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ESA # 7012854

February 8, 2021

Ms. Christine E. Long
Registrar
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: EB-2020-0061 Application for May 1, 2021 Electricity Distribution Rates
Wellington North Power Inc.
Applicant's Interrogatory Responses

In accordance with Procedural Order No. 1, please find attached Wellington North Power Inc.'s (the Applicant) responses to both OEB staff's and Vulnerable Energy Consumer's Coalition's (VECC) interrogatories in the above noted proceeding. OEB staff and VECC have been copied in on this filing.

A copy of the Applicant's interrogatory responses, together with supporting document, has been filed on the OEB's web portal.

Respectfully submitted,

Original signed by

Richard Bucknall

Manager of Customer Service & Regulatory Affairs,

Wellington North Power Inc.

c.c.	Applicant's Counsel:	Mr. Michael Buonaguro
	Applicant's Rate Consultant:	Ms. Manuela Ris-Schofield
	VECC:	Mr. John Lawford, Mr. Mark Garner and Mr. Bill Harper
	OEB Counsel	Mr. Lawren Murray
	OEB Case Manager:	Mr. Donald Lau

Wellington North Power Inc.'s (Applicant) Interrogatory Responses to

Vulnerable Energy Consumers Coalition (VECC) Interrogatories and OEB staff.

2021 Electricity Distribution Rates Application

EB-2020-0061

February 8, 2021

Contents

Summary 3
Exhibit 1 – Administration 6
Exhibit 2 – Rate Base 23
Exhibit 3 – Operating Revenue 83
Exhibit 4 – Operating Costs 107
Exhibit 5 – Cost of Capital 142
Exhibit 7 – Cost Allocation 146
Exhibit 8 – Rate Design 177
Exhibit 9 – Deferral and Variance Accounts 196

Summary

As per Procedural Order number 1 issued on January 4th 2021:

- OEB Staff served a total of 100 interrogatories on all parties on January 19th 2021.
- VECC served 61 interrogatories on all parties on January 21st.

The table below groups the number of interrogatories served on the Applicant, Wellington North Power Inc. (WNP):

Section	Interrogatories	%
Administration	11	7%
Rate Base	9	6%
DSP	40	25%
Finance	14	9%
Load Forecast	12	7%
OM&A	24	15%
LRAMVA	4	2%
Cost Allocation	11	7%
Rate Design	15	9%
Def/Var Accounts	21	13%
Total	**161**	**100%**

The Applicant has reviewed all interrogatories and, in this response document, has diligently replied to each interrogatory. In responding to the interrogatories, WNP has organized this document into the following sections and, where possible, grouped the OEB staff and VECC questions:

- Exhibit 1 – Administration
- Exhibit 2 – Rate Base
- Exhibit 3 – Operating Revenue
- Exhibit 4 – Operating Costs
- Exhibit 5 – Cost of Capital
- Exhibit 7 – Cost Allocation
- Exhibit 8- Rate Design
- Exhibit 9 – Deferral and Variance Accounts.

In addition, and as required, WNP has updated OEB models / work forms to reflect the changes and amendments as discussed in this interrogatory response document. The amended OEB models / work forms have been filed on the OEB's web portal and include:

- 2021 Cost Allocation Model v1.0 EB-2020-0061 IR

- 2021 DVA Continuity Schedule EB-2020-0061 IR
- 2021 Filing Requirements Chapter 2 Appendices EB-2020-0061 IR
- 2021 Filing Requirements Chapter 5 Appendices EB-2020-0061 IR
- 2021 GA Analysis Workform EB-2020-0061 IR
- 2021 OEB LRAMVA Work Form EB-2020-0061 IR
- 2021 Rev Ret Workform EB-2020-0061 IR
- 2021 RTSR Workform EB-2020-0061 IR
- 2021 Tariff and Bill Impact Model EB-2020-0061 IR
- 2021 Test Year Income Tax PILS EB-2020-0061 IR

Finally, the Applicant has filed additional supporting evidence as well as scenarios (as requested in the certain interrogatories) on the OEB's web portal.

Overview of Changes:

Through the course of responding to interrogatories, there have been updates which have resulted in changes to Cost of Capital, Rate Base, Capital Expenditures, Operating Expenses and Revenue Requirement compared to the initial Application as filed on October 30th 2020. The table below summarizes the changes made:

Area	Action	Interrogatory	Initial Application	Latest Update
Cost of Capital	Updated to reflect 2021 Cost of Capital Parameters as issued by OEB	5-Staff-66	Reg Return on Capital: $699,167	Reg Return on Capital: $694,745
Rate Base & Working Capital	Updated Cost of Power to reflect RPP Price Report Nov 1, 2020 to Oct 31, 2021 Updated RTSR rates for 2021 (EB-2020-0030) Updated Asset Continuity Schedule	2-Staff-41 2-Staff-43 8-Staff-74 2-Staff-7 2-Staff-38	Rate Base: $12,301,661 Working Capital: $1,059,680 Depreciation: $500,023	Rate Base: $12,465,815 Working Capital: $1,073,006 Depreciation: $501,284
Other Revenue	Updated to reflect 2021 Retail Service Charges	3-Staff-48 3-VECC-28	Other Revenue: $135,330	Other Revenue: $135,460
OM&A	Reduction to one intervenor	4-Staff-54	OM&A: $1,915,000	OM&A: $1,912,000
Load Forecast	Amended Load Forecast to adjust CDM variable	3-VECC-26 3-VECC-27	Base Rev Requirement: $2,996,360	Base Rev Requirement: $2,990,069

Cost Allocation:

Through responding to interrogatories, WNP has updated the proposed Revenue to Cost ratios for the 2021 Test Year. The table below shows the update ratios compared to the initial application as filed on October 30th 2020:

	Initial Application		Updated	
Customer Class Name	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Calculated R/C Ratio**	**Proposed R/C Ratio**
Residential	98.38	93.79	101.19%	95.78%
GS < 50 kW	120.37	120.00	126.47%	120.00%
GS 50 to 999 kW	107.38	107.38	100.00%	99.98%
GS 1,000 to 4,999 kW	90.23	100.00	83.25%	99.82%
USL	174.73	120.00	179.42%	120.00%
Sentinel Lighting	98.38	98.38	99.72%	99.73%
Street Lighting	51.56	100.00	46.05%	80.00%

The primary reasons for the revised Revenue to Cost ratios relate to the Applicant's response to interrogatories, particularly:

- 7-VECC-45.
- 7-VECC-46.
- 7-Staff-70.
- 7-Staff-72

Bill Impact:

The table below illustrates the latest bill impact as a consequence of the revisions made to data and information through responding to interrogatories:

	A		B		C		Total Bill	
	$	%	$	%	$	%	$	%
Residential	$ 1.33	3.50%	$ 2.97	6.33%	$ 3.24	5.70%	$ 2.62	2.07%
General Service <50kW	$ 2.19	2.58%	$ 6.57	6.13%	$ 7.31	5.60%	$ 5.90	1.84%
General Service 50-999kW	$ 57.03	8.42%	$ 146.07	18.09%	$ 164.91	11.74%	$ 156.61	1.91%
General Service 1000-4999kW	$ 2,489.27	31.49%	$ 4,229.56	43.66%	$4,485.60	25.32%	$ 4,585.30	3.60%
Unmetered Scattered Load	$ (10.35)	-15.92%	$ (9.24)	-13.62%	$ (9.14)	-12.90%	$ (7.43)	-8.69%
Sentinel Lighting	$ 35.65	10.88%	$ 56.29	16.93%	$ 56.85	16.24%	$ 46.16	15.50%
Street Lighting	$ 1,821.28	110.08%	$ 3,764.25	222.03%	$3,770.12	200.59%	$ 4,248.39	89.38%

** Rate Riders are for 24 months disposition period.*

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 2021 Electricity Distributor Rate Applications webpage.

Wellington North Power Inc.'s (WNP) Response:

As directed, Wellington North Power Inc. (WNP) has updated the 2021 Revenue Requirement Work Form (RRWF) to reflect corrections or adjustments and has documented the information relating to the change in the worksheet "14. Tracking Sheet".

Wellington North Power Inc. (WNP) has filed an updated set of models encompassing the corrections or adjustments on the OEB's web-portal to support the Applicant's interrogatory responses.

1-Staff-2

Letters of Comment

Following publication of the Notice of Application, the OEB received one letter of comment. Section 2.1.7 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters or comments, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letters of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

WNP's Response:

The letter of comment filed with the OEB as noted in OEB staff's interrogatory 1-Staff-2 was also e-mailed to WNP on December 5, 2020. WNP e-mailed a response letter to the customer on December 10, 2020.

As required, a copy of the distributor's response letter that was sent to the customer was filed by WNP on the OEB's web portal on the same day, December 10, 2020.

1-Staff-3

COVID-19

Ref 1: Exhibit 1, 1.4.1

Wellington North Power has stated that it has not taken into consideration the effect and/or impact of the COVID-19 Pandemic in the application. Wellington North Power stated that forecasted Capital Expenditures and Operations, Maintenance, and Administration costs in 2020 and 2021 are based on COVID-19 free data. Wellington North Power is recording costs related to COVID-19 in Account 1509 Impacts Arising from the COVID-19 Emergency.

a) Please provide a detailed breakdown of the amounts included in each of the Account 1509 sub-accounts.
    i. Please provide a forecast of the amounts in each sub-account at the end of 2020.
    ii. Please explain the types of costs/savings/lost revenues and the amounts associated that Wellington North Power has recorded in the sub- account(s).
b) Please confirm that Wellington North Power is proposing to continue using Account 1509 even if future OEB guidance that is issued for the account as a result of the consultation is different (e.g. the OEB finds that the deferral account for the COVID-19 impacts is effective until the end of 2020).
    i. If so, please clarify the effective time period for which Wellington North Power proposes to use the account and Wellington North Power's underlying rationale.

WNP's Response:

WNP recognizes that this has been a challenging season for our customers. Many residential and business customers continue face financial hardships including but not limited to job loss, difficulty with cash flow and lower income. As a result, WNP's Board and Management have decided to not seek recovery of costs or lost revenue associated with COVID as recorded in Account 1509.

a) WNP's approach to 1509 expenses has changed since the filing its' Cost of Service application. While there certainly was some effect on profitability due to extra expenses, and decreased revenue, it is unreasonable to expect that WNP must transition through this time unaffected. With this perspective, the only amount in WNP's 1509 accounts is the $13,534.83 remaining to be collected during January to April 2021 in the accounts recording the lost revenue from the delayed rate increase.
   None of the COVID-19 expenses or lost revenue due to shutdowns from 2020 will be entered into 1509.

b) WNP is not proposing to use the 1509 accounts after the lost revenue from the delayed rate increase is recovered in the six month rate rider which began Nov 1, 2020.

1-Staff-4

Customer Engagement

Ref 1: Exhibit 1- Appendix F – Customer Engagement Survey

In section 7 of the customer engagement survey it showed that only 46.1% of residential customers and 42% of small businesses think it's most important to continue with current investment spending levels to balance reliability and rates.

a) Please breakdown the table provided in section 7 of the customer engagement survey by each statement and the number of responses received between "the most important" to the "least important"
b) How did Wellington North Power define to the customer what it means to balance electricity reliability and rates? If Wellington North Power did not define that to the customer, how does Wellington North Power define it for the purpose of business planning?
c) For each of the statements provided in section 7, did Wellington North Power provide the customer with a quantum of the rate increase/decrease? If not, why not?
d) How has Wellington North Power accessed the acceptable rate increase customers are willing to accept?
e) How has Wellington North Power accessed the reliability a customer is willing to accept?
f) "Pay lower electricity rates with reduced reliability" is the second most important item to residential customers. Please provide Wellington North Power's plan for lower rates and the reliability impacts it anticipates as a result. If there is no such plan, please explain why.

WNP's Response:

WNP prepared and managed this survey rather than retaining the services of a professional 3rd - party market research company. WNP was attempting to minimize costs to rate-payers for preparing a DSP and gather general feedback from its customers. Once survey results had been collated, the utility planned to host community meeting in May 2020 to present proposed capital plans, operating budgets and bill impact implications and obtain feedback from customers.

a) Please see below for information as requested:

Residential Customer Survey: Price and Reliability – Responses as a Percentage

Statement	Most Important 1	2	3	4	Least Important 5	No Answer	Total
Pay lower electricity rates with reduced reliability	18.7%	18.7%	29.7%	9.1%	22.8%	0.9%	100%
Pay higher electricity rates with increased reliability	8.2%	16.0%	37.9%	10.5%	26.0%	1.4%	100%
Increase spending to accommodate grid modernization	12.8%	18.3%	42.9%	14.2%	11.0%	0.9%	100%
Pay higher electricity rates to pay for burying cables	8.7%	11.4%	21.9%	20.1%	37.0%	0.9%	100%
Continue with current investment spending levels to balance electricity reliability and rates	46.1%	20.5%	22.4%	5.5%	4.6%	0.9%	100%

Residential Customer Survey: Price and Reliability – Number of Responses

Statement	Most Important 1	2	3	4	Least Important 5	No Answer	Total
Pay lower electricity rates with reduced reliability	41	41	65	20	50	2	219
Pay higher electricity rates with increased reliability	18	35	83	23	57	3	219
Increase spending to accommodate grid modernization	28	40	94	31	24	2	219
Pay higher electricity rates to pay for burying cables	19	25	48	44	81	2	219
Continue with current investment spending levels to balance electricity reliability and rates	101	45	49	12	10	2	219

Small Business Customer Survey: Price and Reliability – Responses as a Percentage

Statement	Most Important 1	2	3	4	Least Important 5	No Answer	Total
Pay lower electricity rates with reduced reliability	25%	8%	42%	8%	17%	0%	100%
Pay higher electricity rates with increased reliability	0%	8%	42%	33%	17%	0%	100%
Increase spending to accommodate grid modernization	8%	25%	42%	17%	8%	0%	100%
Pay higher electricity rates to pay for burying cables	0%	0%	17%	33%	50%	0%	100%
Continue with current investment spending levels to balance electricity reliability and rates	42%	17%	17%	25%	0%	0%	100%

Small Business Customer Survey: Price and Reliability – Number of Responses

Statement	Most Important 1	2	3	4	Least Important 5	No Answer	Total
Pay lower electricity rates with reduced reliability	3	1	5	1	2	0	12
Pay higher electricity rates with increased reliability	0	1	5	4	2	0	12
Increase spending to accommodate grid modernization	1	3	5	2	1	0	12
Pay higher electricity rates to pay for burying cables	0	0	2	4	6	0	12
Continue with current investment spending levels to balance electricity reliability and rates	5	2	2	3	0	0	12

Industrial & Commercial Customer Survey: Price and Reliability – Responses as a Percentage

Statement	Most Important 1	2	3	4	Least Important 5	No Answer	Total
Pay lower electricity rates with reduced reliability	0%	0%	0%	0%	100%	0%	100%
Pay higher electricity rates with increased reliability	0%	33%	33%	0%	33%	0%	100%
Increase spending to accommodate grid modernization	0%	33%	67%	0%	0%	0%	100%
Pay higher electricity rates to pay for burying cables	0%	0%	0%	33%	67%	0%	100%
Continue with current investment spending levels to balance electricity reliability and rates	33%	33%	33%	0%	0%	0%	100%

Industrial & Commercial Customer Survey: Price and Reliability – Number of Responses

Statement	Most Important 1	2	3	4	Least Important 5	No Answer	Total
Pay lower electricity rates with reduced reliability					3		3
Pay higher electricity rates with increased reliability		1	1		1		3
Increase spending to accommodate grid modernization		1	2				3
Pay higher electricity rates to pay for burying cables				1	2		3
Continue with current investment spending levels to balance electricity reliability and rates	1	1	1				3

b) WNP did not define for the customer what it means to balance electricity reliability and rates. As noted in its' DSP and application, WNP had planned to host a community meeting in May 2020 to present survey results to attendees which would have included the opportunity to answer such questions from our customers.

The utility posted the survey on its' website as well as a summary of the rate application, informed customers this information was available using social media and a bill insert. To date, WNP has received no questions or follow-up comments from our customers about the information posted on the utility's website.

WNP acknowledges that its Capital Expenditure requirements need to be balanced against the requirements of its' customers. In preparing and maintaining its 5 year rolling capital plan, the LDC always considers the benefit versus the cost and also takes into consideration the opportunity cost (i.e. the cost of not doing the project). These are challenging considerations to address, with the LDC taking into account the bill impact to the customers, the affordability of the company financing the investment, how many customers will benefit and the implications if there is no investment made.

c) WNP did not provide the customer with a quantum of the rate increase/decrease. As noted in its DSP and application, WNP had planned to host a community meeting in May 2020 to present capital plans and the proposed implication to customers' bills which would have included the opportunity to answer such questions from the attendees.

In the statements contained in the survey, the LDC did not provide a quantum because, in WNP's opinion, if the LDC had provided constraints, it may have minimized customers' feedback and could be perceived as the utility driving a particular project or spend for its own purpose. If we understand the customers' wishes, then the LDC can look at feasibility as well as prioritization and actual cost impact.

d) As per responses to b) and c), the utility was planning to host a community meeting in May 2020, from which the WNP could have assessed, from the attendees, whether the proposed rate change would be acceptable to our customers.

e) To date, the utility has received no complaints about reliability. WNP strives to maintain reliability within the 5-year historic SAIDI and SAIFI targets as set by the regulator.

f) WNP does not have a plan for "*pay lower electricity rates with reduced reliability*" because:
   - For residential customers, this represented 18.7% of all respondents (i.e. 41 customers from 215). The majority of respondents who participated in the survey overwhelming opted for "*Continue with current investment spending levels to balance electricity reliability and rates*" (46.1%). In WNP's opinion, preparing a plan to address the needs of such a small subset portion of the residential customer-base is an unproductive use of time and resources.
   - The responses from other customer classes, namely Small Business and Industrial & Commercial customers want their utility to "*Continue with current investment spending levels to balance electricity reliability and rates*" which is consistent with the most popular statement as voted by the Residential customers who participated in the survey.

1-Staff-5

Customer Engagement Survey

Ref 1: Exhibit 1 – Appendix 1F - Customer Engagement Survey

The customer engagement survey included results for "rating of service provided" and "company profile".

a) Please provide the results in which customers disagreed or undecided with the statement in the survey.

The customer engagement survey also included results for "investment priorities".

b) Was there a preamble given to Wellington North Power customers, to give them more context, prior to asking the question "What are your investment priorities when planning the hydro infrastructure?" If not, why not?

c) Are the capital investment impacts the same for each of the investments presented? If not, how is it a fair comparison between the priorities?

WNP's Response:

WNP prepared and managed this survey rather than retaining the services of a professional 3rd - party market research company. WNP was attempting to minimize costs to rate-payers for preparing a DSP and gather general feedback from its customers. Once survey results had been collated, the utility was planning to host community meeting in May 2020 to present proposed capital plans, operating budgets and bill impact implications and obtain feedback from customers.

a) Please refer to the tables below for the information as requested

Residential Survey – Rating of Service:

Statement	Agree	Disagree	Undecided	No Answer	Total
Provide consistent reliable electricity	217	1	1	0	219
Delivers on its service to customers	213	1	4	1	219
Accurate billing	201	6	12	0	219
Quickly handles outages	194	3	21	1	219
Makes electricity safety a priority	191	0	25	3	219
Uses responsible environmental practices	162	0	56	1	219
Efficient at managing the electric system	181	1	33	4	219
Provides excellent quality service	208	1	9	1	219

Residential Survey – Company Profile:

	Agree	Disagree	Undecided	No Answer	Total
Respected in the Community	202	1	15	1	219
Maintain high standards of business ethics	193	1	23	2	219
A leader in promoting energy conservation	156	5	54	4	219
Keeps it promises to customers and community	173	2	41	3	219
Is a socially responsible company	172	1	44	2	219
Is a trusted and trustworthy company	196	1	21	1	219
Operates a cost-effective hydro system	146	15	56	2	219
Having a local company is a benefit	202	1	14	2	219

Small Business Survey – Rating of Service:

Statement	Agree	Disagree	Undecided	No Answer	Total
Provide consistent reliable electricity	11	0	1	0	12
Delivers on its service to customers	11	0	1	0	12
Accurate billing	9	1	2	0	12
Quickly handles outages	12	0	0	0	12
Makes electricity safety a priority	9	0	3	0	12
Uses responsible environmental practices	7	0	5	0	12
Efficient at managing the electric system	8	1	3	0	12
Provides excellent quality service	11	0	1	0	12

Small Business Survey – Company Profile:

	Agree	Disagree	Undecided	No Answer	Total
Respected in the Community	11	0	1	0	12
Maintain high standards of business ethics	11	1	0	0	12
A leader in promoting energy conservation	9	0	3	0	12
Keeps it promises to customers and community	9	0	3	0	12
Is a socially responsible company	8	0	4	0	12
Is a trusted and trustworthy company	11	1	0	0	12
Operates a cost-effective hydro system	7	2	3	0	12
Having a local company is a benefit	11	0	1	0	12

Industrial & Commercial Survey – Rating of Service:

Statement	Agree	Disagree	Undecided	No Answer	Total
Provide consistent reliable electricity	3				3
Delivers on its service to customers	3				3
Accurate billing	3				3
Quickly handles outages	3				3
Makes electricity safety a priority	3				3
Uses responsible environmental practices	3				3
Efficient at managing the electric system	3				3
Provides excellent quality service	3				3

Industrial & Commercial Survey – Company Profile:

	Agree	Disagree	Undecided	No Answer	Total
Respected in the Community	2		1		3
Maintain high standards of business ethics	2		1		3
A leader in promoting energy conservation	2		1		3
Keeps it promises to customers and community	2		1		3
Is a socially responsible company	1		2		3
Is a trusted and trustworthy company	2		1		3
Operates a cost-effective hydro system	3				3
Having a local company is a benefit	3				3

b) There was no preamble provided to customers who participated in the survey. At the time, WNP wanted to gauge customers' responses based on the statements provided. However, upon reflection, if the utility repeated this activity, then WNP would provide some context.

c) The capital investment impacts are not the same for each of the investments included in the customer surveys.
The purpose of this question was to gather feedback from customers as to what were their preferences and priorities if there were no financial or resource constraints. In WNP's opinion, if the LDC had provided constraints, it may have minimized customers' feedback and could be perceived as the utility driving a particular project or spend for its own purpose. If we

understand the customers' wishes, then the LDC can look at feasibility as well as prioritization and actual cost impact.

1.0-VECC-1

Reference: Exhibit 1, Table -11, page 43

a) Please update Table 11 (2021 Parameters vs 2016 Parameters) adding a new column to show the results with the Board's updated cost of capital numbers (Nov 9, 2020) and any changes made as a result of the responses to the interrogatories.

WNP's Response:

a) WNP has recreated Table 11 from Exhibit 1 below and added columns to show the results achieved by:

i. Applying the Board's issued 2021 Cost of Capital Parameters (November 9th 2020) and;

ii. Changes made as a result of responses to interrogatories.

As filed in Initial Application (October 30, 2020)				2021 Using 2021 Parameters	2021 Parameters and Changes from Responses to IRs
Particular	**2016**	**2021**	**Diff**		
Long Term Debt	4.02%	3.87%	-0.15%	3.87%	3.87%
Short Term Debt	1.65%	2.75%	1.10%	1.75%	1.75%
Return on Equity	9.19%	8.52%	-0.67%	8.34%	8.34%
Weighted Debt Rate	3.86%	3.79%	-0.07%	3.73%	3.73%
Regulated Rate of Return	**5.99%**	**5.68%**	**-0.31%**	**5.57%**	**5.57%**
Controllable Expenses	$1,736,909	$1,932,500	$195,591	$1,932,500	$1,929,500
Power Supply Expense	$14,081,514	$12,196,563	$1,884,951	$12,196,563	$12,377,244
Total Eligible Distribution Expenses	$15,818,423	$14,129,063	$1,689,359	$14,129,063	$14,306,744
Working Capital Allowance Rate	7.50%	7.50%	0.00%	7.50%	7.50%
Total Working Capital Allowance ("WCA")	**$1,186,382**	**$1,059,680**	**-$126,702**	**$1,059,680**	**$1,073,006**
Fixed Asset Opening Bal Bridge Year	$7,683,811	$11,228,623	$3,544,812	$11,228,623	$11,379,160
Fixed Asset Ending Bal Test Year	$8,847,868	$11,255,340	$2,407,472	$11,255,340	$11,406,459
Average Fixed Asset	$8,265,840	$11,241,982	$2,976,142	$11,241,982	$11,392,809
Working Capital Allowance	$1,186,382	$1,059,680	-$114,902	$1,059,680	$1,073,006
Rate Base	**$9,452,221**	**$12,301,661**	**$2,849,440**	**$12,301,661**	**$12,465,815**
Regulated Rate of Return	5.99%	5.68%	-0.31%	5.57%	5.57%
Regulated Return on Capital	**$566,491**	**$699,167**	**$132,677**	**$686,254**	**$694,745**
Deemed Interest Expense	$219,027	$279,927	$60,900	$275,477	$278,885

As filed in Initial Application (October 30, 2020)				2021 Using 2021 Parameters	2021 Parameters and Changes from Responses to IRs
Particular	**2016**	**2021**	**Diff**		
Deemed Return on Equity	$347,464	$419,241	$71,777	$$410,777	$415,860
OM&A	$1,722,909	$1,918,500	$195,591	$1,918,500	$1,915,500
Depreciation Expense	$365,779	$500,023	$134,244	$500,023	$501,284
Property Taxes	$14,000	$14,000	$0	$14,000	$14,000
PILs	$0	$0	$0	$0	$0
Revenue Offset	$130,105	$135,330	$5,225	$135,330	$135,460
Revenue Requirement	**$2,539,073**	**$2,996,360**	**$457,287**	**$2,982,789**	**$2,990,069**

For WNP's 2021 OM&A, the accounts are "clean' and free of COVID costs, i.e. the LDC has not projected for an increase costs as a result of the COVD pandemic such as increase frequency of office cleaning, disinfectant and PPE obligations. WNP's 2021 OMA projects are based on a "business as normal" operating environment.

1.0-VECC-2

Reference: Exhibit 1, page 62, Table 37 page 83 / page 119 (Business Plan page 23)

a) Please confirm (or correct) that no third-party customer survey has been completed by WHP since 2018.
b) Please confirm (or correct) that the Customer Satisfaction Survey Results shown in TABLE 37-WNP's Scorecard for 2017 and 2019 are based on the prior years' surveys.
c) What was the cost of the 2018 survey?
d) Who undertook the customer survey discussed at page 23 of the Business Plan?

WNP's Response:

a) WNP confirms the most recent 3rd- party Customer Satisfaction survey was conducted in 2018.

b) WNP confirms that, in the utility's Scorecard as represented in Table 37 of Exhibit 1, the Customer Satisfaction results are for years 2016 and 2018.

c) The cost of 2018's Customer Satisfaction Survey was $8,432 (before HST).
WNP uses a 3rd party to conduct both the Customer Satisfaction Survey and the Public Safety Electrical Awareness Survey to meet the OEB's survey requirements.

d) The *"Customer Survey – Cost of Service Application"* survey as discussed on page 23 of the Business Plan was undertaken by the Applicant, WNP. The survey questions were prepared by WNP and were available to customers to complete by accessing using the LDC's website; accessing on-line through Survey Monkey™; available at the office counter for walk-in customers; and e-mailed directly to Industrial & Commercial contacts.

1.0-VECC-3

Reference: Exhibit 1, page 68 / Exhibit 2 Appendix 2A, DSP PDF pg. 101

a) What is the lowest cost solution identified by WHP to provide outage information to its customers?

b) Please explain what steps are being taken to implement a SMS Text messaging service for outage notification (or other solution).

c) Does WNP offer any form of subscription/notification service to its customers?

WNP's Response:

a) Other than the informal quote as offered by a vendor in 2018 as mentioned in the DSP (Exhibit 2A, page 101) under section *"5.2.2b Customers – Final Deliverable"*, to date, the Applicant has not explored what options are available. As per page 101 of the DSP:

> *"WNP has not included this item in its capital investment program for 2021-2025 due to having no cost estimates or scope of work available; however during this DSP period, the LDC will identify a solution and circle back with customers to determine if this is still a requirement"*

Therefore, the LDC is unable to advise what the lowest cost-solution is at this time.

b) As per page 101 of the DSP:

> *"…the utility will start exploring what "outage map" solutions exist and whether there are other alternatives (e.g. SMS text messaging to customers of outages and restoration times)"*.
> At this time, the LDC has yet to start exploring options and therefore is unable to explain the steps necessary to implement a solution. As noted in the DSP, "*the LDC will identify a solution and circle back with customers to determine if this is still a requirement"*.

c) No, WNP does not currently offer a power outage subscription/notification service to its customers.

1.0-VECC-4

Reference: Exhibit 1, page 74

a) Please explain the nature of the April 12, 2018 outage that affected 25% of the customer base.

WNP's Response:

a) On April 12th 2018 at approx. 9:07 am, a 46kV solid blade in-line switch failed (cause code "5. Defective Equipment") causing a power outage to 807 customers. The equipment was replaced by WNP and power was restored to the affected customers by approx. 9:22 am (approx. 15 minutes after the start of the outage).

1.0-VECC-5

Reference: Exhibit 1, Table 39, page 86

a) Please update Table 39 to show 2020 (unaudited) results.

WNP's Response:

a) WNP has recreated "Table 39 – Profit and Loss Table" from Exhibit 1 below and has updated 2020 to show unaudited values for the 2020 Bridge Year:

Particulars	**Board Approved 2016**	**Actual 2016**	**Actual 2017**	**Actual 2018**	**Actual 2019**	**Unaudited 2020**	**Projected 2021**
WCA							
Cost of Power	14,081,514	12,536,742	11,574,763	11,109,584	11,362,446	12,197,118	12,377,244
WCA Rate	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%
Working Capital Allowance	1,186,382	1,072,290	998,190	962,922	989,802	1,056,715	1,073,006
Utility Income							
Distribution Revenues	2,538,073	2,594,322	2,505,835	2,569,002	2,618,786	2,652,941	2,990,069
Other Revenue	130,104	127,027	145,241	160,679	173,002	127,610	135,460
Total Operating Revenues	**2,668,177**	**2,721,349**	**2,651,077**	**2,729,681**	**2,791,789**	**2,780,551**	**3,125,519**
OM&A Expenses	1,722,909	1,744,054	1,718,058	1,713,234	1,819,082	1,875,118	1,915,500
Depreciation & Amortization	365,779	365,478	407,729	424,389	441,385	439,306	501,284
Property Taxes	14,000	13,493	13,282	12,892	12,560	14,000	14,000
Total Costs & Expenses	**2,102,688**	**2,123,026**	**2,139,069**	**2,150,515**	**2,273,027**	**2,328,424**	**2,430,784**
Deemed Interest Expenses	218,794	198,269	215,007	213,595	208,541	236,124	278,885
Total Expenses	**2,321,481**	**2,321,295**	**2,354,076**	**2,364,110**	**2,481,568**	**2,564,548**	**2,709,669**
Utility Income before Income Taxes / PILs	**346,696**	**400,054**	**297,001**	**365,571**	**310,220**	**216,003**	**415,860**
PILs / Income Taxes	0	-23,610	-14,330	2,870	-896	0	0
Utility Income	**346,696**	**423,664**	**311,331**	**362,701**	**311,116**	**216,003**	**415,860**

1.0-VECC-6

Reference: Exhibit 1, page 151

a) Please update the Scorecard for 2020 results.

WNP's Response:

a) Please see updated Scorecard below to include preliminary unaudited results for 2020:

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	2020
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%	98.50%
		Scheduled Appointments Met On Time		95.60%	99.00%	99.42%	99.09%	98.11%	99.70%
		Telephone Calls Answered On Time		100.00%	99.90%	99.72%	99.00%	99.00%	86.33%
	Customer Satisfaction	First Contact Resolution		99.63%	99.84%	99.83%	99.87%	99.85%	99.81%
		Billing Accuracy		99.56%	99.47%	99.60%	99.57%	99.49%	99.47%
		Customer Satisfaction Survey Results		A	79.0%	79%	81.1%	81.1	-
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		82.40%	82.40%	83.30%	83.30%	83.50%	83.50%
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	0.000
	System Reliability	Average Number of Hours that Power to a Customer is [2]		0.06	0.34	0.10	0.16	0.24	0.51
		Average Number of Times that Power to a Customer is [2]		0.06	0.20	0.16	0.33	0.20	0.34
	Asset Management	Distribution System Plan Implementation Progress		DSP filed	24%	35%	69%	80%	97%
	Cost Control	Efficiency Assessment		4	4	4	4	3	3
		Total Cost per Customer [3]		$791	$838	$812	$818	$847	$863
		Total Cost per Km of Line [3]		$38,763	$39,667	$38,753	$39,383	$15,594	$16,008
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]		12.05%	22.39%	37.46%	50.00%	51.00%	-
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time					100.00%		
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%		100.00%		
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.97	1.06	1.00	1.03	0.96	
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.56	1.56	1.24	1.48	1.44	1.37
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.12%	9.19%	9.19%	9.19%	9.19%	9.19%
			Achieved	7.30%	10.68%	7.12%	7.77%	6.47%	5.03%

Exhibit 2 – Rate Base

2-Staff-6

Fixed Assets

Ref 1: Exhibit 2, 2.1.4 Fixed Asset Continuity Schedule

Ref 2: Exhibit 1, Appendix M – 2019 RRR to AFS Reconciliation

The ending 2019 net book value in the 2019 Fixed Asset Continuity Schedule differs from that as shown in the 2019 RRR to AFS Reconciliation. The difference is shown in the table below. Please explain and reconcile the difference.

	Financial Statements	Appendix 2-BA	Difference
PP&E	10,193,073		
Intangibles	791,785		
Reduced by Account 1508 ACM	(1,634,485)		
NBV	9,350,373	9,208,195	142,178

WNP's Response:

Under the Financial Statements column, please also subtract the Deferred Revenue amount of $142,177 listed as a non-current liability. When this value is taken into account there is only a rounding difference.

2-Staff-7

Fixed Asset Disposals

Ref 1: Exhibit 2, 2.1.4 Fixed Asset Continuity Schedule

The 2016 to 2019 Fixed Asset Continuity Schedules shows fixed asset disposals (relating to both costs and accumulated depreciation) in various accounts. The 2020 and 2021 Fixed Asset Continuity Schedules only show fixed asset disposals (for costs only) for Account 1860 Smart Meters.

a) Please confirm that there were only disposals for Smart Meters in 2020. Please update the 2020 Fixed Asset Schedule to actuals.
b) Please explain why Wellington North Power has not forecasted any disposals for 2021 except for Smart Meters.
c) Please explain why there are no amounts for disposalsrelating to accumulated depreciation for Account 1860 Smart Meters.
d) Please update the 2021 Fixed Asset Continuity Schedule as needed.

WNP's Response:

a) There were Net Book Value (NBV) disposal losses in accounts other than Smart Meters in 2020. The 2020 Fixed Asset Continuity Schedule has been updated.

b) Many assets that are retired are fully amortized. In this case the asset disposal is equal to the depreciation disposal and the rate-base is unaffected. WNP did not attempt to forecast these types of disposals. Smart meters are an area where a high failure rate is experienced even on relatively new meters and it is predictable that $10,000 - $30,000 of Smart Meter Net Book Value (NBV) will be written off each year. If there are larger values of NBV disposed of in poles or transformers, they are almost always related to an accident insurance claim. It is not possible to forecast when or if these types of accidents will occur.

c) On a forecasted revenue requirement basis, the number that matters to the rate setting process is the net movement in the NBV in the assets. It is quite irrelevant if Smart Meter assets decrease by $20,000 and the matching depreciation movement is nil or if the Smart Meter assets decrease by $50,000 and the matching depreciation decrease is $30,000. WNP has chosen to present the net movement of asset values.

d) The 2021 Fixed Asset Continuity Schedule has been updated to distribute NBV losses to Transformers and Poles as well.

2.0-VECC -7
Reference: Exhibit 2,

a) Please update Appendices 2-AA and 2-AB to show 2020 actuals (unaudited).
b) Please provide a variance analysis as between 2020 planned (963k) and actuals.

WNP's Response:

a) WNP has updated worksheets "App.2-AA Capital Projects" and "App.2-AB Capital Expenditures" of the 2021 Filing Requirements Chapter 2 Appendices and filed a copy on the OEB's web portal.

b) The table below illustrates WNP's capital investment expenditure in 2020 versus 2020 budget:

OEB Investment Category	**Planned as per DSP 2020**	**Actual Capex 2020**	Actual v DSP
System Access	$60,000	$185,994	210%
System Renewal	$450,000	$366,678	-19%
System Service	-	$114,476	-
General Plant	$453,000	$449,680	-1%
Total	**$963,000**	**$1,116,828**	**16%**
Capital Contributions	-	$22,807	

Although the capital expenditure for 2020 was 16% ($153,828) above budget, the WNP's overall 5-year capital expenditure was 97% of the approved DSP budget, i.e. the utility invested $6,279,942 in capital equipment from 2016 to 2020 from an approved DSP plan of $6,473,901.

The overage in spending in System Access can be attributed to:

- New Services: customer service requests for new connections for were 40% above budget at $121,834 (annual budget for 2020 for New Services was $60,000).
- Customer Requests: The utility handled several customer requests for modifications to existing customer connections or expansions which was unplanned and costed a total of $58,176.

The under-spending in System Renewal of approx. $80,000 was due to an underground project not proceeding in 2020. This project will be deferred but will not be included in the 2021 capital program.

In preparing its' 2015 DSP, at that time the utility did not plan for any investment in System, Service in in year 5; however, in 2020, WNP invested $114,476 in this category which can be attributed to the following:

- Distribution Changes: LDC distribution line located on private property was rerouted since WNP had no land easement for the property. This was unplanned and costed approx. $80,000.
- SCADA: WNP invested approx. $30,000 adding PME data to the SCADA as part of its Smart Grid initiative.
- Control: WNP added a 44kV switch at $5,236.

Capital investment in General Plant was less than 1% variance to budget and therefore requires no explanation.

2.0-VECC -8
Reference: Exhibit 2, Appendix 2-AB

a) Please provide the method for calculating the estimate of 20k each year (2021-2025) in capital contributions.
b) Please provide the actual contributions in 2020.
c) Please confirm (or correct) that WNP did not forecast capital contributions in its last Distribution System Plan (DSP).

WNP's Response:

a) Historically WNP's capital contributions have been unpredictable and uncertain. 2017 and 2018 had no capital contributions. Development has been limited to smaller "in-fill" projects which require very little infrastructure to service. The $20,000 estimate represents either two small projects or one larger project which requires a capital contribution.

b) WNP's actual capital contribution for 2020 was $22,807.15.

c) WNP confirms that WNP did not forecast capital contributions in its' previous Distribution System Plan.

2.0-VECC -9

Reference: Exhibit 2, page 17, DSP, page 231

a) Has WNP purchased and taken possession of the budgeted bucket truck?
b) If yes, what was the final cost of that vehicle?
c) Are there any other vehicle purchases planned for 2021? If yes please provide the estimated cost and expected purchase date.

WNP's Response:

a) Wellington North Power took possession of the bucket truck on December 29th 2020.

b) The final cost of the bucket truck was $316,788.86.

c) There are no other vehicle purchases planned for 2021.

2-VECC-10
Reference: Exhibit 2, Table 20, page 31

a) Please update Table 20 to show the capital contributions (budget and actuals) for each year.

WNP's Response:

a) WNP has re-created Table 20 from Exhibit 2 (page 31) and included 2020's (unaudited) expenditures and capital contributions:

Table 20 – DSP Plan (Budget) versus Actual CapEx

DSP Approved:					
	2016	2017	2018	2019	2020
System Access	$55,000	$240,000	$240,000	$240,000	$60,000
System Renewal	$90,000	$390,000	$1,932,000	$290,000	$450,000
System Service	$1,373,217	$0	$0	$0	$0
General Plant	$75,694	$138,670	$24,470	$421,850	$453,000
Total	**$1,593,911**	**$768,670**	**$2,196,470**	**$951,850**	**$963,000**
Cumulative Total	25%	36%	70%	85%	100%
Capital Contributions	$0	$0	$0	$0	$0
Actual CapEx:	Actual	Actual	Actual	Actual	Actual
	2016	2017	2018	2019	2020
System Access	$38,722	$77,353	$140,741	$63,630	$185,994
System Renewal	$113,170	$454,353	$2,012,186	$475,616	$366,678
System Service	$1,307,297	$10,954	$54,500	$5,180	$114,476
General Plant	$86,356	$170,195	$22,304	$130,557	$449,680
Total	**$1,545,545**	**$712,855**	**$2,229,731**	**$674,983**	**$1,116,828**
Cumulative Total	24%	35%	69%	80%	97%
Capital Contributions	$11,555	$0	$0	$25,840	$22,807
Variance: Actual to Budget	2016	2017	2018	2019	2020
Total	-3%	-7%	2%	-29%	16%
Variance: Actual to Budget	2016	2017	2018	2019	2020
System Access	-$16,278	-$162,647	-$99,259	-$176,370	$125,994
System Renewal	$23,170	$64,353	$80,186	$185,616	-$83,322
System Service	-$65,920	$10,954	$54,500	$5,180	$114,476
General Plant	$10,662	$31,525	-$2,166	-$291,293	-$3,320
Total	**-$48,367**	**-$55,815**	**$33,261**	**-$276,867**	**$153,828**

2-VECC-11

Reference: Exhibit 2, Table 20, page 38-40

a) The following table is taken from the last cost of service Distribution System Plan (EB-2015-0110). Please provide the actual amounts spent in each year.

Table 43 IT Projected Expenditure (2016 – 2020)

IT Component		2016	2017	2018	2019	2020	Total
Hardware	$	31,180	$63,750	$ 9,150	$61,150	$58,000	$ 223,230
Network	$	6,250	$ 3,000	$ 8,400	$ 6,500	$ -	$ 24,150
Software	$	1,300	$ -	$ -	$ -	$ -	$ 1,300
Smart Meter Communication	$	1,920	$ 1,920	$ 1,920	$19,200	$ -	$ 24,960
Total	**$**	**40,650**	**$68,670**	**$19,470**	**$86,850**	**$58,000**	**$ 273,640**

WNP's Response:

a) The table below shows the capital expenditure for the year 2016 to 2020:

IT Component	2016	2017	2018	2019	2020	**Total**
Hardware	$6,988	$66,441	$14,566	$71,016	$13,785	**$172,796**
Network	-	$8,509	$5,594	$8,111	$2,564	**$24,778**
Software	$57,949 *	$800	-	$8,019	$19,991	**$86,759**
Smart Meter Communication	$13,391	$758	-	-	$78,589**	**$92,738**
Total	**$78,328**	**$76,508**	**$20,160**	**$87,146**	**$114,929**	**$377,071**

* 2016 software included a CIS software upgrade which was not included in the DSP IT Projected Expenditure.

** 2020 Smart Meter communications included AMI software upgrade which was not included in the DSP IT Projected Expenditure. This upgrade was necessary because the software was at end-of-life and unsupported by the AMI vendor.

2-Staff-8

Customer Consultation

Ref 1: Exhibit 2, Section 5.2.1 page 10

Ref 2: Exhibit 2, Section, 5.2.3c page 57

Wellington North Power states in preparing this Distribution System Plan (DSP), it conducted customer surveys to ascertain customer preferences and investment priorities.

a) For the Customer Satisfaction Survey, what is the expected error rate for a sample size of 300?
b) Were the customers consulted on the specific projects proposed to be undertaken in the forecast period?
c) Were the customers consulted on the final version of the DSP?

WNP's Response:

a) In responding this interrogatory, WNP assumes OEB Staff are referring to the "customer survey" performed as described in the DSP and not the biennial Customer Satisfaction Survey used for the Scorecard. If this assumption is correct then:
   - WNP approx. population of residential, small business and industrial & commercial customers is 3,700.
   - Assuming a confidence level of 95%.
   - Sample size of 300 respondents.
   - Margin of error 5%.

b) As noted in the Applicant's DSP section "5.2.2b Final Deliverable", page 31:

   "WNP planned to host a community meeting in May 2020 to present its proposed operating budget for 2021 and 5-year capital investment plan for 2021-2025 incorporating feedback from customer surveys; however due to the COVID-19 pandemic and public health guidelines regarding social distancing, this meeting did not happen."

   To clarify, at the proposed community meeting, WNP were planning to present and discuss the capital projects for 2021-2025 with attendees.

c) Customers were not consulted on the final version of the DSP.

2-Staff-9

Smart Grid Development

Ref 1: Exhibit 2, Section 5.2.1a page 13

Ref 2: Exhibit 2, Section 5.2.1h page 17

Ref 3: Exhibit 2, Section 5.2.2b page 37

Ref 4: Exhibit 2, Section 5.4.3.1 Overall Plan

Wellington North Power states that it has a "smart grid development initiative", involving equipping all the distribution stations with automated feeder reclosers and Supervisor Control and Data Acquisition (SCADA).

a) Is there a document that outlines the smart grid development plan? If so, please provide.
b) Please provide the business case for the SCADA software project planned in 2024.

WNP's Response:

a) A formal smart grid development plan document has not been created. Only two of WNP's six municipal stations are equipped with automated feeder reclosers. WNP plans to equip stations when they are rebuilt at the end of life of the station.

b) The SCADA project planned for 2024 is the replacement of the existing SCADA server and work station. WNP does not create a business case for the replacement of an existing asset.

2-Staff-10

Customers' Preferences and Expectations

Ref 1: Exhibit 2, Section 5.2.1b page 14

Wellington North Power has determined through its 2020 Customer Survey that burying overhead wires is a customer preference and priority. Wellington North Power has identified burying overhead wire as Priority #6 in the DSP and that Wellington North Power will install plant underground when "cost effective".

a. Considering that the customer survey showed little or no support for ratepayer funded burying of overhead cable, why is this a DSP priority?
b. Please provide examples of where Wellington North Power determines that burying overhead wire is "cost effective" considering customer reluctance to pay for this.

WNP's Response:

a) As noted in section 5.2.2b *"Customers – Final Deliverable"* of the DSP, part "c) Investment Priorities":

> *"Customers were provided with a series of statements enabling respondents to choose either "High Priority", "Low Priority" or "No Opinion" with each statement."*

To clarify, in the survey, customers were given 6 statements in the survey. As described in section *"5.2.1b Overview of Customers' Preferences and Expectations"* of the DSP, of the 6 statements, burying overhead wires was ranked as priority # 6, i.e. the lowest priority. Therefore, based on customers' preferences, WNP does not view burying overhead cables as an investment priority.

b) In the DSP, the Applicant wrote:

> *WNP works closely with the Municipality, as well as contractors and developers. When rebuilding infrastructure, placing assets underground is always a consideration and WNP strives to install plant underground when feasible, cost effective and if there is collaborative scheduling."*

The cost-effectiveness referred to relates to the utility working collaboratively with other parties. For example, if the municipality is undertaking a road-widening, other service providers may need to relocate their equipment (e.g. gas and water pipelines, buried telecom cables.) In such a project, hydro poles may need to be re-located and therefore, it may be cost-effective to bury hydro cables in conduit in the trenches already dug for use by other services providers.

2-Staff-11

Asset Lifecycle Optimization Policies and Practices

Ref 1: Exhibit 2, Section 5.2.1b page 14

Ref 2: Exhibit 2, Section 5.3.3a pages 133, 134

Wellington North Power states that it "has a relatively heavy mature tree cover where overhead hydro lines are in the proximity to trees". Wellington North Power states that priority 4B - Invest in Tree Trimming follows a 3-year schedule. On page 134, Wellington North Power states that it follows a two-year tree trimming schedule.

a. Which trimming schedule is correct?
b. Does the tree trimming program consider the impact of climate change on line clearances and cycles?
c. Please provide a copy of Procedure 2060 – Vegetation Management

---

WNP's Response:

a) WNP follows a 3-year schedule.

b) WNP is not aware of any requirements or guidelines regarding climate change and line clearing activities. WNP follows the IHSA EUSA Safe Practice Guide (SPG) for Line Clearing Operations.

c) WNP has filed a copy of its' "Procedure 2060 – Vegetation Management" on the OEB's web portal as requested.

2-VECC-14

Reference: Exhibit 2, Appendix 2A DSP Section 5.4 PDF page 198 & 208

"*The WNP service area is trimmed on a two-year cycle as per formal requirements and lead hand judgment. This work is primarily carried out by WNP employees, but contractors may be hired, based on cost and availability of resources*." (page 198)
"*WNP has an aggressive 3-year tree trimming schedule and is a direct reflection of the LDC's low outage and duration of outage statistics. WNP will continue with this tree-trimming schedule*." (page 208)

a) Please clarify whether WPN uses a two- or three-year tree trimming cycle?

WNP's Response:

a) WNP uses a three year tree trimming cycle.

The utility has always had a 3- year trimming cycle; the reference to a 2-year cycle was an error.

2-Staff-12

Sources of Expected Cost Savings

Ref 1: Exhibit 2, Section 5.2.1c page 15

Wellington North Power states that reclosers in new substations will reduce call outs to stations. Please provide the expected annual reduction in O&M costs and reliability improvements with the addition of reclosers in the DSP forecast period.

WNP's Response:

WNP has no plans to install reclosers in the DSP forecast period however any future municipal station rebuilds would incorporate the technology. Currently, WNP has a limited number of recloser devices installed (eight).

The savings would be generated during a reclose event and not a lock out event. During a reclose, the recloser attempts to close the circuit. If the fault has cleared the power will remain on. In this case customers would only experience a momentary loss of power. Typical causes of a reclose is animal contact and broken branches. In contrast, stations with fuses would disrupt power until line staff identify the problem and replaced the blown fuse.

2-Staff-13

Grid Modernization, Distributed Energy Resources or Climate Change Projects

Ref 1: Exhibit 2, Section 5.2.1c page 15

Ref 2: Exhibit 2, Section 5.2.1h page 17

Wellington North Power states that through good maintenance practices and replacing assets in a prioritized approach it mitigates and limits the cost of unplanned events such as weather-related costs. Wellington North Power has not identified any projects related to climate change adaptation. How does Wellington North Power expect climate change to impact its operations?

WNP's Response:

a) WNP does not have specific data or is aware of any requirements related to climate change to support specific projects. WNP has not formulated any speculation regarding the impact of climate change, for example, greater number of ice storms with greater ice build-up, higher snow and wind loads or other climate related impacts.

2-Staff-14

Changes to the Asset Management Process

Ref 1: Exhibit 2, Section 5.2.1f page 16

Wellington North Power states that it has purchased a Polux Pole tester "to gather enhanced data about the structural integrity of poles".

a. Please provide examples of enhanced data that has been captured with the pole tester.
b. How many poles have been tested to date with the Polux Pole tester?
c. How many poles were determined to be in "poor" or "very poor" condition based on Pollux Pole tester 2020 data?

WNP's Response:

a) Example data for 10 poles has been filed on the OEB's web portal – see file named "2-Staff-14-Pole Test Example 10 Poles".

b) A total of 1,985 poles have been tested.

c) In 2020 there were 2 poles identified as "Red" and one as "Orange".

2-Staff-15

Aspects of the DSP Reliant on Ongoing Activities or Future Events

Ref 1: Exhibit 2, Section 5.2.1g page 16

Ref 2: Exhibit 2, Section 5.4.1b page 153

Ref 3: Exhibit 2, Section 5.4.3.2 page 177

Wellington North Power states that it is "not aware of ongoing activities or future events that may impact or effect the plans for the DSP forecast period of 2021 to 2025".

Wellington North Power states that smart meters sampled in 2017, 2018 and 2019 passed testing and were sealed for use for a further 6 years. Does Wellington North Power anticipate that any meter requiring recertification and resealing during the 2021 to 2025 period will pass testing?

WNP's Response:

The sample reverification of the meters extended the seal date by eight years. WNP acknowledges that the six years listed in the DSP was an error.

WNP expects that sample sizes will be too small due to on-going meter failures for group reverifications. The utility plans to replace the meters which have approached their seal date for the second time. These meters will have been in service from 16 to 18 years.

2-Staff-16

Methods & Measures to Monitor DSP Planning Process Performance

Ref 1: Exhibit 2, Section 5.2.3a pages 38, 39, 42, 45

Ref 2: Exhibit 2, Section 5.2.3c pages 54, 64, 65

Wellington North Power states that it "measures and monitors its' operating performance using the following performance indicators":

- Customer service quality indicators;
- Supply system reliability & performance indicators;
- Operational effectiveness indicators;
- Planning quality indicators;
- Financial performance indicators; and
- CDM program targets and performance

a. With respect to Customer Service Quality measures, please correct Figure 26 with the correct OEB Minimum standards for Telephone Accessibility and Emergency Response.
b. With respect to System Reliability, please provide the TMED numbers for 2019 and 2020 (if available).
c. Wellington North Power states that it monitors its capital expenditure by comparing budget versus actual spent for each project. What is the threshold for acceptable variance?
d. Wellington North Power states that it prepares Annual Operating Expenditures budgets. What is the threshold for acceptable variance?
e. Wellington North Power states that it measures implementation of the DSP. What is the threshold for acceptable variance?

WNP's Response:

a) Please see updated table below as requested:

Figure 26: Service Quality Indicators - 5-year Historic Performance

Indicator	OEB Minimum Standard	2015	2016	2017	2018	2019
Low Voltage Connections	90.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Appointment Scheduling	90.00%	98.60%	99.70%	100.00%	99.53%	99.37%
Appointments Met	90.00%	95.60%	98.98%	99.42%	99.09%	98.11%
Rescheduling a Missed Appointment	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Telephone Accessibility	65.00%	100.00%	99.92%	99.72%	99.00%	99.00%
Telephone Call Abandon Rate	10.00%	0.00%	0.00%	0.00%	0.00%	0.04%
Written Response to Enquires	80.00%	100.00%	100.00%	100.00%	96.95%	97.35%
Emergency Response - Urban	80.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Reconnection Performance Standard	85.00%	100.00%	100.00%	100.00%	100.00%	100.00%

b) For 2019, the T_{MED} was 21.70957.
For 2020, the T_{MED} was 18.11387.

c) The threshold for acceptable variance for measuring capital expenditure, in WNP's opinion, depends upon the project and the magnitude of the expenditure. For example, a 5% overspend on a replacement substation project budgeted at $1,700,000 will be different to a similar overspend for a server replacement project budgeted at $65,000. Both capital projects are important to the day-to-day running of the utility's operations. Overspend on one project, such as a substation replacement may be justifiable (e.g. despite soil sampling, additional fill was necessary to provide stable footing for the new substation).
At the time of responding to this interrogatory, WNP does not have an "acceptable threshold variance" in place. Instead, operating as a prudent utility, WNP monitors capital expenditure for each project. Through monitoring capital expenditure and progress of projects, the utility may decide to defer or bring forward projects if the resources or needs or requirements dictate. WNP monitors progress of capital projects including spend to date and project status. The effects of WNP monitoring of capital projects have been successful as demonstrated in the implementation of DSP as articulated in the implementation of projects on –time and budget expressed in the results for 2016-2019 as reported in the Applicant's 2020 DSP.

d) Annual Operating Expenditures (OpEx) budgets are prepared and presented to the utility's Directors for review and approval. Once approved, WNP monitors OpEx spending comparing actual to date, with information presented at monthly Board meetings.
In WNP's opinion, when total variances considered cumulatively exceed 5% of the OpEx budget, then actions must be taken to investigate and correct those problems.

e) For DSP implementation, WNP measures:

$$DSP\ Implementation = \frac{Capital\ Investment\ Spent\ to\ Date}{Capital\ Invesment\ Budget\ Approved\ by\ OEB}$$

In its' 2020 DSP, the Applicant illustrated progress to date in "Figure 47: DSP Implementation Progress". In the absence of a DSP implementation reporting method from the regulator, the utility has adopted the above formula that calculates progress as capital expenditure to date as a percentage of the DSP-approved 5-year budget.
At the time of responding to this interrogatory, WNP does not have an "acceptable threshold variance" in place.

2-Staff-17

Unit Cost Metrics

Ref 1: Exhibit 2, Section 5.2.3b page 51

For section 5.2.3 b Unit Cost Metrics, Wellington North Power has used data for 2015 to 2019 to calculate the historical 5-year average metrics. Wellington North Power has used 2021 test year values for the 1-year performance metric. Wellington North Power has also used Operations, Maintenance, and Administration (OM&A) data for metrics requiring Operations and Maintenance (O&M) data. As these are historical performance metrics, please recalculate Appendix 5-A and figure 25 using 2016 – 2020 data for the historical 5-year average metric and 2020 data (actual or projected) for the 1-year performance metric.

a. In calculating values in Appendix 5-A, why does Wellington North Poweruse Pacific Economics Group data for Capital and Capex costs versus data Wellington North Power provided to the OEB that is in the OEB Electricity Distributor Yearbooks?
b. Please recalculate all metrics in Appendix 5-A and Figure 25 that were calculated with OM&A data with O&M data. For example, using data from the OEB 2019 Yearbook, the correct 2019 value for O&M/Customer would be ($407,117 + $214,209)/3,830 = $162/customer as opposed to the figure of $472 shown in Figure 25.
c. Why is there a $ sign for data in the # of metered customers row?

WNP's Response:

a) The Applicant has updated Appendix 5-A using the data from the OEB's Yearbooks.

b) The Applicant has updated and re-filed 2021 Filing Requirements Chapter 5 Appendix workbook containing Appendix 5-A.

WNP has recreated "Figure 25: Calculations for Unit Cost Metrics" from its' DSP and updated the values as required as per below:

"Figure 25: Calculations for Unit Cost Metrics" - ***Updated***

		2016	2017	2018	2019	2020 *Projected*	5-yr Average		2020
	O&M Cost	$661,117	$666,582	$637,798	$621,326	$623,570	$642,079		$623,570
	Capital Additions	$1,545,545	$744,253	$501,091	$664,109	$645,449	$820,089		$645,449
	O&M + Capital	$2,206,662	$1,410,835	$1,138,889	$1,285,435	$1,269,019	$1,462,168		$1,269,019
	# of metered customers	3,739	3,770	3,805	3,830	3,837	3,796		3,837
	km of line	79	79	79	208	208	131		208
	Peak MW	16	16	17	17	17	17		17
Cost	Total Cost per Customer	$590	$374	$299	$336	$331	$386		$331
	Total Cost per km of line	$27,932	$17,859	$14,416	$6,180	$6,101	$14,498		$6,101
	Total Cost per MW	$133,867	$86,126	$68,361	$76,310	$76,172	$88,167		$76,172
CapEx	Total CapEx per Customer	$413	$197	$132	$173	$168	$217		$168
	Total CapEx per km of line	$19,564	$9,421	$6,343	$3,193	$3,103	$8,325		$3,103
	Total CapEx per MW	$93,760	$45,434	$30,077	$39,424.70	$38,742	$49,488		$38,742
O&M	Total O&M per Customer	$177	$177	$168	$162	$163	$169		$163
	Total O&M per km of line	$8,369	$8,438	$8,073	$2,987	$2,998	$6,173		$2,998
	Total O&M per MW	$40,107	$40,692	$38,283	$36,885	$37,429	$38,679		$37,429

c) This was a formatting error in "Figure 25: Calculations for Unit Cost Metrics" in the DSP. The count of meters is a number value and should not have included a $ sign. As illustrated in response to part b) above, number of metered customers is now represented as a numerical.

2-Staff-18

Unit Cost Metrics

Ref 1: Exhibit 2, Section 5.2.3b page 52

Wellington North Power states that the Geographic Information System (GIS) is their Asset Management System "representing a single source of truth for the organization". Please provide particulars of the GIS system (provider, version, etc.).

WNP's Response:

a) WNP uses ESRI ARCMap 10.5 GIS as noted below:

2-Staff-19

Summary of Historical Performance

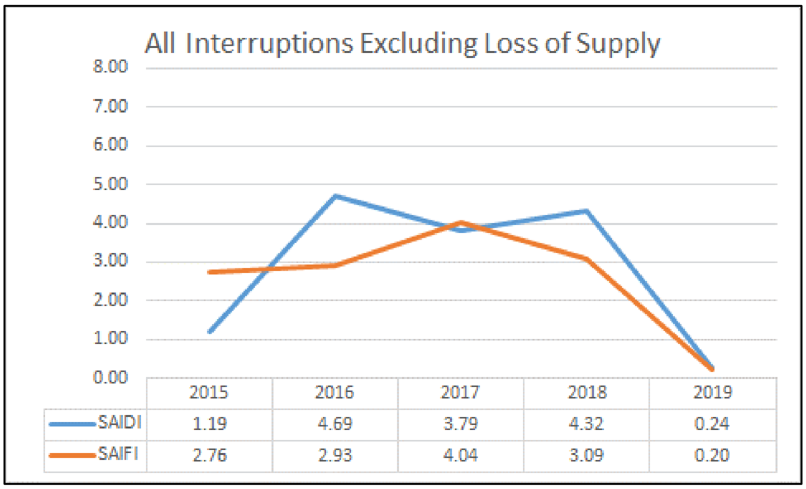
Ref 1: Exhibit 2, Section 5.2.3c page 59

In Figure 37, Wellington North Power states that 2019 System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) performance excluding Loss of Supply is 0.84 and 2.05 respectively. As there were no Major Event Days (MEDs) in 2019, why is this different from the 2019 scorecard SAIFI = 0.20; SAIDI = 0.24?

WNP's Response:

The number reported for 2019 was an error. WNP confirms there were no Major Events Days in 2019 and the SAIFI and SAIDI for this year should have been shown as SAIFI = 0.20; SAIDI = 0.24. WNP has corrected Figure 37 of the DSP as per below:

Figure 37: Excluding Loss of Supply – SAIDI and SAIFI Performance for WNP (corrected)



2-Staff-20

Summary of Historical Performance

Ref 1: Exhibit 2, Section 5.2.3c page 67

Figure 49 shows the 2020 Capex as of May 2020. What is the current 2020 Capex?

WNP's Response:

WNP has re-created Figure 49 from the utility's 2020 DSP and included 2020's (unaudited) expenditures:

Figure 49: DSP Implementation Progress – Planned versus Actual Variance

DSP Approved:					
	2016	2017	2018	2019	2020
Total	**$1,593,911**	**$768,670**	**$2,196,470**	**$951,850**	**$963,000**
Cumulative Total	25%	36%	70%	85%	100%
Actual CapEx:	Actual	Actual	Actual	Actual	Actual
	2016	2017	2018	2019	2020
Total	**$1,545,545**	**$712,855**	**$2,229,731**	**$674,983**	**$1,116,828**
Cumulative Total	24%	35%	69%	80%	97%
Variance: Actual to Budget	2016	2017	2018	2019	2020
Total	-3%	-7%	2%	-29%	16%
Variance: Actual to Budget	2016	2017	2018	2019	2020
Total	**-$48,367**	**-$55,815**	**$33,261**	**-$276,867**	**$153,828**

WNP's overall 5-year capital expenditure was 97% of the approved 2015 DSP budget. The utility invested $6,279,942 in capital equipment from 2016 to 2020 from an approved DSP plan of $6,473,901.

2-Staff-21

Realized Efficiencies Due to Smart Meters

Ref 1: Exhibit 2, Section 5.2.4 page 74

Wellington North Power states that it has "not realized any cost efficiencies related to the utility's use of Smart Meters since its' last Cost of Service application in 2016". What were the cost efficiencies related to the utility's use of Smart Meters that were provided in the 2016 Cost of Service application?

WNP's Response:

The Applicant made this reference to highlight that, from a specific point in time i.e. WNP's last DSP, the LDC has not realized any cost efficiencies through the use of smart meters. Furthermore, the reference does not infer there were cost efficiencies, due to smart meters, cited in the Applicant's 2015 DSP.

2-Staff-22

Asset Management Objectives

Ref 1: Exhibit 2, Section 5.3.1 pages 75, 76

Wellington North Power states that facilitating the connection of new renewable connections is of low importance in terms of its asset management objectives. Wellington North Power also states that it has "reduced the importance of connecting green energy and renewable energy sources". Explain why this is not in conflict with section 6.2.4 of the Distribution System Code.

WNP's Response:

In section 5.3.1a Asset Management Objectives of WNP's 2020 DSP, the distributor stated:

> *"Facilitating new renewable connections: Given that all new renewable contracts were cancelled in 2018, WNP has reduced the importance of connecting green energy and renewable energy sources."*

This statement was part of a list consisting of 10 asset management objectives.

WNP does support renewable and behind the meter projects. However, to date, WNP has received no requests from customers for such projects and therefore, the utility ranks this particular objective as a lower priority compared to other asset management objectives as listed in section 5.3.1a of the DSP.

Should a customer submit an application for connection of a generation facility, the LDC shall, subject to all applicable laws, make all reasonable efforts in accordance with the provisions of section 6.2 of the Distribution System Code, to promptly connect the facility to its' distribution system.

2-Staff-23

Components of the Asset Management Process used for Capital Expenditure Plan

Ref 1: Exhibit 2, Section 5.3.1b page 80

Wellington North Power states that "there is no formal quantitative means of prioritizing projects". Wellington North Power further states that it takes a "qualitative approach" to prioritizing investments. Please provide examples of how this qualitative approach was used to prioritize projects.

WNP's Response:

Example of qualitative approach:

WNP replaced a pole identified as P1496 which had tested as "Amber". Under normal conditions, when only looking at the pole test result, one would assume the pole would be placed as low priority for change or monitor. WNP reviewed other factors that could impact our customers, the environment and general safety. The following points were the considerations that led to the decision to replace the pole:

- The pole, a southern yellow pine, is a species that is known to be susceptible to decay issues.
- A visual inspection noted that the single phase transformer on the pole was leaking.
- If only the transformer was changed, customers would experience a longer outage, that is, the time to remove and install the new transformer on the existing pole (approximately 1 to 1.5hr).
- Eventually, the pole would decay to a point where it absolutely needed to be changed resulting in an additional outage to replace the pole.
- A lower overall cost is achieved by installing the new pole and transformer under a single project engineered and managed once. Customers would only experience a single shorter outage of approximately 0.5hr to transfer secondary connections.

2-Staff-24

Asset Type – Profile and Condition

Ref 1: Exhibit 2, Section 5.3.1b page 79

Ref 2: Exhibit 2, Section 5.2.3c pages 93, 95

The 2019 Asset Condition Assessment (ACA) identified the following quantity of assets in "poor" or "very poor" condition:

- 1 x Municipal Station (MS) switchgear
- 1 x MS loadbreak switch
- 10 x padmount transformers
- 69 x 1-phase polemount transformers
- 8 x 3-phase polemount transformers
- 26 x 4kV poles
- 0 x 44kV poles

The ACA Condition-Based Flagged for Action Plan states that a reactive approach is used for pole and overhead transformer replacement while a proactive approach is used for padmount transformers. Wellington North Power also states that the "actual replacement plans might be only a subset of the Flagged for Action plans".

a. Please confirm that the 10 Year Action in Total numbers in Figure 64 represent quantities in Years 2 through 10.
b. Is it Wellington North Power's expectation that in years 3 and going forward), it will begin replacing padmount transformer units currently in "good" or better condition?
c. How many of the padmount transformers are live front units?
d. Is it Wellington North Power's expectation that in years 3 and going forward, it will begin replacing poles currently in "good" or better condition?
e. Is it Wellington North Power's expectation that in years 3 and going forward, it will begin replacing pole transformers currently in "good" or better condition?
f. The ACA provided four recommendations. When does Wellington North Power plan to start addressing these recommendations and what is the expected completion date?

WNP's Response:

a) It represents quantities in years 0 through 9 where year 0 is 2020. Please refer to table 3 in ACA report for details.

b) Total number of very poor, poor and fair units is 23. This means starting from year 3 and going forward, some units currently in good or better condition might be addressed. This however does not necessarily mean replacement for all of them. The decision is to be made regarding the appropriate course of action taking into account multiple factors.

c) The total number of live front units is eight.

d) In the case of poles, the yearly FFA number is calculated based on the failure rate. This means even for poles in good condition, there is a small probability that they might fail, though such a probability is much lower than for the ones in poor condition. The yearly FFA number is the cumulative count of all such expected failed units each year without identifying specific poles that may fail. It is up to WNP to decide which specific poles need to be replaced.

e) The same principle as for poles. See the replies to question d)

f) Implementation of Recommendations:

i) Kinectrics Recommendation:
In the future, historic records of asset removal need to be collected for all the asset groups, so as to improve the accuracy of asset degradation curves.

WNP Response:

The implementation of this recommendation will be completed this year with changes to some internal processes.

ii) Kinectrics Recommendation:
Inspection records at component level need to be collected for Pad Mounted Transformers and Pole Mounted Transformers, so as to improve the input granularity for better assessment of component condition status.

WNP Response:

WNP plans to review its inspection process and enhance the data collection. This will be in trial for next year 2022.

iii) Kinectrics Recommendation:
Manufacturer Specification limits for contact resistance and operation cycles need to be collected for MS Switchgear and MS Load Switches, so as to set up the thresholds for assessing switch usage.

WNP Response:

WNP will work with its third party electrical testing contractor to note contact tolerance limits. Recording operation cycles on manually operated switches will require more effort to determine a reasonable process that accurately captures the data. A trial process will need to be developed and tested during this DSP period.

iv) Kinectrics Recommendation:
Inspection and test data for the individual units under the same asset group need to be merged under one data file for each asset group, in a form that is electronically extractable. This applies to the asset groups inside stations.

WNP Response:

The merging of test data into one workbook has been completed. WNP will continue to record test results and maintain the workbook.

It is also important to note that Kinectrics stated:

"Compared to other local distribution utilities, WNP had above average amount of data for 2020 ACA study, based on which informed decisions could be made".

2-Staff-25

Overview of Assets Managed

Ref 1: Exhibit 2, Section 5.3.2a page 84

Ref 2: Exhibit 2, Section 5.3.2d page 128

Wellington North Power had a winter peak demand of 16,845 kW. Figure 94 provides feeder loading and capacity calculations per Wellington North Power. Wellington North Power states that in their "opinion, supply and capacity of existing assets are adequate to sustain the forecasted load growth for the forecasted period 2021 to 2025".

a. Please provide the 2019 coincidental peak demand for each of the 6 MS owned and operated by Wellington North Power.

b. Please provide the 2019 non-coincidental peak demand for each of the 6 MS owned and operated by Wellington North Power.

c. Please confirm that the Capacity column of Figure 94 does not reflect the total remaining available capacity on each MS.

WNP's Response:

Background:
The winter peak of 16,845 kW is total demand of Arthur, Holstein and Mount Forest as measured at the Primary Metering Units (four in total). Included in the demand are seven customer owned stations. WNP owns a total of six Municipal Stations, four in Mount Forest (total nameplate capacity of 17MVA) and two in Arthur (total nameplate capacity of 10MVA). WNP has no concerns with loading at this time since the stations operate well below their capacity ratings. As a result, WNP has not invested resources in collecting historical station data and performing coincidental and non-coincidental peak analysis.

a) WNP does not have the coincidental peak demand data for the 6 Municipal Stations.

b) WNP does not have the non-coincidental peak demand for each of the 6 Municipal Stations.

c) The capacity column in Figure 94 represents the estimated remaining feeder capacity during normal loading. Remaining station capacity would be based on the transformer rating and feeder loading.

2-Staff-26

General Plant – Transportation Equipment

Ref 1: Exhibit 2, Section 5.3.2c page 119

Wellington North Power has a guide for replacement of fleet vehicles ranging from 8 to 12 years. Wellington North Power also states that "the vehicle replacement program is based on annual condition surveys and life cycle planning".

a. Please provide current examples of the annual condition survey documents for the Radial Boom Derrick Truck (RBD) to be replaced in 2022 and pickups in 2023 and 2025.
b. If available, please provide the business case for the RBD replacement (Budget = $425,000) in 2022.
c. Considering the significant cost of the RBD procurement, was leasing versus owning the unit considered in the business case analysis?

WNP's Response:

a) For large trucks, a good assessment of the condition is the CVOR certification by a qualified mechanic as well as any maintenance records. WNP does not have a separate set of forms assessing each vehicle on a yearly basis. The fleet consists of three large trucks and three pickup trucks. Vehicles are placed in the plan to pace and prioritize spending.

b) The RBD is a replace "like for like", that is, a budgetary price was obtained for the same model truck. The RBD is a 2004 model and will be 18 years old at our planned time of replacement.

2-Staff-27

Information Systems, Operational Technology and Cyber-Security

Ref 1: Exhibit 2, Section 5.3.2c page 120

Please provide a copy of the 2019 "review of the current and future business requirements and priorities concerning the utility's capital investment in Information Systems".

WNP's Response:

The review involved multiple meetings between WNP, its' IT Vendor and the LDC's retained independent IT consultant. Reports containing detailed hardware, software, licenses and office equipment were produced and consolidated into an Excel workbook single excel file. Over the course of several meetings, the information was reviewed and refreshed by all parties. As part of the discussions, the parties considered what IT/OT was needed to:

- Maintain business operating activities.
- Address a major driver for IT investment in the coming years, the Provincial's Framework Cyber Security requirement. WNP engaged a 3rd party Cyber Audit firm to evaluate IT and SCADA systems, and the result of that audit and the necessary remediation have driven increased spend across our infrastructure, to be implemented in the coming years to meet those cybersecurity mandates.
- Continue to meet customer requirements (e.g. e-bill notification).
- Maintain good asset management practice to replace dated software and hardware.

Due to the confidential and security information contained in the Excel workbook, the Applicant does not wish to disclose this on the public record. The relevant output from the review is illustrated in Figure 92 of section 5.3.2c *"Information Systems, Operational Technology and Cyber-Security"* of the Applicant's DSP.

2-VECC-12

Reference: Exhibit 2, Appendix 2A DSP, Section 5.3.2, PDF page 184

Figure 92: IT Projected Expenditure (2021 – 2025)

Non Cyber-security	2021	2022	2023	2024	2025
Servers	$63,000	$0	$16,000	$26,000	$5,250
Smart Meter Infrastructure	$19,200	$0	$0	$0	$0
Desktop computers; Laptops & Accessories	$7,200	$13,050	$12,050	$9,100	$1,250
SCADA	$15,000	$0	$0	$66,500	$0
Smart Technology	$10,000	$10,000	$10,000	$10,000	$10,000
Office Equipment	$6,000	$17,500	$20,900	$6,200	$18,000
Projects - Software Replacement / Upgrade	$16,000	$130,000	$50,000	$0	$97,500
Total	$136,400	$170,550	$108,950	$117,800	$132,000
Cyber-security	**2021**	**2022**	**2023**	**2024**	**2025**
Network / Firewall	$14,100	$0	$5,000	$32,000	$0
Cyber-Security	$12,500	$10,000	$0	$10,000	$10,000
Total	$26,600	$10,000	$5,000	$42,000	$10,000
Annual Total	**$163,000**	**$180,550**	**$113,950**	**$159,800**	**$142,000**

a) The annual IT budget for the 2021-2025 period (average 151k) has increased significantly from the 2016-2020 period (average 55k). Please explain the reasons for the significant increase in IT spending over the term of the new DSP.

WNP's Response:

a) The table below shows WNP's Planned versus Actual IT capital expenditure for the period 2016-2020:

	2016	2017	2018	2019	2020	5- yr Average
2015 DSP Plan	$40,650	$68,670	$19,470	$86,850	$58,000	$54,728
Actual IT CapEx	$78,328	$76,508	$20,160	$87,146	$114,929	$75,414

For the years 2017 to 2019, WNP actual IT Capital expenditure was very close to the proposed budget. As noted in the response to interrogatory 2-VECC-11:

- In 2016 the LDC upgraded its' CIS software upgrade.
- In 2020, under Smart Meter communications, the LDC upgraded its' AMI software and was necessary because the software was at end-of-life and unsupported by the AMI vendor.

Both of these items were unplanned and not included in the 2015's DSP IT Projected Expenditure. However, the LDC has demonstrated prudent capital investment spending by as the utility spent 97% of its 5-year approved DSP budget, i.e. the expenditures overages noted in the table above, did not cause an-overspending of the total 5 year CapEx plan.

Improved Planning:

In preparing its 2020 DSP, as discussed in response to interrogatory 2-Staff-27 (above), the LDC prepared an IT/OT plan for the period 2021-2025 that assembled the needs of the utility to:

- Maintain business operating activities.
- Address major driver for IT investment in the coming years to progress through the Provincial Framework Cyber Security requirements.
- Continue to meet customer requirements (e.g. e-bill notification).
- Maintain good asset management practice to replace dated software and hardware.

The intent of this consolidated IT/OT plan is to minimize the "unplanned" projects over the course of the next 5 years.

New challenges:

Since preparing and working through the LDC's 2015's DSP capital investment plan, the utility now has increased obligations in working through the Provincial's Framework Cyber Security requirements as discussed in interrogatory response 4-Staff-49. In preparing its 2021-2025, WNP has considered IT/OT investments that are necessary to reduce the risk profile of the LDC.

There are several capital projects that are necessary which contribute significantly to the increased yearly average IT/OT expenditure planned for 2021 to 2025. These include:

- 2021 – Servers to be replaced (budget $63,000): current servers were installed in 2015 and are approaching their end-of –life with no vendor warranty available after 2021.
- 2022 – CIS support & software (budget $130,000): WNP's CIS vendor maintenance agreement is due to expire at the end of 2021 and there is a pending software upgrade. The software was last upgraded in 2016 and the LDC has many patches and workarounds in place to accommodate changes in the industry that are not standard in the current software version.
- 2023 – Collectors (budget $50,000): The current collectors were installed as part of the LDC's Smart meter program roll-out in 2009/2010.

2-VECC-13

Reference: Exhibit 2, Appendix 2A DSP, 5.4.3.2.A, page 259

Table 45 Projected Building Renovation Expenditure (2016 – 2020)

	2016	2017	2018	2019	2020	Total
Building Renovations	$30,000	$30,000	$5,000	$50,000	$50,000	**$165,000**

a) For the above Table taken from the last cost of service Distribution System Plan (EB-2015-0110) please provide the actual amounts spent in each year and explain the variation from budget for building renovations over the 2016 – 2020 period.

b) Does WNP have plans for renovation, rebuilding or moving to a new office/service centre? If not, have the capital spending over the last DSP resolved the issues identified in the application EB-2011-0249 which caused a proposal for a "gutting" or new building at Mount Forest?

WNP's Response:

a) Build Renovation Expenditure

Year	2016	2017	2018	2019	2020	Total
Budget	$ 30,000	$ 30,000	$ 5,000	$ 50,000	$ 50,000	$165,000
Actual	$ 7,748	$ 29,677	$ -	$ 1,215	$ 6,803	$ 45,443

In 2016, WNP completed security camera installation and did not begin any other work on the building. Instead, the utility focused its' efforts on the design and build of the Second Line Feeder Project, which was identified as a "special project" in the 2015 DSP and the utility's 2016 Cost of Service application (EB-2015-0110).

A primary focus was to construct an AODA compliant washroom. The first phase of work involved creating another washroom in the truck bay area for staff to use during the renovation. This new washroom would allow for the demolition of the two existing washrooms. The existing washrooms would become one large compliant washroom. WNP obtained pricing for the smaller washroom which was in WNP's opinion excessive. WNP worked with the designer to look for other cost-effective alternatives. Unfortunately WNP was not able to execute in 2019 and therefore the project was carried over to 2020.

All 2020 renovation work was placed on hold due to COVID 19. This work would have included the AODA renovation.

b) WNP needs to construct the AODA compliant washroom facility in 2021. Some issues as identified in application EB-2011-0249 remain open and need addressing including main office area configuration, windows, insulation and roof. WNP does not intend to consider "gutting" the building or a new build. Although not ideal the building can continue to meet our needs with some investment, as identified in WNP's DSP.

2-Staff-28

Misc. Clarifications

Ref 1: Exhibit 2, Section 5.3.2c page 123

Ref 2: Exhibit 2, Section 5.4.3.1 page 173

Ref 3: Exhibit 2, Section 5.4.3.2 page 191

On page 123 does the statement "WNP's has included IS investment within its 5-year Capital Investment Plan (2016 to 2020) …." actually refer to the 2021 to 2025 period?

On page 173 does the statement "Figure 134 above illustrates the 5-year plan for System Access expenditures …" actually refer to General Plant expenditures?

On page 191 does the statement "This investment is a high priority within the General Plant category as SCADA …." actually refer to System Service expenditures?

WNP's Response:

a) Correct – the statement should have read:
"WNP's has included IS investment within its 5-year Capital Investment Plan (2021 to 2025)…"

b) Correct – the statement should have read:
"Figure 134 above illustrates the 5-year plan for General Plant expenditures…"

c) Correct – the statement should have read:
"This investment is a high priority within the System Service category as SCADA provides…"

2-Staff-29

Expectation of System Development

Ref 1: Exhibit 2, Section 5.4b pages 144, 146

Wellington North Power "forecasts electricity usage (kWh) and demand (kW) to remain static over the forecasted planning period of 2021-2025". Wellington North Power also forecasts population growth over the forecasted planning period of 2021-2025. Has Wellington North Power considered the impact of distributed energy resources, electric vehicle penetration, or other innovative technologies on load growth and demand over the forecast period?

WNP's Response:

Yes. For this DSP forecast period, WNP is not anticipating any signification load growth specific to DER, electric vehicles or other technologies in this rural area. A total of three EV Charging Stations are available in the service territory currently with limited usage.

2-Staff-30

Description of Tools and Methods Used for Risk Management

Ref 1: Exhibit 2, Section 5.4.1a page 147

Wellington North Power states that it maintains a Risk Register that is "used as a guide to assist the utility in identifying and managing risks". Please provide an investment example of where the Risk Register was used in the process of capital expenditure prioritization.

WNP's Response:

An example of using the utility's Risk Register to prioritize capital investment was demonstrated in the procurement of specific cyber-security software and controls in 2019 to enhance protection of data and information. Investment in cyber-security addresses the Ontario Cybersecurity Framework and, 2019's capital investment in cyber-security contributes to the "Protect" covenant of the Framework.

2-Staff-31

Capital Expenditure Summary – Meters

Ref 1: Exhibit 2, Section 5.4.2 page 158

Ref 2: Exhibit 2, Section 5.4.3.1 page 171

Ref 3: Exhibit 2, Section 5.4.3.2 page 175

Figure 106 indicates no costs for meter replacement over the 2018 – 2020 period. Figure 135 indicates an annual meter replacement cost of $25,000. Considering there were no meter replacement costs in the 2018-2020 period, how has Wellington North Power determined that $25,000 should be budgeted annually for the 2021 – 2025 period?

WNP's Response:

The table below shows the number of actual meters scrapped and cost in 2018 – 2020:

	2018	2019	2020
Meters Scrapped	105	96	133
Costs	$ 23,161.95	$ 24,038.40	**
Average Cost/ Meter	$ 220.59	$ 250.40	

** 2020 cost was not available at time of responding to IR.

The cost of the smart meter replacement was included in the Smart Meter Re-seal and Reverification line item.

The failure rate of the meters historically has a range of 2% and 3.5% or 76 to 136 meters. For the purpose of creating a budget, WNP estimated replacement of 100 meters per year at $250 per meter resulting in the $25,000 budget.

The average cost per meter will vary yearly depending upon the types of meters being scrapped i.e. 3-Phase vs 1-Phase.

2.0-VECC-18

Reference: Exhibit 2, Appendix 2A DSP, pg. 33

"*By having the meters tested and resealed, WNP decided it would be in the interest of its rate-payers not to replace the meters but to have them re-verified and resealed, extending the useful lives of the meters by **8 years***.." (page 33)

"*In 2017, WNP started the reverification of its Smart meters. This involves sending a sample of meters, based on the year of manufacturer, for verification according to Measurement Canada standards. The sampling was approved and meter populations were resealed for **six years***". (page 217)

a) Please clarify the meter extension period allowed by Measurement Canada for the testing and resealing of smart meters.

WNP's Response:

a) The meter seal extension is eight (8) years.

2-Staff-32

O&M Budget – Historic and Proposed

Ref 1: Exhibit 2, Section 5.4.3.1 page 169

Figure 128 shows budgeted O&M values for the 2016 – 2019 historical figures. Please provide actual O&M figures for this period.

WNP's Response:

The table below illustrates WNP's historical planned and actual Operations & Maintenance (O&M) expenses for 2016-2019:

	2016	**2017**	**2018**	**2019**
Budget System O&M ($000s)	$651	$667	$684	$701
Actual System O&M ($000s)	$661	$667	$638	$621

2-Staff-33

Overall Plan – System Renewal

Ref 1: Exhibit 2, Section 5.4.3.1 page 171

Figure 132 shows the amount of CapEx spent by Wellington North Power on replacing "poor health" poles and transformers over the 2017 – 2019 period.

a. Why is the 2016 historical information not included?
b. Please update figure 132 to include program work covering the 2016 – 2020 period.

WNP's Response:

a) The information for 2016 was accidently missed. The CapEx Cost for Replacement of Poor Health Poles and Transformers is also provided in Figure 106.

b) The table below includes the 2016 program work.

Figure 1 - CapEx Cost for Replacement of Poor Health Poles & Transformers

	2016	2017	2018	2019	4-year Average
Replacement of "Poor Health" Poles & Transformers	$63,564	$70,668	$69,163	$49,230	$63,156

2-Staff-34

Material Investments – System Renewal

Ref 1: Exhibit 2, Section 5.4.3.1 page 171

Ref 2: Exhibit 2, Section 5.4.3.2 page 177

Wellington North Power has provided costs for System Renewal related replacement of poles and transformers for the 2016 – 2019 historical period. Wellington North Power has also provided costs for System Renewal replacement of poles and transformers for the 2021 – 2025 forecast period. Wellington North Power also has an annual Replacement of Pole & Transformer Assets program that may result in poles in "poor" and "very poor condition" being replaced as part of that specific project. The ACA Flag for Action plan calls for 41 to 51 poles being replaced annually over the forecast period.

a. Please provide the actual number of poles and transformers replaced due to System Renewal during the 2016 – 2020 (2020 as current as possible) historical period.
b. Please provide the actual number of poles and transformers forecasted to be replaced under the annual Replacement of Pole & Transformer Assets program for the 2021 – 2025 forecast period.
c. What is the cost and how many poles are expected to be replaced annually in the Replacement of Pole & Transformer Assets program?
d. What is the cost and how many transformers are expected to be replaced annually in the Replacement of Pole & Transformer Assets program?

WNP's Response:

a) From 2016 to 2020 a total of 234 poles and 51 transformer were replaced due to System Renewal under the Replacement of Pole & Transformer Assets and Pole Line Construction Projects.

b) The Replacement of Pole & Transformer Assets Program for 2021 to 2025 is used to proactively replace assets found to be in poor condition specifically through the inspection programs such as infrared and pole testing. The figure shown in the 2021 to 2025 CapEx is an estimate and covers a range of "one off" pole and/or transformer replacements. The $55,000 requested is slightly below the 4 year average of $63,156.

c) As noted in "b)", the program is used for proactive asset replacement. Numbers of poles will vary year to year. WNP would estimate 5 to 8 poles of varying circuit configurations.

d) As noted in "b)", the program is used for proactive asset replacement and not planned replacement. Numbers of transformers will vary year to year. WNP would estimate 2 to 3 transformers.

2-Staff-35

CapEx Program: Pole-Line Rebuild Projects

Ref 1: Exhibit 2, Section 5.4.3.2 page 183, 186

Wellington North Power states it has a Pole-Line Rebuild program for 48 poles per year at an average cost of $3500 per pole.

a. For each of the pole-line projects noted in Figure 141, please provide the quantity of poles to be replaced and the present condition of the poles (poor, fair, good, etc.)
b. For each of the 2016- 2020 pole-line projects noted in Figure 106, please provide the quantity of poles replaced.
c. Are any transformers in poor or very poor condition expected to be replaced as part of the Pole-Line Rebuild program?
d. Please provide the relative dimensions of the Class 3 and Class 6 poles mentioned in the Pole-Line Rebuild program.
e. What is the proposed pole-line rebuild projects for the 2023 – 2025 period?

WNP's Response:

a) The follow table lists the pole-line projects noted in Figure 141 of WNP's 2020 DSP and includes the pre-engineering projected number of poles and their condition.

Year	Description	Poles Installed	Total	Condition
2021	Smith St (Frederick to Conestoga)	13		Poor - age, class and height
	Ayshire	11		Poor - Southern Yellow Pine, class
	Eliza (Leonard to Carrol)	8		Poor - age, open buss, short
	Misc Road Crossing Pole	12	44	Poor - age
2022	Holstein	11		Poor - age, class and height
	Wellington Rd 109	5		Poor
	Smith St (Preston to Agrisan)	10		Poor - fair
	Oxford	6		Poor - Southern Yellow Pine, class
	Misc Road Crossing Pole	9	41	Poor - age

b) Quantity of pole for each of the 2016 to 2020 pole-line projects as noted in Figure 106 of WNP's 2020 DSP:

Year	Description	Poles Installed	Total
2016	2nd Line Feeder	40	
	Pole & TX Replacements	6	46
2017	Queen St W (Phase 1)	22	
	Holstein	28	
	Pole & TX Replacements	12	62
2018	Isabella St	7	
	Adelaide St	12	
	Pole & TX Replacements	6	25
2019	William St	16	
	Preston St N	10	
	York St at Queen	6	
	Park Side Drive	1	
	Durham St	2	
	Pole & TX Replacements	7	42
2020	Eliza St	18	
	Tucker St	7	
	Queen St W (Phase 2)	9	
	Tucker St	7	
	Waterloo St	12	
	Pole & TX Replacements	6	59
		5 Year Total	234

c) Yes, it is WNP's process to inspect all transformers as they are taken down during the pole-line rebuild process. Any transformers in poor condition are removed from service.

d) Class ratings and dimensions are found in CSA Standard 015-15 Table 8. The lower the class size the greater the circumference (and strength) of the pole

Class		1	2	3	4	5	6	7	8
Minimum circumference at top, in		27	25	23	21	19	17	15	15
Length of pole, ft	Groundline distance from butt,ft*	Minimum circumference at 6 ft from butt, in							
20	4	32.5	30.5	28.5	26.5	24.5	22.5	21.0	20.0
25	5	36.0	33.5	31.0	29.0	27.0	25.0	23.0	22.0
30	5.5	39.0	36.5	34.0	31.5	29.0	27.0	25.0	24.0
35	6	41.5	38.5	36.0	33.5	31.0	28.5	26.5	25.5
40	6	44.0	41.0	38.0	35.5	33.0	30.5		
45	6.5	46.0	43.0	40.0	37.0	34.5	32.0		
S0	7	48.0	45.0	42.0	39.0	36.0			
55	7.5	49.5	46.5	43.5	40.5				
60	8	51.5	48.0	45.0	42.0				
65	8.5	53.0	49.5	46.0	43.0				

For example:
A 35 foot class 6 pole has a 28.5” minimum circumference 6 feet from the butt. Based on the circuit configurations the class 6 pole no longer meets safety clearance or strength requirements.

As a minimum, WNP would replace with a 45 foot class 3. The 45 foot class 3 has a 40” minimum circumference 6 feet from the butt.

e) 2023 to 2025 specific pole line projects are listed in the table below.

Year	Description
2023	Normanby St (Wellington to Birmingham) South Water St Glasgow Main St (Birmingham to Durham)
2024	Wellington St E (Newfoundland to London) Church St & Wellington (Holstein) Francis St (Charles to George) Leonard St (MS5 Feed)
2025 `	Preston St S Walton St York St Church St S Birmingham St (Egremont to Church St N)

2-Staff-36

CapEx Program: Underground Projects

Ref 1: Exhibit 2, Section 5.4.3.2 page 187

Wellington North Power states that the Underground Projects "focus on replacing areas where assets are circa vintage 1965-1970 and approaching the end of their life" and that "replacement of end of life underground assets including vaults, transformers and conduit".

a. Please provide details for the material underground projects expenditures in 2021, 2024 and 2025.

WNP's Response:

a) The projects identified as underground projects in Exhibit 2, Section 5.4.3.2 Figure 135 are outlined in the table below. The projects are the replacement of live front transformers and direct buried primary underground cables.

Proposed U/G Projects:

Year	Description	Transformers	Comments
2021	Forest Glen Crescent	3	Live Front Transformers & direct buried primary
2024	Forest Glen Drive (Phase A)	2	Live Front Transformers & direct buried primary
2025	Forest Glen Drive (Phase B)	1	Live Front Transformers & direct buried primary
	Church St S	1	Live Front Transformers & direct buried primary

2-Staff-37

CapEx Program: Computer – Hardware and Software

Ref 1: Exhibit 2, Section 5.4.3.2 pages 176, 192

Figure 136 provides Computer Hardware/Software/Cyber Security expenditures over the 2021-2025 forecast period while Figure 144 just provides Computer Hardware & Software expenditures over the 2021 -2025 forecast period.

a) Please breakdown the Computer Hardware/Software/Cyber Security numbers in Figure 136 into their separate categories as follows:

Expenditure type	2021	2022	2023	2024	2025
Computer Hardware					
Computer Software					
Cyber Security					

b) Please provide the business case for the Customer Information System in 2022.

WNP's Response:

a) In the table below, WNP has recreated Figure 136 "CapEx Plan 2021 to 2025 – Materiality Projects" from the DSP and split out expenditures as requested:

Project Name #5 General Plan	*Category*	**2021**	**2022**	**2023**	**2024**	**2025**
Hardware	*General Plant*	$76,200	$30,550	$48,950	$41,300	$24,500
Software	*General Plant*	$35,200	$130,000	$50,000	-	$97,500
Cyber-security	*General Plant*	$26,600	$10,000	$5,000	$42,000	$10,000
	Total	$138,000	$170,550	$103,950	$83,300	$132,000

b) The current 5-year maintenance agreement that WNP has with its' Customer Information System (CIS) provider is set to expire on December 31st 2021. As part of its' due diligence, WNP wants to consider what other alternative CIS solutions are available to an Ontario LDC.

2-Staff-38

Advance Capital Module

Ref 1: EB-2017-0082 Advance Capital Module model

Ref 2: 2.1.4 Fixed Asset Continuity Schedule, pp. 25 - 26

In the Advance Capital Module (ACM) model in reference 1, Wellington North Power used a full year depreciation for the purpose of calculating the ACM rate riders. In reference two, it appears Wellington North Power applied the half-year rule for the first year the asset was put into service.

a) Please explain the appropriateness of applying the half-year rule for calculating the ACM amounts to add into rate base when the ACM rate rider allowed Wellington North Power to recover a full year of depreciation.

b) Please recalculate Table 14-16 in reference two using a full year depreciation in 2018 and update chapter 2 appendices – 2-BA Fixed Asset Continuity Schedule.

WNP's Response:

a) WNP completed the ACM Model using the methods allowed at the time. WNP will make the changes requested to the ACM data.

b) The updated Fixed Asset Continuity tables are illustrated below:

Table 2 – 2018 ACM MS3 Substation: Incremental Capital Assets (Acct 1508)

2018	1508 - Incremental Capital Assets			Year	2018								
		Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value			
1508-1500-508-501	Sub Stations Power - Overall	$0	$402,938	$0	$402,938	$0	$8,954	$0	$8,954	$393,984		$ 201,469	$ 196,992
1508-1500-508-502	Sub Stations Power - Bushing	$0	$0	$0	$0	$0	$0	$0	$0	$0		$ -	$ -
1508-1500-508-503	Sub Stations Power - Tap Changer	$0	$0	$0	$0	$0	$0	$0	$0	$0		$ -	$ -
1508-1500-508-504	Sub Stations Switchgear - Overall	$0	$231,666	$0	$231,666	$0	$5,792	$0	$5,792	$225,874		$ 115,833	$ 112,937
1508-1500-508-505	Sub Stations - Station Switch	$0	$682,029	$0	$682,029	$0	$13,641	$0	$13,641	$668,389		$ 341,015	$ 334,194
1508-1500-508-506	Sub Stations - Rigid Busbars	$0	$0	$0	$0	$0	$0	$0	$0	$0		$ -	$ -
1508-1500-508-507	Sub Stations - Steel Structure	$0	$163,086	$0	$163,086	$0	$3,262	$0	$3,262	$159,825		$ 81,543	$ 79,912
1508-1500-508-508	Sub Stations - Fence	$0	$36,241	$0	$36,241	$0	$1,450	$0	$1,450	$34,792		$ 18,121	$ 17,396
1508-1500-508-509	Poles Towers & Fixtures - Wood	$0	$54,449	$0	$54,449	$0	$1,151	$0	$1,151	$53,299		$ 27,225	$ 26,649
1508-1500-508-510	O/H Conductors & Devices - Conductors	$0	$36,259	$0	$36,259	$0	$604	$0	$604	$35,654		$ 18,129	$ 17,827
1508-1500-508-511	U/G Conductors & Devices	$0	$5,780	$0	$5,780	$0	$145	$0	$145	$5,635		$ 2,890	$ 2,818
1508-1500-508-512	Reg - ICE Stn Services	$0	$54,445	$0	$54,445	$0	$1,361	$0	$1,361	$53,084		$ 27,222	$ 26,542
1508-1500-508-513	SCADA	$0	$26,000	$0	$26,000	$0	$2,600	$0	$2,600	$23,400		$ 13,000	$ 11,700
		$0	**$1,692,893**				**$38,958**			**$1,653,935**			

Table 3 – 2019 ACM MS3 Substation: Incremental Capital Assets (Acct 1508)

2019	1508 - Incremental Capital Assets			Year	2019								
		Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value			
1508-1500-508-501	Sub Stations Power - Overall	$402,938	$0	$0	$402,938	$8,954	$8,954	$0	$17,908	$385,029		$ 402,938	$ 196,992
1508-1500-508-502	Sub Stations Power - Bushing	$0	$0	$0	$0	$0	$0	$0	$0	$0		$ -	$ -
1508-1500-508-503	Sub Stations Power - Tap Changer	$0	$0	$0	$0	$0	$0	$0	$0	$0		$ -	$ -
1508-1500-508-504	Sub Stations Switchgear - Overall	$231,666	$0	$0	$231,666	$5,792	$5,792	$0	$11,583	$220,082		$ 231,666	$ 112,937
1508-1500-508-505	Sub Stations - Station Switch	$682,029	$0	$0	$682,029	$13,641	$13,641	$0	$27,281	$654,748		$ 682,029	$ 334,194
1508-1500-508-506	Sub Stations - Rigid Busbars	$0	$0	$0	$0	$0	$0	$0	$0	$0		$ -	$ -
1508-1500-508-507	Sub Stations - Steel Structure	$163,086	$0	$0	$163,086	$3,262	$3,262	$0	$6,523	$156,563		$ 163,086	$ 79,912
1508-1500-508-508	Sub Stations - Fence	$36,241	$0	$0	$36,241	$1,450	$1,450	$0	$2,899	$33,342		$ 36,241	$ 17,396
1508-1500-508-509	Poles Towers & Fixtures - Wood	$54,449	$0	$0	$54,449	$1,151	$1,151	$0	$2,301	$52,148		$ 54,449	$ 26,649
1508-1500-508-510	O/H Conductors & Devices - Conductors	$36,259	$0	$0	$36,259	$604	$604	$0	$1,209	$35,050		$ 36,259	$ 17,827
1508-1500-508-511	U/G Conductors & Devices	$5,780	$0	$0	$5,780	$145	$145	$0	$289	$5,491		$ 5,780	$ 2,818
1508-1500-508-512	Reg - ICE Stn Services	$54,445	$0	$0	$54,445	$1,361	$1,361	$0	$2,722	$51,723		$ 54,445	$ 26,542
1508-1500-508-513	SCADA	$26,000	$0	$0	$26,000	$2,600	$2,600	$0	$5,200	$20,800		$ 26,000	$ 11,700
		$1,692,893	**$0**				**$38,958**			**$1,614,977**			

Table 4 – Bridge Year 2020 ACM MS3 Substation: Incremental Capital Assets (Acct 1508)

2020	1508 - Incremental Capital Assets			Year	2020								
		Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value			
1508-1500-508-501	Sub Stations Power - Overall	$402,938	$0	$0	$402,938	$17,908	$8,954	$0	$26,863	$376,075		$ 402,938	$ 196,992
1508-1500-508-502	Sub Stations Power - Bushing	$0	$0	$0	$0	$0	$0	$0	$0	$0		$ -	$ -
1508-1500-508-503	Sub Stations Power - Tap Changer	$0	$0	$0	$0	$0	$0	$0	$0	$0		$ -	$ -
1508-1500-508-504	Sub Stations Switchgear - Overall	$231,666	$0	$0	$231,666	$11,583	$5,792	$0	$17,375	$214,291		$ 231,666	$ 112,937
1508-1500-508-505	Sub Stations - Station Switch	$682,029	$0	$0	$682,029	$27,281	$13,641	$0	$40,922	$641,107		$ 682,029	$ 334,194
1508-1500-508-506	Sub Stations - Rigid Busbars	$0	$0	$0	$0	$0	$0	$0	$0	$0		$ -	$ -
1508-1500-508-507	Sub Stations - Steel Structure	$163,086	$0	$0	$163,086	$6,523	$3,262	$0	$9,785	$153,301		$ 163,086	$ 79,912
1508-1500-508-508	Sub Stations - Fence	$36,241	$0	$0	$36,241	$2,899	$1,450	$0	$4,349	$31,892		$ 36,241	$ 17,396
1508-1500-508-509	Poles Towers & Fixtures - Wood	$54,449	$0	$0	$54,449	$2,301	$1,151	$0	$3,452	$50,997		$ 54,449	$ 26,649
1508-1500-508-510	O/H Conductors & Devices - Conductors	$36,259	$0	$0	$36,259	$1,209	$604	$0	$1,813	$34,446		$ 36,259	$ 17,827
1508-1500-508-511	U/G Conductors & Devices	$5,780	$0	$0	$5,780	$289	$145	$0	$434	$5,346		$ 5,780	$ 2,818
1508-1500-508-512	Reg - ICE Stn Services	$54,445	$0	$0	$54,445	$2,722	$1,361	$0	$4,083	$50,362		$ 54,445	$ 26,542
1508-1500-508-513	SCADA	$26,000	$0	$0	$26,000	$5,200	$2,600	$0	$7,800	$18,200		$ 26,000	$ 11,700
		$1,692,893	**$0**				**$38,958**			**$1,576,018**			

2-Staff-39

Asset Condition Assessment

Ref 1: Exhibit 2 – Distribution System Plan – 5.3.2. Overview of Assets Managed

Wellington North Power stated that it excluded line switches, cutouts, conductor, and meters due from the ACA study due to limited amounts of data.

a) Does Wellington North Power intend to extend the ACA to these items in the future?

The ACA notes that "in this study the "age" used is in fact "effective age", or condition- based age if available, as opposed to the chronological age of the asset."

b) Please explain how "effective age" or "condition-based age" is calculated.
c) Please confirm that "effective age" or "condition-based age" is the age usedin the age limiting calculation.
d) Please list the number of assets that defaulted to the age limiting factor.

WNP's Response:

a) WNP intends to incorporate the other devices into the ACA over time as more data is recorded. Meters will not likely be added since they are sealed under Measurement Canada requirements.

b) "Effective age" is derived from the condition-based Health Index score and chronological age related to the age limiting curve.

c) Age limiting curve is based on degradation rates of assets and was derived using typical useful life and extreme useful life specific to each asset category as the 2 points to generate these degradation curves.

d) Zero. All of the units in the ACA had at least some condition data. Since none of the units had age only, there was no need to use age limiting factor by default for any of the units.

2.0-VECC-16
Reference: Exhibit 2, Appendix 2A DSP, pg. 157 -158

a) Kinectrics has recommend that WNP improve data collection in four areas (transformers, switches and switchgear, comprehensive data filing, and updates of historical records). Please explain what steps are being taken during the DSP period to implement these recommendations.

WNP’s Response:

a) Please refer to the response to 2-Staff-24 item f).

2-Staff-40

Fleet

Ref 1: Exhibit 2 – Distribution System Plan – 5.3.2c – General Plant

Wellington North Power intends to replace three vehicles during the 2021 to 2025 period which are based on annual condition surveys and life cycle planning.

a) Please provide the condition surveys for the vehicles Wellington North Power intends to replace.

WNP's Response:

a) Please refer to the Applicant's response to interrogatory 2-Staff-26 part a).

2-Staff-41

Cost of Power

Ref 1: Exhibit 2 – 2.3.3. Calculation of Cost of Power

Ref 2: Chapter 2 appendices – 2-ZA and 2-ZB

Ref 3: Regulated Price Plan Report – November 1, 2020 to October 31, 2021,

December 13, 2020

Wellington North Power used the commodity prices from the Regulated Price Plan Report – November 1, 2019 to October 31, 2020 to complete appendix 2-ZA. The OEB issued the Regulated Price Plan Report – November 1, 2020 to October 31, 2021 on December 13, 2020.

a) Please update appendix 2-ZA with the new commodity prices.
b) The updated Ontario Electricity Rebate (OER) of 33.2% was effective November 1, 2020. In appendix 2-ZB, Wellington North Power used the old OER of 31.8%. Please update the OER value in appendix 2-ZB.
c) The number of customers used to forecast the smart meter entity charge in appendix 2-ZB uses 2020 customer numbers for residential and GS<50kW

WNP's Response:

a) The Applicant has updated worksheet "App.2-ZA Com.Exp.Forecast" of the 2021 Filing Requirements Chapter 2 Appendices workbook to include the electricity commodity prices from the "Regulated Price Plan Price Report – November 1, 2019 to October 31, 2020" as issued by the OEB.

b) The Applicant has updated worksheet "App.2-ZB Cost of Power" of the 2021 Filing Requirements Chapter 2 Appendices workbook to show the Ontario Electricity Rebate (OER) as 33.2%.

c) In the "App.2-ZB Cost of Power" of the 2021 Filing Requirements Chapter 2 Appendices workbook, the Applicant has updated the Smart Meter Entity Charge to use the forecasted customer numbers for 2021 Test Year.

Wellington North Power Inc. (WNP) has filed an updated set of models encompassing the above noted corrections or adjustments on the OEB's web-portal to support the Applicant's interrogatory responses.

2-Staff-43

Cost of Power

Ref 1: New Regulated Price Plan (RPP) Prices Effective January 1, 2021, December 15, 2020

Ref 2: Chapter 2 Appendices – 2-ZA and 2-ZB

The OEB issued updated RPP prices and Ontario Electricity Rebate percentage in reference 1.

a) Please update the models in reference 2 to reflect the changes in reference 1.

WNP's Response:

a) Please refer to the Applicant's response to interrogatory 2-Staff-41 Cost of Power.

2-Staff-42

Power Interruption Causes

Ref 1: Distribution System Plan - Figure 36 – All Causes of Power Interruptions

The power interruption cause "other" in reference 1 has a large increase in 2019 as compared to previous years.

a) Please provide details of the event(s) that lead to the increase in 2019.

WNP's Response:

a) The table below summarizes the 3 power outage events in 2019 in WNP's service territory that were classified as "unknown". Despite attempts by the Operations team to locate the faults the causes of the power outages still remain unknown.

2019 Power Outages: Cause – "Unknown"

Date	Status	Minutes Out	# of Customers	Total Customer Hours of Interruption	Cause Type	SAIDI	SAIFI
21-May 2019	Unplanned	516	1	8.60	0. Unknown / Other	0.002	0.000
23-May-2019	Unplanned	54	315	283.50	0. Unknown / Other	0.074	0.082
24-June-2019	Unplanned	15	38	9.50	0. Unknown / Other	0.002	0.010

2-VECC-15

Reference: Exhibit 2, page 68 / Appendix 2A DSP, PDF pg.96 and 99

a) Please explain why outages as shown in Figure 14 (Power Outage Records – pg.96) differ in part from Figure 17 on page 99. For example, the scheduled outages (line 1) total customers affected and total customer hours are shown for 2017 in Figure 14 as 509 and 273 respectively. In Figure 17 the equivalent figures are shown as 529 and 276.17.

b) Please update Figure 17 to include 2020 results.

WNP's Response:

a) In Figure 14: "Power Outage Records 2017-2019" the "Scheduled" values for 2017 were incorrect and should have been:

- Total customer affected = 529.
- Total customer hours = 276.17.

WNP has updated the table as per below:

Figure 14: Power Outage Records 2017-2019

		All Causes of Interruptions					
		2017		2018		2019	
Code	Description	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours
1	Scheduled	529	276.17	248	187.12	291	199.80
2	Loss of Supply	14,745	14,028.70	10,554	15,919.37	7,115	2,288.58
3	Tree Contact	1	1.00	1	6.13	1	1.57
4	Lightning	0	0.00	0	0.00	0	0.00
5	Defective Equipment	38	36.32	875	247.70	40	84.63
6	Weather	22	40.17	92	114.70	48	244.27
7	Adverse Environment	0	0.00	12	2.23	0	0.00
8	Human Element	0	0.00	0	0.00	0	0.00
9	Animal	9	20.33	42	41.32	16	93.32
10	Other	1	0.03	0	0.00	356	305.37
	Major Event	0.00	0.00	5,417	21,875.83	0.00	0.00
	Total	15,345	14,403	17,241	38,394	7,867	3,218

b) As requested, the able below includes 2020 power outage results:

Figure 17: Power Outages – All Causes of Interruptions from 2015 to 2020

		All Causes of Interruptions											
		2015		2016		2017		2018		2019		2020	
Code	Description	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours	Total Customers Affected	Total Customer Hours
1	Scheduled	154	146.87	346	209.72	529	276.17	248	187.12	291	199.80	198	179.08
2	Loss of Supply	17,728	34,856.75	10,230	16,330.52	14,745	14,028.70	10,554	15,919.37	7,115	2,288.58	4,146	5,078.10
3	Tree Contact	0	0.00	28	7.93	1	1.00	1	6.13	1	1.57	3	5.50
4	Lightning	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
5	Defective Equipment	30	42.97	54	55.37	38	36.32	875	247.70	40	84.63	1,060	1,516.48
6	Weather	10	12.33	609	2,216.20	22	40.17	92	114.70	48	244.27	25	240.10
7	Adverse Environment	0	0.00	0	0.00	0	0.00	12	2.23	0	0.00	0	0.00
8	Human Element	6	1.50	1	94.67	0	0.00	0	0.00	0	0.00	0	0.00
9	Animal	2	8.53	1	0.98	9	20.33	42	41.32	16	93.32	1	4.40
10	Other	16	26.02	1	0.17	1	0.03	0	0.00	356	305.37	9	9.60
	Major Event			0.00	0.00	0.00	0.00	5,417	21,875.83	0.00	0.00	5,679	30,619.63
	Total	17,946	35,095	11,270	18,916	15,345	14,403	17,241	38,394	7,867	3,218	11,121	37,653

2.0-VECC-17
Reference: Exhibit 2, Appendix 2A DSP, pg. 126

a) Please explain the source/reason of the loss of supply major events on August 29, 2018 and September 1, 2018.

WNP's Response:

a) The sources / reasons for the loss of supply major events are:

1. August 29th 2018:
   The event was a Loss of Supply. The Ontario Grid Control Centre (OGCC) confirmed that the fault was a broken conductor which was interrupting approximately 8 MW of Hydro One and LDC load.

   WNP's CEO/President was made aware of the outage through notifications received from the utility's internal SCADA system messaging advising that the power supply to the LDC's substations in Mount Forest had been lost. The SCADA messages indicate that the loss of supply to WNP's substations occurred at approx. 2:31am on August 29th 2018.

   OGCC issued an e-mail to its stakeholders, including WNP, at 2:49am on August 29th 2018 advising that its Hanover M5 feeder was forced from service after experiencing an auto reclose which resulted in significant load loss and it was determined that downstream, the Distribution stations at Hanover and Mount Forest were being affected by partial phasing. Once repairs to the broken conductor was completed by Hydro One, the power was restored at 7:56am on August 29th 2018.

2. September 1st 2018:
   This event was a "Loss of Supply".
   WNP's CEO/President was contacted by Hydro One Networks' Ontario Grid Control Centre (OGCC) on Saturday September 1st 2018 at approx. 9:31pm. OGCC advised of the following:
   - The Hanover M4 feeder had been automatically removed from service by protection operation by OGCC at approx. 7:41pm and would not automatically reclose resulting in an interruption to 20 MW of Hydro One and LDC load.
   - Hydro One line staff patrolled the feeder and discovered downed conductors on a section of the M4 feeder.
   - To facilitate repairs to the M4 feeder, Hydro One would need to remove the Hanover M5 feeder from service.

- OGCC advised that the supply to WNP would be interrupted while repairs were being carried out and informed WNP's CEO/President that the interruption would be approx. 20 mins, starting at 9:35pm on September 1st 2018.
- Once the repairs were made, other significant issues were found. After load analysis checks were completed, Hydro One decided to switch the supply feeding WNP's service territory from Hanover TS to Palmerston TS. The supply switching to Palmerston TS was completed and power was restored to WNP affected customers at approx. 12:15am on September 2nd 2018.

Note: WNP is fed from Hydro One's Hanover M5 feeder. This feeder supplies power to WNP's service territory of Holstein and Mount Forest.

Exhibit 3 – Operating Revenue

3-Staff-44

Volumetric Load Forecast

Ref 1: Exhibit 3, page 28

Ref 2: Load Forecast Model, Tab: Load Forecast Summary

Wellington North Power has used a Sensitive Customers kWh explanatory variable in its linear regression. It states that it "has five customer accounts in its General Service 1,000-4,999 kW customer class, all of which are manufacturers."

Wellington North Power indicates that in its prior cost of service, it "removed data for three specific accounts from the analysis due to their negative effect on the results of the regression analysis." Here it "has included the GS>1,000-4,999kW customers in the regression analysis and created a variable based on their monthly billed kWh (without losses)."

The load forecast indicates that the rate class has had at least 5 customers since 2010, the first year for which data is provided. In 2019, the variable used totaled 50.5 GWh, 2020, it totaled 52.1 GWh, and in 2021, it totaled 52.8 GWh. In all three years, the forecast for the GS 1,000 – 4,999 kW rate class totals 42.8 GWh.

a) How has the energy consumption for these customers been forecasted for 2020 and 2021?
b) Why did Wellington North Power select five customers to use in the explanatory variable this time, instead of the three customers as it had removed from its regression methodology in its last load forecast?
c) As a scenario, please prepare a forecast where the consumption of the GS 1,000 – 4,999 kW customers are uplifted for losses and removed from the wholesale purchases, and the resulting wholesale purchase model is used to forecast all rate classes except GS 1,000 – 4,999 kW. In this scenario, please forecast these customers using the methodology proposed for sensitive customers.
d) Please explain the difference in consumption between the Sensitive Customers variable, and the GS 1,000 – 4,999 kW rate class, and why the Sensitive Customers variable changes in the forecast years, while the GS 1,000 – 4,999 kW forecast consumption remains constant.

WNP's Response:

a) In rate class GS 1,000 – 4,999 kW, the metered usage for the past 5 years has continued to decline and the number of customers has remained the same as illustrated in the table below:

Year	Metered Usage	# of Customers	Avg Metered Usage per Customer
2015	47,530,355	5	9,506,071
2016	45,496,516	5	9,099,303
2017	45,750,527	5	9,150,105
2018	43,913,956	5	8,782,791
2019	42,766,148	5	8,553,230
Average	**45,091,500**	**5**	**9,018,300**

This rate-class is not weather sensitive (affected by HDD or CDD). And, as detailed in section "3.2.3 Final CDM Adjusted Load Forecast" of Exhibit 3 (page 54), the Applicant is not making a CDM adjustment for years 2020 and 2021 for any of its' rate classes. Therefore, the Applicant used the actual metered usage of 2019 of 42.8 GWh as its' forecast for the GS 1,000 – 4,999 kW rate class.

b) As demonstrated in the table in part a) the metered usage for customers in GS 1,000-4,999 kW rate class has declined since 2015. Since July 2018, all customers in this rate class have opted-in and participate in the IESO's Industrial Conservation Initiative (ICI). Since its' last load forecast of 2016, the utility has observed more "sensitivity" for all 5 customers in this rate class.

c) The Applicant has filed this scenario on the OEB's web portal as "3-Staff-44 Load Forecast GS1000-4999 kW – Scenario".
Please note that the scenario is provided for illustrative purposes only. By providing this information, WNP is not committing to adopting these changes for rate making purposes.

d) The Sensitive customers variable changes in the forecast years because a 10-year average has been applied to actuals (2020 to 2019) to derive the monthly variable for months January 2020 to December 2021. The forecast consumption remains constant as explained in part a) above.

3.0-VECC-19

Reference: Exhibit 3, page 28

The title for Table 17 indicates that the values are Sensitive Customers Billed kWh (with Losses). However, the preceding sentence indicates that the values are monthly billed kWh (without losses). Please reconcile and if the values include losses please indicate what loss factor was used.

WNP's Response:

The Applicant confirms the values in Table 17 of Exhibit 3 (page 28) illustrates the Sensitive Customers Billed kWh with Losses for the months of January 2010 to December 2019.

The metered usage was multiplied by the OEB-approved loss factor of:

- 2010 – January to December = 1.0699
- 2011 – January to December = 1.0699
- 2012 – January to September = 1.0699
- 2012 – October to December = 1.0716
- 2013 – January to December = 1.0716
- 2014 – January to December = 1.0716
- 2015 – January to December = 1.0716
- 2016 – January to April = 1.0716
- 2016 – May to December = 1.0656
- 2017 – January to December = 1.0656
- 2018 – January to December = 1.0656
- 2019 – January to December = 1.0656

3-Staff-45

Impacts of COVID-19

Ref 1: Exhibit 3, page 28-29, 36

Wellington North Power noted that it observed all customers in the General Service 1,000 – 4,999 kW rate class were affected in April 2020 due to the COVID-19 pandemic. It states that it "has not assumptions to account for the impact of COVID-19 in the Bridget Year (2020) or Test Year (2021) and WNP will track any lost revenue from these customers in the COVID regulatory account if one or more of the customers in this rate class close because of the pandemic."
Wellington North Power states that it "is tracking deviations from the load forecast caused by COVID-19 in the regulatory COVID account as announced by the OEB."

a) In the event that the final direction from the OEB regarding the COVID-19 accounts is incompatible with Wellington North Power's plans, does it plan to follow the COVID-19 related direction from the OEB, or is it seeking approval for the approach described in this application? Does Wellington North Power propose to track lost revenue only from customers in the General Service 1,000 – 4,999 rate class, or other classes as well. If others as well, which ones?
b) Please confirm that only customer closures due to the pandemic are proposed to be captured in the COVID regulatory account.
c) If a customer closes, how will Wellington North Power determine whether the closure was due to the pandemic or other factors?
d) How is Wellington North Power determining which deviations from the load forecast are caused by COVID-19 for the purpose of tracking in the regulatory COVID account?

WNP's Response:

For WNP's Load Forecast and customer growth, the LDC has assumed a "business as normal" operating conditions and has not adjusted its forecasts due to the unknown effect, or duration, of the COVID pandemic to our customers and their energy usage behavioural patterns.

a) WNP's plans on following the OEB COVID-19 related direction. Since the time of the writing of the application, WNP has determined that it will only recover the lost revenue from the delayed rate increase, as per the Final Rate EB-2019-0073 regarding the LDC's Distribution rates for May 1st 2020 being implemented on November 1st 2020.

   WNP recognizes that this has been a challenging season for our customers. Many residential and business customers continue face financial hardships including but not limited to job loss, difficulty with cash flow and lower income. As a result, WNP's Board and Management have decided to not seek recovery of costs or lost revenue associated with COVID as recorded in Account 1509.

   To clarify, none of the COVID-19 expenses or lost revenue due to shutdowns from 2020 will be entered into 1509.

Please refer to WNP's response to 1-Staff-3.

b) WNP will not be seeking to recover any lost revenue due to decreased electricity usage or business closures due to COVID-19.

c) Not Applicable.

d) Not Applicable.

3.0-VECC-22

Reference: Exhibit 3, page 36

a) Please explain how WNP is calculating the 2020 deviations from the load forecast caused by COVID-19 for purposes of the regulatory COVID account.

WNP's Response:

WNP recognizes that this has been a challenging season for our customers. Many residential and business customers continue face financial hardships including but not limited to job loss, difficulty with cash flow and lower income. As a result, WNP's Board and Management have decided to not seek recovery of costs or lost revenue associated with COVID as recorded in Account 1509.

For WNP's Load Forecast and customer growth, the LDC has assumed a "business as normal" operating conditions and has not adjusted its forecasts due to the unknown effect, or duration, of the COVID pandemic to our customers and their energy usage behavioural patterns.

a) WNP will not be seeking to recover any lost revenue due to decreased electricity usage or business closures due to COVID-19.

3-Staff-46

Volumetric Load Forecast

Ref 1: Exhibit 3, page 24

Ref 2: Load Forecast Model, Sheet 2a) Power Purchased Model

Wellington North Power has provided 10-Year average Heating Degree Days (HDD) and Cooling Degree Days (CDD) and used these in the forecast of 2020 energy.
However, the load forecast model (LFM) uses different weather data.

	HDD			CDD		
	Exhibit 3	LFM - 2020	LFM - 2021	Exhibit 3	LFM - 2020	LFM - 2021
Jan	789.65	789.65	789.47	0.00	0.00	0.00
Feb	698.95	698.95	700.84	0.00	0.00	0.00
Mar	614.93	614.93	625.95	0.34	0.34	0.37
Apr	394.49	394.49	406.62	0.10	0.10	0.01
May	168.45	168.45	170.48	16.08	16.08	15.29
Jun	57.87	57.87	58.13	28.28	28.28	29.23
Jul	17.11	17.11	17.55	72.36	72.36	70.63
Aug	24.60	24.60	25.13	52.28	52.28	49.30
Sep	102.41	102.41	98.95	25.18	25.18	26.14
Oct	283.30	283.30	281.53	1.32	1.32	1.45
Nov	487.21	487.21	492.00	0.00	0.00	0.00
Dec	655.25	655.25	646.35	0.00	0.00	0.00

a) Please reconcile the differences and explain why the 2010 to 2019 average as supplied in Exhibit 3 was not used to forecast 2021.

Wellington North Power indicates that in forecasting the Employment Factor, it "Used the 10-year Trend of 2010 to 2019 data and applied to both 2020 and 2021."

b) Has Wellington North Power considered other options such as independent forecasts of regional or provincial employment growth? If not, why not? If so, what was the outcome, and why were they dismissed?

The resulting model has an intercept of -724,236.

c) Please provide an explanation of why Wellington North Power believes the negative intercept is reasonable.
d) Please provide an analysis of multicollinearity of the variables chosen, and if multiple variables are found to be significantly correlated, please explain why it is appropriate to include both.

WNP's Response:

a) Under the OEB's Filing Requirements, there is no requirement for the Test Year 2021 to use the same 10 year HDD and CDD average (2010-2019) as used for the Bridge Year (2020). Exhibit 3 shows a 10-year historical average used to determine the bridge year (2010-2019) however, WNP used an average of 2011-2020 to predict its 2021 test year).

b) The Wholesale Load Forecast Power Purchase excel file submitted with the Application on October 30, 2020, includes the Regional Employment variable.

In Exhibit 3 – Revenues, section "3.1.17 Overview of Variables Used" (page 25), it discusses the Regional Employment variable as used in the load forecast. And, page 29, Table 18 illustrates how the variable was applied in the Bridge and Test Year.

c) The constant just represents the expected value of the outcome when all predictors (independent variables) are equal to zero. The sign of a regression coefficient tells you whether there is a positive or negative correlation between each independent variable the dependent variable. A negative coefficient suggests that as the independent variable increases, the dependent variable tends to decrease.

d) The table below shows the multicollinearity of the variables chosen.

	Coefficients	Standard Error	t Stat	p Value	R Squared	Coefficient	Intercept	Dl=1.69 Du=1.72	Adjusted R-Squared against other Indep	Variables With RSQ at > 90%
Intercept	-724,234.718	653,583.754	-1.108	27.02%				**DW-Stat**		
HDD	2,597.635	65.383	39.729	0.00%	47.19%	1433.71	8483169.00	**0.34**	53.75%	
CDD	10,105.531	678.556	14.893	0.00%	9.45%	-6935.83	9109465.00	**0.84**	49.81%	
# of Days in Month	124,979.132	15,464.215	8.082	0.00%	1.93%	98914.74	5985918.00	**2.96**	3.90%	
Regional Employment	1,781.928	813.569	2.190	3.06%	0.51%	-1314.94	9917054.00	**0.30**	76.95%	
CDM	-1.367	0.222	-6.150	0.00%	0.26%	-0.27	9068164.00	**0.01**	74.55%	
Sensitive Customers	0.907	0.034	27.014	0.00%	10.06%	0.45	7042802.00	**1.12**	18.94%	

WNP is of the opinion that the variables chosen are not significantly correlated therefore the Applicant confirms its' choice of variables.

Please note that the scenario is provided for illustrative purposes only. By providing this information, WNP is not committing to adopting these changes for rate making purposes.

3.0-VECC-20

Reference: Exhibit 3, pages 29-30

a) Are the historical values for Regional Employment available from Stats Can on a monthly basis?
   i. If not, on what basis are they available and how were the monthly values used in the regression analysis derived?
b) Please explain more fully and provide the supporting calculations as to how the 10-year trend for the employment factor was derived from the 2010 to 2019 data and how it was used to forecast the 2020 and 2021 monthly values (e.g., was separate trend established for each month).
c) Please explain more fully and provide the supporting calculations as to how the 10-year trend for the Sensitive Customers' kWh was derived from the 2010 to 2019 data and how it was used to forecast the 2020 and 2021 monthly values (e.g., was separate trend established for each month).

WNP's Response:

a) Yes. The Applicant confirms the monthly Regional Employment values from Stats Can was used as a coefficient variable in its Wholesale Load Forecast.

b) As noted in "Table 18 – Treatment of Variables in Bridge & Test Year" on page 29 of Exhibit 3, the Applicant used a 10-year trend of 2010 to 2019 monthly values to determine monthly values for 2020 and 2021.

The table below shows the monthly Regional Employment values from Stats Can for 2010 to 2019 and the calculated trend values for 2020 and 2021:

											Trend	
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
January	633.60	649.30	670.90	681.60	689.40	705.70	715.80	695.30	703.70	748.70	749.30	756.10
February	630.50	651.20	668.70	682.60	682.30	700.10	710.90	696.50	692.60	741.30	749.80	756.56
March	627.50	657.10	666.00	683.60	680.20	698.30	709.40	697.80	688.90	733.80	750.21	757.02
April	631.60	666.40	667.40	685.40	679.40	697.60	707.40	705.60	695.40	734.00	750.53	757.55
May	641.50	671.50	672.10	690.30	690.00	704.90	712.40	717.20	704.20	747.10	750.88	758.22
June	657.20	681.80	678.40	696.70	704.40	715.10	714.60	736.20	720.20	762.30	751.36	758.95
July	669.80	691.50	682.00	702.80	715.10	716.60	712.30	747.10	739.30	764.20	752.08	759.86
August	672.00	694.90	678.50	701.40	718.70	713.10	707.10	752.80	747.90	760.20	753.00	760.92
September	665.10	688.60	671.90	698.40	719.30	710.20	702.40	744.40	745.50	756.50	753.95	762.05
October	657.20	682.20	672.80	698.40	723.50	716.90	702.30	735.00	742.10	760.70	754.79	763.09
November	622.20	677.00	676.80	700.00	721.00	721.00	680.08	726.20	745.70	758.40	755.47	764.01
December	653.30	676.60	682.70	695.40	714.30	718.70	678.47	716.50	751.00	756.50	755.55	764.85

In excel, the formula used was:

=trend (monthly Reg. Employ values 2010 2019, month count 1-120, monthly forecast period 2020 to 2021)

c) For As noted in "Table 18 – Treatment of Variables in Bridge & Test Year" on page 29 of Exhibit 3, it states the Applicant used "*10-year trend on the actual monthly billed kWh (without losses) values and applied to both 2020 and 2021*" – this is incorrect.

In the load forecast, the Sensitive Customers monthly variable values for 2020 and 2021 were determined by the 10-average of each month's billed with loss values. The table below shows the 2010 to 2019 billed with loss kWh values and the resulting monthly averages for January to December for 2020 and 2021:

											10-yr Average	
Sensitive Customers	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	2020	2021
January	3,487,296	3,844,683	4,250,570	4,525,947	4,667,490	4,513,683	4,405,571	4,687,093	4,526,353	4,403,212	4,331,190	4,415,579
February	3,203,841	3,768,297	4,141,903	4,293,132	4,342,401	4,307,575	4,328,369	4,246,253	4,091,882	3,946,642	4,067,029	4,153,348
March	3,646,819	4,320,214	4,592,874	4,392,825	4,788,789	4,884,587	4,524,815	4,726,111	4,458,043	4,369,393	4,470,447	4,552,810
April	3,531,303	3,411,270	4,218,127	4,685,486	4,624,196	4,732,559	4,449,083	4,367,736	4,217,020	4,248,726	4,248,551	4,320,275
May	3,786,484	3,753,616	4,557,568	4,795,235	4,967,135	5,023,123	4,474,576	4,615,335	4,625,443	4,400,983	4,499,950	4,571,296
June	3,861,171	3,885,860	4,499,266	4,516,928	4,578,201	4,909,278	4,649,235	4,628,754	4,420,602	4,127,497	4,407,679	4,462,330
July	3,721,818	3,654,592	4,141,164	4,372,227	4,518,533	4,834,398	3,951,978	4,242,129	4,194,517	4,161,544	4,179,290	4,225,037
August	4,170,740	4,498,565	4,856,394	4,771,016	4,873,161	5,059,556	5,045,747	4,968,790	4,725,689	4,590,396	4,756,005	4,814,532
September	3,919,809	4,242,245	4,216,762	4,513,365	4,845,023	5,022,140	4,829,713	4,504,351	4,238,332	4,357,475	4,468,921	4,523,833
October	3,943,157	4,411,474	4,599,892	4,880,787	4,964,577	4,871,537	4,731,581	4,755,960	4,538,667	4,416,878	4,611,451	4,678,280
November	3,894,738	4,082,024	4,092,980	4,552,413	4,377,795	4,473,874	4,636,843	4,578,001	4,247,843	4,037,559	4,297,407	4,337,674
December	3,453,656	3,790,571	3,797,850	4,004,843	3,953,464	3,903,048	4,074,210	3,605,479	3,518,108	3,487,389	3,758,862	3,789,382

3.0-VECC-21

Reference: **Exhibit 3, page 31**

a) Please confirm that the -1.37 coefficient for CDM means for every kWh of persisting CDM monthly purchases are reduced by 1.37 kWh.
b) In WNH's view does this result make sense intuitively and, if yes, why?
c) Please provide an alternative purchased power model (i.e., coefficients and statistical results) along with the resulting 2020 and 2021 load forecast where:
   i. The monthly purchased power values used to estimate the regression equation are increased by the persisting monthly CDM and the regression equation is estimated using the balance of the explanatory variables as set out in the Application.
   ii. The 2020 and 2021 monthly purchases are first forecast using this regression model and the forecast values for the explanatory variables per step (i).
   iii. The resulting 2020 and 2021 forecast monthly purchases are reduced by the persisting CDM forecast for each month as set in the Application.

WNP's Response:

a) WNP confirms VECC's statement that the -1.37 coefficient for CDM means for every kWh of persisting CDM monthly purchases are reduced by 1.37 kWh.

b) A negative coefficient would suggest that as the independent variable, in this case the CDM variable, increases, the dependent variable – monthly purchases, tends to decrease. WNP is of the opinion that the relationship between both variables in this case is intuitive and therefore the results justified.

c) The requested scenario has been filed on the OEB's web portal as "3-VECC-21- Wholesale Load Forecast Scenario".
   i. In worksheet "2a. Power Purchased Model" of the excel file, column F was adjusted to add back the CDM savings from column K.
   ii. The regression was re-run using all variables except the CDM variable. The additional worksheets were added to the model to reflect the input and regression results. The results was then imputed in worksheet 2a. Power Purchased Model at cells V3 to AD22.
   iii. The predicted purchases for 2020 and 2021 were calculated to remove the persisting CDM. The calculations are shown at cells Q162 and Q163. The values are referenced in the calculations in 3a. Rate Class Energy Model worksheet.

Please note that the scenario is provided for illustrative purposes only. By providing this information, WNP is not committing to adopting these changes for rate making purposes.

3-Staff-47

LED Conversion

Ref 1: Exhibit 3, page 36-39

Wellington North Power states that it has completed a street light conversion project in 2019 "to replace all high-pressure sodium (HPS) lights used in the streetlights with light emitting diodes (LEDs) in Arthur and Mount Forest owned by the Township of Wellington North Power." This project was approved in Quarter 1 2019 and completed by the end of November 2019. However, it indicates that the same 63.6 kW in Arthur and 92 kW in Mount Forest was charged in the entire year of 2019, only reducing to 15.6 kW in Arthur, and 34.23 kW in Mount Forest in January of 2020.

The change in Arthur reflects a 75% reduction in billing demand, and the change in Mount Forest reflects a 63% reduction in billing demand.

a) Please confirm, that Wellington North Power charged its street lighting customers based on the historic load through to December 2019 despite the project having been completed in the prior month.
b) Please provide any details on consultations Wellington North Power had with its street lighting customers regarding the appropriateness of these charges

WNP's Response:

a) WNP confirms the following:
   - The Arthur LED-conversion projects for all streetlights was completed in October 2019.
     For November 2019's usage onwards, WNP billed the customer the using lower kW demand as a result of the streetlight LED-conversion.
   - The Mount Forest LED-conversion projects for all streetlights was completed in December 2019, not November 2019 as noted in Exhibit 3 page 37.
     For January 2020's usage onwards, WNP billed the customer the using lower kW demand as a result of the streetlight LED-conversion.
     WNP acknowledges the error in Exhibit 3 of stating a project completion date of November rather than December 2019. The LDC understands how this could be construed by parties reading the document that the utility incorrectly billed the customer for December's usage.

b) WNP provided regular progress updates to the customer during the project period as well as notifying them when the project was completed.
   The customer (Township) was made aware of the estimated saveONenergy™ incentive in advance. And, the customer (Township) was made aware that there would also be a reduction to their street lighting invoices based on the LED conversion.

3.0-VECC-23

Reference: Exhibit 3, pages 36-37

a) With respect to the streetlights in Arthur and Mount Forest, please confirm that while the conversion was approved in Q1 of 2019 and completed by the end of November 2019, the kW used to bill for these streetlights was not adjusted until the bills for January 2020.
b) If the conversion occurred during 2019 won't WNP's purchased power values for 2019 capture the impact of the conversion as it occurred such that by December 2019 the purchased power values would reflect the full impact of the conversion? If not, why not?
c) Does the CDM variable used in the regression model include the impact of the streetlight conversion programs for Holstein and Arthur/Mount Forest?
    i. If not, why not?
    ii. If yes, please provide a reference to the IESO reports.

WNP's Response:

a) Please see response to interrogatory 3-Staff-47 part a).

b) As noted in response to 3-Staff-47, WNP acknowledges an error in Exhibit 3 of stating a project completion date of November rather than December 2019. Therefore, the Applicant a corrected statement would be the purchased power values would reflect the full impact of the conversion by January 2020 rather than December 2019

c) No, the CDM variable used in the regression model does not include the impact of the streetlight conversion programs.
    i. As noted in section 3.2.1 Load Forecast CDM Adjustment Work Form" of Exhibit 3 (page 51), there was an absence of information from the IESO concerning the results of the streetlight conversion.
    WNP repeatedly asked the IESO for information with no success. In June 2020, the IESO e-mailed LDC with the following:

    "As the IESO no longer provides LDC-level project data, we recommend that Wellington North Power rely on its internal resources and prior reports issued by the IESO for this data.

    To help address your concerns about the validity of the numbers in Wellington North Power's LRAM submission, please note that all LDCs are providing unverified data to the OEB for 2019. This is as a result of the framework reporting changes that took place in 2019 when the Conservation First Framework ended and the Interim Framework started."

    ii. There are no IESO reports available as mentioned in response to (i) above.
    The streetlight LED conversion program was approved in Quarter 1 2019 and field work began in August 2019.

3.0-VECC-24

Reference: **Exhibit 3, page 38**

WNP Load Forecast Model, Rate Class Energy Model Tab

a) Please reconcile the 2019 kWh for Streetlights in Table 27 (page 38) of 691,016.89 kWh with the 2019 value in the Rate Class Energy Model Tab of 650,270 kWh.

WNP's Response:

a) The 2019 Streetlight data of 650,270 kWh in the Rate Class Energy Model worksheet of the load forecast filed is correct. Table 27 on page 38 of Exhibit 3 was incorrect.
Below is a corrected Table 27:

Table 27 – Actual kWh and kW Streetlight Data for 2019

Light Type	**Arthur Streetlights** *HPS* kWh *(without Loss)*	kW	**Mount Forest Streetlights** *HPS* kWh *(without Loss)*	kW	**Holstein Streetlights** *LED* kWh *(without Loss)*	kW	**Total Streetlights** **kWh** *(without Loss)*	**kW**	*Data*
Jan-19	30,052.64	63.60	43,507.26	92.00	1,361.52	2.90	**74,921.42**	**158.50**	*Actual*
Feb-19	25,809.56	63.60	37,364.60	92.00	1,169.28	2.90	**64,343.44**	**158.50**	*Actual*
Mar-19	25,618.71	63.60	37,088.09	92.00	1,160.64	2.90	**63,867.44**	**158.50**	*Actual*
Apr-19	21,454.80	63.60	31,060.20	92.00	972.00	2.90	**53,487.00**	**158.50**	*Actual*
May-19	19,706.70	63.60	28,529.61	92.00	892.80	2.90	**49,129.11**	**158.50**	*Actual*
Jun-19	16,210.50	63.60	23,468.10	92.00	734.40	2.90	**40,413.00**	**158.50**	*Actual*
Jul-19	17,243.44	63.60	24,963.37	92.00	781.20	2.90	**42,988.01**	**158.50**	*Actual*
Aug-19	19,214.11	63.60	27,816.30	92.00	870.48	2.90	**47,900.89**	**158.50**	*Actual*
Sep-19	20,978.10	63.60	30,370.20	92.00	950.40	2.90	**52,298.70**	**158.50**	*Actual*
Oct-19	24,633.22	63.60	35,661.78	92.00	1,116.00	2.90	**61,411.00**	**158.50**	*Actual*
Nov-19	7,356.32	15.60	38,652.60	92.00	1,209.60	2.90	**47,218.52**	**110.50**	*Actual*
Dec-19	8,158.20	15.60	42,794.26	92.00	1,339.20	2.90	**52,291.66**	**110.50**	*Actual*
Total	**236,436.30**	**667.20**	**401,276.37**	**1,104.00**	**12,557.52**	**34.80**	**650,270.19**	**1,806.00**	

Note: Arthur Streetlights Nov-19 and Dec-19 data is for LED not HPS bulbs as the LED conversion was completed in October 2019.

3.0-VECC-25

Reference: Exhibit 3, pages 40-41

WNP Load Forecast, Rate Class Customer Model Tab

a) Page 40 indicates that the customer count values are yearly averages. How was the average for each year calculated?
b) Please provide a schedule that sets out the number of accounts/connections by customer class as of June 30, 2020 and December 31, 2020.
c) Page 40 indicates that the forecast number of Streetlight Connections for 2021 is 924. However, the Cost Allocation Model (Tab I6.2) reports 889 Connections and 924 Devices for Streetlights for 2021. Please clarify whether the values in Exhibit 3 are number of devices or number of connections.
d) The Application (page 41) indicates that the connection count for Streetlights was revised as a result of a recount during the LED conversion project. However, the Rate Class Customer Model Tab (see Comment 1) suggests that additional connections were installed during the project. Please clarify.

WNP's Response:

a) The customer/connections counts in Table 30 (page 40) of Exhibit 3 are calculated by the sum of the monthly customer counts/connections for the year divided by 12 months. The monthly count is as at month-end. See below for example:

Month-Year	Residential # of Customers at Month-end	Average
Jan-19	3,293	Yearly average number of Residential customers for 2019 is: = 39,623 / 12 months = 3,302 customers
Feb-2019	3,292	
Mar-2019	3,296	
Apr-2019	3,301	
May-2019	3,300	
Jun-2019	3,300	
Jul-2019	3,305	
Aug-2019	3,303	
Sep-2019	3,306	
Oct-2019	3,301	
Nov-19	3,312	
Dec-19	3,314	
Total	**39,623**	

b) Please see schedule below as requested:

	Residential	GS <50 kW	GS 50-999 kW	GS 1,000-4,999 kW	USL	Sentinel	Streetlights
	Customers	*Customers*	*Customers*	*Customers*	*Connections*	*Connections*	*Devices*
Jun 30, 2020	3,324	472	37	5	2	23	924
Dec 31, 2020	3,346	469	39	5	2	21	924

c) WNP confirms the values in Table 30 (page 40) of Exhibit 3 are number of devices for streetlights.

d) WNP confirms that both statements are true, that is:
   i. During the LED conversion project, there was a re-count of the existing number of streetlight devices.
   ii. During 2019, new LED streetlight devices were added to sub-divisions by developers to meet the design specifications of the Township. Once the new streetlights are energized, they are assumed by the Township.

3.0-VECC-26

Reference: **Exhibit 3, pages 26-27**

WNP Load Forecast, Purchased Power Model Tab

WNP 2017 Final Annual Verified CDM Program Results

WNP Participation and Cost (P&C) Report, April 2019

a) Please provide copies of the OPA's published results for 2006-2010 as used to complete Table 15.

b) Please provide a schedule/excel file that for each of the program years 2006 to 2010 sets out the persisting annualized (i.e., without the ½ year rule) CDM impacts through to 2021 as follows:

Impact of Historical and Forecast Annualized CDM					
Calendar Year/ CDM Program Year	2006	Columns for Each Subsequent Year up to 2020			2021
2006 CDM Program Impacts					
Actual CDM impacts for each year to 2009 – one row per year					
2010 CDM Programs Impacts					
Total					

c) Please provide the OPA/IESO reports that support the CDM activity values used for the 2011 to 2014 programs in Table 15.

d) Please provide a schedule/excel file that for each of the program years 2011 to 2014 sets out the persisting annualized CDM impacts through to 2021 as follows:

Impact of Historical and Forecast Annualized CDM					
Calendar Year/ CDM Program Year	2011	Columns for Each Subsequent Year up to 2020			2021
2011 CDM Program Impacts					
Actual CDM impacts for each year to 2013 – one row per year					
2014 CDM Programs Impacts					
Total					

e) In the IESO's Report regarding 2017 Final Annual Verified CDM Program Results the LDC Savings Persistence Tab shows net savings in 2015 from 2015 programs of 806,905 kWh – half of which is

403,453 kWh. It is noted that the April 2019 P&C Report also reports a very similar value for savings in 2015 from 2015 programs of 806,903 kWh. However, Table 15 shows a value for 2015 (using the ½ year rule) of 396,066. Please reconcile.

f) Similarly, the value in Table 15 for savings in 2016 from 2015 & 2016 CDM Programs (1,088,425 kWh) does not match 1,093,293 kWh - the sum of the net savings in 2016 from 2015 Programs (802,794 kWh) plus ½ of the net savings in 2016 from 2016 Programs (0.5 x 580,997 kWh) as provided in IESO's Report regarding 2017 Final Annual Verified CDM Program Results, LDC Savings Persistence Tab. It is noted that the April 2019 P&C Report sets out a value for savings in 2016 from 2016 Programs of 594,557 kWh – which leads to larger discrepancy. Please reconcile.

g) Similarly, the value in Table 15 for savings in 2017 from 2015-2017 CDM Programs (1,812,828 kWh) does not match 1,855,136 kWh - the sum of the net savings in 2017 from 2015 CDM Program and 2016 Programs (1,383,378 kWh) plus ½ of the net savings in 2017 from 2017 Programs (0.5 x 943,515 kWh) as provided in IESO's Report regarding 2017 Final Annual Verified CDM Program Results, LDC Savings Persistence Tab. Again, the savings in 2017 from 2017 Programs is even higher in the April 2019 P&C Report (965,450 kWh) – which leads to a larger discrepancy. Please reconcile.

h) In the IESO's April 2019 P&C Report shows net savings in 2018 from 2018 programs of 646,847 kWh – half of which is 323,424 kWh. However, Table 15 shows a value for 2018 (using the ½ year rule) of 316,401 kWh. Please reconcile.

i) Please explain the derivation of the 992,123 kWh savings in 2019 from 2018 and 2019 programs as set out in Table 15 and provide references for the values used.

j) Please provide a schedule/excel file that for each of the program years 2015 to 2019 sets out the persisting <u>annualized</u> CDM impacts through to 2021 as follows:

Impact of Historical and Forecast Annualized CDM					
Calendar Year/ CDM Program Year	2015	Columns for Each Subsequent Year up to 2020			2021
2015 CDM Program Impacts					
Actual CDM impacts for each year to 2018 – one row per year					
2019 CDM Programs Impacts					
Total					

k) Please explain how the monthly CDM savings values in Table 16 were derived from the annualized CDM savings as reported by the OPA/IESO (per parts (b), (d) and (j) above) and provide the supporting worksheets/calculations.

WNP's Response:

a) WNP is unable to locate the original copy of the OPA's report for published results for 2006-2010; however the Applicant has submitted a file containing the results for Wellington North Power for CDM energy savings for this period. Given this period was 10-15 years ago and with the change in office staff at the utility, the Applicant is unable to confirm if this file was provided to the utility from the OPA or via a 3rd-party energy consultant, Burman Energy Consultants Group, who WNP's CEO/President at that time, retained to assist with the CDM portfolio.
File details are referenced in response to b) below.

b) On the OEB's web portal, WNP has filed an excel file as required. This file is named "3-VECC-26b OPA Results 2006-2010". As instructed, no ½ year rule has been applied.

c) WNP has filed a copy of the IESO's report "2011-2014 Final Results Report for Wellington North Power Inc.". This has been filed on the OEB's web portal as "3-VECC-26c IESO 2011-2014 Final Results Report-Wellington North Power Inc."

d) On the OEB's web portal, WNP has filed an excel file as required. This file is named "3-VECC-26d IESO Results 2011-2014". As instructed, no ½ year rule has been applied.

e) Please refer to response h).

f) Please refer to response h).

g) Please refer to response h).

h) WNP has recreated Table 15 from Exhibit 3 below and for the 2015-2019 program period, the LDC has used data from the most recent CDM report, the Participation & Cost Report dated April 15th 2019.

Table 15 – CDM kWh Variable Data with Half-Year Rule Applied

Year	OPA Annual CDM Results 2006 to 2010 programs (kWh)	OPA / IESO Annual CDM Results 2011 to 2014 programs (kWh)	IESO Annual CDM Results 2015 to 2017 programs (kWh)	2018 and 2019 Programs (kWh) Participation & Cost Report	2020 Programs	Total Annual CDM Results (kWh)
2006	119,655					119,655
2007	317,913					317,913
2008	586,960					586,960
2009	1,153,337					1,153,337
2010	1,406,316					1,406,316
2011	1,426,937	76,759				1,503,696
2012	1,406,861	487,851				1,894,712
2013	1,398,269	831,113				2,229,382
2014	1,353,128	1,146,521				2,499,649
2015	1,226,988	1,300,953	403,452			2,931,393
2016	1,162,172	1,300,953	1,100,073			3,563,197
2017	958,187	1,300,953	1,879,596			4,138,736
2018	724,907	1,300,953	2,271,393	323,423		4,620,676
2019	666,840	1,300,953	2,265,477	743,402		4,976,671
2020	441,871	1,300,953	2,259,779	1,215,224	0	5,217,826
2021	432,369	1,300,953	2,259,348	1,215,224	0	5,207,893

i) In the table above, the results for 2019 from 2018 and 2019 programs of 742,402 kWh is derived by:

1. April 15th 2019 P&C reports showed January to March 2019 programs achieving savings of 39,749 kWh.
   Annualized this by 39,749 x 4 = 158,996 kWh
2. Add 34,115 kWh for December 2019 savings for Streetlight LED conversion (refer to LRAMVA worksheet 8 for streetlight calculations).
3. Add 2019's persistence from 2018 CDM program year of 646,847 kWh
4. 2019 = ((158,996 + 34,115) x ½ yr rule + 646,847 = 743.402 kWh.

j) On the OEB's web portal, WNP has filed an excel file as required. This file is named "3-VECC-26d CDM Results 2015-2019".

k) On the OEB's web portal, WNP has filed an Excel file named "3-VECC-26k WNP 2006-2019 CDM kWh Savings Summary." In this file, worksheet "E. CDM Variable for Rate App" contains the calculations and worksheet "F. Input Variable – Load F'cast" shows the data as used in Table 16 of Exhibit 3.

3.0-VECC-27

Reference: **Exhibit 3, pages 26-27**

WNP Load Forecast, Purchased Power Model Tab

a) At page 26 (lines 4-5), the Applications states that "The addition of the monthly values will equal the sum of the total annual results presented in the table below". However, this is not the case as the sum of the monthly CDM values used Purchased Power Model Tab (and set out in Table 16) do not match the annual values in Table 2015. Please reconcile.
   i. If the discrepancy is due to the fact the values in Table 2016 have been increased to include losses, please explain why and what was the basis for the loss factor(s) used.

WNP's Response:

a) The Applicant confirms that the difference in CDM total values as represented in Table 15 and Table 16 of Exhibit is to do with the Loss Factor. In Table 15, the CDM values do not include Loss factor; whereas Table 16 does show CDM values uplifted by the Loss Factor.
   i. The CDM kWh savings and persistence savings are reported as Net kWh savings which are derived from a gross-to-net ratio conversion. For example, if a customer replaces a bulb with an energy saving bulb and the energy savings are 1 kWh, the gross-to-net ratio may be reported as 0.7 kWh; however on the real energy savings is still 1 kWh. Using the gross-to-net ratio, the true kWh savings are reduced, and one could be argue, the effect of CDM is understated.

   By applying the LDC's Loss Factor to the CDM savings and persistence savings, the kWhs are being uplifted to eradicate the effect of the gross-to-net ratio adjustment and perhaps, more accurately reflect the impact of CDM activities.

   In reviewing VECC's question, WNP assumes that CDM values in the Power Purchase model should not include Losses. Therefore, WNP has updated the CDM variable in its' Load Forecast using CDM values that are not Loss adjusted. In updating the CDM variable, WNP has used the CDM values as discussed in its' response to 3-VECC-26 and as illustrated in the table below:

Without Loss	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
January	123,709	112,928	140,796	176,650	196,974	223,426	270,031	327,075	366,151	405,617	425,519	442,561
February	122,524	115,179	143,905	178,310	199,034	227,218	274,922	330,315	369,589	407,273	427,210	441,002
March	121,339	117,430	147,013	179,970	201,094	231,010	279,813	333,555	373,026	408,928	428,901	439,444
April	120,155	119,681	150,122	181,631	203,154	234,802	284,705	336,795	376,463	410,584	430,592	437,886
May	118,970	121,932	153,230	183,291	205,214	238,595	289,596	340,035	379,900	412,239	432,283	436,328
June	117,785	124,183	156,338	184,952	207,274	242,387	294,487	343,275	383,338	413,895	433,973	434,770
July	116,601	126,433	159,447	186,612	209,334	246,179	299,379	346,515	386,775	415,550	435,664	433,212
August	115,416	128,684	162,555	188,272	211,394	249,971	304,270	349,754	390,212	417,206	437,355	431,654
September	114,231	130,935	165,664	189,933	213,454	253,763	309,161	352,994	393,650	418,862	439,046	430,096
October	113,047	133,186	168,772	191,593	215,514	257,555	314,053	356,234	397,087	420,517	440,737	428,538
November	111,862	135,437	171,881	193,254	217,574	261,347	318,944	359,474	400,524	422,173	442,428	426,980
December	110,677	137,688	174,989	194,914	219,634	265,139	323,836	362,714	403,961	423,828	444,119	425,422
Total CDM kWh	**1,406,316**	**1,503,696**	**1,894,712**	**2,229,382**	**2,499,649**	**2,931,393**	**3,563,197**	**4,138,736**	**4,620,676**	**4,976,671**	**5,217,826**	**5,207,893**

On the OEB's web portal, WNP has filed a revised copy of its' Wholesale Load Forecast in response to the necessary changes as discussed in VECC's IR 3-VECC-26 and 3-VECC-27.

3-Staff-48

Other Revenue

Ref 1: Chapter 2 Appendices – 2-H

Ref 2: EB-2020-0288 Order, December 10, 2020

The other revenue from the specific service charges have been consistently trending downwards since 2016.

a) Please explain the reason for the downward trend.

Wellington North Power has anticipated that the OEB will be issuing a decision increasing the wireline pole attachment charge by 2% and reflected this in the Other Revenue. On December 10, 2020, the OEB issued an order suspending the 2021 inflationary increase and the current charge of $44.50 will remain in effect as of January 1, 2021 on an interim basis.

b) Please update the Other Revenue amount to reflect the current wireline pole attachment charge of $44.50.

The forecasted interest and dividend income is four times lower than the 2020 bridge year and six times lower than 2018 and 2019 levels.

c) Please explain how Wellington North Power forecasted the 2021 interest and dividend income.

WNP's Response:

a) There is obviously variation in miscellaneous charges from year to year, but the biggest and most consistent change has been in the decrease in disconnect notification charge revenue. This has gone from over $27,000 in 2016 to $0 in 2020 as WNP has implemented the incremental changes in OEB policy.

b) WNP has updated the Other Revenue amount in Chapter 2 Appendices to reflect the current wireline pole attachment charge of $44.50.

c) Most of the interest income comes from interest on large DR balances on Deferral Variance Accounts. Since the OEBs prescribed interest was decreased from 2.18% to 0.57% in June 2020 (almost four times lower) and since the Dec 31, 2019 balances in the DVAs will be reduced to zero on May 1 2021 (DR Balances of over $850,000 disposed of), the amount of interest income will be further reduced.

- 2021 Interest on Dec 31, 2019 DR Balances in DVA Continuity Schedule - $1,770
- Interest on Bank account (based in the current prime rate) - $493
- Annual Dividends on Investments - $510
- 2021 Interest on $350,000 (estimated DVA Dec 31, 2020 DR Balances) - $1,995

This interest income was then rounded to $4,800.

3.0-VECC-28

Reference: **Exhibit 3, pages 72 and 80**

Exhibit 8, page 18

RSC Rate Adjustments, EB-2020-0285, December 3, 2020

Wireline Pole Attachment Charge, EB-2020-0288, December 10, 2020

a) WNP has used a 2% inflation factor to estimate 2021 Retail Service Charges. Please revise the Other Revenues for Accounts 4082 and 4084 to reflect the Board's decision in EB-2020-0285.
b) WNP has used a 2% inflation factor to estimate 2021 Pole Attachment Charges. Please revise the Other Revenues for Account 4210 to reflect the Board's decision in EB-2020-0288.
c) Where in Other Revenue is the revenue from the MicroFIT Monthly Service Charge reported?

WNP's Response:

a) Regarding the 2021 Retails Service Charges, WNP has revised the Other Revenues for Accounts 4082 and 4084 to reflect the Board's decision in EB-2020-0285.

b) Regarding the pole attachment charges, WNP has revised the Other Revenues for Account 4210 to reflect the Board's decision in EB-2020-0288.

c) The MicroFIT Monthly Service Charge is recorded in USoA 4235 – Miscellaneous Service Revenues.

Exhibit 4 – Operating Costs

4-Staff-49

Cyber Security

Ref 1: Exhibit 4 – Cyber Security, p. 39

Ref 2: Chapter 2 appendices – 2-JB OM&A cost drier

Ref 3: Letter of the OEB – Cyber Security Readiness Report & Amendments to Electricity Reporting and Record Keeping Requirements, November 29, 2018

Wellington North Power retained a cyber security consultant in 2017 to evaluate current practice and infrastructure. The cyber security changes led to an overall OM&A increase of $52,600. There was also an increase of $25,400 in reoccurring costs to a 3rd party Information Technology (IT) provider.

a) Please provide the request for proposal in searching for the 3rd party IT provider and an explanation of the selection process.
b) Wellington North Power is a member of the Cornerstone Hydro Electric Concepts (CHEC). Did Wellington North Power investigate if there were potential synergies with the CHEC group and hiring of a 3rd party IT provider? If not, why not.
c) Is the cyber security infrastructure on-site or cloud based?
d) Does Wellington North Power have cyber security insurance? If so, how much does it cost?
e) Does Wellington North Power co-locate or share its customer systems with local municipality or telecom providers?

In reference 3, the OEB expects that distributors incorporate cyber security investments into their distribution system plans and that these responsibilities should be addressed in the same manner as any other operational risk.

f) As the cyber security responsibilities should be addressed in the same manner as other operational risks so should costs. How has Wellington North Power tried to manage its Cyber Security costs within its historical OM&A budget.

WNP's Response:

a) WNP did not put out an RFP. WNP was introduced to the Consultant through CHEC as an initiative to share an expert who could assist with completing the Risk Profile, using the Ontario Cyber Security Framework Inherent Risk Profile Tool to determine WNP's risk score. The 3rd party consultant was working with CHEC as well as other CHEC utilities. The decision included several considerations; the consultant has a thorough understanding of utility business systems, network architecture and the general operations of a small utility.

b) Please refer to response a) above.

c) WNP employs a multi-pronged strategy for cyber protection services, utilizing both on and off premises cyber security infrastructure design.

Firewalls, physically on-premises, utilize a private cloud based design for traffic classification and control, intrusion protection and device identification. Anti-Virus and Anti-Malware protections are deployed to all physical devices with updates and monitoring provided via cloud based services. Communications services, such as email, are hosted solutions, with additional cloud based advanced threat protection monitoring and remediation in place. Additionally, IT and OT are segregated to permit individual cyber security solutioning, and overall backup processes utilize a mix of on-premises storage with encrypted off-premises cloud based duplication.

d) Yes, WNP has cybersecurity insurance which is provided as a standard within the insurance policy. A specific cost break out is not provided by the insurer.

e) WNP does not co-locate or share its customers systems.

f) Cyber security requirements changed during the historical period and therefore became an additional cost. The costs were managed by reviewing the various requirements and staging implementation through the recommendations of WNP's 3rd party Consultant.

4-Staff-50

Wages and Benefits

Ref 1: Exhibit 4 – Appendix 4C – CHEC Wage & Benefit Analysis

Ref 2: Chapter 2 Appendices – Appendix 2-K Employee Costs

In reference 1, the report provided a table for salary ranges for a variety of positions.

a) Please confirm if there are any positions within Wellington North Power that fall outside the upper and lower end of the salary range provided. If any positions are outside of this range, please provide an explanation and justification.

The annual salary increases for management provided in reference 1 was estimated to be 2.12% for 2019. The annual salary increases for union positions provided in reference 1 was estimated to be 2.1% for 2019.

b) In reference 2, the average annual management increase between 2016 and 2020 was 6.36%. The average annual non-management increase between 2016 and 2020 was 3.06%. Please explain the higher average yearly increase as compared to the findings in reference 1.

WNP's Response:

a) There are no positions within Wellington North Power that fall outside the upper or lower end of the salary range provided.

b) With respect to the data in Appendix 2-K Employee Costs, WNP is unable to replicate the calculations showing a 6.36% increase in Management Compensation. If you take the $332,218 (3 employees) in actual 2016 salaries and increase it 2.12% for each of the four years to 2020, you get $361,299 which is quite comparable to the $365,243 (3 employees) in the table. Because of the way pension benefits are calculated, there is a slightly larger increase in the benefits compensation.

c) For non-management employees, if the 2016 Total actual compensation of $931,806 is divided by 10 and multiplied by 9 to account for the decrease of one employee in this group, the result is $838,625. Increasing this result by 3.0608% per year for the four years to 2020 gives the 2020 value of $946,110. However, this approach assumes that the job that was eliminated paid the average salary. Using a more accurate wage and benefits savings estimate of $60,000 for the eliminated job, demonstrates that the wage increases for Non-Management positions are easily in line with the 2.1% per year.

4-Staff-51

Retailer Charges

Ref 1: Chapter 2 Appendices – 2-JC OM&A Program

The retailer charges have almost doubled since Wellington North Power's last cost of service.

a) Please provide an explanation to the increase in these costs.

WNP's Response:

a) This increase in costs is directly related to the increased revenue from the retailer charges. Costs for supporting retailers are recorded in 5340. When values are entered into 1518 and 1548 as debit values, the credit is entered into offsetting 5340 accounts. Because there is extra revenue in 4082 and 4084, there are smaller credits entered into these offsetting 5340 accounts. Therefore the 5340 expenses are higher.

4-Staff-52

Distribution Sub-stations and Protection and Control

Ref 1: Chapter 2 Appendices – 2-JC OM&A Program

The distribution sub-stations and protection and control program almost doubled in 2019 and remains at this level into 2021.

a) Please explain what caused the increase in this program in 2019 and sustained through to 2021.

WNP's Response:

a) In 2018 WNP replaced MS3 Sub-station causing a decrease in the Distribution Sub-stations and Protection and Control Program due to some of the maintenance being moved to the next year and labor being capitalized on the substation project. Consequently, 2019 saw an increase as the program returned to normal along with increased associated costs, this included labor costs, truck costs and an increase in the charge from the third party for Substation Maintenance preformed.

4-Staff-53

Distribution Transformers

Ref 1: Exhibit 4 – Program Overview, p. 34

Ref 2: Chapter 2 Appendices – 2-JC OM&A Program

In reference 1, Wellington North Power references a Distribution Transformer program, however, in reference 2, there is no such program.

a) Please confirm if 2-JC is missing a program or is the cost included in another program in 2-JC.

WNP's Response:

a) The costs associated with transformer maintenance and inspections, for example system patrols, replacement of connectors and infra-red inspections are included in the Overhead Lines program. The information in Exhibit 4 – Program Overview on page 34 under the header Distribution Transformers should have been included under the header Overhead/Underground Lines Operation and Maintenance at the top of page 34.

4-Staff-54

Regulatory Costs

Ref 1: Chapter 2 Appendices – 2-M Regulatory Costs

Wellington North Power has budgeted $27k in legal costs, $52k in consultant costs, and $35k in intervenor costs.

a) Please provide the legal and consultant costs incurred to date.
b) To date there is only one intervenor in this application. Please update the estimated intervenor costs, which included provision for two intervenors.

WNP's Response:

a) The following consultant costs have been incurred:
   - Asset Condition Assessment $27,000.
   - DSP Review $8,000.
   - Rate Consultant $5,416.

The following lawyer costs have been incurred:
   - Lawyer $7,200.

b) Intervenor costs have been reduced to $20,000.

4.0 -VECC-42
Reference: Exhibit 4, Tables 21 & 22, pages 56-57

Table 21 - Regulatory Costs specific to the 2021 Cost of Service

	2021
Kinectrics – DSP Review	$25,000
Kinectrics – Asset Condition Assessment	$27,000
Legal Counsel	$27,000
Rate Consultant	$17,000
Production of DSP, Application & Submission – WNP labour to prepare application	$25,000
Reply to Interrogatories – WNP labour	$5,000
Public Notice – newspaper print	$700
Customer Notice – bill inserts	$350
Settlement – assuming 2 day conference	$15,000
Intervenor and OEB costs – assuming 2 intervenors	$35,000
Total Cost	**$160,050**
Total Cost over 5 years	**$32,010**

a) Please clarify what costs in Table 21 are attributable to work carried out by staff at WNP and what costs are payable to consultants or other third parties engaged specifically to work on this application.
b) Please explain what section 30 – Applicant-originated (line 2, $11.5k forecast) costs are contemplated to recover.

WNP's Response:

a) The top two items for Kinectrics DSP consulting should total $35,000 and are external.
The Lawyer and Rate Consultant are both external costs.
The fifth and sixth items totaling $30,000 relate to WNP labour and represent the incremental labour cost of preparing and finalizing the Cost of Service application.

b) This line is mislabeled. Table 2-M in the 2021 Filing Requirements Chapter 2 workform does not contain this line. This image was taken from older models that WNP used during Cost of Service preparations and contains information that no longer apply.
The image from the Chapter 2 Appendices is illustrated below.

	Regulatory Cost Category	USoA Account	USoA Account Balance	Last Rebasing Year (2016 OEB Approved)	Last Rebasing Year (2016 Actual)	Most Current Actuals Year 2019	2020 Bridge Year	Annual % Change	2021 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=[(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
	Regulatory Costs (Ongoing)									
1	OEB Annual Assessment	5655		16,500	17,409	16,826	17,000	1.03%	17,000	0.00%
2	OEB Section 30 Costs (OEB-initiated)	5655		13,600	8,314	18,221	16,500	-9.45%	15,500	-6.06%
3	Expert Witness costs for regulatory matters	5655								
4	Legal costs for regulatory matters	5655		7,088	5,477	5,477	5,477	0.00%		-100.00%
5	Consultants' costs for regulatory matters	5655		1,099						
6	Operating expenses associated with staff resources allocated to regulatory matters	5655		47,744	50,125	83,733	83,523	-0.25%	83,500	-0.03%
7	Operating expenses associated with other resources allocated to regulatory matters [1]	5655		2,000						
8	Other regulatory agency fees or assessments	5655								
9	Any other costs for regulatory matters (please define)	5655		10,000	9,700	9,432	10,300	9.20%	10,500	1.94%
10	Intervenor costs	5655								
11	Include other items in green cells, as applicable	5655								
12	Amortization of Application one-time costs	5655		30,429	29,445	27,098	27,098	0.00%		-100.00%
	Regulatory Costs (One-Time)									
1	Expert Witness costs									
2	Legal costs								27,000.00	
3	Consultants' costs								52,000.00	
4	Incremental operating expenses associated with staff resources allocated to this application.								30,000.00	
5	Incremental operating expenses associated with other resources allocated to this application. [1]								350.00	
6	Intervenor costs								20,000.00	
7	OEB Section 30 Costs (application-related)								15,700.00	
1	Sub-total - Ongoing Costs [2]		$ -	$ 128,460	$ 120,470	$ 160,787	$ 159,898	-0.55%	$ 126,500	-20.89%
2	Sub-total - One-time Costs [3]		$ -	$ -	$ -	$ -	$ -		$ 145,050	
3	Total		$ -	$ 128,460	$ 120,470	$ 160,787	$ 159,898	-0.55%	$ 155,510	-2.74%

4-Staff-55

Metering Compliance

Ref 1: Exhibit 4 – Program Overview

Ref 2: Chapter 2 Appendices – 2-JC OM&A Program

In reference 2, there is a Metering Compliance program, however, in reference 1, there is no program overview for Metering Compliance.

a) Please provide a description of the Metering Compliance program.

WNP's Response:

a) Chapter 2 Appendices – 2JC OM&A Program is incorrectly labelled. Metering Compliance should be labeled Industry Membership Fees. A description of the Industry Membership Fees can be found in Exhibit 4 on page 42-43.

4-Staff-56

Other Post-Employment Benefits

Ref 1: Exhibit 4, 4.3 p.37

In Wellington North Power's 2016 cost of service application, Wellington North Power recovered Other Post-Employment Benefits (OPEBs) on a cash basis and established an account to track the difference in OPEBs between the cash and accrual basis. In the current proceeding, Wellington North Power is proposing to recover OPEBs on an accrual basis.

a) Please confirm that Wellington North Power has recovered OPEBs on an accrual basis prior to its 2016 rate application.
b) If not, please discuss the impact of changing OPEBs recovery from a cash basis to accrual basis in consideration of page 9 of the Report of the Ontario Energy Board, Regulatory Treatment of Pension and Other Post-Employment Benefits (OPEBs) Costs, dated September 14, 2017.
    i. Please provide a calculation showing the cumulative recovery Wellington North Power has collected in rates to date with an indication of the recovery basis (cash or accrual).
    ii. Please also provide the annual cash and accrual amounts for OPEBs from the commencement of when Wellington North Power first recovered OPEBs to 2020.

WNP's Response:

a) WNP confirms that OPEBS were recovered on an accrual basis prior to the 2016 rate application.

b) Not Applicable.

i) and ii) The following table shows the information for 2011 to 2020:

OPEBs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OPEB Recovery Method	Accrual	Accrual	Accrual	Accrual	Accrual	Cash	Cash	Cash	Cash	Cash
OPEB Amounts included in rates	14,640	14,640	18,136	18,136	18,136	12,568	12,568	12,568	12,568	12,568
Liability Increase	9,029	12,570	14,402	2,717	34,264	568	-5,118	3,670	3,523	34,357
Post-Retirement Benefits Paid	5,640	9,089	9,574	10,312	13,223	14,622	15,419	15,630	12,976	11,807
Sub-Total	14,669	21,659	23,976	13,029	47,487	15,190	10,301	19,300	16,499	46,164
Net excess amount included in rates greater than amounts actually paid	-29	-7,019	-5,840	5,107	-29,351	-2,622	2,267	-6,732	-3,931	-33,596

4-Staff-57

Other Post-Employment Benefits

Ref 1: Exhibit 4, 4.4 p.47

Wellington North Power states that "All cash OPEB costs from 2016 to 2020 are included in OM&A and none of these costs have been capitalized".

a) Please confirm whether the above statement refers only to the OPEB cash contributions or to the OPEB accrual expense requested for recovery in rates.
   i. If the statement is referring to OPEB cash contributions only, please provide a breakdown of the amount of OPEB accrual expense requested for recovery that has been included in OM&A vs. capital.

b) Please provide a breakdown of the amount of pension costs that have been included in OM&A vs. capital.

WNP's Response:

a) WNP confirms the statement refers only to the OPEB Cash Contributions from 2016 to 2020.
   i) Historically, WNP has never capitalized OPEB costs. Any future method which might result in capitalizing OPEBs would almost certainly not exceed $1,000 per year and would probably be smaller.

b) Below is a breakdown of the amount of pension costs that have been included in OM&A vs. capital:

	2016	*2017*	*2018*	*2019*	*2020*
Contributions to OMERS	**$103,352**	**$104,863**	**$106,334**	**$109,103**	**$113,002**
% labour capitalized	11.167%	11.000%	13.132%	10.089%	10.800%
Pensions capitalized	$11,541	$11,535	$13,964	$11,007	$12,204
OM&A	$91,811	$93,328	$92,370	$98,096	$100,798

4.0 -VECC-41

Reference: Exhibit 4, Table 18, page 47

Table 18 - OPEB Accrual vs Cash Expense Comparison

	2016	*2017*	*2018*	*2019*	*2020*	*2021*
OPEBs	**Actual**	**Actual**	**Actual**	**Actual**	**Bridge**	**Test**
Accrual						
OPEB Amount in Rates	12,568	12,568	12,568	12,568	12,568	20,000
Actuarial Cost - Income Statement	10,735	11,164	13,950	14,372	15,233	16,690
Actuarial Cost - Other Comprehensive Income		-9,410			29,797	
Cumulative Difference	**-1,833**	**-12,647**	**-11,265**	**-9,461**	**23,361**	
Cash						
Post Retirement Benefits Paid (OM&A and Capital)	**14,533**	**15,419**	**15,630**	**12,976**	**12,204**	

a) Please explain the rationale for increasing the OPEB amount in rates from 12.568k to 20k.

WNP's Response:

a) WNPs OPEB costs are increasing for the following reasons

i. WNP is including costs on an accrual basis for this application instead of cash.

ii. Benefit costs increase naturally.

iii. WNP is providing benefits to a higher number of retirees. WNP will have five retirees in 2021 as compared to four in 2017, 2018 and three in 2019 to 2020.

4.0 -VECC-29

Reference: Exhibit 4, Appendix 2-JC

a) Please update Appendix 2-JC and 2-JA to include 2020 (unaudited) results.

WNP's Response:

a) Appendix 2-JC and 2-JA have both been updated to include 2020 (unaudited) results.

4.0 -VECC-30

Reference: Exhibit 4, Appendix 2-K, page 45, page 49

a) Please update Appendix 2-k to include 2020 (unaudited) results and to add rows showing for each year the total compensation capitalized in each year.

WNP's Response:

a) The table below shows Appendix 2-K updated to include 2020 (unaudited) results and the total compensation capitalized in each year:

Employee Costs

	Board Approved 2016	MIFRS 2016	MIFRS 2017	MIFRS 2018	MIFRS 2019	MIFRS 2020	MIFRS 2021
Number of Employees (FTEs including Part-Time)[1]							
Management (including executive)	4	3	3	4	4	3	3
Non-Management (union and non-union)	9	10	9	8	8	9	9
Total	13	13	12	12	12	12	12
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$392,599	$332,218	$417,428	$395,913	$464,736	$367,402	$373,393
Non-Management (union and non-union)	$658,101	$741,352	$636,546	$669,018	$632,014	$752,566	$770,551
Total	$1,050,700	$1,073,570	$1,053,974	$1,064,931	$1,096,750	$1,119,968	$1,143,944
Total Benefits (Current + Accrued)							
Management (including executive)	$109,085	$79,816	$83,451	$99,820	$115,946	$93,409	$93,006
Non-Management (union and non-union)	$165,015	$190,454	$189,992	$180,136	$167,549	$185,453	$202,579
Total	$274,100	$270,270	$273,443	$279,956	$283,496	$278,861	$295,585
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$501,684	$412,034	$500,879	$495,733	$580,683	$460,811	$466,399
Non-Management (union and non-union)	$823,116	$931,806	$826,538	$849,154	$799,563	$938,019	$973,130
Total	$1,324,800	$1,343,840	$1,327,417	$1,344,887	$1,380,246	$1,398,830	$1,439,529
Percentatge of labour Capitalized		11.167%	11.000%	13.132%	10.089%	10.800%	
Total Capitalized Compensation		$150,066.58	$146,015.83	$176,610.51	$139,253.01	$151,073.61	

4.0 -VECC-31
Reference: Exhibit 4, page 49

WNP shows the current staff compliment as:

- A Chief Executive Officer (CEO)/President
- A Field Lead-hand
- 3 Linesmen
- Senior Operations Technician
- A Finance Manager
- A Financial Analyst
- A Manager of Customer Service & Regulatory Affairs
- A Senior Customer Service Representative
- A Customer Service & Collections Representative
- An Operations Coordinator

a) Please confirm that all these positions are currently filed.
b) Please show the equivalent staff compliment at year end 2016.

WNP's Response:

a) WNP confirms that all the positions are filled.

b) Please see table below:

Current Staff Compliment	Staff Compliment as at Dec 31st 2016
A Chief Executive Officer (CEO)/President	A Chief Operating Officer (COO)
A Field Lead-hand	A Field Lead-hand
3 Linesmen	3 Linesmen
Senior Operations Technician	Senior Operations Technician
A Finance Manager	A Finance Manager
A Financial Analyst	A Financial Analyst
A Manager of Customer Service & Reg. Affairs	A Chief Administration Officer (CAO)
A Senior Customer Service Representative	A Senior Customer Service Representative
A Customer Service & Collections Representative	2 Customer Service & Collections Representative
An Operations Coordinator	An Operations Coordinator
Total Staff: 12	**Total Staff: 13**

4.0 -VECC-32
Reference: Exhibit 4, Appendix JB / page 39

a) Please provide the annual cyber security OM&A costs in 2019, 2020 and 2021 (forecast).

WNP's Response:

a) The utility's annual cyber security OM&A costs in 2019, 2020 and 2021 (forecast) are:

- 2019 $48,913.58
- 2020 $35,711.78
- 2021 $50,000.00

4.0 -VECC-33
Reference: Exhibit 4, JB / page 42

a) Please provide the annual membership fees for 2016 through 2021 (forecast) for each of:
   i. CHEC;
   ii. EDA; and,
   iii. USF.

WNP's Response:

a) Below are the annual membership fees for 2016 through 2021 (forecast) as requested:

	2016	2017	2018	2019	2020	2021
CHEC	$12,500	$12,500	$12,500	$12,500	$12,500	$12,500
EDA	$9,000	$9,100	$9,300	$9,500	$9,700	$9,800
USF	$8,750	$8,750	$8,750	$8,750	$7,950	$8,750

4.0 -VECC-34
Reference: Exhibit 4, Appendix JB

a) Please explain what "1518 and 1548" Charges refer to.

WNP's Response:

a) 1518 and 1548 refer to the Deferral Variance Accounts (DVAs) where expenses to support retailers in excess of the retailer revenues are allocated. These DVAs are being phased out and these extra expenses will be allocated to OM&A.

4.0 -VECC-35
Reference: Exhibit 4, Appendix JC

a) Please explain why the elimination of one position in creating the position of CEO (from COO and CAO) results in only a $10,000 net savings.
b) Please clarify if this is the annual savings or the savings in the year the position was created (i.e., net of any severance or related costs).

WNP's Response:

a) In this case, no position was eliminated. Duties were reassigned among existing employees and the net adjustment of salaries was a savings of $10,000.

b) This reduction in salaries was an ongoing annual savings.

4.0 -VECC-36

Reference: Exhibit 4, Table 13, page 21

a) Please provide the source (and link to) of the inflation rates shown in Table 13.

WNP's Response:

a) The historical inflation rates were sourced from the following web-site:

https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000501&pickMembers%5B0%5D=1.14

The Bridge Year (2020) and Test Year (2021) were estimated based on the year-to-date data available at that time.

4.0 -VECC-37

Reference: Exhibit 4, Appendix JC, page 23

a) Please explain how the bad debt figure of $15,000 was estimated.
b) Please provide the actual bad debt amount in 2020.

WNP's Response:

a) The bad debt expense was lowered from 2016, since our actuals have been lower. However, now that winter disconnects are no longer permitted, the average amount per customer that is written off as a bad debt has increased. This trend is expected to continue, and resulted in the estimate of $15,000.

b) In 2020, the bad debt expense was $14,839.09.

4.0 -VECC-38

Reference: Exhibit 4, Appendix JC, page 23

a) Please explain how the 2021 estimates for the following categories were estimated (specifically address why these costs have increased from the four-year 2016-2019 average actuals):
   i. Customer Service Collections;
   ii. Service Locates
   iii. Line Clear (tree trimming)
   iv. Executive, Financial, Legal.

WNP's Response:

a) Please see below:
   i. Customer Service collections costs have increased due to the increased contact and communication as well as complexities introduced in the updated customer service rules as a result of the OEB's review (phase 1).
   ii. Service Locates are completed by WNP and vary based on underground construction activity by local contractors. Costs have increased with the increase in activity.
   iii. Line clearing was artificially low in 2016 due to the fact that WNP coordinated its tree trimming with the Second line feeder capital project. Since WNP brought in a new 44kV line into its service territory, greater line clearances were required for the higher voltage lines. However, these line clearing costs were capitalized as part of the project. This led to the O&M tree trimming costs being significantly understated in 2016 relative to other years.
   iv. There has been some variation in these accounts but the overall increases are not out of line from what would be expected.

4.0 -VECC-39

Reference: Exhibit 4, page 29

a) For the period 2016 – 2020 please provide:
   i. The number of customers (year-end) billed electronically
   ii. The number of bills issued each year
   iii. The number of bills paid electronically (phone or internet) or via bank or other financial institution (or conversely the number of bills received by mail and in-person at a WNP office.

WNP's Response:

a) For the period 2016 to 2020, please see the information below:

i. Number of customer billed electronically as at December 31st:
   - 2016: 0 – e-bill notification was not launched until 2017.
   - 2017: 241
   - 2018: 275
   - 2019: 345
   - 2020: 427

ii. The number of bills issued each year (paper and electronic, all rate classes):
   - 2016: 45,749
   - 2017: 45,664
   - 2018: 45,398
   - 2019: 45,762
   - 2020: 45,981

iii. Payment method (all rate classes):

Payment Method	**2016**	**2017**	**2018**	**2019**	**2020**
Cheque (mailed or in-person)	3,862	3,433	3,128	2,946	2,516
3rd party cheque (mailed)	301	309	273	252	232
Internet / Bank	24,010	24,303	25,021	25,498	26,006
Pre-Approved Payment	14,351	14,250	13,936	14,154	15,275
Money Order					5
Transfers	52	22	30	27	48
Electronic Funds Transfer	832	863	840	830	1,288
Cash (in-person)	1,028	859	794	770	349
Debit Card (in-person)	2,416	2,355	2,223	2,186	585
Credit Card	269	287	395	388	393
Total	**47,121**	**46,684**	**46,640**	**47,051**	**46,697**

There are more payments received than bills issued because some customers make multiple incremental payments to their account.

4.0 -VECC-40

Reference: Exhibit 4, page 29

a) When a new account is open what is the default billing service offered – mail or electronic?

WNP's Response:

a) For a new account, the default billing service offered is for the customer's monthly bill to be mailed. Once a customer has received their first bill, they can register for e-bill notification. E-bill notification sends an e-mail to the customer advising their monthly bill is ready for review and they can download the bill, review their usage and payment history.

E-bill notification is through CustomerConnect™ which is a software application provided through WNP's Customer Information System (CIS) provider.

WNP's bills include the customer's account number and unique meter number at the property. These two pieces of personal data are required to enable a customer to register for CustomerConnect™ and set-up a password to set-up an account.

4-Staff-58

PILS

Ref 1: PILS Model

ACM assets have been proposed to be included in rate base in 2021.

a) For tax purposes, please confirm that the assets were included in UCC in 2018. If not confirmed, please explain when the assets were included in UCC.

b) Please confirm that the PILS model reflects the resulting CCA from the inclusion of ACM assets in UCC in 2018. If not confirmed, please explain where the ACM assets are added to UCC in the PILS model.

WNP's Response:

a) WNP confirms that the ACM assets were added to UCC for tax purposes in 2018.

b) WNP also confirms that the ACM assets were included in the 2018 UCC in the PILS model.

4-Staff-59

PILS

Ref 1: PILS Model

The depreciation expense in the PILS model does not agree to the depreciation expense in the Fixed Asset Continuity Schedules for 2020 and 2021 as shown in the table below. Please explain and reconcile the difference. Please revise the evidence as needed.

		2020	2021
PILS Model	Amortization of tangible assets	430,563	499,418
	Amortization of intangible assets	73,027	71,227
	Total Amortization in PILS Model	503,590	570,645
2-BA	Depreciation Expense (including ACM)	489,960	515,203
Difference		**13,630**	**55,442**

WNP's Response:

WNP has reconciled the difference and updated the amounts in the PILS model to reflect changes as a result of responding to interrogatories, as summarized below:

		2020	2021
PILS Model	Amortization of tangible assets	405,039	421,661
	Amortization of intangible assets	73,225	79,623
	Total Amortization in PILS Model	478,264	501,284
2-BA	NET Depreciation Expense (including ACM)	478,264	501,284
Difference		**0**	**0**

WNP has filed an updated PILS model on the OEB's web portal.

4-Staff-60

Accelerated CCA

Ref 1: PILS Model

In the Chapter 2 Filing Requirements for 2021 Rate Applications, page 38 states: Applicants may propose a mechanism to smooth the tax impacts over the five-year IRM term. The OEB will assess applicants' smoothing proposals on a case by case basis. If the OEB is satisfied with the smoothing proposals applicants may not be required to use Account 1592 going forward.

The Accelerated Investment Incentive (AII) program is expected to be phased out after 2023.

a) Please confirm that Wellington North Power is not proposing a mechanism to smooth the tax impacts over the IRM term.
b) If a) is confirmed, please confirm that Wellington North Power will continue to use Account 1592 going forward to capture the impact of any future CCA rule changes, including the impacts from the phasing out of the AII program.
c) If a) is not confirmed, please discuss and quantify the smoothing mechanism.

WNP's Response:

a) WNP confirms it is not proposing a mechanism to smooth the tax impacts over the IRM term.

b) WNP does not confirm that it will use Account 1592. Due to the fact there are no PILS currently included in WNPs rates and no taxes have been paid in any tax year since the 2016 COS, WNP has not made any entries into 1592 for AIIP on the advice if its auditors. Since there will be no PILS included in WNPs rates from this COS application and no income taxes payable for several years, there are no plans to use 1592 – PILS and Tax variance until this changes.

c) Not Applicable.

4.0 -VECC-43
Reference: Exhibit 4, page 59

In its July 17, 2020 letter to LDCs the Board said:

Distributors may make a one-time increase to LEAP EFA funding by a maximum of 50% of their 2020 fiscal year funding amount. The additional funding is to be made available to agencies for use in the LEAP EFA for 2020. Given the importance of supporting consumers during this extraordinary time, the OEB is permitting the increased funding to be recorded in the Account Impacts Arising from the COVID-19 Emergency, Sub-account Other Costs.

a) Has WNP taken advantage of this direction?
b) What plans has WNP to expand LEAP funding in 2021?

WNP's Response:

a) WNP received and reviewed the OEB's letter concerning a one-time increase to LEAP Funding. At the time of the OEB's letter, there was 67% of LEAP funds unused (i.e. 2020 funds allocated after 15% agency admin and delivery fee was $3,024.15, of which, at the end of July 2020, $2,022.10 was unused.)

   In WNP's experience, typically LEAP funds are depleted by the end of May, coinciding with when the LDC can resume the disconnection process for non-payment.
   In 2020, 90% of the allocated funds had been used by the end of August, again coinciding with when the LDC can resume the disconnection process for non-payment.

   The utility did not make a one-time increase to LEAP funding in 2020. Instead, prior to the OEB's letter being issued, WNP decided to waive late payment charges for residential and small business customers with overdue balances for April's and May's electricity usage for the months of May and June 2020. This initiative supported low-income customers as well as non-low income residential customers and small businesses in our community.

b) For 2021, WNP will continue to promote LEAP to our customers. Should the OEB repeat the opportunity to increase LEAP funding in 2021, the utility will make a decision at that point in time.

4-Staff-61

Street Lighting Savings in Load Forecast

Ref 1: Load Forecast Model, Tab 5d. Street Lighting LED Conv

Ref 2: Appendix 4I, M&V Report

Wellington North Power included 229,832.85 kWh street light demand in the load forecast. The streetlight demand is based on a LED conversion project completed at the end of 2019. Wellington North Power started billing the Arthur and Mount Forest streetlight accounts using LED streetlight profile data in February 2020.

a) Please confirm that LED street lighting adjustment to the load forecast is comprised of actual billed demand data from Jan-March 2020 and forecast data from April to December 2020.
b) Please explain how the results of the M&V Report produced by the third party were used to inform the calculation of actual savings into 2020.
c) Please further clarify that Wellington North Power does not seek to true-up the forecast street light savings to actuals in a future rate application.

WNP's Response:

a) In the Applicant's Wholesale Load Forecast, the Bridge Year (2020) comprises of forecast data for all the months of 2020 and no actual billed demand was used.

b) In the absence of reports or assistance from the IESO, the M&V report was used for the purpose of calculating the LRAMVA savings as discussed in section "4.12 Conservation and Demand Management" of Exhibit 4.

   For the load forecast, WNP used the wattage rating as provided from the LED fixture manufacturer. It then supplied the information of total LEDs and wattages to Utilismart (WNP's third-party settlement provider) to determine load/usage.

c) In its' Application filed on October 30, 2020 WNP included LRAMVA and Load Forecast models which, based on the evidence submitted, if accepted by parties, the LDC would not intend to seek a true-up of the forecast street light savings to actuals in a future rate application. However, through the course of interrogatories and settlement, the Applicant is cognizant that information to the LRAMVA and/or Load Forecast models is subject to change. Therefore, at this time in the application process, the utility cannot confirm or commit to the statement made in OEB's Staff interrogatory part c).

4-Staff-62

Lost Revenue Adjustment Mechanism Variance Account (LRAMVA)

Ref 1: LRAMVA Workform, Tab 4

Wellington North Power has requested approval of LRAMVA amounts in 2015 related to persisting savings from Conservation Demand Management (CDM) programs implemented from 2014. As part of Wellington North Power's 2016 COS application, it received approval of lost revenues in 2014.

a) Please discuss the appropriateness of including persisting savings from 2014 CDM programs within the 2015 lost revenue amount when the OEB approved 2014 LRAMVA amounts on a final basis as part of the 2016 COS application.
b) Please discuss if actual 2014 CDM results were incorporated within Wellington North Power's updated load forecast approved as part of its 2016 COS application.

WNP's Response:

a) In the LRAMVA model filed with its' 2021 Cost of Service application, WNP included:
   - 2014 savings persisting in 2015 of 137,232 kWh (Residential) and 90,265 kWh (GS<50 kW).
   - The calculated Lost Revenue in 2015 from 2014 programs is $2,525.06 (Residential) and $1,507.43 (GS<50 kW) for a total claim of $4,032.50 (before interest).

   WNP's understanding is the OEB's approval of the 2014 LRAMVA amounts "*on a final basis*" in the LDC's 2016 Cost of Service application (EB-2015-0110) was based upon the reported CDM annual savings achieved for 2014 and did not include persistence-savings from 2014 CDM delivered programs.

   After due consideration, the Applicant is withdrawing its' request to recover any 2015 lost revenue, for all rate classes, as a result of persistence energy savings from 2014 CDM programs. WNP has updated the LRAMVA model to remove all lost revenue amounts in 2015 from the 2014 CDM program and has filed an updated LRAMVA model on the OEB's web portal.

b) In the Settlement Proposal that was accepted by all parties participating in WNP's 2016 Cost of Service Application (EB-2015-0110), section "3.1.2 Load Forecast"[1] shows the 2016 CDM Adjustment Purchase Adjustment of -1,748,874 kWh which consisted of:
   - 2014 CDM result x ½ year.
   - 2015 CDM annual target.
   - 2016 CDM annual target x ½ year.

   Therefore, the 2016 Test Year Load Forecast in Application EB-2015-0110 contained half (0.5) of the LDC's 2014* annual CDM savings.

   (2014 CDM net kWh savings as reported in the "IESO Final Report for Wellington North Power Inc. (CDM) for 2011-2014" filed as Exhibit 4D in EB-2015-0110).*

[1] Wellington North Power Inc. EB-2015-0110, Settlement Proposal filed March 4, 2016, page 44 of 133

4-Staff-63

LRAMVA

Ref 1: LRAMVA Workform, Tab 5

Ref 2: Application, page 84

Wellington North Power has requested approval of LRAMVA amounts in 2020 related to persisting savings from CDM programs implemented from 2015 to 2019. This also includes the persistence of a street lighting conversion project from 2019 persisting into 2020. When the OEB approves lost revenues related to a certain program year, those balances will be approved on a final basis, unless otherwise stated.

Wellington North Power further notes that it wishes to dispose of all balances in Account 1568, and unless instructed by the OEB through policy or accounting guidelines, the utility will not be allocating future lost revenues due to CDM programs in 2020 or beyond to the 1568 LRAMVA variance account.

a) Please discuss if Wellington North Power has or expects to have new, incremental savings from CDM programs deployed in 2020.
b) If Wellington North Power has or expects to have new, incremental CDM savings from 2020 programs and wishes to seek recovery of the associated lost revenues, please discuss whether Wellington North Power can revise the LRAMVA workform to include the incremental 2020 lost revenues now or if they will be included in a future application.
c) If incremental 2020 lost revenues are not available now, please discuss if Wellington North Power will remove all lost revenues in 2020 and defer recovery of 2020 lost revenues until its next rate application when all 2020 amounts can be included (both persisting savings and new savings in 2020).
d) Please confirm that if Wellington North Power proceeds with its application as filed, inclusive of lost revenues in 2020 from persisting savings from 2015 to 2019 CDM programs, it will forego the opportunity to recover lost revenues from any new, incremental savings from 2020 CDM programs.

WNP's Response:

a) WNP does anticipate there will be incremental savings from CDM programs delivered in 2020. As these programs are now delivered centrally by the IESO with no or minimal input by the LDC and with no final-approved IESO yearly reports available, the utility cannot quantify the energy savings.

b) Apart from the unverified information contained in the "Participation and Cost" reports and given there are no verified annual reports from the IESO, the LDC does not feel it is not in the best interest of its' rate-payers to pay for a third-party to create reports to quantify incremental savings from 2020 CDM delivered programs. Therefore, at this time, the Applicant does not have the necessary data to update and revise the LRAMVA workform to include the incremental 2020 lost revenues.

c) Please see response to d) below.

d) WNP wishes to proceed with the LRAMVA model as filed with the inclusion of:
    i. Lost Revenues from CDM programs delivered from 2015 and 2019.
    ii. Lost revenues in 2020 from persisting savings from 2015 to 2019 CDM programs.
    iii. Amendments to the LRAMVA model as a result of the interrogatory responses:

    The Applicant confirms that it will forego the opportunity to recover lost revenues from any new, incremental savings from 2020 CDM programs.

    WNP has filed an updated LRAMVA model to reflect the changes as a result of responding to interrogatories.

4-Staff-64

LRAMVA

Ref 1: LRAMVA Workform, Tab 5

It appears as though there are several minor discrepancies between the CDM savings included within the LRAMVA workform and the savings including in the IESO's 2015 final verified results report.

a) Please discuss and reconcile the programs and savings differences outlined in the table below.

Program Year	Program	LRAMVA Workform (kWh)	IESO Verified Results (kWh)	Difference (kWh)
2015	Coupon Initiative	39,615	39,904	-289
2015	Coupon Initiative – Adjustment	8,961	9,038	-77
2015	Bi-Annual Retailer Event Initiative	57,324	58,361	-1,037
2015	Bi-Annual Retailer Event Initiative - Adjustment	597	604	-7
2015	Efficiency: Equipment Replacement – Adjustment	-5,961	0	-5,961
2015	Direct Install Lighting and Water Heating Initiative	10,802	22,548	-11,746
2015	Direct Install Lighting and Water Heating Initiative – Adjustment	1,895	0	1,895
2015	Low Income Initiative	18,482	22,009	-3,527

WNP's Response:

a) WNP wishes to thank OEB Staff for identifying these discrepancies.

In reviewing VECC's interrogatory, 3–VECC-26 parts e), f) and g), it is evident there are energy-savings reporting differences between using the IESO Annualized Report (2015) and the latest "Participation & Cost Report" (P&C) dated April 15th 2019.

In the response to interrogatory 3-VECC-26, the Applicant has stated that all CDM data has now been reconciled with the P&C report (April 15th 2019). Respectfully, therefore, the Applicant is not able to adjust the LRAMVA data as requested by OEB staff as this would misalign the data used in the CDM analysis performed by the Applicant in responding to VECC's interrogatory.

4-Staff-65

LRAMVA

a) In light of the responses to the above LRAMVA interrogatories, please confirm whether a 24-month disposition period is still required for rate mitigation.
b) If Wellington North Power made any changes to the LRAMVA workform as a result of its responses to the above LRAMVA questions, please file an updated LRAMVA workform and ensure that any changes to the LRAMVA workform are reflected in "Table A-2. Updates to LRAMVA Disposition (Tab 1-a)".

WNP's Response:

a) Given the minimal changes made to the LRAMVA model due to responding to interrogatories, the requested total amount for disposition has not changed significantly. Therefore, to minimize the bill impact to customers, the Applicant still requests a 24-month disposition period.

b) WNP has filed an updated LRAMVA model to reflect the changes as noted in interrogatories relating to the LRAMVA model.

   Within the revised LRAMVA model, WNP has:

   - Made to changes to worksheet "5. 2015-2020 LRAM" in particular the 2015 results and adjustments.
   - Summarized all changes in worksheet "1-a. Summary of Changes".
   - Updated section "Document of Changes" in worksheet 1. LRAMVA summary.

Exhibit 5 – Cost of Capital

5-Staff-66

Cost of Capital Parameters

Ref 1: Exhibit 5 – 5.4 Cost of Capital

Ref 2: Letter of the OEB – 2021 Cost of Capital Parameters, November 9, 2020

Wellington North Power used 2020 cost of capital parameters as a placeholder until 2021 cost of capital parameters were issued. The OEB issued 2021 cost of capital parameters on November 9, 2020.

a) Please update all models and calculations with the 2021 cost of capital parameters.

WNP's Response:

WNP has updated, as applicable, all models and calculations with the 2021 Cost of Capital Parameters, as issued by the OEB on November 9th 2020 for applications for rates effective 2021.

WNP has filed an updated set of models on the OEB's web-portal to support the Applicant's interrogatory responses.

5-Staff-67

Long-Term Debt

Ref 1: Exhibit 5 – 5.4.4 Long-Term Debt Rate

Wellington North Power used a long-term debt rate of 4.54% for the promissory note owed to the Township of Wellington North. Wellington North Power supported this long- term debt rate by stating that in its last cost of service the settlement proposal, which was accepted by the OEB, stated:

> "Affiliate Debt interest rate to be held at the OEB's current long-term debt rate of 4.54% for the period of this (2016) cost of service application and for the period of the next rebasing cost of service rate application or customer IR application."

a) Please explain if Wellington North Power considered replacing the promissory note with bank debt, which was 2.66% for the latest loan from TD bank. If not, why not?

WNP's Response:

a) Aside from the fact that the current instrument and rate were part of a Board approved settlement, Wellington North Power cannot replace the promissory note with bank debt at 2.66% for a number of reasons:

1. Under the "Subordination and Postponement Agreement" of the financing agreements the utility has with Infrastructure Ontario:

   "The Creditor hereby agree that so long as the Borrower (WNP) remains indebted to Infrastructure Ontario (IO), the Debtor shall not make any payments owing to the Creditor under any debts owing by the Debtor to the Creditor."[2]

   [For reference: The Corporation of the Township of Wellington North (the "Creditor"), Ontario Infrastructure and Lands Corporation ("Infrastructure Ontario") and Wellington North Power Inc. (the "Debtor"].

   Therefore WNP would have to pay off its' IO loans of $5.8 million before it could pay off the promissory note.

2. WNP's loan agreements with IO places its bank in a subordinate position to IO in loan security. Accordingly, unlike the latest loan from the TD bank which WNP was able to secure against the new truck the loan was used to purchase, any refinancing of the promissory note, which WNP is precluded from doing in any event, would be on an unsecured basis, which would negatively affect the ability of WNP to negotiate the applicable interest rate. Additionally, for an unsecured loan like this, WNP's bank would

[2] Subordination and Postponement Agreement, item 2

typically require that it be funded through a Cash Flow Loan which would have a Five-year amortization. This means that over the 5 years WNP would need to repay an average of almost $200,000 principal per year. From a cash flow perspective this is not possible to accomplish.

3. In 2021, WNP will be paying $249,257 in principal on its existing loans (other than the promissory note). Even with profitability slightly increased from historical levels, WNP does not have the capacity to increase principal payments by $30,000 per year without violating its Debt Service Coverage loan covenant. Without covenant compliance an unsecured loan would not even be possible.

WNP has filed a copy of the Subordination and Postponement Agreement on the OEB's web portal. This is filed as "5-Staff-67 Subordination & Postponement Agreement 2017".

5.0-VECC-44

Reference: Exhibit 5, page 10 /EB-2015-0110 Interrogatory Response 5-VECC-36

In EB-2015-0110 WNP provided the following response with respect to the Township Promissory Note:

> "*In WNP's opinion, it considers the loan callable; however the Applicant would need to seek legal advice to confirm whether this is true or not as well as to determine if there are penalties for retiring the loan."*

a) Given the precipitous decline in interest rates since that time (e.g., WNP has negotiated a 7-year loan at 2.66% for a bucket truck-page 13) has WNP exercised its due diligence responsibility to: (a) understand whether the affiliated debt is callable; and (b) determine whether the replacement debt might be below the current rate of 4.54%?

b) Why has WNP not set up a schedule to repay the remaining principal of this loan (established at $1,585,016) and so as to retire the affiliate debt in due course?

c) Please file the schedule of payment that was attached to the promissory note.

d) What provision, if any, in the promissory note prohibits WNP from paying principal on the loan?

WNP's Response:

a) Please see response to interrogatory 5-Staff-67. As noted in that response, the Town is unable to compel (or call on) WNP to (and WNP is unable to voluntarily) pay any amounts towards the principal of the promissory note during the course of the Infrastructure Ontario (IO) loans.

b) Please see response to interrogatory 5-Staff-67.

c) An Excel file has been submitted as evidence as part of the interrogatory responses.

d) The Financing Agreements that WNP has with IO precludes the utility from making principal payments on the Promissory Note.

Exhibit 7 – Cost Allocation

7.0 – VECC –45

Reference: **Exhibit 7, pages 7-8**
WNP 2021 Cost Allocation Model (CAM), Tab I4 (BO Assets)
EB-2015-0110, WNP_IR 2016 CAM, Tab I4

a) It is noted that in the 2021 CAM a portion of accounts 1830 and 1835 are designated as "Subtransmission Bulk Delivery". However, in the 2016 CAM none of the assets in these accounts were designated as such. Please explain what changes have occurred in WNP's distribution system since 2016 that give rise to some of the assets in these accounts now being designated as "Subtransmission Bulk Delivery". As part of the response, please describe fully the assets now being designated as "Subtransmission Bulk Delivery" (e.g., voltage, km, role in the overall distribution system, etc.)

b) At page 8 the Application indicates that WNP has 71 km of primary overhead, 15 km of primary underground and 6 km of secondary.

   i. What portion of the 6 km of secondary is underground?

   ii. Please reconcile these values with the fact that in Tab I4, 30% of both accounts 1830 and 1835 are designated as secondary and 70% of accounts 1840 and 1845 are designated as secondary.

WNP's Response:

a) As noted, in previous Applications, in the Cost allocation Model (CAM), WNP has allocated 70% and 30% of assets to Primary and Secondary respectively for account 1830 (Poles, Towers & Fixtures) and account 1835 (Overhead Conductors and Devices) with none (0%) being allocated to Sub-transmission bulk delivery.

   In preparing its' 2021 Cost of Service application, WNP reviewed the CAM and determined that there should be some allocation of assets to Sub-Transmission bulk delivery. WNP's understanding of sub-transmission is:

   > Embedded supply to Local Distribution Companies (LDCs). "Embedded" meaning receiving supply via Hydro One Distribution assets, and where Hydro One is the host distributor to the embedded LDC. Situations where the LDC is directly connected to and supplied from Hydro One Distribution assets between 44 kV and 13.8 kV inclusive.

   In the CAM, for account 1830, WNP has allocated the following percentages:

   - Sub-transmission Bulk Delivery: 20% - the utility has determined that 15 km of all pole line is sub-transmission.
     20% is from 15 km / 77 km - please refer to part b) below for explanation.
   - For the remaining 80% of asset costs, WNP used load by rate class based on billed kWh for 2019 to determine the percentage to be allocated to Primary and Secondary

as illustrated below:

Rate Class	2019 Billed kWh	% of Total Billed kWh	Primary	Secondary
Residential	25,253,896	26%		(26% + 11%) * 80% = 30%
GS <50 kW	11,138,172	11%		
GS 50-999 kW	18,739,880	19%	(19% + 44%) * 80% = 50%	
GS 1,000 – 4,999kW	42,766,148	44%		
Total	97,898,096	100%		

WNP has input these percentages into the CAM.

b) On page 8 of Exhibit 7 – Cost Allocation, the applicant states:

"Structure kilometers of 92km. This is consists of the utility having 71km of primary overhead, 15km of primary underground and 6km of secondary along roads where there is no primary distribution line."

i. WNP has:

- o Primary overhead: 71 km.
- o Primary underground: 15 km.
- o Secondary overhead: 77 km.
- o Secondary underground: 45 km.

To clarify:

In worksheet "I5.1 Misc Data" of the Cost Allocation Model, in cell D15 for "structure of km (km of roads in service area that have a distribution line)," WNP inputted 92 km which is calculated by:

- o Primary overhead = 71 km +
- o Primary underground = 15 km +
- o Secondary overhead = (Secondary Overhead minus Primary Overhead)
  (77 km - 71 km) = 6 km *
- o Total structure km = 71 + 15 + (77-71) = 92 km

* Of the secondary overhead line, 71 km is attached to primary overhead equipment.

ii. The Applicant has reconciled the values as identified.

7.0 – VECC –46

Reference: **Exhibit 7, page 8**
WNP 2021 CAM, Tab I5.1

Preamble: At page 8 the Application indicates that WNP has 71 km of primary overhead and 6 km of secondary

a) Tab I5.1 indicates that 100% of the pole rental revenue is from the use of secondary poles. Given the small proportion for overhead km that are secondary, please re-confirm that this is the case.

WNP's Response:

a) In worksheet "I5.1 Misc Data" of the Cost Allocation Model, in cell D121 for "Portion of pole leasing revenue from Secondary – remainder assumed to be primary (%), WNP inputted 100%. WNP has amended this percentage to 8% which is derived by:

(As per response to 7-VECC-45):

- Primary overhead = 71 km
- Secondary overhead = (Secondary Overhead minus Primary Overhead)
  (77 km - 71 km) = 6 km *
- Total overhead km = (71 km + 6 km) = 77 km

* Of the secondary overhead line, 71 km is attached to primary overhead equipment.

Therefore 6 km / 77 km = 7.79% (shown as 8% in cell D21 of worksheet "I5.1 Misc Data" of the Cost Allocation Model.)

This means that for WNP, 8% of pole rental revenue is from the use of secondary poles with the remainder from primary.

WNP has filed an updated version of the Cost Allocation model on the OEB's web portal.

7-Staff-68

Weighting Factors

Ref 1: Exhibit 7, page 9

Wellington North Power "notes that it has costs for Services USoA Account 1855 for residential and GS<50 kW 2 customers only and these expenses will be almost entirely residential and GS <50 kW since only 3 wire from small transformers (<100 -150 kV) is allocated to 1855."

a) Please indicate what proportion of GS < 50 kW customers are connected using 3-wire from small transformers as note above.
b) Please confirm that small transformers actually refer to <100-150 kW, not kV.

WNP's Response:

a) As of December 31st 2020, there were 469 GS 50-999 kW accounts, of which 125 were 3 phase, or 26.7% of the rate class.

b) WNP confirms that small transformers refers to <100-150 kW.

7.0 – VECC –47

Reference: **Exhibit 7, pages 8-9**
2021 CAM, Tab I4

Preamble: The Application (page 9) states:

"*WNP notes that it has costs for Services USoA Account 1855 for residential and GS<50 kW customers only and these expenses will be almost entirely residential and GS <50 kW since only wire from small transformers (<100 -150 kV) is allocated to 1855. General Service 50 to 999 kW and General Service 1,000 to 4,999 kW classes have a factor of 0 since any costs are recovered fully through capital contributions (USoA 1995/2440) received from those customers*."

a) Does the $560,662 book value assigned to account 1855 include the cost of Services for GS 50-999 and GS 1,000-4,999 customers? If not, where are the costs for these facilities recorded?

b) Does the $106,317 in contributed capital assigned to account 1855 specifically include the contributions received from GS 50-999 and GS 1,000-4,999 customers? If not, to which USOA account(s) are these contributions assigned?

c) Please explain why the weighting for GS<50 is set at 0.4 as opposed to being the same as that for Residential.

WNP's Response:

a. There are no asset values in 1855 for GS 1,000-4999 kW. These customers own their own transformers and WNP only provides primary line power to the transformer. The customer is responsible for their own secondary lines from the transformer.
The book value of account 1855 includes all assets for all rate classes. WNP does not sub-divide any asset values based on rate classes.

b. Yes, the contributed capital assigned to account 1855 specifically includes the contributions received from GS 50-999 kW customers.

c. The weighting for GS<50 kW is less than Residential because there are so many fewer customers (less than one seventh). To make the weighting equal would assume that there is over a 700% increase in the cost of providing service to GS<50 kW versus a Residential customer. A weighting of 0.4 means there is a much more accurate estimate of just under 300% increase in cost for the average GS<50 kW service over residential customer.

7-Staff-69

Meters

Ref 1: Cost Allocation Model, Tab I6.2 Customer Data; Tab I7.1 Meter Capital

Wellington North Power indicates that it has 468 General Service (GS) < 50 kW customers, all with Demand meters without IT, 34 GS 50 - 999 kW customers, and 5 GS 1,000 - 4,999 kW customers all with Demand meters with Interval capability.

a) Does Wellington North Power regularly re-classify customers that that cross above or below the 50kW threshold?
b) If Wellington North Power does regularly re-classify customers, does it change the customer meter?
c) Please confirm whether or not Wellington North Power using demand meters for all GS customers under 50kW when these customers are energy billed?

WNP's Response:

a) Yes, as per Distribution System Code 2.5 *"Frequency and Notice of Customer Reclassification and Notice of kVA Billing"*, WNP reviews each non-residential customer's rate class account to determine if a customer's demand has fallen outside the upper or lower limits applicable to the customer's current rate classification. This review is performed annually in January and looks at customer's kW demand for the prior 12 months to ascertain if the monthly demand is +/-50 kW for 5 consecutive months.

The LDC will also review a non-residential customer's rate classification upon being requested to do so by the customer at any time.

The table below shows the number of accounts re-classified from 2017 to 2020:

Year	Reclassified: From GS<50kW To GS 50-999 kW	Reclassified: From GS 50-999 kW To GS<50kW	Source
2017	0	1	Customer request
2018	0	0	WNP annual review
2019	0	0	WNP annual review
2020	2	0	WNP annual review

b) In the instance where a customer is re-classified from GS<50 kW to GS50-999 kW, then WNP will replace the meter from a Smart Meter to a MIST meter.
Alternatively, for a re-classification from GS50-999 kW to GS<50 kW, WNP will replace the meter from a MIST meter to a Smart Meter.

c) WNP advises that not all customers in rate class GS<50 kW have a demand meter. WNP's

Operations team will decide if a demand meter is required for a new GS<50 kW service connection request once the customer can provide information, such as expected kW demand, and a design layout has been prepared.

7-Staff-70

Demand Allocators

Ref 1: Cost Allocation Model, Tab I6.1 Revenue, Tab I6.2 Customer Data; Tab I8 Demand Data

Wellington North Power indicates on the Customer Data sheet in the Cost Allocation model that every customer relies on Wellington North Power for secondary distribution, and that all customers except for two out of thirty-four customers in the GS > 50 – 999 kW rate class rely on Wellington North Power for line transformation as well.

On the I6.1 Revenue sheet, 10,607 kW out of 52,425 kW (20.2%) of billing demand in the GS 50 – 999 kW rate class is identified as being subject to transformer ownership allowance (i.e. the customer supplies the transformer). On sheet I8 Demand Data, 2,774 kW of 13,712 kW (20.2%) of 4 Non-Coincident Peak (NCP) demand is served by a Wellington North Power owned line transformer and secondary distribution.

Wellington North Power has not identified any GS 1000 - 4,999 kW load as being served by its own line transformers but has identified that all 5 customers rely on Wellington North Power for secondary distribution.

a) Please explain the situation that would give rise to a customer owning their own line transformer but relying on Wellington North Power for secondary distribution.
b) Please explain how on sheet I6.1 approximately 20% of demand in the GS 50 – 999 kW rate class is served by customer owned transformers while in sheet I8, the same 20% of demand is served by Wellington North Power owned line transformers.
c) Please explain how all 34 of the GS 50 – 999 kW customers are indicated as being served by Wellington North Power secondary distribution, but only approximately 20% of 4 NCP is identified as being served by Wellington North Power secondary distribution.
d) What proportion of General Service 1,000 – 4,999 kW customers, and 4 NCP load are served using:
    a. Wellington North Power owned line transformers?
    b. Wellington North Power owned secondary distribution line?
e) Does Wellington North Power serve any multi-unit residential buildings such as condominiums in the residential rate class at primary voltage?
f) Does Wellington North Power serve any GS < 50 kW customers any analogous multi-unit buildings at primary voltage?

WNP's Response:

Preamble:

> *The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distributor's volumetric rates that is a component of the customer's monthly electricity bill.*

Therefore, when a customer provides its' own step-down transformation from primary to secondary, the customer receives a credit of these costs already included in the distributor's volumetric rate billed to the customer.

In WNP's customer-base:

- All customers in the GS 1,000-4,999 kW rate class own their own transformers and therefore are not eligible for the transformer allowance.
- The two customers in the GS 50-999 class however do provide a step-down transformation and as such receive the allowance.

a) WNP wish to confirm that every customer relies on the LDC for secondary distribution.
WNP also confirms that all customers in the General Service 1,000-4,999 kW rate class own their transformation facilities and do not contribute to the system transformation costs. The volumetric rate billed to customers in this rate class exclude the transformation cost (voltage step-down) element because it is the customer's equipment and not the utility's equipment performing the transformation activity.

b) WNP confirms that the demand profiles at sheet I8 should have reflected 80% which supports the fact that 80% of demand is served by Wellington North Power and 20% is served by customer owned transformers. A revised Cost Allocation Model filed with these responses have been amended to reflect this change.

c) Please see response to part b).

d) WNP has updated the model to populate the demand allocator of Line Transformer NCP for the GS 1000-4999 class to reflect the fact that all customers in this class do not receive a transformer allowance.

e) WNP does not serve any multi-unit residential buildings in the residential rate class at primary voltage.

f) WNP does not serve any GS < 50 kW customers any analogous multi-unit buildings at primary voltage.

7-Staff-71

Load Profile Update

Ref 1: Exhibit 7, page 50.

Ref 2: Exhibit 3, page 10.

With respect to metering in the Residential and GS < 50 kW rate classes, Wellington North Power states that "Approximately 140 Smart Meters are configured to record metered kW demand every 15 minutes". Wellington North Power indicates that it had 3,279 Residential and 470 GS < 50 kW customers in 2018, and 3,302 Residential and 470 GS < 50 kW customers in 2019. Wellington North Power explains that no customers were reclassified between GS 50- 999 kW and GS 1,000 – 4,999 kW (either direction) in either of 2018 or 2019.

a) Is this indeed the peak demand over the 15-minute interval, is it the average demand over the interval (i.e. 15 minutes of energy in kWh multiplied by four to arrive at an average hourly rate for the interval), or is some other method used?
b) How are the remainder of the Residential and GS < 50 customers metered? Similar to part a) above, is the measurement based on, or derived from energy over the interval, or is it based on demand?
c) What is Wellington North Power's normal practice with respect to re-classification between rate classes? I.e. what triggers a review of customer classification, how often are customers re-classified?
d) Were customers reclassified between GS < 50 kW and GS 50 – 999 kW?
e) If customers were reclassified between GS < 50 kW and GS 50 – 999 kW, does the data reflect the customer's current rate class, the rate class at the time of the meter reading, or another approach (please explain)?
f) If new customers have come onto the system or customers have left the system, how has Wellington North Power addressed the partial year of meter data for these customers?

WNP's Response:

a) This is the average demand over the hourly interval period. An example is shown in the Applicant's "Exhibit 7 – Cost Allocation" on page 50 and copied below:

<u>Assumptions Applied:</u>

a) Residential and General Service <50 kW.
   - Metered usage:
     The demand profile is based on metered usage (no loss applied).
   - 15-minute interval data:
     Approximately 140 Smart Meters are configured to record metered kW demand every 15 minutes (i.e. a 15-minute interval meter). To create an hourly demand, the average of the four 15-minute interval reads was used, e.g.:

Time	12:15	12:30	12:45	1:00	Average Demand
15 minute kW recorded	6	7	10	8	7.75 kW/h

b) The remainder of WNP's Residential and GS<50 kW customers are metered with an hourly interval Smart meter. This measures kW demand per hour.

c) WNP follows the requirement of section 2.5 of the Distribution System Code (DSC) *"Frequency and Notice of Customer Reclassification and Notice of kVA Billing"*. The utility reviews each non-residential customer's rate class account to determine if a customer's demand has fallen outside the upper or lower limits applicable to the customer's current rate classification. This review is performed annually in January and looks at customer's kW demand for the prior 12 months to ascertain if the monthly demand is +/-50 kW for 5 consecutive months.
As per the DSC, WNP will also review a non-residential customer's rate classification upon being requested to do so by the customer at any time.

d) WNP confirms that no customers were reclassified between GS<50 kW and GS 50-999 kW, either direction, in either of 2018 or 2019.

e) As noted to response d) above, there were no customer reclassifications between GS<50 kW and GS 50-999 kW rate classes in either direction.

f) In the Applicant's "Exhibit 7 – Cost Allocation", page 49 detailed a couple of scenarios.
   - In the instance of a new customer connecting to the LDC's distribution, the example b) shown on page 49, of a brand new development would apply.
   - In the instance of a customer leaving the LDC's distribution, WNP assumes OEB staff is referring to a customer selling their house and moving out of the service territory. If this is correct, then please refer to example a) shown on page 49.

7-Staff-72

Load Profile Update

Ref 1: Exhibit 7, page 56.

A 10-year period from 2009 to 2018 was used to define weather normal for the 2018 load profile, while 2010 to 2019 was used to define weather normal for the 2019 load profile.

a) Please explain why different periods were used to define normal weather for the 2018 and 2019 load profiles.

WNP's Response:

a) WNP confirms that both 2018 and 2019 weather-normal load profiles are based on 10-year of averages of HDD and CDD values up to and including the year in question; that is:
   - 2018 is derived from the 10-year period of 2009 to 2018; and
   - 2019 is derived from the 10-year period of 2010 to 2019.

   WNP acknowledges that it would seem more appropriate to use a common definition of the period for weather normalization and tie it to the period used to determine "weather normal" for the Applicant's 2021 Test Year's load forecast. Therefore, WNP has re-run the 2018 Demand Profile using the 10-year average for the period 2010-2019 (i.e. the same weather-normalized period used for the 2019 Demand Profile as well as the Applicant's Load Forecast.

   The table below summarizes the differences between 2018 Annual Demand for weather-sensitive rate-classes adjusted for HDD and CDD using (a) 10 year weather average of 2009 to 2018 (as filed) and (b) 10 year weather average of 2010 to 2019:

		Annual Demand Hourly Data Adjusted for HDD & CDD	
		As Filed	Updated
	2018 Demand	*10 yr Av of 2009-2018*	*10 yr Av of 2010-2018*
Residential	25,345,905	24,922,053	24,839,344
GS<50 kW	11,582,140	11,388,935	11,344,503
GS 50-999 kW	18,316,320	17,995,259	17,918,406

   The table below shows the NCP and CP for each rate class for 2018 Demand using the 10 year period of 2009 to 2018 filed as "Appendix 7B 2018 Demand Profile" in WNP's initial application:

	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	StreetLights	Sentinel Lights	USL
1NCP	6,293	2,276	3,729	7,264	53	6	2
4NCP	22,208	8,709	14,228	28,664	211	23	8
12NCP	60,082	24,078	39,589	82,518	633	56	18
	Residential	**GS<50kW**	**GS 50 - 999kW**	**GS 1000 - 4999kW**	**Street Lighting**	**Sentinel Lighting**	**USL**
1CP	4,324	2,276	2,778	6,475	0	0	0
4CP	16,868	8,002	12,081	26,182	0	0	0
12CP	47,319	22,434	35,482	77,856	105	7	2

The table below shows the NCP and CP for each rate class for 2018 Demand using the 10 year period of 2010 to 2019 filed as "Appendix 7B 2018 Demand Profile v2" with WNP's interrogatory responses:

	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	StreetLights	Sentinel Lights	USL
1NCP	6,254	2,263	3,414	7,264	53	6	2
4NCP	22,568	8,737	13,374	28,664	211	23	8
12NCP	60,734	24,234	38,608	82,518	633	56	18
	Residential	**General Service <50kW**	**GS 50 - 999kW**	**GS 1000 - 4999kW**	**Street Lighting**	**Sentinel Lighting**	**USL**
1CP	4,380	2,040	3,030	6,990	0	0	0
4CP	16,409	8,235	12,750	26,134	0	0	0
12CP	45,995	22,704	36,260	78,571	105	7	4

The table below summarizes the calculated CP and NCP values using 2018 and 2019 Demand Profiles weather-normalized. The average of the 2018 and 2019 CP and NCP values have been input into worksheet "I8. Demand" of the 2021 Cost Allocation model:

	Coincident Peak						
2018	**Residential**	**General Service <50kW**	**General Service 50-999kW**	**General Service 1000-4999kW**	**StreetLights**	**Sentinel Lights**	**USL**
1CP	4,380	2,040	3,030	6,990	0	0	0
4CP	16,409	8,235	12,750	26,134	0	0	0
12CP	45,995	22,704	36,260	78,571	105	7	4
2019	**Residential**	**General Service <50kW**	**General Service 50-999kW**	**General Service 1000-4999kW**	**StreetLights**	**Sentinel Lights**	**USL**
1CP	5,296	1,967	2,692	6,513	56	3	1
4CP	19,208	7,744	11,164	25,114	152	11	4
12CP	46,713	20,974	33,315	78,794	193	15	5
Average of 2018 & 2019 Coincident Peak	**Residential**	**General Service <50kW**	**General Service 50-999kW**	**General Service 1000-4999kW**	**StreetLights**	**Sentinel Lights**	**USL**
1CP	4,838	2,004	2,861	6,751	28	2	1
4CP	17,808	7,989	11,957	25,624	76	6	2
12CP	46,354	21,839	34,787	78,682	149	11	4
	Non-Coincident Peak						
2018	**Residential**	**General Service <50kW**	**General Service 50-999kW**	**General Service 1000-4999kW**	**StreetLights**	**Sentinel Lights**	**USL**
1NCP	6,254	2,263	3,414	7,264	53	6	2
4NCP	22,568	8,737	13,374	28,664	211	23	8
12NCP	60,734	24,234	38,608	82,518	633	56	18
2019	**Residential**	**General Service <50kW**	**General Service 50-999kW**	**General Service 1000-4999kW**	**StreetLights**	**Sentinel Lights**	**USL**
1NCP	5,882	2,290	3,391	7,508	56	6	2
4NCP	21,904	8,771	13,195	29,250	223	23	7
12NCP	58,446	23,329	37,718	83,616	639	56	18
Average of 2018 & 2019 Non-Coincident Peak	**Residential**	**General Service <50kW**	**General Service 50-999kW**	**General Service 1000-4999kW**	**StreetLights**	**Sentinel Lights**	**USL**
1NCP	6,068	2,277	3,402	7,386	54	6	2
4NCP	22,236	8,754	13,285	28,957	217	23	7
12NCP	59,590	23,782	38,163	83,067	636	56	18

In responding to this interrogatory, the Applicant has filed:

i. A copy of the revised 2018 Demand Profile, using the 10-year period weather-normalization period 2010-2019.

ii. An updated Cost Allocation model that includes revised CP and NCP values using the average of revised 2018 Demand Profile data and the 2019 Demand Profile data.

7.0 – VECC –48

Reference: Exhibit 7, page 14

a) Please provide a revised version of WNP's 2021 Cost Allocation Model where HONI's 2004 load profiles are used to determine the demand allocators in Tab I8 instead of the values derived using the "USF Demand Profile Working Group" methodology.

WNP's Response:

a) WNP has taken a copy of the 2021 Cost Allocation model that was filed on November 20th 2020 and, in worksheet "I8. Demand Data", inputted the demand allocators as derived from using the HONI's 2004 load profiles.

This has been filed on the OEB's web portal, file name:
"7-VECC-48 2021_Cost_Allocation_Model_ v2.1 20201120_HONI Load Profiles."

Please note that the scenario is provided for illustrative purposes only. By providing this information, WNP is not committing to adopting these changes for rate making purposes

7.0 – VECC –49

Reference: **Exhibit 7, pages 14-21 and Appendix 7A**
Exhibit 3, pages 24 and 42

a) Please provide a schedule which sets out the monthly and annual values for HDD and CDD for: i) 2018; ii) 2019; iii) the average of 2018 and 2019 and iv) the 10-year average used in the Load Forecast model to define "weather normal".

b) At Appendix 7A, page 56 the Application states: "Both 2018 and 2019 weather-normal load profiles are based on 10-year of averages of HDD and CDD values up to and including the year in question; that is:
   - 2018 is derived from the 10-year period of 2009 to 2018; and
   - 2019 is derived from the 10-year period of 2010 to 2019."

   Why wasn't the time period that was used to define "weather normal" for purposes of the load forecast used for both years?

c) At Appendix 7A, page 57 the Application states that the GS 1,000-4,999 is treated as not being weather sensitive. At Appendix 7B, pages 68-69 the Application indicates that WNP undertook an analysis of the impact of HDD and CDD on 2018 GS 1,000-4,999 load. Please provide the full results of the regression analysis including the independent variable used, their resulting coefficients and the regression statistics (e.g., t-stats for each independent variable). As part of the response please comment on whether the coefficients for HDD and/or CDD were significantly different (based on the t-statistics) from zero.

d) Per Appendix 7A, page 56 & pages 67-68 and Appendix 7B please confirm that for any given day, the same adjustment factor for the difference between the actual HDD/CDD versus the weather normal HDD/CDD is applied to each hour of the day (e.g., for January 1, 2018 the same HDD adjustment factor of 0.9482 was used for all hours of the day).

e) At Appendix 7A, pages 67-68 the Application states that "The Mount Forest weather station does not record or store HDD or CDD weather data in hourly intervals, only daily. Pearson Airport weather station is the nearest station to WNP's service territory with hourly HDD and CDD data." Based on 2018 data what was the average of the absolute values of the daily variance between: i) the daily HDD values for the Mount Forest weather station vs. the Pearson Airport weather station and ii) the daily CDD values for the Mount Forest weather station vs. the Pearson Airport weather station.

f) Per Appendix 7A, page 56 and Appendix 7B please confirm for each month the same HDD and CDD adjustment factors were used for each of the Residential, GS<50 and GS 50-999 rate classes (e.g., for January 2018 the HDD adjustment factor used was 20% for all customer classes).

   i. If yes, please reconcile this approach with that used in the Load Forecast where the weather normalization assumes that the sensitivity to weather varies by customer class (per Exhibit 3, page 42).

g) At Appendix 7A, pages 68-69, the Application indicates that WNP undertook separate analyses as to the impact of HDD and CDD on the 2018 load for the Residential, GS<50 and GS 50-999 customer classes.

   i. For each customer class, please provide the full results of the regression analysis including the dependent and independent variables used, the resulting coefficients for the independent variables and the regression statistics (e.g., t-stats for each independent variable). As part of the response please comment on whether, for each customer class, the coefficients for HDD and/or CDD were significantly different (based on the t-statistics) from zero.

h) With respect to the Appendix 7A and the table on page 69, please explain why some of the variance values for the Residential, GS<50 and GS 50-999 as between Predicted with HDD and Predicted without HDD are negative and some are positive. If the same estimated coefficient for the HDD variable is used for all months and HDD values are all positive, one would expect variances to all be negative or all be positive.

i) With respect to the Appendix 7A and the table on page 69, please explain why some of the values for the Residential variance between Predicted with CDD and Predicted without CDD are negative and some are positive. If the same estimated coefficient for the CDD variable is used for all months and CDD values are all positive, one would expect variances to all be negative or all be positive

j) At Appendix 7A, pages 66-67 the Application states that the limitations of Microsoft Excel prevent members of the USF Working Group from performing weather normalization of an hourly basis as was done by Elenchus for other utilities. Has the USF Working Group investigated the cost of acquiring the software necessary such that the member LDCs could undertake such analysis?

   i. If yes, what would the initial and annual cost be if the Working Group acquired the software and shared it amongst its members?

WNP's Response:

In relation to the interrogatory responses below, WNP provides the following additional context regarding the Load Profile model developed by the USF Working Group:

> The intent of the USF Working Group was to develop a methodology that could be used by a wide range of LDCs to meet the OEB's Filing Requirement expectations relating to updating load profiles, in particular:
>
> *"The Hydro One profiles were based on 2004 data, and consumption patterns may have changed since then due to factors such as technology, macroeconomic changes, conservation programs and time of use pricing. Distributors should make best efforts to update all classes' load profiles using the most recent available data, particularly from smart, MIST and interval meters."*[3]
>
> The USF Working Group took into consideration the outcome of previous filings regarding Load Profiles such as using an outsourced method as in EB-2017-0039 or an in-house method as in EB-2016-0091. The working group wanted to address all the perceived shortcomings of other methods (i.e. complexity, transparency and lack of weather normalization) while balancing the value to the LDC of retaining ownership and knowledge of the data being submitted. The methodology developed also demonstrates regulatory efficiency, as it can be completed, maintained and updated for many LDC's, using the same tools and data that are readily available to support other filing requirements related to load forecasting.

[3] OEB Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Application, section "2.7.1 Cost Allocation Study Requirements", page 54

a) As requested, please see schedule below relating to monthly and annual values for Heating Degree Day (HDD) and Cooling Degree Day (CDD):

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Heating Degree Day														
	2018	792.90	619.60	631.60	515.70	120.00	46.50	11.00	5.70	87.90	338.70	568.90	623.70	4,362.20
	2019	848.80	690.00	674.13	412.50	227.05	70.20	6.60	25.10	90.90	293.80	576.80	647.30	4,563.18
	Average (2018 + 2019)	820.85	654.80	652.86	464.10	173.53	58.35	8.80	15.40	89.40	316.25	572.85	635.50	4,462.69
10 year Average from Load Forecast	2020 Bridge Year	789.65	698.95	614.93	394.49	168.45	57.87	17.11	24.60	102.41	283.30	487.21	655.25	4,294.22
	2021 Test Year	789.47	700.84	625.95	406.62	170.48	58.13	17.55	25.13	98.95	281.53	492.00	646.35	4,312.99
Cooling Degree Day		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
	2018	0.00	0.00	0.00	0.00	30.70	28.70	77.30	80.90	46.10	7.90	0.00	0.00	271.60
	2019	0.00	0.00	0.00	0.00	1.00	16.40	92.50	33.30	13.20	2.10	0.00	0.00	158.50
	Average (2018 + 2019)	0.00	0.00	0.00	0.00	15.85	22.55	84.90	57.10	29.65	5.00	0.00	0.00	215.05
10 year Average from Load Forecast	2020 Bridge Year	0.00	0.00	0.34	0.10	16.08	28.28	72.36	52.28	25.18	1.32	0.00	0.00	195.93
	2021 Test Year	0.00	0.00	0.37	0.01	15.29	29.23	70.63	49.30	26.14	1.45	0.00	0.00	192.43

Load Forecast 2020 Bridge Year HDD & CDD is the 10 year average of 2010 to 2019 data.
Load Forecast 2021 Test Year HDD & CDD is the 10 year average of 2011 to 2020 data.
Weather data source: Mount Forest, Ontario weather station (as per application).

b) WNP acknowledges that it would seem more appropriate to use a common definition of the period for weather normalization and tie it to the period used to determine "weather normal" for the Applicant's 2021 Test Year's load forecast. Therefore, WNP has re-run the 2018 Demand Profile using the 10-year average for the period 2010-2019 (i.e. the same weather-normalized period used for the 2019 Demand Profile as well as the Applicant's Load Forecast.

In responding to this interrogatory question, the Applicant has filed:

- A copy of the revised 2018 Demand Profile, using the 10-year period weather-normalization period 2010-2019.
- An updated Cost Allocation model that includes revised CP and NCP values using the average of revised 2018 Demand Profile data and the 2019 Demand Profile data.

For more information, please to WNP's response to interrogatory 7-Staff-72.

c) In preparing the response to this interrogatory, WNP re-ran the GS 1,000 -4,999 kW rate-class load forecast using the same variable data that was used in the Applicant's Wholesale Power Purchases Load Forecast as submitted with its' application on October 30th 2020. WNP notes there is slight difference in the "Predicted Purchases" monthly and total quantities between the re-ran version and the tables shown on page 69 of Appendix C in the "Exhibit 7 – Cost Allocation" exhibit. The tables below shows the monthly Demand (actuals), Predicted Purchases with and without HDD or CDD:

2018 GS 1,000 – 4999 kW Load – Effects of HDD

	Actual Demand	Predicted Purchases **with HDD**	Predicted Purchases **without HDD**	Variance (HDD to no HDD)	
Jan-18	3,853,209	3,826,643	3,841,332	*-14,688*	*-0.38%*
Feb-18	3,480,850	3,398,353	3,409,831	*-11,478*	*-0.34%*
Mar-18	3,785,927	3,738,948	3,750,648	*-11,700*	*-0.31%*
Apr-18	3,576,532	3,519,565	3,529,118	*-9,553*	*-0.27%*
May-18	3,944,814	3,917,838	3,920,061	*-2,223*	*-0.06%*
Jun-18	3,760,516	3,745,740	3,746,601	*-861*	*-0.02%*
Jul-18	3,579,181	3,551,189	3,551,393	*-204*	*-0.01%*
Aug-18	3,995,352	4,061,005	4,061,111	*-106*	*0.00%*
Sep-18	3,575,441	3,598,973	3,600,601	*-1,628*	*-0.05%*
Oct-18	3,831,665	3,877,620	3,883,894	*-6,274*	*-0.16%*
Nov-18	3,572,886	3,602,077	3,612,616	*-10,539*	*-0.29%*
Dec-18	2,957,583	2,919,720	2,931,274	*-11,554*	*-0.40%*
	43,913,956	**43,757,670**	**43,838,480**		

2018 GS 1,000 – 4999 kW Load – Effects of CDD

	Actual Demand	Predicted Purchases **with CDD**	Predicted Purchases **without CDD**	Variance (CDD to no CDD)	
Jan-18	3,853,209	3,826,643	3,826,643	*0*	*0.00%*
Feb-18	3,480,850	3,398,353	3,398,353	*0*	*0.00%*
Mar-18	3,785,927	3,738,948	3,738,948	*0*	*0.00%*
Apr-18	3,576,532	3,519,565	3,519,565	*0*	*0.00%*
May-18	3,944,814	3,917,838	3,923,057	*-5,219*	*-0.13%*
Jun-18	3,760,516	3,745,740	3,750,618	*-4,879*	*-0.13%*
Jul-18	3,579,181	3,551,189	3,564,330	*-13,140*	*-0.37%*
Aug-18	3,995,352	4,061,005	4,074,758	*-13,752*	*-0.34%*
Sep-18	3,575,441	3,598,973	3,606,810	*-7,837*	*-0.22%*
Oct-18	3,831,665	3,877,620	3,878,963	*-1,343*	*-0.03%*
Nov-18	3,572,886	3,602,077	3,602,077	*0*	*0.00%*
Dec-18	2,957,583	2,919,720	2,919,720	*0*	*0.00%*
	43,913,956	**43,757,670**	**43,803,840**		

For reference, page 69 of Appendix C in the "Exhibit 7 – Cost Allocation" showed:

- Predicted Purchases with HDD as 43,929,560 kWh and without HDD as 43,945,539 kWh.
- Predicted Purchases with CDD as 43,929,560 kWh and without CDD as 43,962,335 kWh.

The difference is due to using the CDM variable data and the Sensitive Customer variable data as used in the Wholesale Load Forecast. (These variable data-sets were not updated in the Rate-Class Load Forecast because the LDC discounted filing individual rate class load forecast due to poor multiple regression analysis results for some rate-classes.)

Below are the regression results for the rate class load forecast for GS 1,000-4,999 kW:

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.915378253
R Square	0.837917346
Adjusted R Square	0.829311187
Standard Error	179014.4821
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	18720585077332	3120097512889	97.36	0.00
Residual	113	3621218880565	32046184784		
Total	119	22341803957896			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-1265999.466	873627.7907	-1.449129114	0.150071027	-2996813.687	464814.7542	-2996813.687	464814.754
Heating Degree Day	-18.5250324	87.39603742	-0.211966503	0.832515022	-191.6723452	154.6222804	-191.6723452	154.62228
Cooling Degree Day	-169.991503	907.0074835	-0.187420177	0.851667317	-1966.936915	1626.953909	-1966.936915	1626.95391
# of Days in Month	1210.637913	20670.59901	0.05856811	0.953399559	-39741.54687	42162.82269	-39741.54687	42162.8227
Regional Employment	1435.448781	1087.475452	1.319982698	0.189508544	-719.0362254	3589.933787	-719.0362254	3589.93379
CDM	-0.53930998	0.29708549	-1.815335984	0.072124347	-1.127889917	0.049269957	-1.127889917	0.04926996
Sensitive Customers	0.942295078	0.044880668	20.99556696	8.35428E-41	0.85337838	1.031211777	0.85337838	1.03121178

The t-stat measures how many standard errors the coefficient is away from zero. Generally, any t-value greater than +2 or less than – 2 is acceptable; however the higher the t-value, the greater the confidence we have in the coefficient as a predictor.

Based on the results above, the HDD and CDD coefficients are not statistically significant for this rate class. This reinforces WNP's decision to not normalize the GS 1000-4999 kW class in this or previous Cost of Service rate applications as HDD and CDD are not meaningful for this class. Furthermore, this supports the Applicant's decision to use a Wholesale Purchase model for the load forecast in this application.

d) WNP confirms that for any given day, the same adjustment factor for the difference between the actual HDD/CDD versus the weather normal HDD/CDD is applied to each hour of the day. For example:

- For January 1, 2018 the same HDD adjustment factor of 0.9482 was used for all hours of that particular day, January 1, 2018.
- For January 2, 2018 the same HDD adjustment factor of 0.9543 was used for all hours of that particular day, January 2, 2018.

e) The tables on the following pages show the daily variance between:
   i. The daily HDD values for the Mount Forest weather station versus Pearson International Airport weather station for 2018; and
   ii. The daily CDD values for the Mount Forest weather station versus Pearson International Airport weather station for 2018.

General observations from the analysis are:

- Daily HDD values for the Mount Forest weather station for all months are higher than those of weather station at Toronto Pearson. From this it can be implied that there is a cooler temperature at Mount Forest compared to Toronto.
- Equally, the daily CDD values for the Mount Forest weather station for May to October are lower than those of weather station at Toronto Pearson. From this it can be implied that there is a cooler temperature during these months at Mount Forest compared to Toronto.

As noted in section "3.1.5 Economic Overview" of the Applicant's "Exhibit 3 – Revenues":

- Page 15: WNP's service territory is "*approx. 120 km northwest of Toronto (as the crow flies)*"; and
- Page 16 – climate: *"Mount Forest features a humid continental climate, characterized by warm, sometimes wet summers and cold, snowy winters. At an elevation of 430 meters (1,410 ft.) above sea level, Mount Forest is one of the highest towns in Southern Ontario being located in the western portion of the Dundalk Highlands. As such, its elevation and location downwind of Lake Huron makes it prone to hefty snow totals from lake effect snow averaging nearly 300 centimeters per year. Summers, with a daily mean average of 18°C to 20°C are often cooler than they otherwise would be due to the town's elevation and overnight lows are considerably cooler than places along the lakeshore. Winter average mean temperatures are between -9°C to -11°C."*

These two statements indicate that the weather conditions at WNP's service territory are different to that of Toronto. In WNP's opinion, although the Mount Forest weather station does not have hourly HDD or CDD data, the daily HDD and CDD data available at this station is more reflective of the weather conditions compared to the data from the Toronto Pearson weather station.

The Applicant has filed an excel file containing the data represented in the tables – please refer to file named "7-VECC-49e HDD& CDD Station Comparison".

The daily variance of daily HDD values for the Mount Forest weather station versus Pearson International Airport weather station for 2018

	Heating Deg Days (°C) - Toronto Pearson Int'l											
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	32.69	19.72	15.79	18.13	0.03	0.00	0.00	0.00	0.00	8.54	11.45	16.13
2	28.55	29.63	17.48	16.09	0.00	1.53	0.00	0.00	0.00	7.07	13.43	11.82
3	27.65	25.07	18.47	15.18	0.48	0.52	0.00	0.00	0.00	4.53	13.57	15.88
4	30.60	20.18	19.60	17.07	5.30	1.59	0.00	0.00	0.00	1.30	14.22	20.51
5	37.33	27.81	19.97	19.92	1.77	5.61	0.00	0.00	0.00	8.96	9.32	20.44
6	37.60	26.00	18.26	18.31	3.49	5.28	0.00	0.00	0.00	5.01	7.48	18.71
7	30.21	26.15	17.06	20.38	4.98	0.45	0.00	0.00	0.00	4.89	11.60	23.47
8	18.01	27.38	19.78	19.88	4.45	0.00	0.00	0.00	3.23	5.50	13.72	20.60
9	18.78	25.47	17.99	18.91	1.81	0.00	0.00	0.00	4.53	0.00	15.26	20.40
10	18.66	23.62	19.11	16.28	1.89	0.00	0.00	0.00	4.26	0.00	18.45	18.05
11	8.93	22.11	19.36	15.48	10.05	0.00	0.00	0.00	0.81	0.97	17.10	19.65
12	17.18	23.95	20.16	12.91	7.10	0.00	0.00	0.00	0.00	10.28	14.31	17.73
13	31.32	25.37	19.65	14.29	5.53	0.00	0.00	0.00	0.00	11.39	18.00	17.21
14	29.11	16.70	19.43	18.65	0.46	0.00	0.00	0.00	0.00	8.83	21.20	15.18
15	25.94	12.94	19.16	19.81	1.00	0.00	0.00	0.00	0.00	8.94	19.48	16.16
16	24.98	18.96	22.29	16.26	4.23	0.00	0.00	0.00	0.00	11.14	17.13	16.73
17	26.88	21.43	19.06	17.98	0.43	0.00	0.00	0.00	0.00	11.93	17.27	16.67
18	24.68	17.60	17.18	16.12	4.17	0.00	0.00	0.00	0.00	14.40	18.65	20.83
19	19.75	16.27	21.31	16.48	5.13	0.00	0.00	0.00	0.92	8.08	17.68	16.75
20	15.80	8.53	20.30	15.35	2.50	0.00	0.00	0.00	0.66	9.16	19.12	15.14
21	16.80	13.10	18.17	10.87	2.66	0.00	0.00	0.00	0.00	14.88	22.13	15.03
22	16.48	19.15	18.26	8.38	3.91	0.00	0.00	0.00	5.18	11.44	27.40	19.42
23	15.87	15.72	18.60	6.75	0.00	0.36	0.00	0.00	4.47	12.26	19.56	18.55
24	25.38	15.44	19.98	6.82	0.00	0.00	0.00	0.00	3.15	14.40	15.22	17.74
25	24.77	12.77	19.99	9.64	0.00	0.03	0.00	0.00	0.00	13.43	12.62	19.31
26	17.94	14.83	14.63	9.12	0.00	0.00	0.00	0.00	0.00	12.26	14.09	18.80
27	11.65	11.87	14.17	8.68	0.00	0.00	0.00	0.00	4.37	14.73	17.44	20.54
28	17.15	9.75	13.46	13.05	0.00	0.00	0.00	0.00	2.98	14.63	17.54	9.98
29	21.78		13.91	12.60	0.00	0.00	0.00	0.00	5.79	12.67	17.23	20.53
30	28.04		15.06	6.64	0.00	0.00	0.00	0.83	7.11	12.55	17.22	20.40
31	22.98		13.90		0.00		0.00	0.00		9.03		16.80

	Heating Deg Days (°C) - Mount Forest											
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	35.60	24.20	17.90	21.80	8.10	0.10	0.00	0.00	0.00	10.70	13.30	18.00
2	30.40	33.20	19.50	19.80	6.10	2.40	0.00	0.00	0.00	7.80	14.50	11.80
3	31.60	25.90	20.70	16.20	4.80	1.00	0.00	0.00	0.00	3.50	16.40	17.60
4	33.80	25.70	21.40	19.90	4.10	5.30	0.00	0.00	0.00	6.50	15.40	23.40
5	39.20	32.10	21.00	23.20	3.30	9.60	0.00	0.00	0.00	12.40	10.50	21.40
6	39.60	28.90	21.70	20.70	4.20	5.50	2.80	0.00	1.20	3.30	9.50	23.00
7	29.80	29.40	19.20	23.20	7.00	1.50	1.40	0.00	3.00	6.50	14.10	26.80
8	20.70	29.70	22.50	23.80	3.30	2.00	0.00	0.00	6.60	3.20	16.60	23.20
9	22.40	28.50	21.20	20.90	0.70	2.10	0.00	0.00	6.90	0.00	18.30	23.50
10	18.30	26.50	21.80	18.90	9.30	0.90	0.00	0.00	5.80	0.00	20.80	21.20
11	10.30	24.60	21.20	18.20	12.50	1.30	0.10	0.00	1.40	5.70	19.90	21.60
12	19.80	28.30	22.40	12.10	7.00	0.00	0.00	0.00	1.30	12.90	16.80	19.40
13	34.00	29.40	22.50	16.70	4.50	0.00	0.00	0.00	0.00	14.60	21.70	18.90
14	31.30	19.30	24.20	20.40	3.30	3.10	0.00	0.00	0.00	10.40	24.80	17.00
15	28.40	16.30	23.00	20.90	6.10	1.60	0.00	0.00	0.00	12.30	22.80	17.70
16	27.90	23.60	25.70	18.90	3.80	0.00	0.00	0.00	0.00	12.90	18.20	18.20
17	28.50	24.40	21.70	20.80	3.30	0.00	0.50	0.00	0.00	15.00	21.00	19.60
18	26.70	19.80	18.90	18.70	4.70	0.00	1.50	0.00	0.30	15.80	21.80	22.10
19	21.30	16.20	22.60	19.70	3.50	0.00	0.70	0.00	2.10	9.80	20.70	18.50
20	17.50	8.70	21.60	19.40	7.70	0.00	0.00	0.00	2.20	13.70	22.00	15.80
21	17.40	15.40	20.70	16.10	5.20	1.20	0.00	0.00	0.00	17.10	27.40	18.70
22	15.80	19.80	20.80	13.10	4.60	0.20	0.50	2.40	7.80	12.80	30.60	22.40
23	20.40	17.10	21.10	7.30	2.20	0.50	0.00	0.10	7.30	14.40	21.60	20.50
24	29.10	17.10	22.30	6.80	0.70	3.20	0.00	0.00	5.30	16.90	15.80	20.50
25	26.90	14.40	20.90	13.20	0.00	3.30	0.00	0.00	0.20	13.90	15.70	21.20
26	18.30	16.20	14.90	12.20	0.00	1.70	0.00	0.00	4.20	12.70	18.00	23.00
27	15.20	13.00	14.80	8.90	0.00	0.00	0.00	0.00	7.30	16.20	20.70	20.60
28	20.60	11.90	13.90	16.90	0.00	0.00	3.20	0.00	6.10	15.70	20.50	13.40
29	25.80		15.90	15.60	0.00	0.00	0.30	0.00	8.80	15.90	20.00	22.60
30	32.20		18.60	11.40	0.00	0.00	0.00	1.90	10.10	14.10	19.50	22.50
31	24.10		17.00		0.00		0.00	1.30		12.00		19.60

	Variance: Heating Deg Days (°C) - Mount Forest vs - Toronto Pearson Int'l											
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	2.91	4.48	2.11	3.67	8.07	0.10	0.00	0.00	0.00	2.16	1.85	1.87
2	1.85	3.57	2.02	3.71	6.10	0.87	0.00	0.00	0.00	0.73	1.07	-0.02
3	3.95	0.83	2.23	1.02	4.32	0.48	0.00	0.00	0.00	-1.03	2.83	1.73
4	3.20	5.53	1.80	2.83	-1.20	3.71	0.00	0.00	0.00	5.20	1.18	2.89
5	1.88	4.29	1.03	3.28	1.53	3.99	0.00	0.00	0.00	3.44	1.18	0.96
6	2.00	2.90	3.44	2.39	0.71	0.22	2.80	0.00	1.20	-1.71	2.02	4.29
7	-0.41	3.25	2.14	2.82	2.03	1.05	1.40	0.00	3.00	1.61	2.50	3.33
8	2.69	2.32	2.72	3.92	-1.15	2.00	0.00	0.00	3.38	-2.30	2.88	2.60
9	3.63	3.03	3.21	1.99	-1.11	2.10	0.00	0.00	2.37	0.00	3.04	3.10
10	-0.36	2.88	2.69	2.63	7.41	0.90	0.00	0.00	1.54	0.00	2.35	3.15
11	1.37	2.49	1.84	2.73	2.45	1.30	0.10	0.00	0.59	4.73	2.80	1.95
12	2.62	4.35	2.24	-0.81	-0.10	0.00	0.00	0.00	1.30	2.63	2.49	1.68
13	2.68	4.03	2.85	2.41	-1.03	0.00	0.00	0.00	0.00	3.21	3.70	1.69
14	2.19	2.60	4.77	1.75	2.84	3.10	0.00	0.00	0.00	1.57	3.60	1.82
15	2.46	3.36	3.84	1.09	5.10	1.60	0.00	0.00	0.00	3.36	3.33	1.54
16	2.92	4.64	3.41	2.64	-0.43	0.00	0.00	0.00	0.00	1.76	1.08	1.47
17	1.62	2.97	2.64	2.82	2.87	0.00	0.50	0.00	0.00	3.08	3.73	2.93
18	2.03	2.20	1.72	2.58	0.53	0.00	1.50	0.00	0.30	1.40	3.15	1.27
19	1.55	-0.07	1.29	3.22	-1.63	0.00	0.70	0.00	1.18	1.72	3.02	1.75
20	1.70	0.17	1.30	4.05	5.20	0.00	0.00	0.00	1.54	4.54	2.88	0.66
21	0.60	2.30	2.53	5.23	2.54	1.20	0.00	0.00	0.00	2.23	5.27	3.67
22	-0.68	0.65	2.54	4.72	0.69	0.20	0.50	2.40	2.62	1.36	3.20	2.98
23	4.53	1.38	2.50	0.55	2.20	0.14	0.00	0.10	2.83	2.14	2.04	1.95
24	3.72	1.66	2.33	-0.02	0.70	3.20	0.00	0.00	2.15	2.50	0.58	2.76
25	2.13	1.63	0.91	3.56	0.00	3.27	0.00	0.00	0.20	0.47	3.08	1.89
26	0.36	1.37	0.28	3.08	0.00	1.70	0.00	0.00	4.20	0.44	3.91	4.20
27	3.55	1.13	0.63	0.22	0.00	0.00	0.00	0.00	2.93	1.47	3.26	0.06
28	3.45	2.15	0.44	3.85	0.00	0.00	3.20	0.00	3.13	1.07	2.96	3.42
29	4.02		1.99	3.00	0.00	0.00	0.30	0.00	3.01	3.23	2.78	2.08
30	4.16		3.54	4.76	0.00	0.00	0.00	1.07	2.99	1.55	2.28	2.10
31	1.13		3.10		0.00		0.00	1.30		2.98		2.80
	69.42	72.08	70.05	79.68	48.65	31.13	11.00	4.87	40.46	55.50	80.01	68.58

The daily variance of daily CDD values for the Mount Forest weather station versus Pearson International Airport weather station for 2018

	Cooling Deg Days (°C) - Toronto Pearson Int'l											
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	4.30	11.38	5.48	4.01	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	4.61	0.00	10.38	5.93	7.73	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	7.28	6.03	8.59	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	8.38	7.34	5.63	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	9.10	9.14	9.49	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	2.31	8.36	4.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	3.18	5.73	1.32	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.07	5.00	4.55	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.70	6.84	5.33	0.00	2.75	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.87	6.79	3.68	0.00	4.03	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.17	4.20	3.82	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	1.47	6.10	5.25	0.55	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	4.10	8.33	5.47	2.88	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	1.91	7.12	7.28	5.14	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	1.85	7.75	7.85	6.15	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	4.96	6.94	6.53	5.82	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	7.83	5.08	5.87	5.13	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	8.89	1.98	3.85	3.43	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	1.64	3.34	3.09	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	1.90	6.70	4.08	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.50	5.63	4.32	5.69	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.14	1.63	1.10	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	1.14	0.00	5.67	2.84	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	2.63	0.07	6.67	3.81	0.00	0.00	0.00	0.00
25	0.00	0.00	0.00	0.00	5.76	0.00	6.24	4.05	0.63	0.00	0.00	0.00
26	0.00	0.00	0.00	0.00	4.48	0.12	4.45	5.85	0.61	0.00	0.00	0.00
27	0.00	0.00	0.00	0.00	2.76	1.43	3.29	6.12	0.00	0.00	0.00	0.00
28	0.00	0.00	0.00	0.00	6.23	5.92	1.01	9.09	0.00	0.00	0.00	0.00
29	0.00		0.00	0.00	4.96	8.15	2.22	7.00	0.00	0.00	0.00	0.00
30	0.00		0.00	0.00	5.22	10.40	3.85	0.00	0.00	0.00	0.00	0.00
31	0.00		0.00		6.53		4.45	1.13		0.00		0.00

	Cooling Deg Days (°C) - Mount Forest											
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	9.20	2.60	3.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	2.90	3.50	5.70	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	3.80	4.40	4.10	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	5.60	3.20	4.80	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	6.10	6.40	6.60	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.50	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.00	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.90	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	0.00	3.80	2.60	0.00	4.00	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	0.00	1.20	1.00	0.00	3.90	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.90	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	0.60	1.50	2.60	0.00	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	0.90	4.20	2.90	1.60	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	0.00	3.20	2.50	4.40	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	5.70	3.90	5.00	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.50	6.50	4.90	5.40	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	5.80	0.00	3.60	4.50	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	2.60	0.00	1.70	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.50	0.00	1.20	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.60	4.10	1.10	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	3.80	1.60	1.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	4.20	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	3.80	1.10	0.00	0.00	0.00	0.00
25	0.00	0.00	0.00	0.00	3.20	0.00	2.00	1.70	0.00	0.00	0.00	0.00
26	0.00	0.00	0.00	0.00	5.00	0.00	2.40	3.30	0.00	0.00	0.00	0.00
27	0.00	0.00	0.00	0.00	4.30	1.40	0.70	4.70	0.00	0.00	0.00	0.00
28	0.00	0.00	0.00	0.00	3.40	3.40	0.00	6.10	0.00	0.00	0.00	0.00
29	0.00		0.00	0.00	3.30	4.20	0.00	2.00	0.00	0.00	0.00	0.00
30	0.00		0.00	0.00	5.60	8.20	0.20	0.00	0.00	0.00	0.00	0.00
31	0.00		0.00		5.90		1.40	0.00		0.00		0.00

	Variance: Cooling Deg Days (°C): Mount Forest vs - Toronto Pearson Int'l											
Day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	-4.30	-2.18	-2.88	-1.01	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	-4.61	0.00	-7.48	-2.43	-2.03	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	-3.48	-1.63	-4.49	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	-2.78	-4.14	-0.83	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	-3.00	-2.74	-2.89	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	-2.31	-2.86	-4.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	-3.18	-1.73	-1.32	0.00	0.00	0.00
8	0.00	0.00	0.00	0.00	0.00	-0.07	-4.00	-3.65	0.00	0.00	0.00	0.00
9	0.00	0.00	0.00	0.00	0.00	-0.70	-3.04	-2.73	0.00	1.25	0.00	0.00
10	0.00	0.00	0.00	0.00	0.00	-0.87	-5.59	-2.68	0.00	-0.13	0.00	0.00
11	0.00	0.00	0.00	0.00	0.00	-0.17	-4.20	-1.92	0.00	0.00	0.00	0.00
12	0.00	0.00	0.00	0.00	0.00	-0.87	-4.60	-2.65	-0.55	0.00	0.00	0.00
13	0.00	0.00	0.00	0.00	0.00	-3.20	-4.13	-2.57	-1.28	0.00	0.00	0.00
14	0.00	0.00	0.00	0.00	0.00	-1.91	-3.92	-4.78	-0.74	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	-1.85	-2.05	-3.95	-1.15	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	-4.46	-0.44	-1.63	-0.42	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	-2.03	-5.08	-2.27	-0.63	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	-6.29	-1.98	-2.15	-3.43	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	-1.14	-3.34	-1.89	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	-1.30	-2.60	-2.98	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	-0.50	-1.83	-2.72	-4.69	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	-0.14	-1.63	-1.10	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	-1.14	0.00	-1.47	-2.84	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	-2.63	-0.07	-2.87	-2.71	0.00	0.00	0.00	0.00
25	0.00	0.00	0.00	0.00	-2.56	0.00	-4.24	-2.35	-0.63	0.00	0.00	0.00
26	0.00	0.00	0.00	0.00	0.52	-0.12	-2.05	-2.55	-0.61	0.00	0.00	0.00
27	0.00	0.00	0.00	0.00	1.54	-0.03	-2.59	-1.42	0.00	0.00	0.00	0.00
28	0.00	0.00	0.00	0.00	-2.83	-2.52	-1.01	-2.99	0.00	0.00	0.00	0.00
29	0.00		0.00	0.00	-1.66	-3.95	-2.22	-5.00	0.00	0.00	0.00	0.00
30	0.00		0.00	0.00	0.38	-2.20	-3.65	0.00	0.00	0.00	0.00	0.00
31	0.00		0.00		-0.63		-3.05	-1.13		0.00		0.00
	0.00	0.00	0.00	0.00	-13.62	-38.70	-95.97	-79.04	-30.68	1.11	0.00	0.00

f) WNP confirms that for each month the same HDD and CDD adjustment factors were used for the Residential, GS<50 kW and GS 50-999 kW rate classes. For example:
   - For January 2018, the HDD adjustment factor used was 20% for all customer classes.
   - For February 2018, HDD adjustment factor used was 18% for all customer classes.

   i. The USF Demand Profile method was developed to assist LDC's in being responsive to the expectations contained in the OEB's Filing Requirements with respect to updating demand profiles by leveraging data available from Smart and MIST meters.
   A preliminary review of methods advanced by other LDCs in recent years revealed criticisms related to lack of weather normalization when historical data covered a short period of time, or criticism that the weather normalization process was overly complicated. WNP acknowledges that the USF Demand Profile method incorporates certain assumptions and approximations including applying daily weather data to hourly demand values, and applying the same weather-normalizing adjustments to multiple rate classes. These approximations were included to allow the method to be applicable to a wide range of LDCs, including WNP, where one or more of the following conditions are present:
      - Hourly demand data is available for a limited number of years.
      - The most appropriate weather station records daily rather than hourly data.
      - The load forecast is based on a Wholesale Power Purchase model and, as such a single set of HDD and CDD coefficients are applied to all weather-sensitive rate classes

g) As per the Applicant's response to part c) above, in preparing the reply to this interrogatory, WNP re-ran the rate-class load forecast for Residential, GS<50 kW and GS 50-999 kW using the same variable data that was used in the Applicant's Wholesale Load Forecast as submitted with its' application on October 30th 2020.
The tables below summarizes the monthly 2018 Demand (actuals), Predicted Purchases with and without HDD or CDD for each rate class:

2018 Residential Load – Effects of HDD and CDD

	Actual Demand	Predicted Purchases **with HDD**	Predicted Purchases **without HDD**	Variance (HDD to no HDD)	
Jan-18	2,662,950	2,619,229	1,402,469	*1,216,759*	*46.45%*
Feb-18	2,192,785	2,180,768	1,229,949	*950,819*	*43.60%*
Mar-18	2,246,218	2,342,667	1,373,433	*969,234*	*41.37%*
Apr-18	2,068,260	2,132,889	1,341,512	*791,377*	*37.10%*
May-18	1,713,358	1,756,909	1,572,760	*184,148*	*10.48%*
Jun-18	1,766,241	1,615,760	1,544,402	*71,357*	*4.42%*
Jul-18	2,132,795	1,971,052	1,954,172	*16,880*	*0.86%*
Aug-18	2,102,658	1,958,090	1,949,343	*8,747*	*0.45%*
Sep-18	1,855,017	1,841,167	1,706,279	*134,889*	*7.33%*
Oct-18	1,937,514	2,020,564	1,500,805	*519,758*	*25.72%*
Nov-18	2,205,153	2,291,776	1,418,759	*873,016*	*38.09%*
Dec-18	2,462,955	2,500,402	1,543,291	*957,110*	*38.28%*
	25,345,905	**25,231,271**	**18,537,176**		

	Actual Demand	Predicted Purchases **with CDD**	Predicted Purchases **without CDD**	Variance (CDD to no CDD)	
Jan-18	2,662,950	2,619,229	2,619,229	*0*	*0.00%*
Feb-18	2,192,785	2,180,768	2,180,768	*0*	*0.00%*
Mar-18	2,246,218	2,342,667	2,342,667	*0*	*0.00%*
Apr-18	2,068,260	2,132,889	2,132,889	*0*	*0.00%*
May-18	1,713,358	1,756,909	1,569,234	*187,675*	*10.68%*
Jun-18	1,766,241	1,615,760	1,440,311	*175,448*	*10.86%*
Jul-18	2,132,795	1,971,052	1,498,503	*472,549*	*23.97%*
Aug-18	2,102,658	1,958,090	1,463,533	*494,557*	*25.26%*
Sep-18	1,855,017	1,841,167	1,559,349	*281,818*	*15.31%*
Oct-18	1,937,514	2,020,564	1,972,269	*48,294*	*2.39%*
Nov-18	2,205,153	2,291,776	2,291,776	*0*	*0.00%*
Dec-18	2,462,955	2,500,402	2,500,402	*0*	*0.00%*
	25,345,905	**25,231,271**	**23,570,929**		

2018 GS<50 kW Load – Effects of HDD and CDD

	Actual Demand	Predicted Purchases **with HDD**	Predicted Purchases **without HDD**	Variance (HDD to no HDD)	
Jan-18	1,203,032	1,167,201	755,826	*411,375*	*35.24%*
Feb-18	1,010,130	1,006,813	685,350	*321,463*	*31.93%*
Mar-18	1,057,383	1,077,826	750,137	*327,689*	*30.40%*
Apr-18	970,762	990,566	723,009	*267,557*	*27.01%*
May-18	868,998	878,777	816,518	*62,259*	*7.08%*
Jun-18	859,701	812,013	787,888	*24,125*	*2.97%*
Jul-18	947,003	895,974	890,267	*5,707*	*0.64%*
Aug-18	931,195	922,585	919,627	*2,957*	*0.32%*
Sep-18	824,468	859,539	813,934	*45,605*	*5.31%*
Oct-18	890,135	944,090	768,364	*175,725*	*18.61%*
Nov-18	984,437	1,018,738	723,579	*295,159*	*28.97%*
Dec-18	1,034,896	1,032,986	709,396	*323,590*	*31.33%*
	11,582,140	**11,607,108**	**9,343,897**		

	Actual Demand	Predicted Purchases **with CDD**	Predicted Purchases **without CDD**	Variance (CDD to no CDD)	
Jan-18	1,203,032	1,167,201	1,167,201	*0*	*0.00%*
Feb-18	1,010,130	1,006,813	1,006,813	*0*	*0.00%*
Mar-18	1,057,383	1,077,826	1,077,826	*0*	*0.00%*
Apr-18	970,762	990,566	990,566	*0*	*0.00%*
May-18	868,998	878,777	819,320	*59,457*	*6.77%*
Jun-18	859,701	812,013	756,429	*55,583*	*6.85%*
Jul-18	947,003	895,974	746,267	*149,707*	*16.71%*
Aug-18	931,195	922,585	765,905	*156,680*	*16.98%*
Sep-18	824,468	859,539	770,257	*89,282*	*10.39%*
Oct-18	890,135	944,090	928,790	*15,300*	*1.62%*
Nov-18	984,437	1,018,738	1,018,738	*0*	*0.00%*
Dec-18	1,034,896	1,032,986	1,032,986	*0*	*0.00%*
	11,582,140	**11,607,108**	**11,081,098**		

2018 GS50 - 999 kW Load – Effects of HDD and CDD

	Actual Demand	Predicted Purchases **with HDD**	Predicted Purchases **without HDD**	Variance (HDD to no HDD)	
Jan-18	1,597,632	1,741,846	1,495,181	*246,665*	*14.16%*
Feb-18	1,529,396	1,643,467	1,450,714	*192,752*	*11.73%*
Mar-18	1,587,004	1,727,817	1,531,332	*196,485*	*11.37%*
Apr-18	1,474,277	1,662,011	1,501,581	*160,430*	*9.65%*
May-18	1,448,012	1,547,021	1,509,690	*37,331*	*2.41%*
Jun-18	1,421,656	1,471,013	1,456,547	*14,466*	*0.98%*
Jul-18	1,423,713	1,497,970	1,494,548	*3,422*	*0.23%*
Aug-18	1,548,176	1,447,839	1,446,066	*1,773*	*0.12%*
Sep-18	1,504,574	1,455,220	1,427,875	*27,345*	*1.88%*
Oct-18	1,589,320	1,529,094	1,423,727	*105,367*	*6.89%*
Nov-18	1,594,027	1,575,033	1,398,053	*176,980*	*11.24%*
Dec-18	1,587,643	1,659,107	1,465,079	*194,028*	*11.69%*
	18,305,429	**18,957,437**	**17,600,393**		

	Actual Demand	Predicted Purchases **with CDD**	Predicted Purchases **without CDD**	Variance (CDD to no CDD)	
Jan-18	1,597,632	1,741,846	1,741,846	*0*	*0.00%*
Feb-18	1,529,396	1,643,467	1,643,467	*0*	*0.00%*
Mar-18	1,587,004	1,727,817	1,727,817	*0*	*0.00%*
Apr-18	1,474,277	1,662,011	1,662,011	*0*	*0.00%*
May-18	1,448,012	1,547,021	1,527,190	*19,831*	*1.28%*
Jun-18	1,421,656	1,471,013	1,452,474	*18,539*	*1.26%*
Jul-18	1,423,713	1,497,970	1,448,037	*49,933*	*3.33%*
Aug-18	1,548,176	1,447,839	1,395,581	*52,258*	*3.61%*
Sep-18	1,504,574	1,455,220	1,425,442	*29,779*	*2.05%*
Oct-18	1,589,320	1,529,094	1,523,991	*5,103*	*0.33%*
Nov-18	1,594,027	1,575,033	1,575,033	*0*	*0.00%*
Dec-18	1,587,643	1,659,107	1,659,107	*0*	*0.00%*
	18,305,429	**18,957,437**	**18,781,995**		

i. Below is the information for the Residential, GS<50 kW and GS 50-999 kW rate classes:

Regression results for the Rate Class Forecast for Residential

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.962451011
R Square	0.926311949
Adjusted R Square	0.92239931
Standard Error	98125.03572
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	13677234676799	2279539112800	237	0
Residual	113	1088023057740	9628522635		
Total	119	14765257734539			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-1284587.548	478870.5203	-2.682536288	0.008402942	-2233316.418	-335858.6784	-2233316.418	-335858.6784
Heating Degree Day	1534.568584	47.90528227	32.03338986	1.58153E-58	1439.659579	1629.477588	1439.659579	1629.477588
Cooling Degree Day	6113.186952	497.1672722	12.29603655	1.42324E-22	5128.208917	7098.164987	5128.208917	7098.164987
# of Days in Month	60549.28994	11330.38648	5.34397393	4.77879E-07	38101.75079	82996.82909	38101.75079	82996.82909
Regional Employment	1955.883665	596.0890221	3.281193903	0.00137524	774.9238021	3136.843528	774.9238021	3136.843528
CDM	-0.56989877	0.162844503	-3.499650037	0.000667619	-0.8925231	-0.247274439	-0.8925231	-0.247274439
Sensitive Customers	-0.077145532	0.024600899	-3.135882653	0.002184292	-0.12588435	-0.028406714	-0.12588435	-0.028406714

Based on the results above, the HDD and CDD coefficients are statistically significant for this rate class demonstrating that HDD and CDD does influence the load of the Residential rate class.

Regression results for the Rate Class Forecast for GS <50 kW

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.906741132
R Square	0.82217948
Adjusted R Square	0.812737682
Standard Error	53143.94359
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	1475607172982	245934528830	87	0
Residual	113	319143497668	2824278740		
Total	119	1794750670650			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	41550.90168	259353.464	0.16020955	0.87300205	-472275.0874	555376.8907	-472275.0874	555376.8907
Heating Degree Day	518.8233786	25.94521979	19.99687737	6.4669E-39	467.4212188	570.2255385	467.4212188	570.2255385
Cooling Degree Day	1936.707292	269.2628774	7.19262644	7.3917E-11	1403.248967	2470.165616	1403.248967	2470.165616
# of Days in Month	16815.10557	6136.470834	2.740191557	0.00713849	4657.650078	28972.56106	4657.650078	28972.56106
Regional Employment	89.29700282	322.8383168	0.276599766	0.78259274	-550.3039296	728.8979353	-550.3039296	728.8979353
CDM	-0.158575247	0.088195627	-1.797994432	0.07484807	-0.333306691	0.016156198	-0.333306691	0.016156198
Sensitive Customers	0.042106311	0.013323703	3.160255973	0.00202326	0.015709653	0.068502968	0.015709653	0.068502968

Based on the results above, the HDD and CDD coefficients are statistically significant for this rate class demonstrating that HDD and CDD does influence the load of the GS<50 kW rate class.

Regression results for the Rate Class Forecast for GS 50-999 kW

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.522414691
R Square	0.272917109
Adjusted R Square	0.234310938
Standard Error	196192.9341
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	6	1632645913253	272107652209	7	0
Residual	113	4349558417351	38491667410		
Total	119	5982204330605			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2223066.448	957462.1989	2.321832079	0.02203	326161.1443	4119971.75	326161.1443	4119971.751
Heating Degree Day	311.091581	95.78266975	3.24789006	0.00153	121.3288369	500.854325	121.3288369	500.8543251
Cooling Degree Day	645.9585718	994.0450485	0.649828268	0.51712	-1323.423955	2615.3411	-1323.42395	2615.341098
# of Days in Month	31797.78252	22654.17537	1.403616861	0.16318	-13084.22479	76679.7898	-13084.2248	76679.78983
Regional Employment	-2087.28395	1191.830947	-1.751325518	0.0826	-4448.516015	273.948114	-4448.51601	273.9481137
CDM	0.103217548	0.325594182	0.317012874	0.75182	-0.541843252	0.74827835	-0.54184325	0.748278347
Sensitive Customers	-0.06277056	0.049187473	-1.276149231	0.20452	-0.160219812	0.0346787	-0.16021981	0.0346787

Based on the results above, the HDD and CDD coefficients are acceptable implying that these coefficients are statistically meaningful and suggests HDD and CDD has some effect to the load of this rate class.

h) As described above in response c) and g) above, in replying to this interrogatory, WNP re-ran the rate-class load forecast for Residential, GS<50 kW, GS 50-999 kW and GS 1,000-4,999 kW rate classes using the same variable data that was used in the Applicant's Wholesale Load Forecast as submitted with its' application on October 30th 2020. As noted in the tables in responses to c) and g), the resulting effects of HDD on the rate class load did:
   - Produce HDD positive variance values for each month of 2018 for Residential, GS<50 kW and GS 50-999 kW rate classes (i.e. all months in the same variance direction).
   - Produce HDD negative variance values for each month of 2018 for the GS 1,000-4,999 kW rate class (i.e. all months in the same variance direction).

i) Similarly to the response in question h) above, the re-ran rate class load forecast as noted in the tables in responses to c) and g) the resulting effects of CDD on the rate class load did:
   - Produce CDD positive variance values for each month of 2018 for Residential, GS<50 kW and GS 50-999 kW rate classes (i.e. all months in the same variance direction).
   - Produce CDD negative variance values for each month of 2018 for the GS 1,000-4,999 kW rate class (i.e. all months in the same variance direction).

j) Modifications to the USF Demand Profile model to increase granularity and/or differentiate the weather-normalization calculations between weather-sensitive rate classes would significantly increase the complexity of the model. Such modifications would require that hourly weather data be available from an appropriate weather station. They would also require the LDC to be able to produce statistically significant regression-based load forecasts for each weather-sensitive rate class. Even if both of these requirements could be overcome, the sheer amount of effort related to data gathering input and verification would result in a process that could no longer be reasonably completed by internal staff for most LDCs.

   i. No, the USF Working Group has not investigated the cost of acquiring software to perform weather normalization on an hourly-basis to perform supporting analysis.
   Please refer to the USF Working Group statement (at the start of the response to this interrogatory) that re-iterates the intent of the group to satisfy the needs of the OEB's Filing Requirements.

7-Staff-73

Revenue-to-Cost

Ref 1: Exhibit 7, pages 28-30.

Wellington North Power has outlined several revenue-to cost adjustments. Namely, it is proposing to reduce the revenue-to-cost ratios for Unmetered Scattered Load (USL) and GS < 50 kW from above the ceiling to the ceiling, which is 120% in both rate classes. Street Light is proposed to increase from 51.56%, which is below the floor to 100%.
GS 1,000 – 4,999 kW is proposed to increase from 90.23%, which is within the range, to 100%. Wellington North Power attributes this to several un-billed services available only to these customers.
An adjustment is made to reduce Residential from 98.38% to 93.79%.

a) Please provide an estimate of the annual cost, by Uniform System of Account, of providing the described services to the General Service 1,000 – 4,999 customers.
b) Please provide the rationale for decreasing the residential rate class revenue-to- cost ratio, which is already below 100%.
c) Please provide a scenario where first, USL, GS < 50 kW, and Street Lights are moved to the nearest boundary of the respective ranges, that is 120%, 120%, and 80% respectively. Second, any offsetting adjustments are only made to rate classes that would bring them closer to 100%. This may include further adjustments to the rate classes already moved to the boundary of the range.

WNP's Response:

a) WNP has not formally quantified the value of the additional services as listed at page 29 of Exhibit 7. WNP notes that there are metrics to customer service and satisfaction such as personal attention, loyalty and retention, reachability outside of business hours that cannot be quantified through a cost allocation study. For those reasons, WNP is of the opinion that the value of the additional customer service as experienced by the GS 1,000-4,999 does compensate for these costs.

b) WNP's customer based is predominantly residential many of which are senior citizen, on a fixed income or considered low income. WNP is particularly sensitive and mindful of the effects of a drastic change to the revenue to cost ratio on its residential customers. Therefore, it is WNP's intention to keep its revenue to cost ratio at its 2016 level and keep its residential customer as unaffected as possible with respect to its fixed monthly charge.

c) Please see tables below:

Existing Rates: Revenue/Cost Ratio and Resulting Revenues

Rate Class	Existing Rates Proposed Rev/Cost Ratio	Base Rev	Rate Class Allocation	Misc. Rev	Rate Class Allocation	Service Rev	Rate Class Allocation
Residential	98%	$ 1,658,939	55%	$ 86,284	64%	$1,745,223	56%
GS <50 kW	120%	$ 522,079	17%	$ 18,231	13%	$ 540,311	17%
GS 50-999 kW	107%	$ 290,475	10%	$ 5,120	4%	$ 295,594	9%
GS 1,000-4,999 kW	90%	$ 497,193	17%	$ 18,423	14%	$ 515,616	16%
USL	175%	$ 1,058	0.04%	$ 32	0.02%	$ 1,090	0.03%
Sentinel	98%	$ 4,197	0.14%	$ 255	0.19%	$ 4,453	0.14%
Street Lighting	52%	$ 22,419	1%	$ 6,985	5%	$ 29,404	1%
		$ 2,996,360	100%	$ 135,330	100%	$3,131,690	100%

Staff Scenario: Revenue/Cost Ratio and Resulting Revenues

Rate Class	7-Staff-73 Scenario Proposed Rev/Cost Ratio	Base Rev	Rate Class Allocation	Misc. Rev	Rate Class Allocation	Service Rev	Rate Class Allocation
Residential	97%	$ 1,633,453	55%	$ 86,284	64%	$1,719,738	55%
GS <50 kW	120%	$ 520,408	17%	$ 18,231	13%	$ 538,639	17%
GS 50-999 kW	107%	$ 290,475	10%	$ 5,120	4%	$ 295,594	9%
GS 1,000-4,999 kW	90%	$ 497,193	17%	$ 18,423	14%	$ 515,616	16%
USL	100%	$ 592	0.02%	$ 32	0.02%	$ 624	0.02%
Sentinel	98%	$ 4,197	0.14%	$ 255	0.19%	$ 4,453	0.14%
Street Lighting	100%	$ 50,042	2%	$ 6,985	5%	$ 57,027	2%
		$ 2,996,360	100%	$ 135,330	100%	$3,131,690	100%

Staff Scenario: Resulting Bill Impacts

	A		B		C		Total Bill	
	$	%	$	%	$	%	$	%
Residential	$ 2.62	6.92%	$ 4.26	9.09%	$ 4.37	7.69%	$ 3.54	2.80%
General Service <50kW	$ 6.93	8.18%	$ 11.71	10.94%	$ 11.81	9.05%	$ 9.56	2.99%
General Service 50-999kW	$ 58.79	8.68%	$ 176.85	21.90%	$ 184.40	13.12%	$ 178.63	2.18%
General Service 1000-4999kW	$ 714.67	9.04%	$ 2,967.86	30.63%	$ 3,073.00	17.35%	$ 2,989.05	2.35%
Unmetered Scattered Load	$ (18.46)	-28.38%	$ (18.23)	-26.87%	$ (18.21)	-25.70%	$ (14.79)	-17.31%
Sentinel Lighting	$ 36.41	11.11%	$ 36.06	10.84%	$ 36.29	10.36%	$ 29.46	9.89%
Street Lighting	$ 2,516.98	152.12%	$ 3,645.87	215.05%	$ 3,648.27	194.10%	$ 4,110.70	86.48%

** Bill impact based on Rate Riders, RTSR rates, LV rates as filed in the Applicant's initial application*

Please note that the scenario is provided for illustrative purposes only. By providing this information, WNP is not committing to adopting these changes for rate making purposes

7.0 – VECC –50

Reference: Exhibit 7, pages 26 and 28-30

a) Given the significant bill impact on the Street Lights class of moving from a revenue to cost ratio of 51.56% to 100% in 2021, did WNP give any consideration to phasing the increase in the class' revenue to cost ratio in over a number of years?

i. If not, why not?

ii. If yes, why was any form of phase-in rejected?

b) What is the increase in the costs assigned to the GS 1,000-4,999 class as a result of moving the ratio from 90.23% to 100%?

c) Do the GS 1,000-4,999 customers receive any additional services apart from the example cited on page 29 that are not costed and accounted for in the CAM? If yes, what are they?

d) Overall, does WNP consider the value of the additional services received by the GS 1,000-4,999 customers (and not accounted for in the CAM) to be equal/greater than the additional costs noted in response to part (b)?

e) Why is WNP proposing to reduce the revenue to cost ratio for Residential from 98.38% to 93.79%?

WNP's Response:

a) Please refer to WNP's response to 8-Staff-76 b).

b) The table below shows the increase in the costs assigned to the GS 1,000-4,999 class as a result of moving the ratio from 90.23% to 100%:

Revenue to Cost Ratio	Base Revenue	Misc. Revenue	Total Revenue
90.23%	$497,192.97	$18,422.98	$515,615.94
100.00	$553,038.25	$18,422.98	$571,461.23
Change	$55,845.28	$-	55,845.28

Please note that the scenario is provided for illustrative purposes only. By providing this information, WNP is not committing to adopting these changes for rate making purposes

c) All additional services are detailed at page 29 of Exhibit 7.

d) WNP has not formally quantified the value of the additional services as listed at page 29 of Exhibit 7. WNP notes that there are metrics to customer service and satisfaction such as personal attention, loyalty and retention, reachability outside of business hours that cannot be quantified through a cost allocation study For those reasons, WNP is of the opinion that the value of the additional customer service as experienced by the GS 1,000-4,999 does compensate for the costs as calculated in part b).

e) WNP's customer based is predominantly residential many of which are senior citizen, on a fixed income or considered low income. WNP is particularly sensitive and mindful of the effects of a drastic change to the revenue to cost ratio on its residential customers. Therefore, it is WNP's intention to keep its revenue to cost ratio at its 2016 level and keep its residential customer as unaffected as possible with respect to its fixed monthly charge.

7.0 – VECC –51

Reference: Exhibit 7, page 32

a) In what USOA account are the capital costs for the MicroFIT meters recorded?

WNP's Response:

a) The capital costs for MicroFIT meters are recorded in USOA account 1860.

Exhibit 8 – Rate Design

8-Staff-74

Retail Transmission Service Rates (RTSRs)

Ref 1: Exhibit 8, page 17

Ref 2: EB-2020-0030, Decision and Rate Order, December 17, 2020.

Ref 3: EB-2020-0251, Decision and Rate Order, December 17, 2020

Wellington North Power indicates that "Hydro One Sub-Transmission rates for 2021 have yet to be approved by the OEB. The above table replicates the 2021 forecast rates as per the OEB's 2021 RTSR model"

Since Wellington North Power filed its application, the OEB has approved updated sub- transmission rates for Hydro One Networks Inc and the Uniform Transmission Rates (UTRs).

a) Please update the RTSR model to reflect the Hydro One Sub-Transmission rates and the UTRs issued on December 17, 2020.

WNP's Response:

a) WNP has updated the RTSR model to incorporate the 2021 OEB Hydro One Sub-Transmission rates and UTRs as approved by the OEB in Decision and Orders EB-2020-0030 and EB-2020-0251.

   The Applicant has filed an updated set of models encompassing the adjustments on the OEB's web-portal to support the Applicant's interrogatory responses.

8.0 –VECC-56

Reference: Exhibit 8, page 18

a) Please update the proposed 2021 Tariffs to reflect the Board's decision in EB-2020-0285 regarding Retail Service Charges.

WNP's Response:

a) WNP has updated the proposed 2021 Tariff of Rates and Charges in worksheet "5. Final Tariff Schedule" of the "2021 Tariff Schedule and Bill Impact Model" to reflect the Board's Decision and Rate Order EB-2020-0285 concerning inflationary adjustment to retailer service charges. The Applicant has filed an updated "2021 Tariff Schedule and Bill Impact Model" containing these updated Retail Service Charges on the OEB's web portal.

8-Staff-75

Pole Rental

Ref 1: Exhibit 8, page 25

Ref 2: EB-2020-0288, Wireline Pole Attachment Charge, December 10, 2020.

Wellington North Power indicates that with respect to the Pole Rental charge it "has applied a 2% inflation rate above the Bridge Year (2020) in the absence of an OEB rate being available at the time of preparing this application."

Since Wellington North Power filed its application, the OEB has decided that the wireline pole attachment charge will be maintained at $44.50 for 2021.

a) Please update the pole rental charge and revenue to be consistent with the above noted decision.

WNP's Response:

a) Please see Applicant's response to 7-VECC-57.

8.0 –VECC-57

Reference: Exhibit 8, page 25

a) Please update the proposed 2021 Tariffs to reflect the Board's decision in EB-2020-0288 regarding Pole Attachment Charges

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WNP's Response:

a) WNP has updated the proposed 2021 Tariffs to reflect the Board's decision in EB-2020-0288 regarding Pole Attachment Charges as confirmed in the Applicants response to interrogatory 8-Staff-75.

8.0 –VECC-58

Reference: **Exhibit 8, page 26**

a) Please explain why WNP is proposing to maintain the MicroFIT Monthly Service Charge at $15.69 as opposed to setting equal to estimated cost of providing the service ($16.33).

WNP's Response:

a) In its' application, WNP proposed to maintain the MicroFIT Monthly Service Charge at $15.69 because the utility is cognizant this rate is higher than the province-wide value of $4.55 as determined by the OEB[4]

However, in responding to this interrogatory and after further consideration, WNP proposes that the MicroFIT Monthly Service Charge should be adjusted to $16.33 as per the calculations and evidence provided in in Exhibit 3[5] so that this rate class is not being subsidized by other rate classes.

[4] OEB letter "Review of Fixed Monthly Charge for microFIT Generator Service Classification OEB File Numbers EB-2009-0326 and EB-2010-0219" dated February 24, 2020

[5] EB-2020-0061 Exhibit 3 – Revenues, section 3.4.3. Proposed Specific Service Charges, pages 80 to 81

8.0 –VECC-59

Reference: **Exhibit 8, page 27**
WNP Cost Allocation Model, Tabs I6.2 and O4

a) At page 27 the Application states: "Regarding the General Service >1,000-4,999 kW customer class, in the Cost Allocation model this customer class was not assigned costs associated with transformation. All customers in this class own their transformation facilities and do not contribute to the system transformation costs. Therefore, there is no need for WNP to provide a transformer allowance for this customer class." However, Tab I6.2 of the CAM attributes a customer count to Transformers for this class and Tab O4 of the CAM indicates that some costs related to Transformers (Account #1850) are allocated to the GS>1,000-4,999 kW class. Please reconcile.

b) Tab I6.2 of the CAM shows a customer count of 5 (of a total of 5 customers) for the GS>1,000-4,999 Secondary Customer Base. If all of these customers own their own transformer, please explain why none of these customers own the secondary services from the transformer to their premises.

WNP's Response:

a) Please refer to WNP's response to 7-Staff-70.

b) Please refer to WNP's response to 7-Staff-70.

8-Staff-76

Bill Impacts

Ref 1: Exhibit 8, pages 45-48

Wellington North Power indicates that the bill impacts for the street lighting rate class are 87%. It has indicated that OER serves as a form of mitigation.

a) Please confirm that the bill impact resulting from this rate application is 87% when OER is applied to both current and proposed rates.
b) Did Wellington North Power consider other options for mitigating the bill impacts for the street lighting rate class such as increasing the revenue-to-cost ratio to 80% or adopting a phase-in approach to increasing the revenue-to-cost ratios?
c) Please provide a bill impact where a three-year transition is used to a final revenue-to-cost ratio of 80%, and OER is applied both at current rates, and at proposed rates.

WNP's Response:

a) WNP confirm that the bill impact resulting from this rate application is 87% when OER is applied to both current and proposed rates.

b) WNP confirms that it considered phasing in the adjustment to the revenue to cost ratio over several years however, as explained in detail at section 8.1.19 of Exhibit 8, in preparing the application, WNP discussed the reasons for the bill impact as well as the effects of the LRAMVA rate rider to the Street Lighting customers, who accept the rationale for the utility being able to recover the lost revenue and accepted the fixed and volumetric rates and bill impacts as proposed.

c) Please see tables below:

Scenario - Streetlight Rate Class Transition over 3 year period
From Rev/Cost 51.56% (current) to 80.00% in Year 3

Status	Rev/Cost Ratio	Base Rev	Misc. Rev	Service Rev
Existing Rates	51.56%	$22,419	$ 6,985	$ 29,404
Yr 1	61.04%	$27,824	$ 6,986	$ 34,810
Yr 2	70.52%	$33,230	$ 6,987	$ 40,216
Yr 3	80.00%	$38,638	$ 6,988	$ 45,626

Scenario - Streetlight Rate Class Transition over 3 year period – Bill Impact

		Bill Impact							
		A		B		C		Total Bill	
Status	Rev/Cost Ratio	$	%	$	%	$	%	$	%
Existing Rates	51.56%	$ 214.33	12.95%	$1,343.23	79.23%	$1,345.63	71.59%	$1,508.72	31.74%
Yr 1	61.04%	$ 664.89	40.19%	$1,793.78	105.81%	$1,796.18	95.56%	$2,017.84	42.45%
Yr 2	70.52%	$ 1,115.49	67.42%	$2,244.38	132.38%	$2,246.78	119.54%	$2,527.02	53.16%
Yr 3	80.00%	$ 1,566.33	94.67%	$2,695.23	158.98%	$2,697.62	143.52%	$3,036.47	63.88%

Notes:

- *Bill impact based on Rate Riders disposition period of 24 months, RTSR rates, LV rates as filed in the Applicant's initial application.*
- *For year 3, Applicant has still include Rate Riders for comparison purposes. In reality, these Rate Riders would have been removed at the end of Year 2.*
- *Bill impact compares increase over existing 2020 OEB-approved Tariff of Rate and Charges.*

Based upon the scenario illustrated above, the resulting impact would create a revenue shortfall from the Streetlight rate class in years 1 and 2. Consequently, this revenue shortfall would be recovered from the other rate-classes in years 1 and 2, with predominately the Residential rate-class making-up this deficiency.

Please note that the scenario is provided for illustrative purposes only. By providing this information, WNP is not committing to adopting these changes for rate making purposes.

8.0 –VECC-52

Reference: Exhibit 8, page 8 and Appendix 8A, page 59

a) The calculation of 2021 revenues at 2020 rates used a Streetlights connection count of 924 and a Streetlights fixed charge per connection (per Exhibit A). However, according to the Cost Allocation Model, 924 is the number of Streetlight devices forecast for 2021 while the forecast connection count is 889. Please clarify whether the fixed charge for Streetlights is on a per connection basis (per the approved Tariff) or per device as suggested by Table 1.

i. If per Device, please confirm that the Tariff wording needs to be revised.

ii. If per Connection, please confirm that the derivation of the Streetlights rate needs to be revised.

WNP's Response:

a) WNP proposes the Monthly Service Charge (fixed charge) for Streetlight is per Device.

i. WNP confirms that the Tariff wording needs to be revised for Street Lighting Service Classification to be: revised to:

STREET LIGHTING SERVICE CLASSIFICATION

MONTHLY RATES AND CHARGES – Delivery Component

Monthly Service Charge (per device) $

ii. Not applicable.

On the OEB's web-portal, the Applicant has filed an updated version of the 2021 Tariff Schedule and Bill Impact Model that contains the revised wording as noted above.

8.0 –VECC-53

Reference: **Exhibit 8, pages 11 and 14**
WNP Cost Allocation Model (CAM), Tab O2

a) The please confirm that the fixed rate for Streetlights in Exhibit 8 is determined based on the 2021 forecast number of devices (994) whereas the Customer Unit Cost with Minimum System PLCC Adjustment in Tab O2 of the CAM is calculated based on the 2021 forecast number of connections (889).

b) What would the Customer Unit Cost with Minimum System PLCC Adjustment for Streetlights be if calculated per device and, based on this value, how would the fixed-variable ratio, as discussed at page 14, change?

WNP's Response:

a) WNP concurs with VECC's statement.

b) Please see tables below:

As filed in Initial Application: Street Lighting:
Unit Cost per Month – Minimum System with PLCC Adjustment and Revenue to Cost

I6.2 Customer Data	Count	Customer Unit Cost per month - Minimum System with PLCC Adjustment	Revenue to Cost
Number of Devices	924	$16.28	51.56%
Number of Connections	889		

In the Cost Allocation Model as filed in the Applicant's initial application, in cell J19 of worksheet "I6.2 Customer Data", WNP inputted "924" to reflect the number of devices in order to response to VECC"s question. The table below illustrates the outcome of this change:

Calculation using Number of Devices: Street Lighting:
Unit Cost per Month – Minimum System with PLCC Adjustment and Revenue to Cost

Streetlight I6.2 Customer Data		Customer Unit Cost per month - Minimum System with PLCC Adjustment	Revenue to Cost
Number of Devices	924	$16.25	50.51%
Number of Connections	924		

Please note that the scenario is provided for illustrative purposes only. By providing this information, WNP is not committing to adopting these changes for rate making purposes.

8-Staff-77

Tariff of Rates and Charges

Ref 1: Exhibit 8, page 65

Ref 2: Revenue Requirement Work Form, Sheet 13. Rate Design

Ref 3: DVA Continuity Schedule, Sheet 7. Rate Rider Calculation

The Revenue Requirement Work Form (RRWF) has calculated a fixed charge of $289.04 in the GS 50-999 kW rate class, however the tariff reflects $289.38. Similarly, the RRWF has calculated a fixed charge of $22.78 for the USL rate class, but the tariff has $22.58.
The Residential rate rider for group 2 accounts is calculated to be -$1.09, but the tariff reflects -$0.09.

a) Please ensure that the tariff reflects the models where rates and rate riders are derived.

WNP's Response:

a) Regarding the Residential Rate Rider for Group 2 account disposition, in WNP's initial application (October 30, 2020) the allocated disposal amount for this particular rate class, as calculated in the OEB's 2021 DVA Continuity Schedule, was ($7,339) (worksheet 7. Rate Rider Calculations, cell E152). As per Board's policy, for the residential rate class, group 2 account balances rate riders are to be calculated on a per customer basis.

In WNP's opinion, the Rate Rider formula calculation in the OEB's 2021 DVA Continuity Schedule in worksheet 7. Rate Rider Calculations, cell F152 is incorrect because it is calculating an annual Rate Rider amount instead of a monthly Rate Rider amount.
The formula in cell F152 is:

$$Residential\ Rate\ Rider = \frac{Group\ 2\ Balance\ /\ \#\ of\ Customers}{24\ months\ /12}$$

Using this method would result in a total disposal amount of $88,068 over 2 years (24 months) as illustrated below:

Method	Allocated Group 2 Balance	# of Residential Customers	Rate Rider Recovery in Months	Rate Rider (per month per customer) *	Check
	A	B	C	D = (A / B) / C	E = D * C * B
OEB Model	($7,339)	3,335	(24/12) = 2	($1.09374)	($88,068)
WNP	($7,339)	3,335	24	($0.09115)	($7,339)

** Result is to 4 decimal places for illustration purposes. As this is fixed rate rider, the rate rider will be to 2 dp.*

The formula is cell F152 in OEB's 2021 DVA Continuity Schedule in worksheet 7. Rate Rider Calculations is password protected meaning that the Applicant was unable to correct the formula when filing its' application. The Applicant did show the correct Group 2 rate rider amount for the Residential rate-class in the Tariff of Rates and Charges filed with the initial application.

Through this response, the Applicant requests OEB staff to review and correct the formula in cell F152.

Regarding OEB staff's question of the Applicant ensuring the tariff reflects the models, please refer to WNP's response to interrogatory 8-VECC-54 (below).

8.0 –VECC-54

Reference: Exhibit 8, page 12 and Appendix 8B, page 55
RRWF, Tab 13

a) On page 12 the proposed 2021 monthly service charge for the GS 50-999 class is $289.39. However, in the proposed Tariff Sheet it is $289.38 and in the RRWF it is $289.04. Please reconcile.

WNP's Response:

a) WNP acknowledges the error.

In responding to the interrogatories, the Applicant has updated the OEB's 2021 Work Forms to reflect corrections or adjustments which may have resulted to changes to the proposed 2021 Monthly Service Charges for customer rate classes.

Prior to filing set of models encompassing the corrections or adjustments on the OEB's web-portal, WNP has checked that the proposed Monthly Service Charges for each rate class are consistent in the Bill Impact Work Form and the Revenue Requirement Work Form.

8-Staff-78

Low Voltage Charge

Ref 1: Exhibit 8 – 8.1.13 Low Voltage Service Rates

Wellington North Power stated that there are times it would be charged double-peak demand in the Town of Mount Forest as a result of the metering configuration for the two meters used to meter the supply points. Wellington North Power has identified incidents where loading has shifted between feeders supplying the Town of Mount Forest resulting in the double peak billing.

a) When Wellington North Power is charged double-peak demand, is this rectified by Hydro One to reflect the true peak experienced in the Town of Mount Forest? If not, please explain how this is fair to Wellington North Power's customers.
b) If the load shift between the two meters is at Hydro One's request, does Wellington North Power receive a credit for the double-peak demand charge? If not, why?
c) Has Wellington North Power discussed with Hydro One to be billed on the concurrent peak of both meters? If not, why not?
d) What steps is Wellington North Power taking to reduce the frequency of these incidents, or recover funds from Hydro One where it is to blame?

WNP's Response:

a) When WNP is charged double-peak demand, it is not rectified by Hydro One to reflect the true peak demand.

   To be clear, Hydro One's invoice to the LDC for the usage period will show and charge for the peak demand measured by each meter point. For example:

   In July 2017, there was an unplanned outage which resulted in load feeding WNP's service territory of Mount Forest, being switched from HONI's Hanover TS to Palmerston TS. HONI's invoice to WNP for the usage period of July 2017 charged for a peak demand of 15,875.26 kW (non-adjusted) which was the aggregation of the peak demand of Hanover 8,363.97 kW (non-adjusted) and Palmerston 7,511.29 kW (non-adjusted).

   For reference, the peak demand billed by HONI to WNP in July 2016 was 9,086.47 kW (non-adjusted).

   WNP does not believe this is fair for the LDC's customers.

   The OEB-approved Uniform Transmission Rates (UTR) schedule states that transmission delivery points at separate transformer stations cannot be aggregated; and as a result, Hydro One is required to pay transmission charges to the IESO on the basis of the highest peak demands at Hanover and Palmerston, respectively.

The UTR approach for charging transmission is reflected in Hydro One Networks Inc. Distribution Tariff of Rates and Charges for the recovery of sub-transmission (ST) and RTSR charges. As per Hydro One Networks Inc. Tariff of Rates and Charges:

NOTES[6]

1. The basis of the charge is the customer's monthly maximum demand. For an ST customer with multiple delivery points served from the same Transformer Station or High Voltage Distribution Station, the aggregated demand will be the applicable billing determinant. <u>Demand is not aggregated between stations</u>.
6. Delivery point with respect to RTSR is defined as the low side of the Transformer Station that steps down voltage from above 50 kV to below 50 kV. For customer with multiple interval-metered delivery points served from the same Transformer Station, the aggregated demand at the said delivery points on the low side of the Transformer Station will be the applicable billing determinant.
   [Note 6. applies to the collection of RTSR charges].

b) No, WNP does not receive a credit for the double-peak demand charged if the switching was at HONI's request.

c) HONI and WNP met on January 10th 2019. The purpose of this meeting was to discuss HONI's October 2018 invoice (based on September usage) in regards to double peak billing, which was precipitated by a HONI initiated planned outage and coincident equipment issue.
At the meeting HONI discussed their policy on double-peak billing that complies with Ontario Energy Board's approved UTRs and Hydro ne Networks' approved Distribution Tariff such that transmission delivery points at separate transformer stations cannot be aggregated; and as a result, transmission charges are required to be paid to the IESO on the basis of the highest peak demands at individual transformer stations.

d) As noted in the responses above, HONI is abiding by its approved Distribution Tariff and therefore, does not have to refund WNP (or its' customers) where there is a double-peak demand charged.
At the meeting noted in c) above, HONI recognized the issue and did advise they would be raising awareness of the issue within their organization in order minimize the occurrences of load switching.

HONI (and its' customers) are billed for the double-peak by the IESO under the UTR schedule. As a suggestion to the OEB, one approach to resolving this matter could be for the IESO to adjust the UTR billing requirements such that the double peak charge is not billed to HONI, in which case HONI would not have to pass the double peak charge on to embedded LDCs.

[6] Decision and Rate Order EB-2020-0030 Hydro One Networks Inc., December 17, 2020, page 54

8.0 –VECC-55

Reference: **Exhibit 8, pages 15 and 29-31**
RTSR Workform, Tabs 3 and 4

a) Please confirm that the Retail Sales data by customer class in Tab 3 is based on the same historical year as the Hydro One billing units in Tab 4.

b) Please confirm that there were no instances of Hydro One invoicing WNP a "double-peak demand charge" (per pages 29-31) included in the Hydro One billing determinants used in Tab 4 of the RTSR Workform.

   i. If not confirmed, what adjustments are required?

c) Please update the RTSR Workform for Hydro One's 2021 approved Sub-Transmission Rates (EB-2020-0030).

WNP's Response:

a) In the 2021 RTSR Workform:
   - Worksheet "3. RRR Data" contains the 2019 non-loss adjusted metered kWh and kW for 2019
   - Worksheet "3. RRR Data" contains the RTSR rates from WNP's latest OEB-Tariff of Rates and Charges (EB-2019-0073) effective May 1, 2020 amended to reflect the implementation date of November 1, 2020 as per Final Rate Order (updated October 16, 2020).
   - Worksheet "4. UTRs and Sub-Transmission" contain the 2019, 2020 and 2021 Rates.

   WNP is unclear what VECC is asking in this interrogatory as the worksheets referenced relate to different sets of data (i.e. worksheet "3. RRR Data" is the RTSR rates that WNP bills its' customers whereas worksheet "4. UTRs and Sub-Transmission" shows HONI Sub-transmission rates it bills WNP).

b) WNP confirms the Hydro One Sub-Transmission rates billing determinants used in worksheet "4. UTRs and Sub-Transmission" were used by HONI to bill WNP in 2019.
   The "double-peak demand charge" relates not to the unit rate charged, but the "aggregated" peak kW demand value as illustrated in Exhibit 8 – Rate Design, table 22 on page 30.

   i. WNP advises that the LDC was billed by HONI for "double-peak demand" for the months of April 2019 and May 219. WNP does not have the "normal" peak kW demand values (i.e. what would have been the peak demand if there was no load switching) for these months to replicate HONI's invoices.

c) WNP has updated the 2021 RTSR Work Form using the 2021 OEB Hydro One Sub-Transmission rates and Uniform Transmission Rates (UTRs) as approved by the OEB in Decision & Orders EB-2020-0030 and EB-2020-0251 (issued December 17, 2020) as summarized below:

2021 Hydro One Sub-Transmission Rates

Rate Description	Rate (per kW)
Network Service Rate	$3.4778
Line Connection Service Rate	$0.8128
Transformation Connection Service Rate	$2.0458
Both Line and Transformation Connection Service Rate	$2.8586

The Applicant has filed an updated set of models encompassing the adjustments on the OEB's web-portal to support the Applicant's interrogatory responses.

8.0 –VECC-60

Reference: Exhibit 8, pages 29-31 and 35

a) Please confirm that there were no instances of HONI invoicing WNP a "double-peak demand charge" in 2019 included in the determination of the actual 2019 LV charges of $368,332 that WNP is proposing to use as the basis for its 2021 LV rates.

   i. If not confirmed, what adjustment should be made to the $368,332 value?

WNP's Response:

a) In the determination of the actual 2019 LV charges of $368,332, WNP did include "double-peak demand charges" that were incurred during 2019. These double-peak demand events occurred in April 2019 and May 2019, as illustrated in Exhibit 8 – Rate Design, table 25 on page 34.

   The Applicant is proposing that the LV annual charge for the Test Year of 2021 is $368,332, as per evidence filed.

   i. WNP cannot exclude the double-peak demand charges for the months of April 2019 and May 219 as the invoices from HONI to WNP for these months show the aggregated ("inflated") peak kW demand. WNP does not have the "normal" peak kW demand values (i.e. what would have been the peak demand if there was no load switching) for these months to replicate HONI's invoices.

      Removing these months from the LV calculation would reduce the proposed LV annual charge for the 2021 Test Year which would negatively affect the LDC's cash-flow and also create a larger delta difference in the regulatory 1550 LV account.

      As noted in interrogatory response 8-Staff-78 part d), HONI are abiding by the regulations as set by the OEB, and therefore one could question why an LDC, like WNP, should be treated any differently to HONI.

      The Applicant is proposing the 2021 Test Year LV annual charge should be $368,332 as filed in the initial application and based on the evidence provided.

8-Staff-79

Loss Factor

Ref 1: Chapter 2 Appendices – 2-R Loss Factors

In reference 1, the loss factor in distributor's system is trending upwards.

a) Please explain why the distributor's loss factor is trending higher and does Wellington North Power have plans to address this? If not, why?

WNP's Response:

a) WNP notes that its' proposed loss factor is lower than the actual loss factor for 2016 and 2018 as well as lower than the current loss factor of 1.0656 as approved in its' 2016 Cost of Service application. That said, WNP commits to continuing its' efforts to explore ways reducing its losses by monitoring and maintaining its asset base at optimal conditions and performance levels.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-80

Account 1557 – MIST Meters

Ref 1: Exhibit 9, 9.2.2, p.12

Wellington North Power is requesting disposition of Account 1557 Meter Cost Deferral Account for $8,415.

a) Please confirm that the amount requested for recovery is only for OM&A related to MIST meters, and not capital.
   i. If not confirmed, please explain whether the $8,415 represents the revenue requirement relating to the capital requested for recovery.

b) In the March 2015 Accounting Procedures Handbook Guidance, #3 states the following regarding Account 1557

> Distributors should be guided by the various Board documents related to recordkeeping and disposition of smart meter costs. Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications dated July 18, 2014 contains the materiality thresholds in section 2.4.5.

Please explain whether Wellington North Power has considered materiality thresholds in its request to recover Account 1557. Please revise the DVA Continuity Schedule as necessary.

WNP's Response:

a. WNP confirms that the amount requested for recovery is only related to the OM&A for monitoring MIST meters.

b. The annual amount for MIST meter OM&A is very similar to the annual refund to the ratepayer for Account 1508 large project variance. Therefore, in WNP's opinion, the balance in Account 1557 should be handled in the same manner as that of Account 1508. Based on this, the Applicant has not removed this item from the DVA Continuity Schedule.

9-Staff-81

Account 1508, Sub-account Energy East Consultation Costs

Ref 1: Exhibit 9, 9.2.2, p.13

Wellington North Power is requesting disposition of Account 1508, Sub-account Energy East Consultation Costs for $591. In March 2015 Accounting Procedures Handbook Guidance, #4 indicates that materiality thresholds will apply to the amounts recorded in the sub-account. Please confirm that the amount recorded in the sub-account does not meet the materiality threshold. If confirmed, please update the DVA Continuity Schedule to remove the account for disposition.

WNP's Response:

WNP confirms that it has removed this account from the DVA Schedule as it does not meet the materiality threshold.

9-Staff-82

Account 1518 – RSVA Retail

Ref 1: Exhibit 9, 9.2.2, p.13

Ref 2: DVA Continuity Schedule

Wellington North Power is requesting disposition of Account 1518 - RSVA Retail for $97,382. In the DVA Continuity Schedule, there is a principal adjustment for of $16,800.

a) Please confirm that this amount represents the forecasted amount for 2020 and January to April 2021.
b) If not confirmed, please explain what the principal adjustment represents.

WNP's Response:

a) WNP confirms that the principal adjustment of $16,800 represents the forecasted amount for 2020 and January to April 2021.

b) Not Applicable.

9-Staff-83

Account 1518 – RSVA Retail, Account 1548 – RSVA STR

Ref 1: DVA Continuity Schedule

Ref 2: Report of the Board on Electricity Distributor's Deferral and Variance Account Review Initiative (EDDVAR), July 31, 2009

Per the EDDVAR Report, the default cost allocation method for Account 1518 – RSVA Retail and RSVA STR is based on number of customers. Please explain why Wellington North Power has chosen to allocate the account balances based on kWh. Please revise the DVA Continuity Schedule as needed.

WNP's Response:

The DVA Continuity Schedule has been corrected to recover Accounts 1518 and 1548 based on number of customers.

9-Staff-84

Account 1592, Sub-account CCA Changes

Ref 1: Exhibit 9, 9.2.2, p. 14

Ref 2: Exhibit 4, Appendix 2019 4-G Tax Return

Wellington North Power has not recorded a balance in Account 1592, Sub-account CCA Changes as it does not have any PILS for the 2021 test year and has not paid any taxes in any tax year since its 2016 cost of service rate application.

a) Please explain the main drivers for the actual tax losses incurred.
b) In its 2019 tax return, it appears that Wellington North Power has claimed AII on all additions. Please confirm whether this was the case.

WNP's Response:

a) Since 2015 WNP has been making significant investments in capital assets to replace aging infrastructure. As mentioned, even before the AII was initiated, WNP had CCA credits which reduced its taxable income to zero. With accumulated tax losses from another 3 years of AII, WNP is projecting zero taxable income will continue for another 5 years.

b) WNP confirms that "AII" was claimed on all capital additions.

9-Staff-85

Account 1508, Sub-account Other Pension and Employment Benefits

Ref 1: Exhibit 9, 9.2.3, p. 16

Wellington North Power is requesting disposition of Account 1508, Sub-account Other Pension and Employment Benefits for $23,361.

a) The accounting order states the account is to record "the difference between in revenue requirement each year between both the capitalized and OM&A components of OPEBs accounted for using a forecasted cash basis, as reflected in rates and the capitalized and OM&A components of OPEBs accounted for using a forecasted accrual basis." Wellington North Power's calculation of the balance in the account appear to be based on the actual annual accrual amount rather than the forecasted accrual amount. Please provide a calculation of the amount in the account based on the forecasted accrual amount.
    i. Please clarify whether Wellington North is seeking disposition of the account balance calculated based on the actual annual accrual amount or the forecasted accrual amount.
b) The $23,361 balance is calculated using the accrual amount of $85,841, which is composed of $65,454 in net income and $20,387 in other comprehensive income. Other comprehensive income is not included in revenue requirement, and therefore, would not be included in the accrual amount that should have been recovered in rates. Please revise the calculation for the sub-account to only reflect the accrual amount for OPEBs included in net income. Please update the DVA Continuity Schedule.
c) Wellington North Power states that it has recorded the difference in revenue requirement each year between both the capitalized and OM&A components of OPEBs accounted for using an actual cash basis. Please confirm whether any OPEB amounts were capitalized in consideration of 4-Staff-56.

WNP's Response:

a) The difference between the forecasted cash amount embedded in 2016 rates and the forecasted accrual amount for 2016 was $568 (i.e. the forecast accrual amount was $568 more than the cash amount) Accordingly the difference between the amount embedded in rates on a cash basis and the comparable accrual amount is $568 per year x 5 years or $2,840 without accounting for IRM adjustments to rates over that period. Once b) is completed as requested the forecast and actual are extremely close. WNP will request disposition based on the actual amounts without Other Comprehensive Income amounts as OEB staff have outlined in b).

b) The DVA schedule has been updated.

c) WNP confirms that no OPEB amounts were capitalized from 2016 to 2020.

9-Staff-86

Account 1508, Sub-account Second Line Feeder Project Variance Account

Ref 1: Exhibit 9, 9.2.3, p. 16

Wellington North Power is requesting Account 1508, Sub-account Second Line Feeder Project Variance Account of ($16,249) for disposition. Wellington North Power confirms that it has recorded the revenue requirement impact of differences in capital contribution to Hydro One and the pole line project costs incurred by Wellington North Power for the Second Line Feeder project. The sub-account was also to record the revenue requirement impact of the project not being placed in service in 2016.

a) The ($16,249) appears to be calculated solely from the difference in capital contributions. Please explain whether this is the case.
    a. If so, please provide the revenue requirement impact from the difference in pole line project costs incurred by Wellington North Power and update the sub-account balance in the DVA Continuity Schedule.

b) Please confirm the project was placed in service in 2016. If not, please provide the revenue requirement impact of timing differences and update the sub- account balance in the DVA Continuity Schedule.

WNP's Response:

a) The ($16,249) is not the difference in capital contributions. This is the accumulation of the annual $3,131 decrease in revenue requirement which occurred due to the $74,496 decrease in the cost of the project. Therefore no update to the DVA Continuity Schedule is required.

b) WNP confirms that the Second Line Feeder project was placed in service in 2016.

9-Staff-87

Embedded Generation

Ref 1: Exhibit 9, 9.8.4, p. 20 Table 4

Ref 2: Exhibit 9, 9.2.1, p. 7 Table 1

The total Group 2 balances requested for disposition in Table 4 do not agree to the DVA Continuity Schedule as there appears to be a discrepancy in the Account 1508, sub- account Large Project Variance. The total Group 1 balances requested for disposition in Table 1 do not agree to the DVA Continuity Schedule as it appears to be missing Account 1580, Sub-account CBR Class B. Please confirm that Tables 4 and 1 are incorrect in this regard, and the amount requested for disposition is appropriately reflected in the DVA Continuity Schedule. If not confirmed, please explain which accounts are requested for disposition.

WNP's Response:

The Total Line in Table 4 is incorrect, however, all the individual items listed there are correct. Table 1 is correct, but is just a different view of the DVA balances, it matches exactly to tab "5. Allocation of Balances".

WNP confirms that the amounts requested for disposition are appropriately reflected in the DVA Schedule.

9-Staff-88

Account 1588

Ref 1: Exhibit 9, 9.2.2, p.10

Regarding Account 1588, it states that the account is to "capture variances due to billing timing differences (i.e., electricity charged by the IESO to LDCs vs. electricity billed by LDCs to their customers), price and quantity differences (i.e.: arising from final vs. preliminary IESO settlement invoices), and line loss differences (i.e., actual vs. estimate line loss factors).

The February 21, 2019 Accounting Guidance for Accounts 1588 and 1589[1][7] requires Account 1588 to be trued-up to actual revenues and expenses for disposition purposes. Therefore, there should be no variance due to billing timing differences as well as price and quantity differences from final vs. preliminary settlement statements.

a) Please confirm that this is aligned with Wellington North Power's treatment for Account 1588.
b) If not confirmed, please explain Wellington North Power's treatment of Account 1588 and the type of variances it holds in consideration of the February 21, 2019 Accounting Guidance.

WNP's Response:

a) There are still timing differences at the end of each year up until 2018. For Dec 31, 2019, differences were accrued at yearend to align with the Feb 21, 2019 Accounting Guidance for Accounts 1588 and 1589.

b) The changes made to the DVA Continuity will be itemized under 9-Staff-97 since this is where they are most relevant.

[7] Accounting Procedures Handbook Update - Accounting Guidance Related to Commodity PassThrough Accounts 1588 & 1589, February 21, 2019

9-Staff-89

Accounts 1588 and 1589

Ref 1: Exhibit 9, 9.8.3, p. 45-53

Ref 2: GA Analysis Workform

Wellington North Power states that it had incorrectly recorded the GA unbilled revenue accrual in Account 1588 instead of Account 1589 from 2015 to 2017. Wellington North Power shows principal adjustments in the principal adjustment tab and reconciling items in the 2015 to 2017 GA Analysis Workforms that correct for this. There are no reconciling items 2a/2b for the GA unbilled revenue to actual true-up in the 2015 to 2019 GA Analysis Workforms.

a) Please confirm that Wellington North Power has included the true-up of GA unbilled revenue to actual in Account 1589 in the general ledger for each year- end.
b) If not confirmed, please explain whether the GA unbilled revenue to actual true up has been included in the adjustments to correct the recording of the GA unbilled revenue accrual noted above.
    i. If the unbilled revenue to actual true-up is not included in the adjustments relating to the unbilled revenue accrual, please explain why the unbilled revenue to actual true up is not shown as a principal adjustment or reconciling item 2a/2b in the 2015 to 2019 GA Analysis Workform.
    ii. If the unbilled revenue to actual true-up is included in the 2015-2018 adjustments relating to GA unbilled revenue accrual, please explain why there is no unbilled revenue to actual true up principal adjustment or reconciling item 2a/2b in the GA Analysis Workform for 2018 and 2019.
c) Please revise the GA Analysis Workform as needed.

WNP's Response:

a) WNP does not confirm that it has included the true-up of GA unbilled revenue to actual in Account 1589.

b) WNP has not included the GA unbilled revenue to actual true up in the large adjustments to correct the recording of the GA unbilled revenue accrual in 1589.

    i. When WNP first started using the GA Analysis Workform, it was apparent that there were discrepancies and reconciling efforts were focused on the addressing the material differences. The amounts for the GA unbilled revenue to actual true-up are relatively small and were not included.
    ii. WNP has now included the adjustments for reconciling item 2a/2b in the 2015 to 2019 GA Analysis Workform.

c) The GA Analysis Workform has been revised and filed on the OEB's web portal.

9-Staff-90

Accounts 1588 and 1589

Ref 1: Exhibit 9, 9.8.3, p. 45-53

Ref 2: GA Analysis Workform

Wellington North Power indicated that it has adjusted for its RPP/non-RPP proration to include embedded generation. These adjustments are included as principal adjustments in the principal adjustment tab and also included as reconciling items in the 2015 to 2018 GA Analysis Workform. There are no reconciling items 1a or 1b for the charge type 148 true-up based on actual volumes in the 2015 to 2019 GA Analysis Workform.

a) Please confirm that the charge type 148 true-up based on actual volumes has already been included in the year-end general ledger volume
b) If not confirmed, please explain whether the charge type 148 true up has been included in the adjustments relating to embedded generation.
    i. If the charge type 148 true up has not been included in the adjustments relating to embedded generation, please explain why it is also not shown as a principal adjustment or reconciling item 1a/1b in the 2015 to 2019 GA Analysis Workform.
    ii. If it is included in the adjustments relating to embedded generation, please explain why there is no principal adjustment or reconciling item 1a/1b for the charge type 148 true-up in the 2019 GA Analysis Workform.
c) Please revise the GA Analysis Workform as needed.

WNP's Response:

a) WNP confirms that the charge type 148 true up has taken place.

b) Not Applicable.

c) Not Applicable.

9-Staff-91

Accounts 1589

Ref: GA Analysis Workform

In the 2015 to 2018 GA Analysis Workform, there is a reconciling item each year for the difference between the IESO GA posted rate and the GA invoiced rate. In the 2019 GA Analysis Workform, there is a reconciling item for CT 2148.

a) Please explain whether Wellington North Power has made revisions to its IESO settlements annually, which would result in a difference between the posted and invoiced GA rates. If not, please explain the reason for the difference between posted and invoiced GA rates.
b) In the 2016 to 2018 GA Analysis Workform, the description for reconciling item #6 for difference in GA posted and invoiced rate states "Only the Non-RPP portion of this was allocated here. The remainder is in Cost of Power. See tab 1 of supporting GA". Please confirm that this description is related to reconciling item #7 for differences in actual system losses and billed TLF and revise the GA Analysis Workform. If not, please explain what the description means.

WNP's Response:

a) WNP has not made revisions to its IESO settlements which would result in these changes. WNP did not investigate these changes each month because they were so commonplace. In July 2017 there was a difference of $34,169.85 which was investigated in detail because of its size which turned out to be a few Ontario wide GA adjustments the IESO made for time periods four and five years previous.
   In the conversation the LDC had with OEB Staff in early Aug 2020, WNP were informed by OEB Staff that this reconciling item had been removed for 2019 since the issues that led to these differences had been resolved.

b) This description is related to the IESO adjustments from 2015 to 2018. It is incorrectly applied to line 7 instead of line 6 in 2015 in the GA_Analysis_Workform. That has been corrected. The description means that the extra GA costs on the IESO invoice from 2015 to 2018 were divided between GA and Cost of Power as is normal practice. In 2017, these costs increased GA expenses by $40,019.36 as indicated in the GA 2017. However, the remaining $23,281.72 of these costs will be in cost of Power. WNP is including the evidence filed in EB-2018-0076 detailing these calculations.

9-Staff-92

Accounts 1589

Ref: GA Analysis Workform

In the 2017 GA Analysis Workform, there is a reconciling item for $405,166 with the description "GA Workform Data Adjustments". This appears to correspond to the sum of the 2017 principal adjustments for the "Reversal of 2015 GA Unbilled Correction" for $221,740, "Reversal of 2016 GA Unbilled Correction" for ($58,474) and "GA Unbilled Correction not entered in 2017".

a) Please confirm this to be the case.
b) If confirmed, please revise the GA Analysis Workform to show each of the principal adjustments as a reconciling item.
c) If not confirmed, please provide a detailed explanation for what this reconciling item represents and how it is quantified.
    i. Please also explain why the reversals for the prior year's unbilled GA revenue accrual and the current year's GA revenue accrual are not shown as a reconciling items in the 2017 GA Analysis Workform.

WNP's Response:

a) WNP confirms that this is the case.

b) There are only 2 available lines in the GA 2017 tab of the GA Analysis Workform and since it is locked for adding lines, no new lines can be added. Therefore WNP has combined the 2015 and 2016 Unbilled correction.

c) Not Applicable.

9-Staff-93

Accounts 1589

Ref: GA Analysis Workform

In the 2018 GA Analysis Workform, there is a reconciling item for ($241,900) with the description "Actual Entry of final adjustment from 2016. Discussed in previous applications." This reconciling item appears to correspond to the 2018 principal adjustment to reverse the 2017 principal adjustment for the unbilled GA accrual.

a) Please confirm this to be the case.
b) If confirmed, please revise the GA Analysis Workform to the appropriate description of the adjustment.
c) If not confirmed, please clarify the application and specific evidence Welling North Power is referring to in the description for the reconciling item
    a. Please also explain why the reversal for the prior year's GA unbilled revenue accrual is not a reconciling item in the 2018 GA Analysis Workform.

WNP's Response:

a) WNP does not confirm this to be the case.

b) Not Applicable.

c) The "GA Workform Data Adjustments" in the description refers to an additional excel file named "GA Workform Data Adjustments -2019-01-18.xlsx" which WNP filed as evidence in the EB-2018-0076 proceeding itemizing the calculations.
    a) To give some background, the GA Unbilled misallocation existed ever since 1589 was created and divided from 1588. WNPs GA unbilled was simply never moved from 1588 to 1589 until July 2017. At the end of 2017 an adjustment of $500,430.34 was in WNPs accounting records to correct this. However, $241,899.68 of this 2017 entry hade to be removed in 2018 due to the fact that Dec 31, 2014 balances were disposed of on a final basis and no adjustments previous to that date were to be made. The final correction did not get made in 2017 and had to be finalized in the accounting records in 2018. There is no reversal of the 2017 GA unbilled revenue accrual in 2018 because this entry was made in 2017 and is included in the "Net Change in principal balance in the GL" number on the 2018 GA Analysis workform sheet. Therefore it is only the 2017 over correction which must be reversed. These calculations are itemized in the excel file mentioned above.

9-Staff-94

Accounts 1588 Principal Adjustments

Ref: GA Analysis Workform

Please confirm that in 2019, Wellington North Power changed its process to include the RPP settlement true-up in its Account 1588 balance at year-end in the general ledger and therefore, no principal adjustments are shown in 2019. If not confirmed, please explain why there is no principal adjustment for RPP settlement true-up in 2019.

WNP's Response:

WNP confirms that there are no 2019 principal adjustments for the RPP true-up. The 2019 RPP true-up in its Account 1588 balance is accrued at year-end in the general ledger as of Dec 31, 2019.

9-Staff-95

Accounts 1588 and 1589

Ref 1: Exhibit 9, 9.8.3, p. 51

Regarding the RPP settlement process, Wellington North Power states that RPP settlements are trued-up to the GA actual rate. Wellington North Power further states that the variances are recorded in accounts 1588 and 1589. The RPP settlement results in charge type 142 on the IESO invoice, which is only recorded in Account 1588 in accordance with the February 21, 2019 Accounting Guidance.

a) Please confirm that Wellington North Power is only recording charge type 142 in Account 1588.
b) If not confirmed, please explain which variances are recorded in Account 1588 and Account 1589.

WNP's Response:

a) WNP confirms that charge type 142 is only recorded in Account 1588.

b) Not Applicable.

9-Staff-96

RPP Settlements

Ref 1: Exhibit 9, 9.8.3, p. 51

In determining RPP consumption for RPP settlement submission, Wellington North Power starts with wholesale consumption, adds MicroFIT and FIT generation and deducts non-RPP consumption. Wellington North Power compares this to actual Net System Load Shape minus non-RPP consumption. In the February 21, 2019 Illustrative Model attached to the Accounting Guidance, wholesale consumption is first derived from AQEW plus embedded generation minus Class A consumption. This is then split into RPP and non-RPP consumption. Please confirm that Wellington North Power's process for determining wholesale consumption and RPP consumption would be consistent with that in the Accounting Guidance. If not, please explain the difference.

WNP's Response:

WNP confirms that Wellington North Power's process for determining wholesale consumption and RPP consumption is consistent with the process in the Accounting Guidance of Feb 21, 2019. WNP ran these systems in parallel for 2019, and both processes produced consistent results. Since WNP has calendar month billing and is not required to close its month end quickly, WNP can simplify its' processes.

9-Staff-97

Account 1588

Ref 1: DVA Continuity Schedule

Typically, large balances are not expected for Account 1588 as it should only hold the variance between commodity costs based on actual line losses and commodity revenues calculated using values for line losses approved by the. Based on RRR data filed for Wellington North Power for Account 4705 Cost of Power, OEB staff calculates the annual net activity (i.e. transactions plus principal adjustments) from the DVA Continuity Schedule as a percentage of annual Account 4705 amounts to be as follows:

	Account 4705 ($)	**Net Activity in Account 1588 ($)**	**% of net activity compared to Account 4705**
2019	3,814,398	40,806	1.07%
2018	4,038,573	152,482	3.78%
2017	3,694,396	- 45,819	-1.24%
2016	4,206,311	33,655	0.80%
2015	4,711,265	- 97,781	-2.08%
Cumulative	**20,464,943**	**83,343**	**2.3%**

a) For the years where the percentage is greater than +/-1%, please provide an explanation as to why the Account 1588 activity would be high in consideration of line losses.

WNP's Response:

WNP would like to note that the cumulative net activity in 1588 ($83,343) divided by the cumulative account 4705 total ($20,464,943) yields a total percentage variance of 0.41%. This is the most accurate way of calculating the percentage variance and is under the required 1%.

There are also some corrections required to the DVA schedule. These changes have been corrected in the GA Analysis Workform.

a) The RPP Yearend Reconciliation for 2017 was incorrect. It was entered as $-91,249 and was intended to be $91,249. This was reversed in 2018. The Adjustment is double this amount.
b) The RPP Yearend Reconciliation for 2018 of $-23,635 was unnecessary since the total amount was fully accrued in the GL Balances. This adjustment was removed from 2018 and the reversal was removed in 2019.
c) Historically, the WNPs RPP cost was adjusted one month behind during the IESO settlement, when the Actual GA for the previous month was known. (This is still the case, but the variances are now very small since WNP uses the second GA estimate and has better usage data. WNP also accrues the actual variance at yearend) This amount was not reflected in the DVA schedule

The following table shows the adjustments to the DVA continuity schedule for this delayed RPP adjustment and the result on the total and percentage variance.

		4705 Costs	1588 Net Activity	Annual Recon Adjustmnts	Adj for Dec filed in Jan	Reversal of prev Yr.	New 1588 Net Activity		
2019		3,814,398	40806	23,635	0	-60,698	3,743		0.10%
2018		4,038,573	152482	-206,133	60,698	30,819	37,866		0.94%
2017		3,694,396	-45819	182,498	-30,819	-70,931	34,929		0.95%
2016		4,206,311	33,655		70,931	-65,344	39,243		0.93%
2015		4,711,265	-97,781		65,344	0	-32,437		-0.69%
Totals		$20,464,943	$83,343			Total Percentage Variance			0.41%

There are three years where the amount is close to 1%, but part of this is related to the IESO adjustments itemized in IR 9-Staff-91.

9-Staff-98

RPP Settlements

Ref 1: Exhibit 9, 9.8.3, p. 52

Wellington North Power discusses the true up of RPP settlements to be for the true-up of the 2nd GA rate to actual GA rate. Wellington North Power bills its customers on a calendar month basis.

a) Please confirm that Wellington North Power has actual calendar month consumption for the previous month by the time of the RPP settlement submission.

b) If not confirmed, please explain whether Wellington North Power trues-up RPP settlement variances for estimated to actual consumption. If consumption is not trued up, please explain why not.

WNP's Response:

a) WNP has the raw actual data by the time of the RPP settlement submission. This is the best data available at that time and WNP uses this for settlement.

b) WNP still does a quarterly true up to actual consumption, however, the dollar value of these adjustments is quite small.

9-Staff-99

Embedded Generation

Ref 1: Exhibit 9, 9.8.3, p. 52

Regarding MicroFIT and FIT, Wellington North Power indicated that its settlements for embedded generation is performed between the contract price and TOU on-peak and off-peak rates on a monthly basis.

a) Please explain why the settlement is for the difference between contract price and TOU prices instead of the difference between contract price and wholesale market price (i.e. HOEP).

b) If Wellington North Power has been settling embedded generation based on the difference between contract price and TOU prices, please quantify the impact to the Account 1588 had Wellington North Power settled embedded generation based on the difference between contract price and HOEP. Please update the DVA Continuity Schedule as needed.

WNP's Response:

a) The statement in Exhibit 9 is incorrect.

b) WNP settles MicroFIT and FIT between the contract price and the HOEP price.

c) Not Applicable.

9-Staff-100

Account 1550

Ref 1: DVA Continuity Schedule

Wellington North Power is requesting $419,350 for Account 1550 LV Variance for disposition. From 2015 to 2019, annual transactions range from $76,474 to $109,980 except for 2018, where transactions were $7,034. Please explain why 2018 transactions were substantially lower.

WNP's Response:

The annual amount that accumulates in the LV Variance account is directly related to Hydro One's LV Rate riders. In 2018 there were no extra LV rate riders on our Hydro One bills, and the amount which was allocated to the 1550 LV Variance account was much lower as a result.

9.0 –VECC-61

Reference: Exhibit 9, page

Per the Board's letter of July 25, 2019 Utilities are required to record the impact of the accelerated CCA rule change in Account 1592 for the period November 21, 2018 until the effective date of the next cost-based rate order. Distributors are also to bring forward any amounts tracked in this account for review and disposition at the next (this) cost of service rate application.

a) Has WNP made any entries into this account for AIIP? If yes, what are the balances and what is the proposal for disposition of the balances. If no, please explain why not.

WNP's Response:

a) Due to the fact there are no PILS currently included in WNPs rates; no taxes have been paid in any tax year since the 2016 Cost of Serive application; and on the advice if its' auditors, WNP has not made any entries into 1592 for AIIP. Since there will be no PILS included in WNPs rates from this COS application and no income taxes payable for several years, there are no plans to use 1592 – PILS and Tax variance until this changes.