distributor to a lender or a prospective lender.

7-VECC-43

Reference: Exhibit 7, Tab 1, pages 1-2

Preamble: The Application states:"*For Street Lighting, Unmetered Scattered Load and Embedded Distributor classes Grimsby Power does not have assets in account 1855 associated with these classes which causes the assigned weighting factor to be set at 0.0*".

a) Are there services assets associated Street Lighting or USL that are included in another USOA account and, if yes, which account and what are the dollar values?

Response:

a) There are no services assets associated with Street Lighting or USL that are included in other USoA accounts.

7-VECC-44

Reference: Exhibit 7, Tab 1, pages 2-3
EB-2015-0072, DRO Cost Allocation Model, Tab I5.2

Preamble: The Application states:
"*In determining the weighting factors for Billing and Collecting, an analysis of Accounts 5305 – 5340, was conducted*".

In the EB-2015-0072 DRO Cost Allocation Model the Billing and Collecting weighting factors were:

	Residential	GS <50	General Service 50 to 4,999 KW	Street Light	Unmetered Scattered Load	Embedded Distributor
Insert Weighting Factor for Billing and Collecting	1.00	1.02	9.62	15.05	11.19	0.00106360

a) Please provide copy of the analysis undertaken to determine the Billing and Collecting weighting factors for this Application.

b) Please explain the reasons for the material change in the Billing and Collecting weighting factors from those used in EB-2015-0072.

Response:

a) Grimsby Power reviewing the weighting factors for Billing and Collecting and realized account 5310 was including in the costs used to calculate the weighting factors. Grimsby Power has removed those costs and provided an analysis for the billing and collecting weighting factor below.

Expense Category	Residential	GS<50	GS> 50-4,999	Street Light	USL	Embedded Distributor	Total
CIS System	$104,719.26	$ 7,893.76	$ 892.14	$ 18.68	$ 556.58	$ 9.19	**$114,089.60**
Collections	$ 2,857.58	$ 215.41	$ 16.42	$ 0.34	$ 10.25	$ -	**$ 3,100.00**
Invoice Printing, Ebill and Mailing	$138,891.62	$ 10,469.67	$ 1,431.06	$ 23.20	$ 624.07	$ 11.30	**$151,450.92**
Labour & Benefits	$301,143.84	$ 22,700.27	$ 3,054.18	$ 23.72	$ 1,278.62	$ 1,020.23	**$329,220.87**
Phone System	$ 5,403.49	$ 407.32	$ 46.03	$ 0.96	$ 28.72	$ 0.48	**$ 5,887.00**
Supplies	$ 605.79	$ 45.66	$ 5.16	$ 0.11	$ 3.22	$ 0.05	**$ 660.00**
Write Offs	$ 20,000.00	$ 3,593.83	$ 406.17	$ -	$ -	$ -	**$ 24,000.00**
Total	**$573,621.58**	**$ 45,325.92**	**$ 5,851.18**	**$ 67.01**	**$ 2,501.45**	**$ 1,041.26**	**$628,408.39**
Number of Customers	11,213	845	96	2	60	1	
Cost per Customer	$ 51.16	$ 53.62	$ 61.25	$ 33.50	$ 41.97	$ 1,041.26	
Weighting	1	1.05	1.20	0.65	0.82	20.35	

b) The material change in Billing and Collecting weighting factors are directly related to the elimination of the Director of Customer accounts position. In 2016 a large portion of wages and benefits for the Director of Customer Accounts position was allocated to the GS>40 – 4,999, Street Light and USL rate categories. The 2022 weighting factors are a reflection of the position being eliminated.

7-VECC-45

Reference: Cost Allocation Model, Tabs I6.2 and I8

a) Do all GS 50-4,999 customer that own their transformer also own the secondary assets on the customer side of the transformer?

b) If yes, why in Tab I6.2, is the GS 50-4,999 customer count for Secondary Customer Base (94) greater than the customer count for Line Transformer Base?

c) If yes, why in Tab I8 is the GS 50-4,999 4NCP value for Secondary Customer greater than the 4NCP value for Line Transformer?

Response:

a) Yes all GS>50 – 4,999 customers own the secondary assets on the customer side of the transformer.

b) Grimsby Power has changed Tab I6.2 to reflect the response in a)

c) Grimsby Power has changed Tab I8 to reflect the response in a)

7-NPEI-1

References:

1. **GPI_2022 Cost Allocation Model_20210908**
2. **Grimsby_DRO_Detailed CA Model Run4_20160914 (GPI's 2016 COS Rate Application - EB-2015-0072)**

NPEI has compiled the following table of costs that have been allocated to the Embedded Distributor rate class in GPI's current application, as well as the Board-approved final CA model in GPI's previous COS Rate Application (EB-2015-0072).

Costs Allocated to the Embedded Distributor Rate Class				
Acct #	**Account Name**	**2016 Final CA Model**	**2022 CA Model Proposed**	**Difference (2022 Model vs 2016 Model)**
	Directly Allocated Assets			
1805	Land	59,997	59,997	-
1808	Buildings and Fixtures	502,474	508,586	6,112
1815	Transformer Station Equipment - Normally Primary above 50 kV	3,736,789	3,925,465	188,676
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	(903,924)	(1,345,626)	(441,701)
1995	Contributions and Grants - Credit	(1,218,270)	(1,218,270)	-
	Directly Allocated Net Fixed Assets	2,177,065	1,930,152	(246,913)
	Directly Allocated Expenses			
5005	Operation Supervision and Engineering	7,978	-	(7,978)
5010	Load Dispatching	28,668	36,024	7,356
5012	Station Buildings and Fixtures Expense	8,558	11,308	2,750
5014	Transformer Station Equipment - Operation Labour	-	1,894	1,894
5015	Transformer Station Equipment - Operation Supplies and Expenses	23,615	34,672	11,058
5112	Maintenance of Transformer Station Equipment	18,276	25,410	7,134
5315	Customer Billing	-	4,320	4,320
5705	Amortization Expense - Property, Plant, and Equipment	97,115	106,692	9,578
	Directly Allocated Expenses	184,210	220,321	36,112
	Approved Total PILs	3,795	21,417	17,622
	Approved Total Return on Debt	46,664	37,035	(9,628)
	Approved Total Return on Equity	94,408	77,168	(17,240)
	Total Direct Allocation (Agrees to Row 36 on Sheet O1)	329,075	355,941	26,866
	Allocated on Sheet O4			
5070	Customer Premises - Operation Labour	1	2	1
5075	Customer Premises - Materials and Expenses	0	1	0
5305	Supervision	-	119	119
5315	Customer Billing	-	887	887
5320	Collecting	-	40	40
5330	Collection Charges	-	2	2
5340	Miscellaneous Customer Accounts Expenses	-	1	1
5605	Executive Salaries and Expenses	10,163	12,662	2,499
5610	Management Salaries and Expenses	22,213	21,195	(1,019)
5615	General Administrative Salaries and Expenses	10,166	20,917	10,751
5620	Office Supplies and Expenses	2,319	2,523	204
5630	Outside Services Employed	3,088	6,292	3,204
5635	Property Insurance	3,834	4,576	742
5645	Employee Pensions and Benefits	343	725	381
5655	Regulatory Expenses	4,591	5,698	1,107
5660	General Advertising Expenses	616	430	(186)
5665	Miscellaneous General Expenses	4,906	5,241	335
5675	Maintenance of General Plant	3,059	8,797	5,739
6105	Taxes Other Than Income Taxes	2,884	3,498	614
6205-1	Sub-account LEAP Funding	360	427	67
	Total Expenses (Agrees to Row 34 on Sheet O1)	68,543	94,034	25,491
	Revenue Requirement (Agrees to Row 40 on Sheet O1)	397,618	449,975	52,357

a) Please confirm that the table above is correct. If not confirmed, please provide a corrected version of the above table.
b) Please confirm that GPI's invoice to NPEI each month is generated from GPI's accounting system, not GPI's CIS system.

c) Please provide the details of the costs to prepare and issue monthly invoices to NPEI (amount by USoA account) that have been included in the 2022 Test Year.
d) Please provide the details of GPI's calculation of the $4,320 in Account 5315 Customer Billing that has been directly allocated to the Embedded Distributor rate class in the current CA Model, given that the Embedded Distributor class is also allocated a portion of Billing and Collection Accounts 5305-5340 on Sheet O4.

Response:

a) Grimsby Power has provided the table below with slightly corrected figures.

Account	Directly Allocated Assets	2016 Final CA Model	2022 CA Model	Difference (2022 Model vs. 2016 Model)
1995	Contributions and Grants - Credit	- 1,218,270	- 1,218,270	-
1805	Land	59,997	59,997	-
1808	Buildings and Fixtures	502,474	508,586	6,112
1815	Transformer Station Equipment - Normally Primary above 50 kV	3,736,789	3,925,465	188,676
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	- 903,924	- 1,345,626	- 441,701
	Directly Allocated Net Fixed Assets	**2,177,065**	**1,930,152**	**- 246,913**
5005	Operation Supervision and Engineering	7,978	-	- 7,978
5010	Load Dispatching	28,668	36,024	7,356
5012	Station Buildings and Fixtures Expense	8,558	11,308	2,750
5014	Transformer Station Equipment - Operation Labour	-	1,894	1,894
5015	Transformer Station Equipment - Operation Supplies and Expenses	23,615	34,672	11,058
5112	Maintenance of Transformer Station Equipment	18,276	25,410	7,134
5315	Customer Billing		4,320	4,320
5705	Amortization Expense - Property, Plant, and Equipment	97,115	106,692	9,578
	Directly Allocated Expenses	**184,210**	**220,321**	**36,112**
	Approved Total PILs	3,795	21,420	17,625
	Approved Total Return on Debt	46,664	37,040	- 9,624
	Approved Total Return on Equity	94,408	77,177	- 17,231
	Total Direct Allocation (Agrees to Row 36 on Sheet O1)	**329,075**	**355,958**	**26,882**
	Allocated on Sheet O4			
5070	Customer Premises - Operation Labour	1	2	1
5075	Customer Premises - Materials and Expenses	0	1	0
5305	Supervision	0	119	119
5315	Customer Billing	0	887	887
5320	Collecting	0	40	40
5330	Collection Charges	0	2	2
5340	Miscellaneous Customer Accounts Expenses	-	1	1
5605	Executive Salaries and Expenses	10,163	12,662	2,499
5610	Management Salaries and Expenses	22,213	21,195	- 1,019
5615	General Administrative Salaries and Expenses	10,166	20,917	10,751
5620	Office Supplies and Expenses	2,319	2,523	204
5630	Outside Services Employed	3,088	6,292	3,204
5635	Property Insurance	3,834	4,576	742
5645	Employee Pensions and Benefits	343	725	381
5655	Regulatory Expenses	4,591	5,698	1,107
5660	General Advertising Expenses	616	430	- 186
5665	Miscellaneous General Expenses	4,906	5,241	335
5675	Maintenance of General Plant	3,059	8,797	5,739
6105	Taxes Other Than Income Taxes	2,884	3,498	614
6205-1	Sub-account LEAP Funding	360	427	67
	Total Expenses (Agrees to Row 34 on Sheet O1)	**68,543**	**94,034**	**25,491**
	Revenue Requirement (Agrees to Row 40 on Sheet O1)	**397,618**	**449,992**	**52,373**

b) The monthly invoice to NPEI is currently issued out of our accounting system. Prior to the issuance from our accounting system information is pulled from Utilismart and the invoice amounts are calculated using an excel spreadsheet. Once calculated in excel that excel sheet is sent to NPEI for verification prior to the amounts being manually entered into our accounting system to produce an invoice that is issued to NPEI. Grimsby Power has configurations in place to move the issuing of the invoice to the CIS system in 2022.

c) The largest expense in preparing the monthly invoice is the cost for Utilismart to split the IESO invoice between NPEI and GPI. GPI uses this information for verification of calculations in the excel spreadsheet. This cost is directly allocated as it does not apply to any other rate class or customer.

   Other costs include internal labour hours of various staff to calculate, issue and document the monthly invoice totals. These costs are included in accounts 5305 – 5340 and allocated based on weighting factors.

d) The costs directly allocated under account 5315 are the costs paid by Grimsby Power to have the IESO split between GPI and NPEI. See c) above.

7-NPEI-2

References:

1. **GPI_2022 Cost Allocation Model_20210908**
2. **Grimsby_DRO_Detailed CA Model Run4_20160914 (GPI's 2016 COS Rate Application - EB-2015-0072)**

EB-2021-0027

Sheet I5.2 Weighting Factors Worksheet -

	1	2	3	7	9	10
	Residential	GS <50	GS 50 to 4,999 kW	Street Light	Unmetered Scattered Load	Embedded Distributor
Insert Weighting Factor for Services Account 1855	1.0	3.1	0.0	0.0	0.0	0.0
Insert Weighting Factor for Billing and Collecting	1.0	1.0	7.4	1.5	0.9	22.3

EB-2015-0072

Sheet I5.2 Weighting Factors Worksheet -

	1	2	3	7	9	10
	Residential	GS <50	General Service 50 to 4,999 KW	Street Light	Unmetered Scattered Load	Embedded Distributor
Insert Weighting Factor for Services Account 1855	1.00	3.14	-	-	-	-
Insert Weighting Factor for Billing and Collecting	1.00	1.02	9.62	15.05	11.19	0.00106360

a) Please provide details of the calculation of the Billing and Collecting Weighting Factor for the Embedded Distributor rate class of 22.3 in Sheet I5.2 Weighting Factors of GPI's 2022 CA Model.

b) Please confirm that the Billing and Collecting Weighting Factor for the Embedded Distributor rate class in GPI's final 2016 CA Model is 0.00106360. Please explain the large increase in the Billing and Collecting Weighting Factor for the Embedded Distributor rate class from 0.00106360 in the 2016 CA Model to 22.3 the 2022 CA Model.

Response:

a) Please see 7-VECC-44.

b) The billing and collecting weighting factor in GPI's final 2016 CA model was 0.00106360. In the 2016 weighting factor only one expense was attributed to the Embedded Distributor at that time and it was related to the posting of new rates.

Since 2016 GPI has begun invoicing the Embedded Distributor using software and processes that were not in place in 2016. The software and processes are fully considered in the weighting factors for 2022 and thus the increase compared to 2016 (7-VECC-44)). The process to produce the monthly invoice to the Embedded Distributor is labour intensive as it is a complex process.

7-NPEI-3

References:

1. **GPI_2022 Cost Allocation Model_20210908**
2. **Exhibit 7, Tab 1, page 7 of 8**
3. **Grimsby_DRO_Detailed CA Model Run4_20160914 (GPI's 2016 COS Rate Application - EB-2015-0072)**

NPEI has compiled the following table of allocators from Sheet E2 Allocators in GPI's 2022 CA Model and the Board-approved final CA model in GPI's previous COS Rate Application (EB-2015-0072) for the allocator types that include an allocation to the Embedded Distributor rate class.

Explanation	ID and Factors	2016 CA Model - Embedded Distributor %	2022 CA Model - Embedded Distributor %
CUSTOMER ALLOCATORS			
Billing Data			
kWh	CEN	0.00%	22.66%
kW	CDEM	42.99%	45.76%
kWh - Excl WMP	CEN EWMP	0.00%	0.00%
Dollar Billed	CREV	5.50%	7.90%
Bad Debt 3 Year Historical Average	BDHA	0.00%	0.00%
Late Payment 3 Year Historical Average	LPHA	0.00%	0.00%
Number of Bills	CNB	0.01%	0.01%
Number of Connections (Unmetered)	CCON	0.00%	0.00%
Embedded Distributor	ED	100.00%	100.00%
CDM Participtant Percentage	CDMPP	0.00%	0.00%
Total Number of Customer	CCA	0.01%	0.01%
Subtransmission Customer Base	CCB	0.00%	0.00%
Primary Feeder Customer Base	CCP	0.00%	0.00%
Line Transformer Customer Base	CCLT	0.00%	0.00%
Secondary Feeder Customer Base	CCS	0.00%	0.00%
Weighted - Services	CWCS	0.00%	0.00%
Weighted Meter -Capital	CWMC	0.00%	0.00%
Weighted Meter Reading	CWMR	0.00%	0.00%
Weighted Bills	CWNB	0.00%	0.17%
CUSTOMER ALLOCATORS - Composite			
CUSTOMER 1815-1855	1815-1855 C	0.00%	0.00%
CUSTOMER 1808	1808 C	0.00%	0.00%
CUSTOMER 1815	1815 C	0.00%	0.00%
CUSTOMER 1820	1820 C	0.00%	22.66%
CUSTOMER 1815 & 1820	1815 & 1820 C	0.00%	22.66%
CUSTOMER 1830	1830 C	0.00%	0.00%
CUSTOMER 1835	1835 C	0.00%	0.00%
CUSTOMER 1830 & 1835	1830 & 1835 C	0.00%	0.00%
CUSTOMER 1840	1840 C	0.00%	0.00%
CUSTOMER 1845	1845 C	0.00%	0.00%
CUSTOMER 1840 & 1845	1840 & 1845 C	0.00%	0.00%
CUSTOMER 1850	1850 C	0.00%	0.00%
CUSTOMER 1855	1855 C	0.00%	0.00%
CUSTOMER 1860	1860 C	0.00%	0.00%
Composite Allocators			
Net Fixed Assets	NFA	10.45%	7.99%
Net Fixed Assets Excluding Capital Contribution	NFA ECC	12.65%	10.99%
5005-5340	O&M	4.79%	5.03%
Account Setup	Acct	4.79%	5.03%
Access to Poles	POLE	0.00%	0.00%
5005-6225	OM&A	2.22%	2.39%
Net Fixed Assets Excluding Direct Allocation	NFAEXDA	0.00%	0.00%
Net Fixed Assets Excluding Capital Contribution	NFA ECCEXDA	0.00%	0.00%

a) Please confirm that the table above is correct. If not confirmed, please provide a corrected version of the above table.

b) The allocators that include an allocation to the Embedded Distributor rate class in the 2022 CA Model, that did not include an allocation to the Embedded Distributor rate class in the final 2016 CA Model are highlighted in the table above. In reference 2), GPI indicates that it proposes to apply the same cost allocation methodology that was used in its 2016 COS Rate Application. Please provide the rationale for the change in allocation methodology for the highlighted allocators.

c) Please explain the basis for the other allocators. Specifically, please explain the change in the OM&A allocator in the table above from 2.22% in the 2016 CA Model to 2.39% in the 2022 CA Model.

Response:

a) Confirmed.

b) Customer 1820 (1820 C), Customer 1815 & 1820 (1815 & 1820 C), and kWh (CEN) have values for the Embedded Distributor in the 2022 cost allocation model because forecast consumption was entered for the class in tab 'I6.1 Revenue' but left blank in the 2016 cost allocation model. These allocators have no impact on the costs allocated to the Embedded Distributor class so there is no change in methodology. Please note that clearing Embedded Distributor Forecast kWh (cell M25 in tab 'I6.1 Revenue') returns the allocators to 0% in tab 'E2 Allocators' without changing the allocation in 'O1 Revenue to Cost|RR'.

Please see the response to 7-NPEI-2 for details on the change in allocation to Weighted Bills (CWNB). Please note the 2016 CWNB value is not 0, it is a low figure which rounds to 0.00%.

c) The changes to other allocators reflect the changes in direct Embedded Distributor net book values as a share of total net book assets and directly allocated expenses as a share of Grimsby Power's total expenses. OM&A is a composite allocator that is influenced by many factors. Generally, the expenses for which the Embedded Distributor class receives an allocation have increased at a faster rate than Grimsby Power's total expenses, which causes an increase to its share of OM&A.

7-NPEI-4

References:

1. **GPI_2022 Cost Allocation Model_20210908**
2. **Exhibit 7, Tab 1, page 7 of 8**

a) Please provide the details of the calculation of the Account 1815 amount of $3,925,465 that has been directly allocated to the Embedded Distributor rate class (Sheet I3 TB Data, cell G137) in GPI's 2022 CA Model.

b) In reference 2), GPI indicates that 40% of the costs related to the Niagara West MTS have been allocated to the Embedded Distributor rate class. The forecast 2022 total cost in Account 1815 (Sheet I3 TB Data, cell D137) is $7,986,258. Please explain why the amount directly allocated to the Embedded Distributor rate class in Account 1815 (Sheet I3 TB Data, cell G137 of $3,925,465) does not equal $7,986,258 * 40% = $3,194,503.

Response:

a) The calculation of amount directly allocated for account 1815 takes into consideration the contributed capital (Contributions & Grants) for the HAF Wind project. The calculation is as follows. Account balance for 1815 plus the Contributions and Grants directly allocated to the Embedded Distributor multiplied by 40% less the Contributions and Grants directly allocated to the Embedded Distributor ((7,986,258-1,218,270)*.4+1,218,270). The formula is also in cell G137 of the GPI_2022_Cost_Allocation_Model_20210730 tab I3.

b) See a) above.

7-NPEI-5

References:

1. **GPI_2022 Cost Allocation Model_20210908**
2. **Exhibit 7, Tab 2, Table 7-8**

GPI is proposing a Revenue-to-Cost Ratio of 116.24% for the Embedded Distributor rate class, versus a 2016 Board Approved Revenue-to-Cost Ratio of 100.0%.

a) Please provide a 2022 Revenue Requirement Workform Model, based on the scenario where the Revenue-to-Cost Ratio for the Embedded Distributor rate class is set to 100.0%.

Response:

a) Grimsby Power has provided a 2022 Revenue Requirement Workform model with the Embedded Distributor set to 100%. The reduction in revenue due to the change in the revenue to cost ratio was absorbed by the Residential rate class. Grimsby Power is not proposing this revised revenue to cost ratio split.

7-NPEI-6

References:

1. **GPI_2022 Cost Allocation Model_20210908**
2. **Grimsby_DRO_Detailed CA Model Run4_20160914 (GPI's 2016 COS Rate Application - EB-2015-0072)**

NPEI has compiled the following tables of Operations and Maintenance costs, and General and Administrative costs, where a portion has been allocated to the Embedded Distributor rate class in GPI's current application, as well as the Board-approved final CA model in GPI's previous COS Rate Application (EB-2015-0072).

Operations and Maintenance Costs

Account #	2016 Final CA Model	2022 CA Model Proposed	$ Difference	% Difference
5010	71,671	90,060	18,389	25.7%
5012	21,396	28,270	6,874	32.1%
5014	19,944	4,735	(15,209)	-76.3%
5015	59,036	86,681	27,645	46.8%
5112	45,690	63,526	17,836	39.0%
Total	217,737	273,272	55,535	25.5%

General and Administrative Costs

Per Sheet O1 Allocated to Embedded Distributor Class	2016 Final CA Model	2022 CA Model Proposed	$ Difference	% Difference
General and Administration (ad)	68,541	92,981	24,440	35.7%

a) Please confirm that the tables above are correct. If not confirmed, please provide corrected versions of the above tables.
b) Please explain the 25.5% increase in Operations and Maintenance costs relating to Niagara West TS between 2016 Board Approved and the 2022 Test Year.
c) Please provide the details of the 2022 Proposed Operations and Maintenance costs in each of the USoA accounts in the first table above. Please identify which costs are incurred annually and which costs are cyclical in nature.
d) Please explain the increase of 35.7% between 2016 Board Approved and the 2022 Test Year in General and Administration costs that are allocated to the Embedded Distributor rate class.

Response:

a) Grimsby Power has provided a corrected table for Operations and Maintenance Costs. The table for General and Administrative Costs was correct.

Account #	2016 Final CA Model	2022 CA Model Proposed	$ Difference	% Difference
5010	71,670.82	90,060.00	18,389.18	25.7%
5012	21,395.57	28,270.00	6,874.43	32.1%
5014	-	4,735.23	4,735.23	
5015	59,036.49	86,681.00	27,644.51	46.8%
5112	45,690.24	63,525.90	17,835.66	39.0%
	197,793.12	**273,272.13**	**75,479.01**	**38.2%**

b) The increase in Operations and Maintenance costs relating to Niagara West TS between 2016 Board Approved and the 2022 Test Year is shown in the table below:

CATEGORY	AMOUNT
Station Operation and Maintenance	20,295.32
Communication	19,020.51
Operating Control	18,389.18
Building and lawn Maintainance	7,650.00
Insurance	5,087.00
Property Taxes	3,537.00
Utilities	1,500.00
TOTAL	**75,479.01**

c) The details of the 2022 Proposed Operations and Maintenance costs in each of the USoA accounts is shown in the table below:

Account #	Description	Increase Amount	Cost Nature
5010		**$ 18,389.18**	
	Operating Control Centre	18,389.18	annually
5012		**$ 6,874.43**	
	Phone Service	124.43	annually
	Utilities	1,500.00	annually
	Snow Removal and Cutting Grass	5,250.00	annually
5014		**$ 4,735.23**	
	GPI Labour	4,735.23	annually
5015		**$ 27,644.51**	
	Communication Devices	19,020.51	one time cost
	Annual Insurance	5,087.00	annually
	Property Taxes	3,537.00	annually
5112		**$ 17,835.66**	
	Station Maintenance	11,800.00	annually
	GPI Labour	6,035.66	annually

d) The increase of the General and Administration between 2016 Board Approved and the 2022 Test Year are mainly due to:
   a. Addition of two new positions : Accounting Supervisor and IT System and Communication Specialist;
   b. Increase IT and cybersecurity costs;
   c. Increase Audit Services cost;
   d. Inflationary increase in labour and non-labour costs

Exhibit 8 – Rate Design

8-Staff-51
Retail Transmission Service Rates
Ref: RTSR Workform

Preamble:
On June 25, 2021 the OEB issued the RTSR workform for 2022 rate applications.

Question(s):

a) Please file an updated RTSR workform ensuring that both the historic wholesale and retail volumes are consistent with 2020 actuals.

Response:

a) Grimsby Power has completed and filed the RTSR workform issued June 25, 2021 and ensured that the historic wholesale and retail volumes are consistent with 2020 actuals.

8-Staff-52
Rate Class Definition
Ref: Exhibit 8, Tab 5 pages 1-2

Preamble:
Grimsby is proposing to amend the definition of its GS < 50 kW and GS 50 – 4,999 kW rate classes such that the boundary is based on the average peak demand, rather than the highest peak demand. It indicates that this will result in reclassification of the smallest GS 50 – 4,999 customers into the GS < 50 kW rate class.

Question(s):

a) Were the affected customers consulted regarding the proposed change, and if so, how did they respond?

b) Please provide the rationale for the proposed changes to the rate class definitions.

c) Please provide a sample bill impact reflecting full impact of the rate application on a typical customer that would be reclassified by this proposal.

d) If a customer taking power over 750 volts were to drop below 50 kW average, which rate class would apply?

Response:

a) Grimsby Power did not consult the individual customers that would be affected by the proposed change.

b) The current definition of the GS>50 – 4,999 rate class prescribes that customers that hit a demand greater that 50kW one month of the year will be placed in the rate category. Grimsby Power believes this definition places customers that very rarely hit a demand of >50kw in a more expensive rate class. The move to an average of >50kW would move Grimsby Power customers in line with other utilities' customers.

c) A typical customer would have an annual reduction in cost of approximately $4,354. The table below shows a comparison of a typical customer that would be switching from GS>50 to GS<50.

	January	February	March	April	May	June	July	August	September	October	November	December	Annual Totals
						Invoice Amounts GS>50 Rate Class							
Delivery	$536.34	$533.68	$524.17	$507.61	$615.26	$687.78	$595.11	$633.60	$602.94	$540.57	$518.18	$520.22	$6,815.46
Regulatory	$ 47.31	$ 47.52	$ 43.17	$ 40.43	$ 42.53	$ 55.21	$ 49.41	$ 51.18	$ 44.81	$ 45.33	$ 46.25	$ 49.04	$ 562.19
Electricity	$ 1,394.43	$ 1,570.54	$ 1,398.12	$ 1,250.60	$ 1,347.92	$ 1,820.57	$ 1,471.26	$ 1,654.23	$ 1,633.91	$ 1,668.58	$ 1,471.92	$ 1,455.01	$ 18,137.09
HST	$ 257.15	$ 279.73	$ 255.51	$ 233.82	$ 260.74	$ 333.26	$ 275.05	$ 304.07	$ 296.62	$ 293.08	$ 264.73	$ 263.16	$ 3,316.92
OER	-$ 373.86	-$ 406.68	-$ 371.47	-$ 339.94	-$ 379.08	-$ 484.51	-$ 399.88	-$ 442.07	-$ 431.23	-$ 426.10	-$ 384.87	-$ 382.59	-$ 4,822.29
Total Invoice GS>50	**$ 1,861.37**	**$ 2,024.79**	**$ 1,849.50**	**$ 1,692.52**	**$ 1,887.37**	**$ 2,412.31**	**$ 1,990.95**	**$ 2,201.01**	**$ 2,147.04**	**$ 2,121.47**	**$ 1,916.21**	**$ 1,904.84**	**$24,009.37**
						Invoice Amounts GS<50 Rate Class							
Delivery	$ 516.26	$ 484.79	$440.02	$423.05	$436.03	$560.73	$502.71	$520.46	$458.85	$464.26	$472.60	$499.67	$5,779.44
Regulatory	$ 47.31	$ 47.52	$ 43.17	$ 40.43	$ 42.53	$ 55.21	$ 49.41	$ 51.18	$ 44.81	$ 45.33	$ 46.25	$ 49.04	$ 562.20
Electricity	$ 1,225.81	$ 1,208.13	$ 1,035.54	$ 1,193.55	$ 1,069.95	$ 1,439.76	$ 1,285.21	$ 1,306.48	$ 1,162.88	$ 1,164.95	$ 1,197.65	$ 1,255.82	$ 14,545.76
HST	$ 232.62	$ 226.26	$ 197.44	$ 215.42	$ 201.31	$ 267.24	$ 238.85	$ 244.16	$ 216.65	$ 217.69	$ 223.15	$ 234.59	$ 2,715.36
OER	-$ 338.19	-$ 328.94	-$ 287.04	-$ 313.18	-$ 292.67	-$ 388.53	-$ 347.26	-$ 354.97	-$ 314.98	-$ 316.49	-$ 324.42	-$ 341.06	-$ 3,947.72
Total Invoice GS<50	**$ 1,683.81**	**$ 1,637.75**	**$ 1,429.13**	**$ 1,559.28**	**$ 1,457.15**	**$ 1,934.41**	**$ 1,728.93**	**$ 1,767.32**	**$ 1,568.22**	**$ 1,575.75**	**$ 1,615.23**	**$ 1,698.06**	**$19,655.04**
Delivery	-$ 20.08	-$ 48.89	-$ 84.15	-$ 84.56	-$ 179.23	-$ 127.05	-$ 92.40	-$ 113.14	-$ 144.09	-$ 76.31	-$ 45.58	-$ 20.55	-$ 1,036.02
Regulatory	-$ 0.00	-$ 0.00	-$ 0.00	$ 0.00	-$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	-$ 0.00	-$ 0.00	$ 0.01
Electricity	-$ 168.62	-$ 362.41	-$ 362.58	-$ 57.05	-$ 277.97	-$ 380.81	-$ 186.05	-$ 347.75	-$ 471.03	-$ 503.63	-$ 274.27	-$ 199.19	-$ 3,591.33
HST	-$ 24.53	-$ 53.47	-$ 58.07	-$ 18.41	-$ 59.44	-$ 66.02	-$ 36.20	-$ 59.91	-$ 79.96	-$ 75.39	-$ 41.58	-$ 28.57	-$ 601.55
OER	$ 35.66	$ 77.74	$ 84.43	$ 26.76	$ 86.41	$ 95.99	$ 52.63	$ 87.11	$ 116.26	$ 109.61	$ 60.45	$ 41.53	$ 874.57
Total Difference	**-$ 177.57**	**-$ 387.03**	**-$ 420.36**	**-$ 133.25**	**-$ 430.23**	**-$ 477.90**	**-$ 262.02**	**-$ 433.69**	**-$ 578.82**	**-$ 545.72**	**-$ 300.98**	**-$ 206.78**	**-$ 4,354.33**

d) Grimsby Power would apply the GS<50 rate class.

8-SEC-32

[Ex.8, Tab 2, p.3] With respect to the increase in volumetric charge due to the adjustment for Transformer Allowance:

1. Please provide the number of customers in the General Service >50 to 4,999 kW class who provide their own step down transformation.
2. Please provide the amount of Transformer Allowance credit that BPI has actually paid out in each year from 2016 to 2021 and GPI's forecast of the same in each year of the Application period.

Response:

Grimsby Power is not proposing an increase to the Transformer Allowance. *[Ex.8, Tab 2, p.3] "Currently, Grimsby Power provides a transformer allowance to those customers that own their transformation facilities.* ***Grimsby Power proposes to maintain the current approved transformer ownership allowance of $0.60 per kW*** *("Transformer Allowance")."*

1. Please see the response to 2 below.

2. Please see the table below for number of customers, amount of Transform Allowance paid and the amount forecast.

Transformer Allowance						
	2016	2017	2018	2019	2020	2021
Number of Customers	12	13	13	12	12	11
Amount Paid	$ 30,523	$ 29,937	$ 29,838	$ 27,272	$ 32,110	$ 32,201
Forecast	$ 28,999	$ 28,999	$ 28,999	$ 28,999	$ 28,999	$ 28,999

8-VECC-46

Reference: Exhibit 8, Tab 2 page 2
Cost Allocation Model, Tabs O1 and O2
EB-2015-0072, DRO Cost Allocation Model, Tabs O1 and O2

Preamble: In the EB-2015-0072 DRO Cost Allocation Model the Customer Unit Cost per month – Minimum System PLCC were:

Summary

	1	2	3	7	9	10
	Residential	GS <50	General Service 50 to 4,999 KW	Street Light	Unmetered Scattered Load	Embedded Distributor
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$15.84	$24.32	$204.49	$2.56	$61.38	$0.55

a) The Customer Unit Cost per month – Minimum System PLCC value for the USL rate class in the current Cost Allocation Model is $12.87. Can GPI explain the significant change in the Customer Unit Cost per month – Minimum System PLCC value for the USL rate class from that derived in EB-2015-0072?

b) Please provide a schedule that for each rate class (except Residential) set outs the following based on EB-2015-0072 and based on the current Application:
   i. The Customer Unit Cost per month – Minimum System PLCC value
   ii. The number of customers/connections
   iii. The total costs allocated to the class (per Tab O1)
   iv. The total miscellaneous revenues allocated to the class (per Tab O1)
   v. Total allocated costs less miscellaneous revenues (Item (iii)-Item (iv))
   vi. The product of Items (i) and (ii)
   vii. The percentage Item (vi) represents of Item (v).

Response:

a) The significant change in the Customer Unit Cost per month is directly related to the change in the weighting factor. Please see the response to 7-VEC-44 above.
b) Below is a schedule with the items described in question b.

		EB-2015-0072					EB-2021-0027				
		GS<50	GS>50-4,999	Street Light	USL	Embedded Distributor	GS<50	GS>50-4,999	Street Light	USL	Embedded Distributor
1	Customer Unit Cost per month – Minimum System PLCC value	$ 24.32	$ 204.49	$ 2.56	$ 61.38	$ 0.55	$ 27.52	$ 241.84	$ 3.44	$ 12.87	$ 129.94
2	Number of customers/connections	772	111	2653	72	1	845	96	2730	60	1
3	Total costs allocated to the class (per Tab O1)	$ 500,451	$ 854,277	$ 70,606	$ 54,609	$ 68,543	$ 659,437	$ 1,075,168	$ 98,876	$ 11,100	$ 94,034
4	Total miscellaneous revenues allocated to the class (per Tab O1)	$ 26,769	$ 40,666	$ 8,657	$ 5,819	$ 14,089	$ 56,001	$ 90,887	$ 12,732	$ 1,211	$ 6,331
5	Total allocated costs less miscellaneous revenues	$ 473,682	$ 813,611	$ 61,949	$ 48,790	$ 54,454	$ 603,436	$ 984,281	$ 86,144	$ 9,889	$ 87,703
6	The product of Items (i) and (ii)	$ 18,775	$ 22,698	$ 6,792	$ 4,419	$ 1	$ 23,254	$ 23,217	$ 9,391	$ 772	$ 130
	The percentage Item (vi) represents of Item (v).	3.96%	2.79%	10.96%	9.06%	0.00%	3.85%	2.36%	10.90%	7.81%	0.15%

8-VECC-47

Reference: Exhibit 8, Tab 3, page 3

Preamble: The Application states: "*Forecasted low voltage charges of $478,224 from Hydro One for 2022 have been allocated to each rate class based on the proportion of proposed retail transmission connection revenue collected from each class.*

*The 2022 Test Year Low Voltage expense of $480,000 has been estimated based on 2020 charges paid to Hydro One, adjusted to $472,224 to account for charges rounded to the fourth decima*l".

a) Please clarify whether the forecast LV charges for 2022 are $478,224 or $472,224.

b) The 2020 LV charges from Hydro One are reported as $464,993 (per page 3). Please provide schedule that sets out how the 2022 forecast charges of were derived from this value.

Response:

a) The forecast LV charges for 2022 are $478,224.

b) The charges for 2022 were estimated based on the actual 2020 charges of $464,993. The increase from the $464,993 to $478,224 was in anticipation of a rate increase from Hydro One.

8-VECC-48

Reference: Exhibit 8, Tab 4, page 1

Load Forecast Model, Power Purchases Tab

a) Please reconcile the wholesale delivered kWh used in Table 8-12 with the purchased power values in the Load Forecast Model.

Response:

a) The difference between the wholesale delivered kWh and purchased power values in the load forecast model are losses. The table below shows the difference of 3.06% which equates to the station loss percentage.

	Purchases excluding Generation	H1 + NW Supply	Losses
		Table 8-12	
2016	189,005,763	181,812,459	1.0396
2017	209,175,693	202,928,210	1.0308
2018	231,527,062	224,843,323	1.0297
2019	236,747,171	230,412,310	1.0275
2020	256,295,922	249,908,736	1.0256
		Average	1.0306
			3.06%

Exhibit 9 – Deferral and Variance Accounts

9-Staff-53
LRAMVA
Ref: Exhibit 9, Page 5
Exhibit 9, Page 9
DVA Continuity Schedule

Preamble:
On page 5, Grimsby Hydro stated that LRAMVA balance and interest were adjusted within the DVA Continuity Schedule. An adjustment of ($26,676) for the principal amount and an adjustment of $1,391 for the interest were included in the DVA Continuity Schedule. Grimsby Power stated that these two adjustments were made to have the amount of principal and interest as December 31, 2020 coincide with the 2022 LRAM work form. On page 9, Grimsby Power stated that it adjusted the lost revenue for 2020 to reflect participation and cost reports from the IESO.

Question(s):

a) Please provide some further explanation on the nature of the adjustments and why they are needed.

Response:

a) GPI adjusted the balance in the DVA schedule to match the amount being requested in the LRAMVA workform. The balance in the DVA schedule at the end of December 2020 needed to be corrected to be in line with the 2022 LRAM workform. The amount calculated in the LRAM workform was more accurate because the calculation used to book the LRAMVA amounts in 2020 was missing information in cells that properly allocated the LRAM to specific rate classes.

9-Staff-54
GA Analysis
Ref: Exhibit 9, Tab 1, page 23 of 27
GA Analysis Workform

Preamble:
In Exhibit 9, Grimsby Power indicated that the unresolved difference between the GL and the GA Analysis Workform was $64,364. In the GA Analysis Workform, the unresolved difference shown in tab "GA2020" cell C92 is $101,940.

Question(s):

a) Please explain the difference between the unresolved differences referenced above.

b) Please quantify the reconciling item "Impact of GA deferral" (cell C83) in the GA Analysis Workform as explained in item 5 of the Instructions for Completing GA Analysis Workform – 2022 Rates.

Response:

a) The unresolved difference between the GL and the GA Analysis Workform is $101,940 not $64,364 as noted on page 23 of 27.

   The difference between the $101,940 and $64,364 is $37,576. The explanation of the unresolved difference was written prior to the addition of the adjustment of $37,576 for the Embedded Distributor was added to the spreadsheet. In error the explanation in the Exhibit was not changed.

b) The amount of the reconciling item for the impact of GA deferral is $46,797. GPI has input this figure in cell C83 of the GA Analysis Workform. GPI has also entered the reconciling item for prior year unbilled to the reconciling times. The updated workform has been filing with the OEB.

9-Staff-55
Account 1592
Ref: Exhibit 9, Tab 1, page 10

Preamble:
Grimsby Power is proposing that account 1592 is discontinued after disposition of ($169,193).

Question(s):

a) Please explain why Grimsby Power is proposing to discontinue a generic account.

Response:

a) Grimsby Power will only dispose of the amounts accumulated in account 1592 up to and including amounts associated with accelerated CCA through 2021. After full disposition of amounts the generic account will be continued and used as directed by the OEB; for example, Grimsby Power expects to track the impact of the phase out of the current accelerated CCA rules during its IRM period in account 1592 for disposal in its next COS application.

9-Staff-56
Account 1518 and 1548
Ref: Exhibit 9, Tab 1, page 21

Preamble:
Grimsby Power provided the balances to be disposed for accounts 1518 and 1548 and stated that the balances are as of December 31, 2020, plus interest to December 31, 2022.

Question(s):

a) Please confirm the interest were calculated up to December 31, 2021 and not 2022 as mentioned above.

b) Please confirm whether Grimsby Power is able to forecast the principal balances for accounts 1518 and 1548 up to December 31, 2021 with reasonable accuracy.

   i. If so, please provide the 2021 transactions forecasted

   ii. Please discuss Grimsby Power's position on the notion of disposing the forecasted balance and discontinuing the accounts effective January 1, 2022. If Grimsby Power agrees with disposition of a forecasted balance to the end of 2021, please update the DVA Continuity Schedule in the 2020 principal adjustment column to include the 2021 transactions.

Response:

a) Grimsby Power confirms that interest was calculated up to December 31, 2021.

b)

   i. Grimsby Power is able to forecast the principal balances for accounts 1518 and 1548 up to December 31, 2021 with reasonable accuracy. The table below provides the actual and forecast transactions for 2021.

	Interest Rate	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	
	# of days	31	28	31	30	31	30	31	31	30	31	30	31	
		January 2021	February 2021	March 2021	April 2021	May 2021	June 2021	July 2021	August 2021	September 2021	October 2021	November 2021	December 2021	
Account Description		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast	Forecast	Total
RCVA - Retail 1518														
Revenue		(1,070.40)	(1,107.10)	(1,097.14)	(1,091.54)	(1,089.88)	(1,082.20)	(1,077.22)	(1,072.24)	(1,085.97)	(1,087.91)	(1,085.51)	(1,084.06)	(13,031.17)
Expense		453.02	446.02	424.99	432.00	509.85	482.27	425.68	418.11	448.99	448.49	448.80	451.77	5,389.99
Net Change		(617.38)	(661.08)	(672.15)	(659.54)	(580.03)	(599.93)	(651.54)	(654.13)	(636.97)	(639.42)	(636.71)	(632.28)	(7,641.17)
Balance Forward		23,618.58	23,001.20	22,340.12	21,667.97	21,008.43	20,428.40	19,828.47	19,176.93	18,522.80	17,885.83	17,246.41	16,609.69	23,618.58
Account Balance		23,001.20	22,340.12	21,667.97	21,008.43	20,428.40	19,828.47	19,176.93	18,522.80	17,885.83	17,246.41	16,609.69	15,977.41	15,977.41
Retail Carrying Charges														
Net Change		11.43	10.06	10.82	10.15	10.17	9.57	9.60	9.28	8.68	8.66	8.08	8.04	114.54
Balance Forward		1,436.54	1,447.97	1,458.03	1,468.85	1,479.00	1,489.17	1,498.74	1,508.34	1,517.62	1,526.30	1,534.96	1,543.04	1,436.54
Account Balance		1,447.97	1,458.03	1,468.85	1,479.00	1,489.17	1,498.74	1,508.34	1,517.62	1,526.30	1,534.96	1,543.04	1,551.08	1,551.08
TOTAL RETAIL		**24,449.17**	**23,798.15**	**23,136.82**	**22,487.43**	**21,917.57**	**21,327.21**	**20,685.27**	**20,040.42**	**19,412.13**	**18,781.37**	**18,152.73**	**17,528.49**	**17,528.49**
RCVA - Service Transaction Requests 1548														
Revenue		(17.00)	(4.16)	(0.52)	(4.68)	(1.56)	(2.08)	(2.60)	(2.60)	(2.60)	(2.38)	(2.64)	(2.35)	(45.17)
		(9.00)	(6.24)	(1.04)	(7.28)	(3.12)	(5.20)	(4.16)	(5.20)	(4.61)	(4.37)	(4.85)	(4.50)	(59.57)
Expense		150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	1,800.00
Net Change		124.00	139.60	148.44	138.04	145.32	142.72	143.24	142.20	142.79	143.25	142.51	143.15	1,695.26
Balance Forward		13,614.01	13,738.01	13,877.61	14,026.05	14,164.09	14,309.41	14,452.13	14,595.37	14,737.57	14,880.36	15,023.61	15,166.12	13,614.01
Account Balance		13,738.01	13,877.61	14,026.05	14,164.09	14,309.41	14,452.13	14,595.37	14,737.57	14,880.36	15,023.61	15,166.12	15,309.27	15,309.27
Retail Carrying Charges														
Net Change		6.59	6.01	6.72	6.57	6.86	6.70	7.00	7.07	6.90	7.20	7.04	7.34	82.00
Balance Forward		788.14	794.73	800.74	807.46	814.03	820.89	827.59	834.59	841.66	848.56	855.76	862.80	788.14
Account Balance		794.73	800.74	807.46	814.03	820.89	827.59	834.59	841.66	848.56	855.76	862.80	870.14	870.14
TOTAL STRs		**14,532.74**	**14,678.35**	**14,833.51**	**14,978.12**	**15,130.30**	**15,279.72**	**15,429.96**	**15,579.23**	**15,728.92**	**15,879.37**	**16,028.92**	**16,179.41**	**16,179.41**

ii. Grimsby Power agrees with using the actual and forecast amounts for 2021 as provided above and disposing of the accounts effective January 1, 2022. Grimsby Power has updated the DVA Continuity Schedule and included the 2021 principal amounts in the 2020 principal adjustments column.

For account 1518, an adjustment of -$7,641 was added cell BF71 bringing the principal balance to $15,977. Interest was also adjusted from $448 to $115 in cell BQ71 to adjust interest to be based on actual and forecast 2021 principal amounts. The two adjustments bring the total claim for account 1518 to $17,528.49.

For account 1548, an adjustment of $1,695 was added to cell BF74 bringing the principal balance to $15,309. Interest was also adjusted from $78 to $82 in cell BQ74 to adjust interest to be based on actual and forecast 2021 principal amounts. The two adjustments bring the total for account 1548 to $16,179.41.

9-Staff-57
Income before Taxes

Ref: Exhibit 4, Tab 9, page 1
Revenue Requirement Workform

Preamble:
In Exhibit 4, Grimsby Power states that the utility income before taxes is $268,205. The Revenue Requirement workform shows $966,360 as the utility income before taxes.

Question(s):

a) Please confirm that the reference to the utility income before taxes in Exhibit 4, Tab 9, page 1 is a typo. If not, please explain.

Response:

a) The reference to utility income before taxes in Exhibit 4 is a typo and should have been $966,360.

9-Staff-58
Account 1509

Ref: Exhibit 9, Tab 1, page 8 of 30
Exhibit 1, Tab 3, page 23 of 28

Preamble:
Grimsby Power is proposing to dispose the balance of account 1509 - Impacts Arising from the COVID-19 Emergency in the amount of $80,199. The Report of the OEB: Regulatory Treatment of Impacts Arising from the COVID-19 Emergency (the Report), was released dated June 17, 2021. The Report summarizes on pages 2 and 3 the rules and operations of Account 1509. Included in that summary are the following:

- The OEB will adopt a means test for recovery.
- The means test will be based on a utility's achieved regulatory return on equity (ROE) compared to its OEB-approved ROE less 300 basis points (bps). Recovery will be anchored to this ROE-based means test (i.e., no greater than the lower end of the dead band of 300 bps from a utility's approved ROE).
- The net amounts recorded in the Account are subject to a 50% recovery rate.
- The OEB will apply a separate set of rules for the costs necessary to comply with government or OEB-initiated programs aimed at providing relief to customers which is referred to as the Exceptional Pool. Those costs are eligible for a 100% recovery rate and are subject to an approved ROE plus 300 bps means test.
- For those utilities that intend to submit claims for recovery, both costs and savings are to be recorded in the Account and presented on a net basis.

Question(s):

a) Please provide an update on Grimsby Power's proposal for the Account 1509 sub-accounts in consideration of the rules for the account set out in the Report and update the evidence as necessary. For any aspects of Grimsby Power's proposal that deviates from the Report, please explain why Grimsby Power believes the deviation to be appropriate.

b) In Exhibit 1, Grimsby Power calculated the ROE for the years 2016-2019. Please file the ROE for 2020 calculated prior to making any entries into Account 1509 as specified in the OEB's Report.

c) Given Grimsby Power is seeking disposition of the 1509 sub-accounts, please:

i. provide the supporting calculations of the annual sub-account balances, broken down into categories, as appropriate, and the amount for disposition after applying the applicable recovery rate.

ii. provide discussion on the applicable aspects of the Report, such as interim/final disposition and rationale for it, causation, materiality, prudence, calculation of incremental costs and savings, etc.

d) At the first reference above, Grimsby Power is requesting the continuance of account 1509 throughout this rate-setting term. Please explain if Grimsby Power has embedded the COVID-19 related impacts into the 2022 revenue requirement. If not, please explain why not.

Response:

a) Grimsby Power has considered the rules for the account set out in the Report of the Board and agrees the comments issued by various stakeholders objecting to the OEB's proposed treatment of Account 1509. Grimsby Power understands that the report indicates the OEB will adopt a means test for recovery based on the utility's achieved regulatory return on equity and the net amount is subject to a 50% recovery rate.

b) Grimsby Power is proposing that the amount currently sought for disposition be deferred until Grimsby Power's next Cost of Service application.

c) Grimsby Power is proposing to defer the disposition until Grimsby Power's next Cost of Service application.

d) Grimsby Power is proposing to defer the disposition until Grimsby Power's next Cost of Service application.

e) Grimsby Power has not experienced any expenses that would move permanently into the OM&A related to Covid-19. Any Covid-19 related expenses are being recorded in account 1509.

9-Staff-59
Account 1592
Ref: Exhibit 9, Tab 1, page 10 of 30

Preamble:

Grimsby Power is requesting disposition of $169,193, comprised of a $165,205 principal balance and $3,988 in interest. Grimsby Power did not explain how the revenue requirement impacts are calculated and the percentage of sharing with ratepayers in Exhibit 9.

Question(s):

a) Please explain whether the amount calculated in Account 1592 is based on actual additions in the year or approved capital additions from Grimsby Power's last rebasing application and provide justification for the approach taken.

b) Please provide the calculation for the Account 1592 entries in 2018 and 2019 on both of the following bases:

   i. The difference in CCA between the calculations embedded in Grimsby Power's rates and what that calculation would have been had the AIIP rules been applied in its last rebasing application (i.e. based on approved capital additions)

   ii. The difference in CCA between the amounts claimed in 2018 and 2019 and what the claims would have been had the AIIP program not been introduced (i.e., based on actual capital additions in the year).

c) Please confirm that Grimsby Power is proposing to dispose 100% of the revenue requirement impacts to customers.

Response:

a) The principal balance of $165,205 in account 1592 is based on actual capital additions for the 2018, 2019 and 2020 taxation years.

   The principal values represent the difference between the tax benefits taking accelerated CCA into consideration and the amount of taxes built into rates. In the calculation of CCA Grimsby Power compares the actual capital additions in

each year compared to the capital additions approved in GPI's last rebasing. For example in GPI 2016 CoS 1.5 million was approved for capital additions. GPI compared the tax implications of the 1.5 million in additions compared to the actual capital spend each year.

b)

i. Please refer to calculation in Grimsby Power AIIP Comparison - Test Year

ii. The difference in CCA between the amounts claimed in 2018 and 2019 and what the claims would have been had the AIIP rules not been introduced (based on actual capital additions in each year), is summarized as follows:

- In 2018, there would have been a $78,921 change in CCA resulting in a tax impact of $20,914, or a revenue requirement of $28,454 (before carrying charges).

2018 No AIIP

Class No. [200]	2 UCC BOY [201]	3 Additions [203]	5 Proceeds* [207]	6 UCC	7 1/2 of [203] - [207] [211]	8 Reduced UCC	9 Rate % [212]	10 Recapture [213]	11 Terminal Loss [215]	12 CCA [217]	13 UCC EOY [220]	CCA As Filed	Difference
1	$ 11,311,974	$ 81,578		$ 11,393,552	$ 40,789	$ 11,352,763	4	$ -	$ -	$ 454,111	$ 10,939,441	$ 454,111	$ (0)
8	$ 419,143	$ 74,721		$ 493,864	$ 37,361	$ 456,503	20	$ -	$ -	$ 91,301	$ 402,563	$ 104,311	$ (13,010)
10	$ 301,430	373,868	$ (5,000)	$ 670,298	$ 184,434	$ 485,864	30	$ -	$ -	$ 145,759	$ 524,539	$ 145,759	$ 0
2	$ 314,257	$ -		$ 314,257	$ -	$ 314,257	6	$ -	$ -	$ 18,855	$ 295,402	$ 18,855	$ 0
45	$ 38	$ -		$ 38	$ -	$ 38	45	$ -	$ -	$ 17	$ 21	$ 17	$ 0
47	$ 8,972,190	$ 982,105		$ 9,954,295	$ 491,053	$ 9,463,242	8	$ -	$ -	$ 757,059	$ 9,197,236	$ 822,721	$ (65,662)
50	$ 18,477	$ 3,695		$ 22,172	$ 1,848	$ 20,324	55	$ -	$ -	$ 11,178	$ 10,994	$ 11,178	$ 0
12	$ 18,130	$ 25,371		$ 43,501	$ 12,686	$ 30,815	100	$ -	$ -	$ 30,816	$ 12,686	$ 31,065	$ (250)
6	$ 16,070	$ -		$ 16,070	$ -	$ 16,070	10	$ -	$ -	$ 1,607	$ 14,463	$ 1,607	$ -
95	$ -			$ -	$ -	$ -	0	$ -	$ -	$ -	$ -	$ -	$ -
	$ 21,371,709	$ 1,541,338	$ (5,000)	$ 22,908,047	$ 768,171	$ 22,139,876		$ -	$ -	**$ 1,510,703**	$ 21,397,344	$ 1,589,624	$ (78,921)
												Tax Impact	$ (20,914)
												Grossed-up	**$ (28,454)**

- In 2019, there would have been a $251,748 change in CCA resulting in a tax impact of $66,713, and a revenue requirement of $90,766 (before carrying charges).

2019 Rolled with NO Accelerated CCA Applied

	2 UCC BOY [201]	3 Additions [203]	5 Proceeds* [207]	6 UCC	7 1/2 of [203] - [207] [211]	8 Reduced UCC	9 Rate % [212]	10 Recapture [213]	11 Terminal Loss [215]	12 CCA [217]	13 UCC EOY [220]	**CCA As Filed**	**Difference**
1	**$ 10,939,441**	$ -		$ 10,939,441	$ -	$ 10,939,441	4	$ -	$ -	$ 437,578	$ 10,501,864	**$ 437,578**	$ (0)
1b	$ -	$ 10,679		$ 10,679	$ 5,340	$ 5,339	6	$ -	$ -	$ 320	$ 10,359	**$ 961**	$ (641)
8	**$ 402,563**	$ 122,597		$ 525,160	$ 61,299	$ 463,861	20	$ -	$ -	$ 92,772	$ 432,388	**$ 114,690**	$ (21,918)
10	**$ 524,539**	157,145	$ (1,000)	$ 680,684	$ 78,073	$ 602,611	30	$ -	$ -	$ 180,783	$ 499,900	**$ 227,627**	$ (46,844)
2	**$ 295,402**	$ -		$ 295,402	$ -	$ 295,402	6	$ -	$ -	$ 17,724	$ 277,677	**$ 17,724**	$ 0
45	**$ 21**	$ -		$ 21	$ -	$ 21	45	$ -	$ -	$ 9	$ 11	**$ 9**	$ 0
47	**$ 9,197,236**	$ 1,707,839	$ (24,404)	$ 10,880,671	$ 841,718	$ 10,038,953	8	$ -	$ -	$ 803,116	$ 10,077,554	**$ 929,411**	$ (126,295)
50	**$ 10,994**	$ 49,827		$ 60,821	$ 24,914	$ 35,907	55	$ -	$ -	$ 19,749	$ 41,072	**$ 47,154**	$ (27,405)
12	**$ 12,686**	$ -		$ 12,686	$ -	$ 12,686	100	$ -	$ -	$ 12,686	$ -	**$ 12,436**	$ 250
6	**$ 14,463**	$ -		$ 14,463	$ -	$ 14,463	10	$ -	$ -	$ 1,446	$ 13,017	**$ 1,446**	$ 0
54	$ -	$ 41,280		$ 41,280	$ -	$ 41,280	30	$ -	$ -	$ 12,384	$ 28,896	**$ 41,280**	$ (28,896)
95	$ -			$ -	$ -	$ -	0	$ -	$ -	$ -	$ -		
	$ 21,397,344	$ 2,089,367	$ (25,404)	$ 23,461,307	$ 1,011,344	$ 22,449,963		$ -	$ -	**$ 1,578,568**	$ 21,882,738	**$ 1,830,316**	$ (251,748)
												Tax Impact	$ (66,713)
												Grossed-up	**$ (90,766)**

c) GPI confirms that is proposing to dispose 100% of the revenue requirement impacts to customers.

9-Staff-60
PILs
Ref: PILs Workform, Tab H4, Schedule 4

Preamble:

At the reference above, cell G14 Grimsby Power states the Non-Capital Loss Carry forward Deduction was $748,421. The Non-Distribution portion of this amount was $458,212 or 61%.

Question(s):

a) Please explain how the non-distribution portion of the historical loss carry-forward was calculated.

Response:

a) The adjustment to the non-capital losses in the historical year of the PILS model represents the amount of CCA to be given back to the customer through Account 1592 (note, the adjustment to the PILS model is pre-tax).

   In summary, Grimsby Power determined that the non-capital loss carry-forward balance of $556,002 would have been lower by $458,212 if Grimsby Power did not take accelerated CCA in the 2018-2020 taxation years. The amount of $458,212 ($165,205 tax effected1), has been included in Account 1592. Refer to table 4-54 for the calculations supporting the change in CCA (based on actual additions). These calculations show that the non-capital losses in the historical years were directly impacted by the accelerated CCA taken by Grimsby Power. In other words, the non-capital loss balance is higher because of the accelerated CCA taken by Grimsby Power. As Grimsby Power has already included the benefit of the accelerated CCA impact to the customers through Account 1592, it must remove the losses resulting from the accelerated CCA, otherwise the accelerated CCA benefit would effectively be given back to the customer twice (once through Account 1592, and again through the non-capital loss balance).

9-SEC-33

[Ex.9, Tab 1, p.7] With respect to Account 1508 - Other Regulatory Assets-Sub Account OEB Cost Assessment, please provide a table that shows for each year from 2016 to 2021, the calculation of the principal balance that is included in the account.

Response:

The table below shows the calculation of the principal balance in account 1508 - Other Regulatory Assets-Sub Account OEB Cost Assessment from 2016-August 2021.

	2016	2017	2018	2019	2020	2021
OEB Cost Assessment Invoiced Amount	$ 44,964	$ 50,012	$ 47,129	$ 47,960	$ 48,037	$ 34,052
Expense Amount Built into Rates	$ 29,098	$ 29,400	$ 29,400	$ 29,400	$ 29,400	$ 22,005
Amount Booked to 1508 OEB Cost Assessment	**$ 15,866**	**$ 20,612**	**$ 17,729**	**$ 18,560**	**$ 18,637**	**$ 12,047**
Balance Forward	$ -	$ 15,866	$ 36,478	$ 54,207	$ 72,767	$ 91,404
Account Balance	**$ 15,866**	**$ 36,478**	**$ 54,207**	**$ 72,767**	**$ 91,404**	**$ 103,451**

9-SEC-34

[Ex.9, Tab 1, p.7] For each Group 2 account that the Applicant is seeking to discontinue to the account, please provide a forecast f the balance to the end of 2021, including forecast 2021 principal balance. For each account, please explain how the 2021 principal was forecast.

Response:

The table below provides the forecast of the balance at the end of 2021 for the principal amount of each of the accounts that GPI has requested discontinuation. The 2021 principal amounts include eight months of actuals and four months of forecast additions. GPI has provided and explanation of how the principal amounts were derived in the forecast period from September to December.

9–VECC-49

Reference: Exhibit 9, Tab 1, page 7

a) We are unclear as to how the balance of $95,745 was calculated. In Appendix 2-M (Regulatory Cost Schedule) the amount of $30,064 is shown as the amount estimated in 2016 for the OEB Annual Assessment (this is the same as was filed in Schedule 2-M in the prior cost of service application EB-2015-0072). The most current actuals for 2020 show Board assessment costs of $29,400 indicating that the value built into rates is slightly higher than the actual OEB invoiced costs. If this is correct please explain how a debit value of over $95k accrued over the rate plan period.
b) If the annual assessment costs in Appendix 2-M are incorrect please provide the actual OEB annual assessment costs for each year 2016 through 2020.

Response:

a) The most current costs of $29,400 in 2020 represent the amount booked to the expense account. It does not consider the amount being booked to 1508. When the quarterly invoice is received and booked $7,350 ($29,400/4=$7,350) is booked to expense and any amount above that is booked to 1508.

b) The actual OEB annual assessment costs from 2016 to 2020 are recorded in the table below.

	2016	2017	2018	2019	2020
OEB Cost Assessment	$ 44,964.00	$ 50,012.00	$ 47,129.00	$ 47,960.00	$ 48,037.00

	Interest Rate	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%		
	# of days	31	28	31	30	31	30	31	31	30	31	30	31		
Account Description		January 2021 Actual	February 2021 Actual	March 2021 Actual	April 2021 Actual	May 2021 Actual	June 2021 Actual	July 2021 Actual	August 2021 Actual	September 2021 Forecast	October 2021 Forecast	November 2021 Forecast	December 2021 Forecast	Total	Calcuation of 2021 additions in the forecast period from September - December
OEB Cost Assessment 1508															
Net Change		4,566.00			4,131.00			3,305.00			4,148.00			16,150.00	Anticipated invoice of $11,481 for OEB Cost Assessment less $7,350
Balance Forward		91,404.00	95,970.00	95,970.00	95,970.00	100,101.00	100,101.00	100,101.00	103,406.00	103,406.00	103,406.00	107,554.00	107,554.00	91,404.00	
Account Balance		95,970.00	95,970.00	95,970.00	100,101.00	100,101.00	100,101.00	103,406.00	103,406.00	103,406.00	107,554.00	107,554.00	107,554.00	107,554.00	
OEB Cost Assessment Carrying Charges															
Net Change		44.25	41.96	46.46	44.96	48.46	46.90	48.46	50.06	48.45	50.06	50.39	52.07	572.48	
Balance Forward		3,820.29	3,864.54	3,906.50	3,952.96	3,997.92	4,046.38	4,093.28	4,141.74	4,191.80	4,240.25	4,290.31	4,340.70	3,820.29	
Account Balance		3,864.54	3,906.50	3,952.96	3,997.92	4,046.38	4,093.28	4,141.74	4,191.80	4,240.25	4,290.31	4,340.70	4,392.77	4,392.77	
TOTAL OEB COST ASSESSMENT		**99,834.54**	**99,876.50**	**99,922.96**	**104,098.92**	**104,147.38**	**104,194.28**	**107,547.74**	**107,597.80**	**107,646.25**	**111,844.31**	**111,894.70**	**111,946.77**	**111,946.77**	
Asset Condition Assessment 1508															
Net Change															No anticipated additions in 2021
Balance Forward		45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	
Account Balance		45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	45,000.00	
Retail Carrying Charges															
Net Change		21.78	19.68	21.78	21.08	21.78	21.08	21.78	21.78	21.08	21.78	21.08	21.78	256.46	
Disposition														-	
Balance Forward		1,799.57	1,821.35	1,841.03	1,862.81	1,883.89	1,905.67	1,926.75	1,948.53	1,970.31	1,991.39	2,013.17	2,034.25	1,799.57	
Account Balance		1,821.35	1,841.03	1,862.81	1,883.89	1,905.67	1,926.75	1,948.53	1,970.31	1,991.39	2,013.17	2,034.25	2,056.03	2,056.03	
TOTAL Asset Condition Assessment		**46,821.35**	**46,841.03**	**46,862.81**	**46,883.89**	**46,905.67**	**46,926.75**	**46,948.53**	**46,970.31**	**46,991.39**	**47,013.17**	**47,034.25**	**47,056.03**	**47,056.03**	

Account Description	January 2021 Actual	February 2021 Actual	March 2021 Actual	April 2021 Actual	May 2021 Actual	June 2021 Actual	July 2021 Actual	August 2021 Actual	September 2021 Forecast	October 2021 Forecast	November 2021 Forecast	December 2021 Forecast	Total	Calcuation of 2021 additions in the forecast period from September - December
Interest Rate	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%	0.57%		
# of days	31	28	31	30	31	30	31	31	30	31	30	31		
Pole Attachment Revenue Variance														
Net Change	(6,809.32)	(6,809.32)	(6,809.32)	(6,809.32)	(6,809.31)	(6,809.32)	(6,809.31)	(6,809.32)	(6,809.32)	(6,809.32)	(6,809.32)	(6,809.32)	(81,711.82)	Previous 8 months Average
Balance Forward	(166,335.61)	(173,144.93)	(179,954.25)	(186,763.57)	(193,572.89)	(200,382.20)	(207,191.52)	(214,000.83)	(220,810.15)	(227,619.47)	(234,428.79)	(241,238.11)	(166,335.61)	
Account Balance	(173,144.93)	(179,954.25)	(186,763.57)	(193,572.89)	(200,382.20)	(207,191.52)	(214,000.83)	(220,810.15)	(227,619.47)	(234,428.79)	(241,238.11)	(248,047.43)	(248,047.43)	
Retail Carrying Charges														
Net Change	(80.52)	(75.71)	(87.12)	(87.50)	(93.71)	(93.88)	(100.30)	(103.60)	(103.45)	(110.19)	(109.83)	(116.79)	(1,162.60)	
Disposition													-	
Balance Forward	(2,468.28)	(2,548.80)	(2,624.51)	(2,711.63)	(2,799.13)	(2,892.84)	(2,986.72)	(3,087.02)	(3,190.62)	(3,294.07)	(3,404.26)	(3,514.09)	(2,468.28)	
Account Balance	(2,548.80)	(2,624.51)	(2,711.63)	(2,799.13)	(2,892.84)	(2,986.72)	(3,087.02)	(3,190.62)	(3,294.07)	(3,404.26)	(3,514.09)	(3,630.88)	(3,630.88)	
TOTAL Pole Attachment Revenue Variance	**(175,693.73)**	**(182,578.76)**	**(189,475.20)**	**(196,372.02)**	**(203,275.04)**	**(210,178.24)**	**(217,087.85)**	**(224,000.77)**	**(230,913.54)**	**(237,833.05)**	**(244,752.20)**	**(251,678.31)**	**(251,678.31)**	
RCVA - Retail 1518														
Revenue	(1,070.40)	(1,107.10)	(1,097.14)	(1,091.54)	(1,089.88)	(1,082.20)	(1,077.22)	(1,072.24)	(1,085.97)	(1,087.91)	(1,085.51)	(1,084.06)	(13,031.17)	Previous 8 months Average
Expense	453.02	446.02	424.99	432.00	509.85	482.27	425.68	418.11	448.99	448.49	448.80	451.77	5,389.99	Previous 8 months Average
Net Change	(617.38)	(661.08)	(672.15)	(659.54)	(580.03)	(599.93)	(651.54)	(654.13)	(636.97)	(639.42)	(636.71)	(632.28)	(7,641.17)	
Balance Forward	23,618.58	23,001.20	22,340.12	21,667.97	21,008.43	20,428.40	19,828.47	19,176.93	18,522.80	17,885.83	17,246.41	16,609.69	23,618.58	
Account Balance	23,001.20	22,340.12	21,667.97	21,008.43	20,428.40	19,828.47	19,176.93	18,522.80	17,885.83	17,246.41	16,609.69	15,977.41	15,977.41	
Retail Carrying Charges														
Net Change	11.43	10.06	10.82	10.15	10.17	9.57	9.60	9.28	8.68	8.66	8.08	8.04	114.54	
Balance Forward	1,436.54	1,447.97	1,458.03	1,468.85	1,479.00	1,489.17	1,498.74	1,508.34	1,517.62	1,526.30	1,534.96	1,543.04	1,436.54	
Account Balance	1,447.97	1,458.03	1,468.85	1,479.00	1,489.17	1,498.74	1,508.34	1,517.62	1,526.30	1,534.96	1,543.04	1,551.08	1,551.08	
TOTAL RETAIL	**24,449.17**	**23,798.15**	**23,136.82**	**22,487.43**	**21,917.57**	**21,327.21**	**20,685.27**	**20,040.42**	**19,412.13**	**18,781.37**	**18,152.73**	**17,528.49**	**17,528.49**	
RCVA - Service Transaction Requests 1548														
Revenue	(17.00)	(4.16)	(0.52)	(4.68)	(1.56)	(2.08)	(2.60)	(2.60)	(2.60)	(2.38)	(2.64)	(2.35)	(45.17)	Previous 8 months Average
	(9.00)	(6.24)	(1.04)	(7.28)	(3.12)	(5.20)	(4.16)	(5.20)	(4.61)	(4.37)	(4.85)	(4.50)	(59.57)	Previous 8 months Average
Expense	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	1,800.00	Previous 8 months Average
Net Change	124.00	139.60	148.44	138.04	145.32	142.72	143.24	142.20	142.79	143.25	142.51	143.15	1,695.26	
Balance Forward	13,614.01	13,738.01	13,877.61	14,026.05	14,164.09	14,309.41	14,452.13	14,595.37	14,737.57	14,880.36	15,023.61	15,166.12	13,614.01	
Account Balance	13,738.01	13,877.61	14,026.05	14,164.09	14,309.41	14,452.13	14,595.37	14,737.57	14,880.36	15,023.61	15,166.12	15,309.27	15,309.27	
Retail Carrying Charges														
Net Change	6.59	6.01	6.72	6.57	6.86	6.70	7.00	7.07	6.90	7.20	7.04	7.34	82.00	
Balance Forward	788.14	794.73	800.74	807.46	814.03	820.89	827.59	834.59	841.66	848.56	855.76	862.80	788.14	
Account Balance	794.73	800.74	807.46	814.03	820.89	827.59	834.59	841.66	848.56	855.76	862.80	870.14	870.14	
TOTAL STRs	**14,532.74**	**14,678.35**	**14,833.51**	**14,978.12**	**15,130.30**	**15,279.72**	**15,429.96**	**15,579.23**	**15,728.92**	**15,879.37**	**16,028.92**	**16,179.41**	**16,179.41**	