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7.0 Cost Allocation

7.1 Cost Allocation Study Requirements

7.1.0 Overview

BPI's Cost Allocation filing follows the cost allocation policies outlined in the Board's report of March 31, 2011 *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) (the "Cost Allocation Report").

A completed cost allocation study using the Board approved model (version 1.0) has been filed in MS Excel format (Brantford_2022 _Cost_Allocation_Model_20210512.xlsm).

BPI has used the "USF Demand Profile Working Groups" methodology as previously submitted by Wellington North Power Inc. (WNP) (EB-2020-0061) to prepare a load profile to match the load forecast as it relates to the respective rate classes.

BPI has used the 2021 version of the Cost Allocation Model "the Model" released by the OEB on May 20, 2020 to conduct its 2022 Test Year Cost Allocation study consistent with the OEB's Cost allocation policies. The Model has been populated using 2022 Test Year costs, customer numbers and demand values for BPI. The 2022 demand values are based on the weather-normalized load forecast used to design rates. The various weighting factors used in this 2022 study are explained below in this exhibit.

The results of the Model for the 2022 Test Year, along with the proposed ratios are presented in this Exhibit, in Attachment 7-E: Cost Allocation.

7.1.0.1 Load Profiles

For previous Cost of Service Applications BPI relied on its load profile prepared by Hydro One Networks Inc., (HONI) based on sample data from 2004. In a letter dated June 12, 2015, the OEB requested distributors to be mindful of material changes to load profiles and propose updates, as appropriate, in COS rate applications. In preparation of this Application BPI undertook a project to update its load profile utilizing the same methodology as proposed by WNP in its 2021 rate application (EB-2020-0061).

BPI has used the "USF Demand Profile Working Group" methodology to determine the Coincident Peak (CP) and Non-Coincident Peak (NCP) Demand for its rate classes as inputs into worksheet "I8 Demand Data" of the Cost Allocation Model. The "USF Demand Profile Methodology Paper" that describes the methodology, data, and a review of other options considered has been filed with this Exhibit as Attachment 7-A. BPI has filed excel copies of the supporting demand profile data for three historical years, 2017, 2018 and 2019, included as Attachments 7-B, 7-C and 7-D.

BPI compiled hourly consumption data for each of its metered classes beginning with January 2017 using smart meter data for its Residential and General Service <50kW rate classes and a combination of conventional and interval metered data (MIST Metered) for its General Service >50kW class. BPI used this data to update load profiles for all of its rate classes, in accordance with Section 2.7.1 of the Filing Requirements.

BPI used the three years of collected data to create three separate models for each year 2017, 2018 and 2019 to weather normalize and scale to its 2022 Test Year Load Forecast using Wholesale kWh purchases. BPI used this weather normalized, scaled load profile to determine the NCP and CP for each year. The average of the three years CPs and NCPs Demand data was input into worksheet "I8 Demand Data" of the Cost Allocation Model.

Tables 7.1.0-A and 7.1.0-B below summarize the NCP and CP demand values for years 2017 to 2019 by customer class as well as the average NCP and CP used in the Cost Allocation Model.

Table 7.1.0-A Non-Coincident Peak: 2017, 2018, 2019 and 3-Year Average

NCP	Residential	General Service <50kW	General Service >50kW	Embedded Distributor	StreetLights	Sentinel Lights	USL
			2017				
1NCP	136,753	24,502	95,193	8,954	1,857	39	259
4NCP	367,728	74,417	360,840	33,441	7,429	157	984
12NCP	780,537	184,772	966,097	92,714	22,144	471	2,572
			2018				
1NCP	80,267	23,513	90,394	11,658	1,857	39	259
4NCP	313,620	74,428	351,089	36,171	7,429	157	984
12NCP	732,125	183,387	981,338	97,537	22,144	471	2,572
			2019				
1NCP	85,392	18,972	87,568	10,390	1,857	39	259
4NCP	300,285	68,520	342,988	37,593	7,429	157	984
12NCP	700,765	175,816	950,520	99,360	22,144	471	2,572
			Average				
1NCP	100,804	22,329	91,051	10,334	1,857	39	259
4NCP	327,211	72,455	351,639	35,735	7,429	157	984
12NCP	737,809	181,325	965,985	96,537	22,144	471	2,572

Table 7.1.0-B Coincident Peak: 2017, 2018, 2019 and 3-Year Average

CP	Residential	General Service <50kW	General Service >50kW	Embedded Distributor	StreetLights	Sentinel Lights	USL
2017							
1CP	136,753	22,042	46,755	6,768	0	0	145
4CP	354,173	64,908	278,074	23,615	0	0	589
12CP	704,499	155,685	835,318	69,049	7,402	196	1,890
2018							
1CP	72,831	17,856	83,703	7,793	0	0	145
4CP	294,940	70,685	309,096	29,149	0	0	589
12CP	629,584	171,515	907,798	82,272	3,688	118	1,712
2019							
1CP	71,682	16,992	82,764	7,676	0	0	145
4CP	265,391	60,736	315,960	31,273	0	0	589
12CP	597,232	158,261	876,894	86,263	5,545	157	1,769
Average							
1CP	93,755	18,963	71,074	7,412	0	0	145
4CP	304,835	65,443	301,043	28,013	0	0	589
12CP	643,771	161,821	873,336	79,195	5,545	157	1,790

Table 7.1.0-C below shows the Demand Data used in BPI's 2017 Cost of Service Application (EB-2016-0058) which was based on the 2004 HONI Load Profiles and scaled to the level of the 2017 Load Forecast.

Table 7.1.0-C 2017 Test Year Demand Data

EB-2016-XXXX

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9	10
Customer Classes		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	176,839	65,421	21,126	81,035	-	-	139	9,118
Bulk Delivery CP	BCP1	176,839	65,421	21,126	81,035	-	-	139	9,118
Total Sytem CP	DCP1	176,839	65,421	21,126	81,035	-	-	139	9,118
4 CP									
Transformation CP	TCP4	657,577	253,817	70,997	297,605	311	15	553	34,280
Bulk Delivery CP	BCP4	657,577	253,817	70,997	297,605	311	15	553	34,280
Total Sytem CP	DCP4	657,577	253,817	70,997	297,605	311	15	553	34,280
12 CP									
Transformation CP	TCP12	1,788,433	644,322	200,444	839,109	6,797	285	1,738	95,738
Bulk Delivery CP	BCP12	1,788,433	644,322	200,444	839,109	6,797	285	1,738	95,738
Total Sytem CP	DCP12	1,788,433	644,322	200,444	839,109	6,797	285	1,738	95,738
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	194,307	71,897	24,053	86,152	2,118	154	242	9,691
Primary NCP	PNCP1	194,307	71,897	24,053	86,152	2,118	154	242	9,691
Line Transformer NCP	LTNCP1	171,925	71,896.82	24,036.10	73,479.32	2,118	154	242	-
Secondary NCP	SNCP1	180,767	71,896.82	24,044.57	82,312.07	2,118	154	242	-
4 NCP									
Classification NCP from Load Data Provider	DNCP4	733,742	269,020	91,126	325,497	8,408	531	917	38,243
Primary NCP	PNCP4	733,742	269,020	91,126	325,497	8,408	531	917	38,243
Line Transformer NCP	LTNCP4	647,554	269,019.53	91,061.52	277,615.94	8,408	531	917	-
Secondary NCP	SNCP4	680,958	269,019.53	91,093.61	310,987.39	8,408	531	917	-
12 NCP									
Classification NCP from Load Data Provider	DNCP12	1,989,323	702,073	232,528	920,039	23,533	1,259	2,397	107,494
Primary NCP	PNCP12	1,989,323	702,073	232,528	920,039	23,533	1,259	2,397	107,494
Line Transformer NCP	LTNCP12	1,746,327	702,072.98	232,364.47	784,700.61	23,533	1,259	2,397	-
Secondary NCP	SNCP12	1,840,735	702,072.98	232,446.35	879,027.32	23,533	1,259	2,397	-

Table 7.1.0-D shows the Demand Data included in this Application utilizing the previously mentioned methodology.

Table 7.1.0-D 2022 Test Year Demand Data

EB-2021-0009

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9	10	11
Customer Classes		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
		CP Sanity Check	Pass	Pass	Check 4CP and 12CP	Check 12CP	Check 12CP	Check 4CP and 12CP	Pass	Pass
CO-INCIDENT PEAK										
1 CP										
Transformation CP	TCP1	191,350	93,755	18,963	71,074	-	-	145	7,412	
Bulk Delivery CP	BCP1	191,350	93,755	18,963	71,074	-	-	145	7,412	
Total Sytem CP	DCP1	191,350	93,755	18,963	71,074	-	-	145	7,412	
4 CP										
Transformation CP	TCP4	699,923	304,835	65,443	301,043	-	-	589	28,013	
Bulk Delivery CP	BCP4	699,923	304,835	65,443	301,043	-	-	589	28,013	
Total Sytem CP	DCP4	699,923	304,835	65,443	301,043	-	-	589	28,013	
12 CP										
Transformation CP	TCP12	1,765,616	643,771	161,821	873,336	5,545	157	1,790	79,195	
Bulk Delivery CP	BCP12	1,765,616	643,771	161,821	873,336	5,545	157	1,790	79,195	
Total Sytem CP	DCP12	1,765,616	643,771	161,821	873,336	5,545	157	1,790	79,195	
NON CO_INCIDENT PEAK		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP										
Classification NCP from Load Data Provider	DNCP1	226,674	100,804	22,329	91,051	1,857	39	259	10,334	
Primary NCP	PNCP1	226,674	100,804	22,329	91,051	1,857	39	259	10,334	
Line Transformer NCP	LTNCP1	203,934	100,803.82	22,268.97	78,705.83	1,857	39.25	259.24	-	
Secondary NCP	SNCP1	211,680	100,803.82	22,321.40	86,399.40	1,857	39.25	259.24	-	
4 NCP										
Classification NCP from Load Data Provider	DNCP4	795,610	327,211	72,455	351,639	7,429	157	984	35,735	
Primary NCP	PNCP4	795,610	327,211	72,455	351,639	7,429	157	984	35,735	
Line Transformer NCP	LTNCP4	712,003	327,211.04	72,260.48	303,960.87	7,429	156.99	984.26	-	
Secondary NCP	SNCP4	712,003	327,211.04	72,260.48	303,960.87	7,429	156.99	984.26	-	
12 NCP										
Classification NCP from Load Data Provider	DNCP12	2,006,842	737,809	181,325	965,985	22,144	471	2,572	96,537	
Primary NCP	PNCP12	2,006,842	737,809	181,325	965,985	22,144	471	2,572	96,537	
Line Transformer NCP	LTNCP12	1,137,315	737,808.91	72,260.48	303,960.87	22,144	156.99	984.26	-	
Secondary NCP	SNCP12	1,137,315	737,808.91	72,260.48	303,960.87	22,144	156.99	984.26	-	

BPI notes that the CP Sanity Checks not showing as “Pass” have been reviewed, and BPI believes the levels entered are appropriate. These are explained further below:

- GS>50-Regular and Unmetered Scattered Load – Check 4CP and 12CP

    - The Coincident Peak is the hour during the year when BPI's system reaches its peak demand, since these sanity checks are at the customer class level unless the customer classes NCP's are completely aligned with the CPs these sanity checks will not work
- Street Light – Check 12CP
    - BPI's Coincident Peak occurs during the day of the warmest months of the year i.e. July and August, at these times during these months Street Lights are not in use, therefore they do not contribute to BPI's CP so at the time of that CP the peak demand for this class is 0kW
    - This check is checking that 1CP x 12 = 12CP, since 0x12= 0 this results in the sanity check producing a notice in error
- Sentinel Lighting – Check 12CP
    - The reasoning for this error is the same as the explanation provided above for the Street Light class

BPI confirms that it has validated all of its demand data populated in worksheet I8 Demand Data in the Cost Allocation Model. BPI believes the "USF Demand Profile Working Group" Method has produced a realistic demand profile for all of its rate class. BPI used the most recent 3-years historical data, weather data (HDD and CDD) averaged over a 10-year period and scaled to the 2022 Test Year load forecast as filed as part of this Application. For more information provided in the "USF Demand Profile Methodology Paper" provided as Attachment 7-A, as well as the supporting demand profile excel files, Attachment 7-B, Attachment 7-C and Attachment 7-D submitted with this Exhibit.

7.1.0.2 Cost Allocation Model Inputs/Weighting Factors

On September 2, 2010 the Board began proceeding EB-2010-0219 with the mandate to review and revise the existing cost allocation policy as needed. On March 31, 2011 the Report of the Board called the *Review of Electricity Distribution Cost Allocation Policy* (the "March 31, 2011 Cost Allocation Report") was released in relation to EB-2010-0219. In the March 31, 2011 Cost Allocation Report, the Board stated, "default weighting factors should now be utilized only in exceptional circumstances". Distributors are therefore now expected to develop their own weighting factors as part of their cost allocation study.

7.1.0.3 Weighting Factors for Services and Billing and Collecting (Sheet I5.2)

Services (Account 1855)

The Services Weight Factors was derived by comparing the cost of a typical service drop in each customer class. BPI does not record the cost of service drops for USL, Street Lighting, Sentinel Lighting or Embedded Distributor in account 1855. This practice has resulted in a services weighting factor of 0 for those classes. Further, BPI does not record the cost of service drops on underground General Service assets in 1855. This has been reflected in the services weighting factor calculation for those classes.

For each class, BPI calculated a separate typical service drop cost for overhead and underground assets. The next step consisted of computing the expected proportion of underground and overhead service drops in each customer class. A weighted average cost for each class was evaluated using these factors. As per the suggested methodology on the Cost Allocation instruction sheet, the Residential class was set as a weighting factor of 1. The General Service weighting factors were determined by dividing their respective weighted average service drop cost per customer by the residential weighted average cost on a per customer basis.

Table 7.1-A summarizes the assigned service weighting factors for each rate class.

Table 7.1-A – Weighting Factors for Services

Rate Class	Weighting Factors for Services
Residential	1.0
GS <50	1.1
GS>50-Regular	1.4
Street Light	0.0
Sentinel	0.0
Unmetered Scattered Load	0.0
Embedded Distributor	0.0

Billing and Collection (Accounts 5315-5340, excluding 5335)

The weight factors for Billing and Collecting were updated by conducting an analysis on Accounts 5315-5340 and excluding 5335. These weighting factors were derived based on internal consultations regarding the level of effort and time necessary for billing and collecting activities for each type of customer. One of the high-cost elements in billing and collecting is the level of effort and time associated with interval accounts, as there is a greater focus on the accuracy of billing.

For rate classes in which a number of accounts may be consolidated on one bill, the weighting factor has been left at 1. This reflects the observation that minimal additional effort is required to consolidate the billing.

The weighting factors applied to Billing and Collecting costs are set out in Table 7.1-B below.

Table 7.1-B – Weighting Factors for Billing and Collecting

Rate Class	Weighting Factors for Billing and Collecting
Residential	1.0
GS <50	1.1
GS>50-Regular	3.1
Street Light	1.0
Sentinel	1.0
Unmetered Scattered Load	1.0
Embedded Distributor	1.0

7.1.0.4 Meter Capital (Sheet I7.1)

The purpose of this input is to derive the weighting factors of each customer class for the allocator CMWC (Cost Weighted Meter Capital) which is used to allocate accounts 1860 (Meters), 5065 (Meter Expense), and 5175 (Maintenance).

The meter capital costs per meter were calculated based on the actual installed cost of the meters in BPI’s service area.

The meter capital costs per meter are presented below in Table 7.1-C.

Table 7.1-C – Cost per Meter Type

Meter Type	Cost per Meter
Smart Meters	$ 280
Demand without IT (usually three-phase)	$ 1,681
Demand with IT	$ 3,417
Demand with IT and Interval Capability - Secondary	$ 3,417
Smart Meters - Network	$ 556
Smart Meters - GS<50	$ 814

Meter Reading (Sheet I7.2)

The purpose of this input is to derive the weighting factors for the allocator CWMR (Cost Weighted Meter Reading), which is used only to allocate costs that are recorded in Account 5310 Meter Reading Expenses.

BPI completed an analysis of the costs included in account 5310 and assigned the costs to the appropriate classes based on the nature of the cost. Based on this analysis, BPI calculated the overall cost per class by customer and assigned a weighting factor of 1 for the costs relating to Smart Meters for the residential class.

The Meter Reading Weighting Factors are set out in Table 7.1-D below

Table 7.1-D – Meter Reading Weighting Factors

Meter Type	Reading Weighting Factor
Smart Meters	1.00
Interval Phone line	0.78
Interval	0.40

7.1.0.5 Direct Allocation (Sheet I9)

BPI has not directly allocated any costs to specific rate classes.

7.1.1 Specific Customer Class(es)

7.1.1.1 Large General Service and Large User Classes

The Chapter 2 Filing Requirements has the following statement in regards to Large General Service and Large Use Classes:

> *"As a reminder, the treatment of the Transformer Ownership Allowance has been revised in the current version of the cost allocation model, as compared to the version that the distributor may have used in a previous rebasing application."*

BPI has used the current version of the model for this application. BPI is proposing to change the nomenclature regarding the current General Service 50 to 4,999 kW class. Please see the proposal in Exhibit 8. No restatement of revenue requirement is applicable for this change.

7.1.1.2 Embedded Distributor Class

BPI does have a separate embedded distributor class which has been included in the cost allocation study. Energy+ (E+), formerly Brant County Power Inc. (BCPI or BCP) is the only embedded distributor of BPI. BPI charges E+ the monthly service charge for the two embedded feeder points. The remaining cost allocated to the embedded distributor class is recovered through a distribution volumetric charge.

BPI has consulted with its Embedded Distributor, Energy + regarding its Cost Allocation and Rate Design. BPI has proposed a revenue to cost ratio of 100%, consistent with BPI's past practice in its 2013 and 2017 Cost of Service Rate Applications, and the Board's Decision in case number EB-2009-0063 "The "Brant County Motion", which first established BPI's Embedded Distributor class. The base revenue requirement proposed to be collected from the embedded distributor class has increased from $199,626 in the 2017 Decision and Order to $223,963 in BPI's 2022 proposal. BPI has communicated the proposed updated Embedded Distributor rates to Energy +, as well as providing the key inputs and outputs of the Cost Allocation model. Attachment 7-F is the formal letter sent to Energy+ regarding BPI's Cost Allocation inputs. Energy+ confirmed its support of BPI's proposals as included in the letter. Please note BPI has further amended its rate proposals following the letter to Energy+, BPI intends to notify Energy+ of the updates made following the filing of this Application.

7.1.1.3 Unmetered Loads (Unmetered Scattered Load, Sentinel Lighting and Street Lighting)

On June 12, 2015 the OEB released their Report of the Board on Review of the Board's Cost Allocation Policy for Unmetered Loads, which amended section 2.4.6 of the DSC (Distribution System Code). The amendment outlined a new cost allocation policy for the street lighting rate class. A new "street lighting adjustment factor" will be used to allocate costs to the street lighting rate class for primary and line transformer assets. The "street lighting adjustment factor" replaces the "number of connections" allocator. The Model has been updated to reflect the street lighting adjustment factor. BPI implemented these changes in its 2017 COS Application and has continued to follow this policy in this 2022 Application.

In August 2020, BPI sent a letter notifying customers in the Unmetered Scattered Load and Sentinel Light classes of BPI's Cost of Service Application, and soliciting the unmetered load customers' input and comments regarding the activities currently in progress with respect to BPI's cost allocations, load profiles, and other rate-related undertakings. A copy of the template for this letter can be found as Attachment 7-G of the exhibit. BPI received responses from five of its customers. As a result of this consultation, BPI did not receive any response from customers disputing what the letter outlined were the current billing units.

BPI has also consulted with its only Street lighting customer, the City of Brantford, regarding the Cost of Service and Billing inputs to its Cost Allocation. As a result of this consultation, BPI engineering staff, with input from representatives from the City of Brantford, determined the number of street lighting connections will remain the same for 2021 and 2022 in BPI's service territory.

7.1.1.4 MicroFIT class

In accordance with the Chapter 2 Filing Requirements updated July 16, 2015, the microFIT class has not been included as a separate class in the cost allocation model. Also, the OEB issued the Review of Fixed Monthly Charge for microFIT Generator Service Classification (EB-2009-0326 and EB-2010-0219) on February 24, 2020. The review stated distributors which have been approved for a rate which is calculated value based on the previous approved amount of \$5.40 province-wide rate should include a proposal to update the calculated charge based on the updated province-wide rate of \$4.55 at the time of their next rate application. Therefore, BPI is requesting to maintain the uniform Board approved rate of $4.55 until the Board updates the uniform microFIT rate at a future date.

7.1.1.5 Standby Rates

At this time BPI's Standby Rate has been deemed interim per the board's March 21, 2006 Decision in EB-2005-0529 which addressed the development of a standardized methodology for setting Standby Rates. BPI does not propose to change its interim Standby Rate, or to have it deemed final. BPI is unable to produce a reasonable proposed Standby Rate at this time because it has no standby customers.

Therefore, this rate class has not been included in the Cost Allocation Study. BPI expects to treat its standby customer(s) in accordance with the current tariff and any subsequent Board Decision or Direction resulting from future consultations. No expected revenue from Standby rates has been included as distribution revenue offset.

7.1.2 New Customer Class(es)

BPI is not requesting new customer classes in this Application.

7.1.3 Eliminated Customer Classes

BPI is not requesting to eliminate or combine customer classes in this Application.

7.2 Class Revenue Requirements

7.2.0 Summary of Results and Proposed Changes

BPI is filing a completed cost allocation study using the Board approved methodology. This filing reflects 2022 proposed test year loads and costs.

The data used in the updated cost allocation study is consistent with BPI's cost data supporting the proposed 2022 revenue requirement outlined in this Application. Consistent with the Guidelines, BPI's assets were broken out into primary and secondary distribution functions using breakout percentages consistent with the original cost allocation information filing. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were kept in line with previous Cost Allocation model versions.

An Excel version of the updated Cost Allocation Study has been included with the filed application material. In addition, Attachment 7-E outlines input sheets I-6 and I-8 and output sheets O-1 and O-2.

Capital contributions, depreciation and accumulated depreciation by USoA are consistent with the information provided in the 2022 continuity Statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2022 customer forecast outlined in Exhibit 3.

7.2.1 Class Revenue Requirements

The allocated cost by rate class for the 2017 Cost of Service filing and the 2022 updated study are provided in Table 7.2-A.

Table 7.2-A – Allocated Costs

Rate Class	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study	%
Residential	11,684,876	63.46%	16,181,041	67.85%
GS <50	2,099,765	11.40%	2,141,292	8.98%
GS>50-Regular	4,014,970	21.80%	4,881,933	20.47%
Street Light	273,784	1.49%	273,981	1.15%
Sentinel	56,917	0.31%	49,968	0.21%
Unmetered Scattered Load	75,997	0.41%	84,008	0.35%
Embedded Distributor	207,647	1.13%	234,606	0.98%
Total	**18,413,956**	**100%**	**23,846,829**	**100.00%**

The following table, Table 7.2-B, provides information on calculated class revenue. The resulting 2022 Proposed Base Revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

Table 7.2-B – Calculated Class Revenue

Rate Class	2022 Base Revenue at Existing Rates	2022 Proposed Base Revenue allocated at Existing Rates Proportion	2022 Proposed Base Revenue	Miscellaneous Revenue
Residential	$ 11,006,554	$ 13,639,308	$ 14,232,489	$ 741,392
GS <50	$ 1,790,407	$ 2,218,670	$ 2,218,670	$ 85,526
GS>50-Regular	$ 5,061,249	$ 6,271,893	$ 5,659,355	$ 198,965
Street Light	$ 248,442	$ 307,869	$ 305,942	$ 22,835
Sentinel	$ 34,790	$ 43,112	$ 43,196	$ 3,044
Unmetered Scattered Load	$ 79,829	$ 98,924	$ 96,182	$ 4,628
Embedded Distributor	$ 161,412	$ 200,022	$ 223,963	$ 10,643
Total	**$ 18,382,682**	**$ 22,779,797**	**$ 22,779,797**	**$ 1,067,032**

7.3 Revenue to Cost Ratios

7.3.1 Revenue to Cost Ratios

The results of the Cost Allocation Study are typically presented in the form of Revenue to Cost Ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications being subsidized and those over contributing. A percentage of less than 100% means the rate classification is under contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over contributing and is subsidizing other classes of customers.

The Board's March 31, 2011 Report, on Cost Allocation, section 2.9.4, outlines the range of acceptable ratios. Per the Board's June 12, 2015 letter, the Board narrowed the revenue to cost ratio policy range for the street lighting rate class from 70-120% to 80-120%. Table 7.3-A provides BPI's Revenue to Cost Ratios from the previous Cost of Service Application, the status quo 2022 ratios, and the proposed 2022 Cost Allocation. To bring the ratios within the appropriate policy ranges, BPI has proposed to keep the remaining ratios equal to the status quo, except where necessary to bring a rate class within the proposed range or in order to balance the revenue requirement. The GS>50 kW, Street Light and

Unmetered Scattered Load levels were set to the appropriate minimum or maximum level. As discussed previously, BPI has proposed a revenue-to-cost ratio of 100% for its Embedded Distributor class, consistent with BPI's past rate design. BPI adjusted the Residential class upwards in order to allocate the remaining revenue requirement.

Table 7.3-A – Revenue to Cost Ratios

Rate Class	2017 Cost of Service Ratios	Status Quo 2022 Ratios	2022 Proposed Ratios
Residential	94.23%	88.87%	92.54%
GS <50	94.23%	107.61%	107.61%
GS>50-Regular	120.00%	132.55%	120.00%
Street Light	94.23%	120.70%	120.00%
Sentinel	98.85%	92.37%	92.54%
Unmetered Scattered Load	111.24%	123.26%	120.00%
Embedded Distributor	100.00%	89.80%	100.00%

List of Attachments

Attachment 7-A – USF Demand Profile Methodology Paper

Attachment 7-B – 2017 Demand Profile Model

The 2017 Demand Profile Model has been filed as an excel file only as part of this Application "Attachment 7-B 2017 Demand Profile Model"

Attachment 7-C – 2018 Demand Profile Model

The 2018 Demand Profile Model has been filed as an excel file only as part of this Application. "Attachment 7-C 2018 Demand Profile Model"

Attachment 7-D – 2019 Demand Profile Model

The 2019 Demand Profile Model has been filed as an excel file only as part of this Application. "Attachment 7-D 2019 Demand Profile Model"

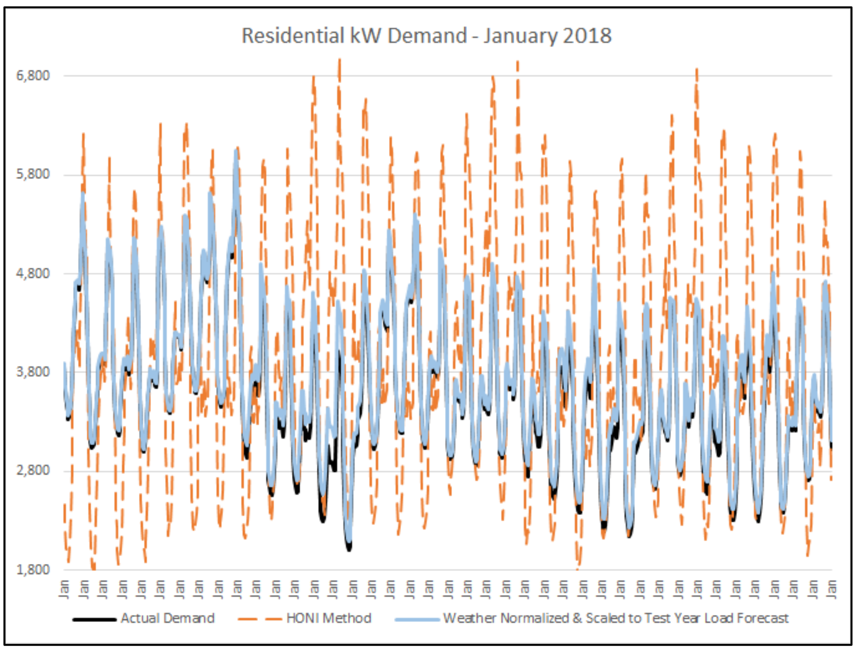
Attachment 7-E - Cost Allocation Model – Specific Input and Output Sheets

Attachment 7-F - Letter to Energy+ - Embedded Distributor Communication

Attachment 7-G - Communication to Unmetered Customers

Attachment 7-A

USF Demand Profile Methodology Paper



DEMAND PROFILE METHODLOGY PAPER

Version 1.1: April 2021

ABSTRACT

A summary of the methodology to determine Coincident Peak Demand and Non-Coincident Peak Demand values by customer rate class.

Richard Bucknall

Purpose

The purpose this document is to share information with USF members in preparing Demand Profile data for a Cost of Service application should they choose to use the USF methodology as described in this paper.

In its' 2021 Cost of Service application (EB-2020-0061), Wellington North Power Inc. used the "USF Demand Profile Working Group" methodology, as described in this document, to determine the Non Coincident Peak Demand (NCP) and Coincident Peak Demand Values (CP) for input into worksheet "I8. Demand" Data of the Ontario Energy Board's (OEB) Cost Allocation Model.

Version 1.0 (August 2020) of this methodology paper was included as evidence in Wellington North Power Inc.'s Exhibit 7 – Cost Allocation, section "7.2.8 Demand Data", as filed with the regulator on October 30th 2020. This evidence provided information to Intervenors and OEB Staff about how the utility determined the NCP and CP data.

Version 1.1 (March 2021) of this methodology incorporates minor changes to the USF Demand Profile Methodology used to determine the NCP and CP values as a result of Wellington North Power Inc.'s 2021 Cost of Service application progressing through the OEB's rate-application process, i.e. from initial application, interrogatories, clarification questions and settlement. All information and data contained reflects the evidence as filed on record with the OEB in the Settlement Proposal for Wellington North Power Inc.'s 2021 Cost of Service application (EB-2020-0061).

OEB Staff & Intervenor Feedback of USF Demand Profile Methodology

Below are comments included in Wellington North Power Inc.'s (WNP) Settlement Proposal (*pages 45 to 46*) that make specific reference to the USF Demand Profile Methodology:

Wellington North Power Inc.
EB-2020-0061
Settlement Proposal Filed March 25, 2021.

3.2 Are the proposed cost allocation methodology, allocations, and revenue-to-cost ratios, appropriate?

Full Settlement

In its' 2021 Cost of Service application, WNP used the "USF Demand Profile Working Group" methodology to determine the Coincident Peak (CP) and Non-Coincident Peak (NCP) Demand for the Applicant's rate classes for input into worksheet "I8 Demand Data" of the OEB's Cost Allocation model. In Exhibit 7 – Cost Allocation, Appendix 7A contained the "USF Demand Profile Methodology Paper" that described the methodology, data, and a review of other options considered. In addition, WNP filed excel copies of supporting information as listed in the Appendices of Exhibit 7.

Parties commend WNP for its work on developing demand allocators and agree to accept the demand allocators proposed by WNP for purposes of settlement. However, there is no agreement that the methodology used to derive the values is appropriate.

The parties note the proposed methodology is a good first step in establishing generic demand allocators, but may require further improvements to produce reasonable results in future proceedings. Parties note that the issue is an industry-wide one and that work on appropriate methodologies is ongoing by other distributors, including work based on the methodology employed by WNP in this proceeding.

** Parties consist of:*

- *Intervenors: OEB Staff and Vulnerable Energy Consumers Coalition (VECC).*
- *Applicant: Wellington North Power Inc.*

Contents

Table of Figures

1. Background

For previous Cost of Service applications (e.g. EB-2015-0110 and EB-2011-0249) for Wellington North Power Inc. ("WNP", the "Applicant") relied on demand profiles produced by Hydro One Networks Inc., (HONI) which were based on sample data from 2004. The Coincident Peak (CP) and Non-Coincident Peak (NCP) values populated in worksheet "I8 Demand Data" of the OEB's Cost Allocation Model were scaled from WNP's initial cost allocation informational filing, using the ratio of the Test Year load forecast to the base year load for each rate class.

In its' 2021 Cost of Service application (EB-2020-0061), WNP used the "USF Demand Profile Methodology" to determine the Coincident Peak (CP) and Non-Coincident Peak (NCP) values to be inputted into the OEB Cost Allocation Model, worksheet "I8 Demand Data". This method, as described in this paper, uses the average of NCP and CP derived from 2018 and 2019 weather-normalized data and scaled to the Applicant's 2021 Test Year Load Forecast using Wholesale kWh purchases.

2. Use of Actual Demand Data to Determine NCP and CP

By January 2018, WNP had completed installation of MIST[1] meters for all customers in its' General Service 50-999kW rate classes. WNP was therefore able to compile hourly consumption data for each of its metered rate classes, beginning with 2018, and used this data to update load profiles for all of its rate classes, in accordance with Section 2.7.1 of the Ontario Energy Board ("OEB") Filing Requirements.

The methodology described in detail in Appendix A and as used in Cost of Service application (EB-2020-0061) was prepared by the Utilities Standards Forum[2] ("USF"). USF formed the "USF Demand Profile Working Group" comprising of five LDC members,[3] with assistance from Bruce Bacon (Senior Rate Consultant at BLG), with a common objective of creating a methodology to use updated weather-normalized load profiles that, if accepted by the OEB and Intervenors, could be used by LDCs in rate applications.

WNP collected actual hourly demand data for the years 2018 and 2019. With this data, WNP created separate models for each year 2018 to 2019 to determine the Non Coincident Peak (NCP) and Coincident Peak for each year. The average of the non-coincident peak (NCP) and coincident peak (CP) values from the years 2018 and 2019 were input in worksheet "I8 Demand Data" of the OEB's Cost Allocation Model.

[1] "MIST meter" is an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to "Metering Inside the Settlement Timeframe." Requirement to be installed by August 21st 2020 as per DSC Section 5.1.3 (EB-2013-0311)

[2] Utilities Standards Forum is a non-profit, volunteer based corporation owned by 53 Ontario electricity distributor Members. It is where Member representatives network, share best practices and troubleshoot on common challenges, providing opportunities to share the cost of engaging subject matter experts, and develop common templates, processes and tools.

[3] Representatives from Canadian Niagara Power Inc., Entegrus Powerlines Inc., Kitchener-Wilmot Hydro Inc., Milton Hydro Distribution Inc. and Wellington North Power Inc.

3. Summary of Process Used to Determine NCP and CP

Below is a summary of the process the "USF Demand Profile Working Group" developed:

1. Collect hourly data by rate class for each year.
2. Validate the data (e.g. compare the aggregated annual data against RRR filings).
3. Weather Normalize the data by:
   a) An adjustment to remove the estimated weather-sensitive portion of the load for each hour, based on HDD and CDD components of the load forecast presented in Exhibit 3; and,
   b) An adjustment to add an estimate of "weather-normal" load, based on 10-year average HDD and CDD values.
4. Scaling to Test Year Load Forecast: because WNP's load forecast is by wholesale predicted kWh purchases, the weather normalized data was scaled to match the Test Year Load Forecast. In essence, this takes the daily demand weather normalized profile (or shape) for each rate class and adjusts it to match the Test Year predicted Load Forecast for each rate class.
5. Once the data had been scaled to the Test Year Load Forecast, it was possible to calculate the required NCP and CP values.
6. WNP performed this process for the hourly demand data collected for the year 2018.
7. WNP then repeated the process the hourly demand data collected for the year 2019.
8. WNP took the average of the 2018 and 2019 NCP and CP values for input into worksheet "I8 Demand Data" of the OEB's Cost Allocation Model.

4. 2018 Demand - NCP and CP Values

The table below illustrates the NCP and CP values as derived using the process summarized above for 2018 demand data:

Figure 1: Demand Profiles Using 2018 Demand Data

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Lighting	Sentinel Lighting	USL
1 NCP	6,080	2,200	3,338	7,264	53	6	2
4 NCP	21,940	8,494	13,078	28,664	211	23	8
12 NCP	59,043	23,560	37,756	82,518	633	56	18
1 CP	4,258	1,984	2,963	6,990	0	0	0
4 CP	15,952	8,005	12,469	26,134	0	0	0
12 CP	44,714	22,072	35,459	78,571	105	7	4

5. 2019 Demand - NCP and CP Values

The table below illustrates the NCP and CP values as derived using the process summarized above for 2019 demand data:

Figure 2: Demand Profiles Using 2019 Demand Data

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Lighting	Sentinel Lighting	USL
1 NCP	5,718	2,226	3,316	7,508	56	6	2
4 NCP	21,295	8,527	12,904	29,250	223	23	7
12 NCP	56,819	22,680	36,885	83,616	639	56	18
1 CP	5,149	1,912	2,632	6,513	56	3	1
4 CP	18,674	7,528	10,918	25,114	152	11	4
12 CP	44,144	20,595	33,210	79,235	193	15	5

6. NCP and CP Used in Cost Allocation Model

The various NCP and CP values for each year (2018 and 2019) were averaged for the purpose of determining the demand allocator inputs to Tab I8 of the OEB's Cost Allocation Model, as shown in the following tables:

Figure 3: Non-Coincident Peak: 2018, 2019 and Average of 2018 & 2019

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Lighting	Sentinel Lighting	USL
2018 Values:							
1 NCP	6,080	2,200	3,338	7,264	53	6	2
4 NCP	21,940	8,494	13,078	28,664	211	23	8
12 NCP	59,043	23,560	37,756	82,518	633	56	18
2019 Values:							
1 NCP	5,718	2,226	3,316	7,508	56	6	2
4 NCP	21,295	8,527	12,904	29,250	223	23	7
12 NCP	56,819	22,680	36,885	83,616	639	56	18
Average of 2018 and 2019 values:							
1 NCP	5,899	2,213	3,327	7,386	54	6	2
4 NCP	21,617	8,510	12,991	28,957	217	23	7
12 NCP	57,931	23,120	37,320	83,067	636	56	18

Figure 4: Coincident Peak: 2018, 2019 and Average of 2018 & 2019

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Lighting	Sentinel Lighting	USL
2018 Values:							
1 CP	4,258	1,984	2,963	6,990	0	0	0
4 CP	15,952	8,005	12,469	26,134	0	0	0
12 CP	44,714	22,072	35,459	78,571	105	7	4
2019 Values:							
1 CP	5,149	1,912	2,632	6,513	56	3	1
4 CP	18,674	7,528	10,918	25,114	152	11	4
12 CP	44,144	20,595	33,210	79,235	193	15	5
Average of 2018 and 2019 values:							
1 CP	4,704	1,948	2,798	6,751	28	2	1
4 CP	17,313	7,767	11,693	25,624	76	6	2
12 CP	44,429	21,333	34,335	78,903	149	11	4

The NCP and CP derived from the average of years 2018 and 2019 were inputted into worksheet "I8 Demand Data" of the OEB's Cost Allocation Model that was filed with WNP rate application EB-2020-0061.

7. Shift of Demand Allocators between Rate Classes

In WNP's last Cost of Service rate application (EB-2015-0110)[4], the Applicant, consistent with rate applications at the time, used the "HONI method"[5] to determine the demand allocators for the OEB's Cost Allocation model worksheet "I8 Demand Data". The table below summarizes WNP's demand allocators that were used Cost Allocation model in the Applicant's 20106 rate application:

Figure 5: Demand Allocators by Rate Class in 2016 CoS Application (EB-2015-0110)

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Light	Sentinel Light	USL
1 NCP	7,144	2,117	2,377	8,278	166	7	0.40
4 NCP	26,821	8,179	9,117	32,715	663	26	1
12 NCP	67,219	21,868	24,489	95,257	1,984	65	4
1 CP	6,232	1,317	1,609	8,126	166	5	0.35
4 CP	24,672	5,337	7,620	29,563	658	18	1
12 CP	60,968	13,651	20,756	88,323	1,487	46	4

The Non Coincident Peak (NCP) and Coincident Peak (CP) Demand allocators were reviewed and approved by the OEB and Intervenors in WNP's Cost of Service rate application (EB-2015-0110).

The table below shows the NCP and CP demand allocators for the weather-sensitive rate classes as approved by all parties in WNP's Cost of Service rate application (EB-2015-0110). In particular, this table shows the percentage allocation of 4NCP and 4CP demand allocated across the weather-sensitive rate classes.

Figure 6: Weather Sensitive Rate Classes Demand Allocators Previously Approved

	Residential	General Service <50 kW	General Service 50-999 kW	Total
1 NCP	7,144	2,117	2,377	11,638
4 NCP	**26,821**	**8,179**	**9,117**	**44,117**
12 NCP	67,219	21,868	24,489	113,576
Allocation of 4NCP	*61%*	*19%*	*21%*	*100%*
1 CP	6,232	1,317	1,609	9,158
4 CP	**24,672**	**5,337**	**7,620**	**37,629**
12 CP	60,968	13,651	20,756	95,375
Allocation of 4CP	*66%*	*14%*	*20%*	*100%*

WNP wanted to compare the NCP and CP demand allocators using the method described above compared to the traditional "HONI method" as used in the Applicant's 2016 Cost of Service

[4] Wellington North Power Inc. 2016 Cost of Service rate application EB-2015-0110 for rates May 1st 2016.
[5] The "HONI method" (Hydro One Networks Inc.) has been used in many rate applications since the 2006 EDR process and relies on 2004 interval LDC data based on work that was coordinated by the OEB and completed by Hydro One Networks Inc. in 2006. The 2004 interval data provides the demand profile which is scaled using the LDC's Test Year Load Forecast data to determine the required NCP and CP values for input to Tab I8 of the OEB's Cost Allocation Model.

application. The Applicant was curious to see if there had been changes (a shift) in demand allocators across the rate classes.

WNP used the actual demand data for 2018 for the weather-sensitive rate classes and scaled it to the Test Year Load Forecast to calculate the required NCP values. This actual demand data was not weather normalized. Next, WNP used the same actual 2018 demand data and weather normalized it, using the methodology described earlier. This process was repeated using 2019 actual demand data.

The table below shows the NCP using 2018 and 2019 actual demand data before weather normalization and after weather normalization:

Figure 7: NCP using 2018 & 2019 Actual Demand: Before & After Weather Normalization

	2018 Actual Demand **Before** Weather Normal Adj			
	Non-Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1NCP	6,082	2,216	3,296	11,594
4NCP	**21,469**	**8,443**	**12,984**	**42,896**
12NCP	58,570	23,381	37,534	119,485
Allocation of 4NCP	50%	20%	30%	100%

	2019 Actual Demand **Before** Weather Normal Adj			
	Non-Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1NCP	5,717	2,212	3,302	11,230
4NCP	**21,301**	**8,517**	**12,860**	**42,678**
12NCP	56,619	22,550	36,746	115,915
Allocation of 4NCP	50%	20%	30%	100%

	2018 Actual Demand **After** Weather Normal Adj			
	Non-Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1NCP	6,080	2,200	3,338	11,619
4NCP	**21,940**	**8,494**	**13,078**	**43,512**
12NCP	59,043	23,560	37,756	120,359
Allocation of 4NCP	50%	20%	30%	100%

	2019 Actual Demand **After** Weather Normal Adj			
	Non-Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1NCP	5,718	2,226	3,316	11,261
4NCP	**21,295**	**8,527**	**12,904**	**42,726**
12NCP	56,819	22,680	36,885	116,384
Allocation of 4NCP	50%	20%	30%	100%

WNP repeated this process to determine CP values; the results are summarized below:

Figure 8: CP using 2018 & 2019 Actual Demand: Before & After Weather Normalization

	2018 Actual Demand **Before** Weather Normal Adj			
	Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1CP	4,040	2,042	3,221	9,302
4CP	**16,662**	**7,894**	**11,899**	**36,455**
12CP	45,505	21,655	34,867	102,028
Allocation of 4CP	46%	22%	33%	100%

	2019 Actual Demand **Before** Weather Normal Adj			
	Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1CP	5,176	1,921	2,644	9,741
4CP	18,239	7,767	10,949	**36,954**
12CP	46,147	20,648	32,519	99,314
Allocation of 4CP	49%	21%	30%	100%

	2018 Actual Demand **After** Weather Normal Adj			
	Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1CP	4,258	1,984	2,963	9,205
4CP	**15,952**	**8,005**	**12,469**	**36,426**
12CP	44,714	22,072	35,459	102,246
Allocation of 4CP	44%	22%	34%	100%

	2019 Actual Demand **After** Weather Normal Adj			
	Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1CP	5,149	1,912	2,632	9,693
4CP	**18,674**	**7,528**	**10,918**	**37,119**
12CP	44,144	20,595	33,210	97,949
Allocation of 4CP	50%	20%	29%	100%

The tables below provides a summary comparing 4NCP and 4CP for weather-sensitive rate classes:

a) Weather normalized demand as used in WNP's 2016 Cost of Service application (EB-2015-0110) using the traditional "HONI method" scaled to 2016 Test Year Load Forecast;
b) Weather normalized demand using the traditional "HONI method" scaled to 2021 Test Year Load Forecast as filed with this application;

c) 2018 and 2019 actual demand not weather-normalized; and
d) 2018 & 2019 actual demand weather normalized using the methodology described above.

Figure 9: 4NCP Demand Allocator Comparison

	Residential	General Service <50 kW	General Service 50-999 kW	Total
2016 CoS "HONI Method	26,821	8,179	9,117	44,117
% of Total	*61%*	*19%*	*21%*	*100%*
2019 Data – "HONI Method"	26,573	7,683	12,358	46,615
% of Total	*61%*	*19%*	*21%*	*100%*
2018 – **Not** Weather Normalized	21,469	8,443	12,984	42,896
% of Total	*50%*	*20%*	*30%*	*100%*
2018 – Weather Normalized	21,940	8,494	13,078	43,512
% of Total	*50%*	*20%*	*30%*	*100%*
2019 – **Not** Weather Normalized	21,301	8,517	12,860	42,678
% of Total	*50%*	*20%*	*30%*	*100%*
2019 – Weather Normalized	21,295	8,527	12,904	42,726
% of Total	*50%*	*20%*	*30%*	*100%*

Figure 10: 4CP Demand Allocator Comparison

	Residential	General Service <50 kW	General Service 50-999 kW	Total
2016 CoS "HONI Method	24,672	5,337	7,620	37,629
% of Total	*66%*	*14%*	*20%*	*100%*
2019 Data – "HONI Method"	24,444	5,014	10,328	39,786
% of Total	*61%*	*13%*	*26%*	*100%*
2018 – **Not** Weather Normalized	16,662	7,894	11,899	36,455
% of Total	*46%*	*22%*	*33%*	*100%*
2018 – Weather Normalized	15,952	8,005	12,469	36,426
% of Total	*44%*	*22%*	*34%*	*100%*
2019 – **Not** Weather Normalized	18,239	7,767	10,949	36,954
% of Total	*49%*	*21%*	*30%*	*100%*
2019 – Weather Normalized	18,674	7,528	10,918	37,119
% of Total	*50%*	*20%*	*29%*	*100%*

Observations

The following observations can be made from this analysis:

i. The traditional "HONI method", as applied in WNP's 2016 Cost of Service application (EB-2015-0110) when compared to 2018 and 2019 demand data, appears to allocate more demand to the Residential rate class when compared to USF's working group method as described earlier.[6]

ii. Looking at 2018 and 2019 values as derived from the USF's working group method:

a) There is minimal percentage change between years 2018 to 2019 for 4NCP for the weather-sensitive rate classes.

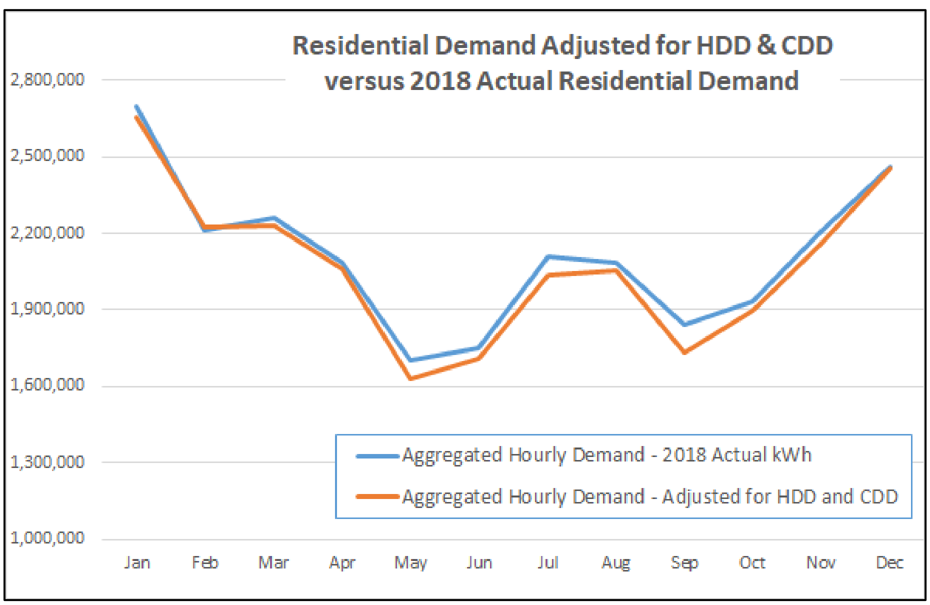
b) The observation noted in a) is also true for 4CP.

c) There is also minimal difference between actual demand (not weather-normalized) NCP & CP values and weather normalized NCP & CP values.

To support the statement above concerning minimal difference between actual demand and weather normalized demand, WNP plotted the data points in a graph for the weather-sensitive rate-classes of Residential and General Service <50kW.

The graph below shows 2018 Actual Demand for WNP's Residential customers overlaid with the Weather Adjusted Demand:

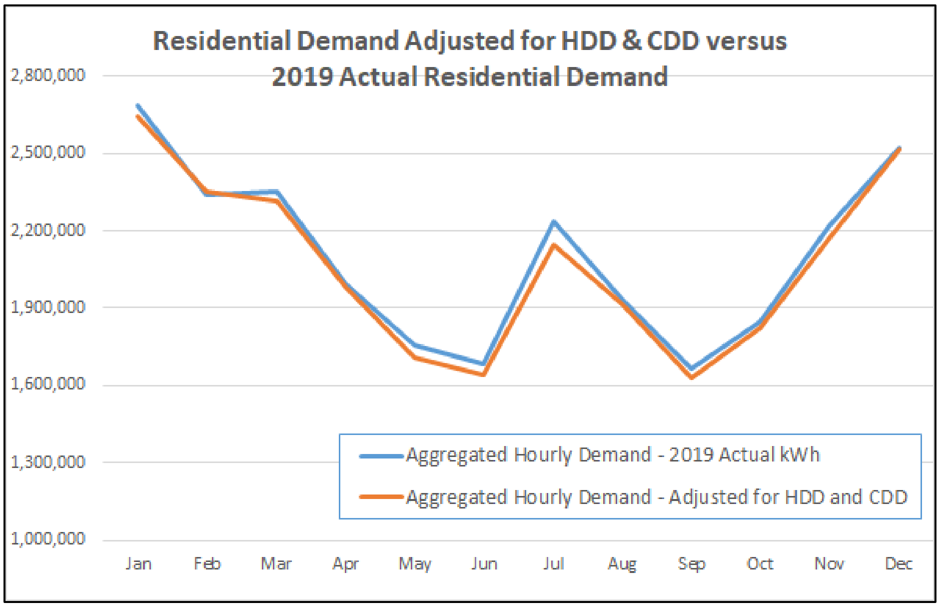
Figure 11: 2018 Residential Demand Actual and Weather Adjusted



[6] The Applicant acknowledges this method is based on the data available at the time of the 2016 Cost of Service application and, by no means, is criticizing the traditional method that OEB and HONI developed

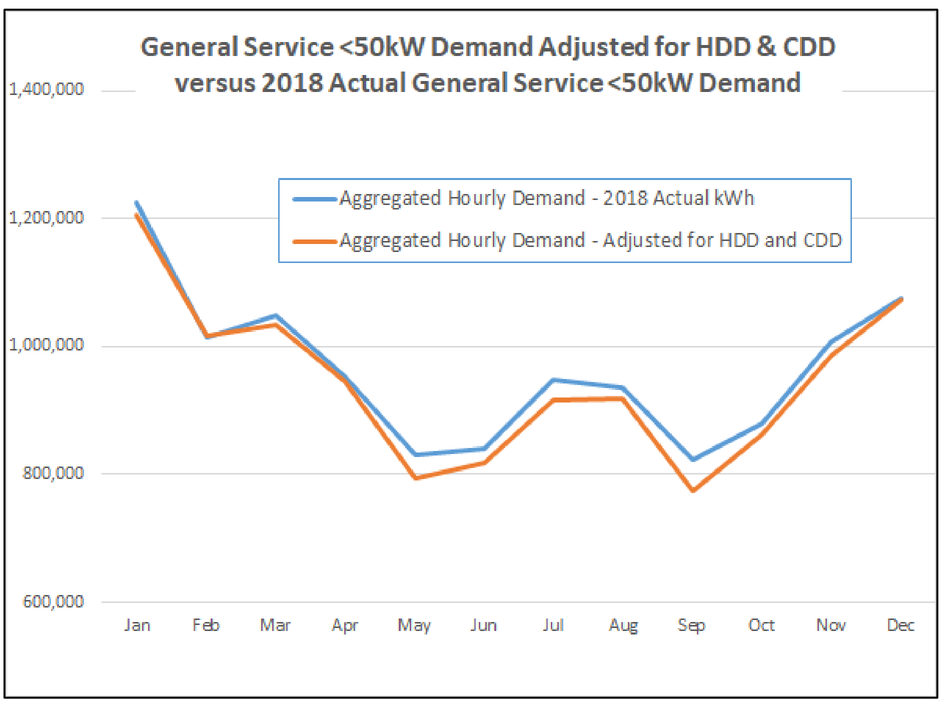
The graph below shows 2019 Actual Demand for WNP's Residential customers overlaid with the Weather Adjusted Demand:

Figure 12: 2019 Residential Demand Actual and Weather Adjusted



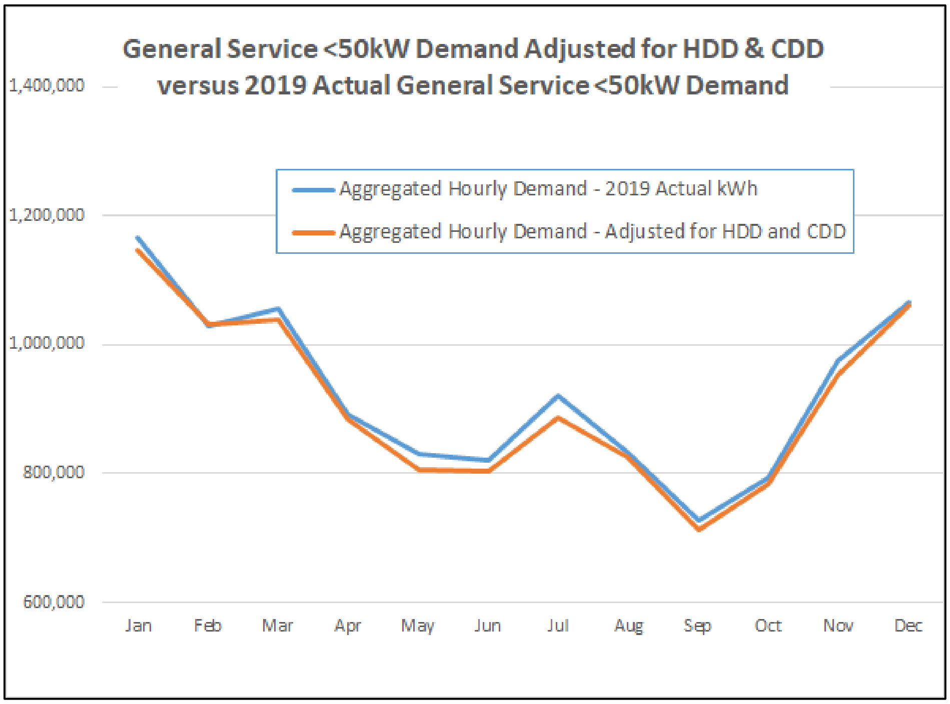
The graph below shows 2018 Actual Demand for WNP's General Service customers overlaid with the Weather Adjusted Demand:

Figure 13: 2018 General Service <50 kW Demand Actual and Weather Adjusted



The graph below shows 2019 Actual Demand for WNP's General Service customers overlaid with the Weather Adjusted Demand:

Figure 14: 2019 General Service <50 kW Demand Actual and Weather Adjusted



As demonstrated, there is minimal difference between actual demand NCP & CP values and weather normalized NCP & CP values. This observation, from the analysis presented, supports the LDC's opinions that:

a) The actual demand pattern by customers has actually changed;
b) This demand pattern change is not a result from the weather normalization process; and
c) The demand profile as used in the "HONI method" does not accurately reflect today's customer's demand.

Based upon the above evidence and analysis presented, WNP has inputted the NCP and CP values derived from the weather-normalized average of years 2018 and 2019, as calculated in the USF's working group method described above, into worksheet "I8 Demand Data" of the OEB's Cost Allocation Model was filed with WNP's application EB-2020-0061.

Appendices

Appendix A – Detailed Process Used to Determine NCP and CP

Aggregated Hourly Consumption Data

The first step in updating load profiles was to aggregate hourly consumption data by rate class for each year 2018 to 2019 and to verify the reasonability of the aggregated amounts.

<u>Data Sources:</u>

The following sources were used to collect the data:

Rate Class	Data Source:
Residential	Operational Data Store (ODS) provider - Savage Data Systems
General Service <50kW	Operational Data Store (ODS) provider - Savage Data Systems
General Service 50-999kW	Utility Data Management provider – Utilismart Corporation
General Service 1,000-4,999kW	Utility Data Management provider – Utilismart Corporation
Street Lights	Utility Data Management provider – Utilismart Corporation
Sentinel Lighting	LDC’s monthly billed data
Unmetered Scattered Load	LDC’s monthly billed data

Methodology:

The following methodology and assumptions were applied

<table>
<tr><th>Rate Class</th><th>Methodology</th></tr>
<tr><td>Residential</td><td rowspan="2">○ ODS stores data for each registered Smart Meter.
○ In ODS, each meter has a unique Meter ID and is assigned a Unique Supply Point I.D. number (USPID). Data tagged to USPID is submitted to MDMR for validation.
○ For each USPID extracted raw hourly interval kWh data for the period January 1st 2018 to December 31st 2018. Data input into MS Access database.
○ MS Access database: imported list of Meter IDs with their Account Number and rate class. Rate Class as at December 31st 2018.
○ MS Access database: ran query to match Meter ID and Rate Class. By identifying rate class, able to identify if Residential account or GS<50kW.
○ MS Access database: ran query to sum interval data for each hour of 2018. This provided the separate hourly demand profile for Residential and GS<50kW rate class.</td></tr>
<tr><td>GS<50kW</td></tr>
<tr><td>GS50-999kW</td><td>○ Rate class has hourly demand metering. Able to obtain data from meter (through Utilismart) for every hour of 2018 for each GS50-999kW customer.
○ Summated each customer's meter(s) to give an hourly demand profile for GS50-999kW rate class.</td></tr>
<tr><td>GS 1,000-4,999kW</td><td>○ Rate class has hourly demand metering. Able to obtain data from meter (through Utilismart) for every hour of 2018 for each GS1,000-4,999kW customer.
○ Summated each customer's meter(s) to give an hourly demand profile for GS1,000-4,999kW rate class.</td></tr>
<tr><td>Street Lights</td><td>○ LDC bills Streetlights using a streetlight profile consisting of number of connections, kW per connection, number of days per month, number hours of daylight hours.
○ The LDC updates the Streetlight profile each year to reflect any changes in the number of streetlight connections.
○ Streetlight profile is maintained by Utilismart and used the profile to determine hourly demand for 2018.</td></tr>
<tr><td>Sentinel Lighting</td><td>○ LDC bills Sentinel Lighting customers using a sentinel lighting profile provided by the customer which includes, number of connections, kW per connection, number of hours of operation per month and number of days per month.
○ The LDC used the profile to create an hourly demand profile.</td></tr>
<tr><td>USL</td><td>○ LDC bills Unmetered Scattered Load Lighting customers using an unmetered load profile provided by the customer which includes, number of connections, kW per connection, number of hours of operation per month and number of days per month.
○ The LDC used the profile to create an hourly demand profile.</td></tr>
<tr><td>Weather normalization</td><td>○ The weather normalization process to determine WNP's weather sensitive load uses daily heating degree days (HDD) and cooling degree days as measured at Environment Canada's weather station at Mount Forest, Ontario which is the nearest station to the LDC's service territory.</td></tr>
</table>

The above methodology was used to produce the hourly demand data for 2018 (January 1st to December 31st). The same methodology was used to extract and produce the hourly demand data for 2019 (January 1st to December 31st).

Hourly Data Compilation by Customer Class:

The hourly data used in the demand profile is the same as used for billing customers.

The Demand Profile Data used is calculated based upon the metered usage and energization status:

a) Customers who closed their account during the year were included up to the point they were responsible for the usage at the premises. The demand profile data is based on meters at properties, not accounts. For example:
   - If customer A sold the property with a move-out date of May 31st 2018, they are still responsible for payment of the hydro account up to this date.
   - Customer B purchases the property and moves in on June 1st 2018. This person is required to sign a hydro agreement form and is responsible for the electricity account from this date.
   - In this example, the meter has not been disconnected and it is still the same meter.
   - In the demand profile data set, the data is assigned to a USPID (a Unique Supply Point I.D. attached to a specific meter at the property – the meter has a unique ID known by the LDC). In this example, in the demand profile data set, the metered data would be continuous (i.e. every day and every hour) as there is no break in supply (i.e. the meter was not disconnected).
   - If customer A sold the property and moved out on May 31st 2018 and the new owner, customer B, took possession on June 1st but did not move in until August 1st, then customer B could arrange for a supply disconnection to avoid minimum usage and delivery fees for the months of June and July when the property was vacant. If the property is disconnected, then there would be zero (nil) metered data during the disconnection period. This zero data would continue until the meter was physically reconnected and there was usage at the property.

b) If the property is a brand new development, then because a new meter has been installed, the data would be available from the date of energization.
   If the property is an existing property with a meter, then the meter would already be included in the demand profile data set. As mentioned above in a), unless the meter was disconnected, it will still be transmitting data including 0 interval data as well as meter readings.

c) Customer Reclassification: In the instance where there is a customer reclassification because a customer's demand has fallen outside the upper or lower limits applicable to the customer's current rate class, set-out below is how the USF's Demand Profile model would handle the data:

Assumptions:

i. In January 2019, the LDC reviews a GS<50 kW customer's monthly kW demand data for the period January 2018 to December 2018.
The GS 50 kW customer's monthly kW demand has been over 50 kW for 5 or more consecutive months of 2018.
The LDC decides to reclassify the customer to rate class GS50-999 kW. The utility writes to the customer at least one billing cycle before the reclassification takes effect for billing.

ii. The LDC will schedule to change the meter at the customer's premises from a Smart Meter to a MIST meter. Assuming the meter change happens at 11:00 am on February 26th 2019, the LDC will bill the customer as a GS<50 kW account up to 11:00 am on February 26th 2019. From 11.01 am on February 26th 2019 onwards the LDC will bill the customer as a GS 50-999 kW customer.

Settlement:

iii. Up to 11:00 am on February 26th 2019, the meter will be registered with the MDM/R and the LDC's Operational Data Store (ODS). After this time, the meter will be "de-registered" from MDM/R as this database does not handle non-Residential or non GS<50 kW accounts.

iv. For the LDC, the meter will be set-up as a MIST customer with the utility's third-party settlement provider effective from 11:01 am on February 26th 2019.

USF Demand Profile – data sources:

v. The LDC will acquire the hourly demand from its' ODS provider for each GS<50 kW meter for the year 2019. This data extract will include the metered demand data for the re-classified customer for the period of Hour 1 of January 1st 2019 to Hour 11 (11am) of February 26th 2019. As the customer was reclassified to a GS50-999 kW rate class from 11am on February 26th 2019, there will be no data after this point in time.

vi. The LDC will acquire the hourly demand data from Utilismart for all GS50-999 kW customers for 2019. In this data extract, there will be the hourly demand data for the reclassified customer for the period 11:00 am February 26th 2019 onwards. (For the period Hour 1 January 1 2019 to Hour 10 February 26th 2019, there will be no demand data for this customer's meter as during this time, the customer was not a GS 50-999 kW).

In summary, the data in the demand profile data set will be attributed to the customer's rate class at that specific point in time. Using the example the above, the demand profile for the re-classified customer would appears as:

Figure 15: kW Hourly – Customer 'X'; Meter "WN123"

Re-classified customer	February 26th Hour Ending 9	February 26th Hour Ending 10	February 26th Hour Ending 11	February 26th Hour Ending 12	February 26th Hour Ending 13	February 26th Hour Ending 14
GS<50 kW	14 kW	15 kW	16 kW	-	-	-
GS 50-999 kW	-	-	-	15 kW	16 kW	17 kW

Assumptions Applied:

a) Residential and General Service <50kW:
- 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.:

Figure 16: Average kW Demand Over the Hourly Interval Period

Time	12:15	12:30	12:45	1:00	Average Demand
15 minute kW recorded	6	7	10	8	7.75 kW/h

b) General Service 50-999kW and General Service 1000-4999kW:
- Metered usage:
  The demand profile is based on metered usage (no loss applied).
- Multipliers:
  Any meter multipliers were also applied to the hourly demand profile. For instance, if the meter has a multiplier of 30, for billing, all meter data has to be multiplied by 30 to show the true demand and usage of the customer. The demand profile data used reflects the application of the meter multiplier being used.
- Customer switching:
  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 each January by WNP with the utility reviewing each customer's monthly kW demand for the prior 5 consecutive

months. And, 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.
No customers switched from General Service 50-999kW to General Service 1,000-4,999kW in 2018 or 2019.
No customers switched from General Service 1,000-4,999kW to General Service 50-999kW in 2018 or 2019.

The above assumptions were used to produce the hourly demand data for 2018 (January 1st to December 31st). The same assumptions were used to produce the hourly demand data for 2019 (January 1st to December 31st).

No measures have been taken to address the potential difference in lines losses between rate-classes. Metered data is the data captured at the customer's premises and does not include line-losses. By using metered data, one could argue the data is not affected or distorted by potentially differing line losses due to varying physical distances from the supply source.

Data Comparison:

The tables below illustrate the variances between the aggregated load profile versus the annual RRR filings[7] for each rate class for years 2018 and 2019:

Figure 17: Year: 2018 – Annual kWh

Rate Class	Demand Profile	RRR Filings	*Variance*
Residential	25,345,905	25,359,188	*-0.05%*
General Service <50 kW	11,582,140	11,564,095	*0.16%*
General Service 50-999 kW	18,316,320	18,305,428	*0.06%*
General Service 1,000-4,999 kW	43,913,956	43,918,718	*-0.01%*
Street Lights	691,015	691,015	*0.00%*
Sentinel Lighting	19,673	19,673	*0.00%*
Unmetered Scattered Load	6,801	6,801	*0.00%*

Figure 18: Year: 2019 – Annual kWh

Rate Class	Demand Profile	RRR Filings	*Variance*
Residential	25,242,540	25,253,896	*-0.04%*
General Service <50 kW	11,109,758	11,138,172	*-0.26%*
General Service 50-999 kW	18,739,595	18,739,880	*0.00%*
General Service 1,000-4,999 kW	42,766,148	42,766,148	*0.00%*
Street Lights	652,367	650,270	*0.32%*
Sentinel Lighting	19,673	19,673	*0.00%*
Unmetered Scattered Load	6,344	6,288	*0.89%*

The "Demand Profile" data, sourced from ODS and Utilismart, as illustrated in the above tables have not been weather normalized at this stage.

For the Residential and GS<50kW rate classes, the variances probably relate to VEE[8] data adjustments to meet MDM/R requirements. VEE data adjustments are validation, estimating or editing of interval metered data. The Operational Data Storage provider (ODS) validate interval data to ensure its completeness (i.e. no missing intervals) and tolerance parameters (i.e. no exceptionally high or low usage for the interval period when compared to the same period last week, month or year). Through their routine validation checks, ODS may adjust the interval data to fill-in missing interval periods. Once validation checks have been performed and data is complete, the data is sent to MDM/R. The MDM/R will then perform their own checks for conformity and completeness. If MDM/R validation checks are passed, the LDC can use the data for billing; if the validation checks identify issues, then the data for those specific meters require re-work by the LDC and/or ODS. During the journey of this data-cycle from the meter, to the ODS

[7] Annual RRR filings 2.1.5 Performance Based Regulation – Demand And Revenue
[8] VEE is Validation, Editing and Estimation of data collected by Advanced Metering Infrastructure (AMI) and stored in the IESO's MDM/R database.

and MDMR, one could expect some data anomalies or inconsistencies; however, the tables above illustrate there are minimal variances between the annual kWh and annual RRR filings data.

For WNP, Utilismart collects and stores kW demand data and kWh consumption usage data for rate classes GS50-999kW, GS1,000-4,999kW and Streetlights. For rate classes GS50-999kW, GS1,000-4,999kW, each customer's meter downloads data daily using a telephone line or a cellular device to transmit data from the meter to Utilismart. The data is typically transmitted after midnight and contains the data for the previous day. If the data does is not transmitted or is incomplete, then Utilismart will attempt to retrieve the data the following day. This process is repeated each day until there is a complete data for that particular day. Upon the rare occasion there is a missing interval period, Utilismart and WNP can manually enter data to get a complete interval data-set for the day.

The above tables illustrate the variances between "Annual kWh" compared to "RRR filings" for years 2018 and 2019. For rate classes GS50-999, GS1,000-4,999kW and Streetlights the variances is below a fraction of 1 % and, in WNP's opinion, there are no data gaps or abnormalities that need addressing.

The IESO Meter Data Management/Repository (MDM/R) has not been considered as a data source. MDM/R collects data and validates for Smart Meter metered customers only, i.e. rate classes Residential and GS<50kW, typically with hourly data interval periods. For larger and more intensive electricity consuming customers, (e.g. manufacturing plants), interval metered data may be as frequent as 5-minute-period so as to measure peak demand periods with precision. Also, LDCs use a combination of kW demand and kWh consumption to bill rate classes GS50 and above. MDM/R does not hold kW demand data.

Weather Normalization

Two adjustments were made to the aggregated hourly consumption data by rate class in order to weather-normalize the data:

1. An adjustment to remove the estimated weather-sensitive portion of the load for each hour, based on Heating Degree Day (HDD) and Cooling Degree Day (CDD) components of the load forecast presented in Exhibit 3; and,
2. An adjustment to add an estimate of "weather-normal" load, based on 10-year average HDD and CDD values.

Each of the above adjustments is described in more detail below.

Remove Actual Weather-Sensitive Load

WNP's load forecast, presented in Exhibit 3[9] of this rate application, provides monthly Wholesale Predicted kWh Purchases for each month in 2018 to 2019, based on actual historical HDD and CDD data, using the following formula:

Predicted kWh = Intercept + B1*HDD + B2*CDD + B3*# of Days in Month + B4*Regional Employment + B5*CDM + B6*Sensitive Customers

The amount of weather-sensitive consumption for each month was estimated using the following formulas:

HDD Load = Predicted kWh – Predicted kWh $_{HDD=0}$

HDD% = HDD Load / Predicted kWh

CDD Load = Predicted kWh – Predicted kWh $_{CDD=0}$

CDD% = CDD Load / Predicted kWh

The above calculations were completed for each month of 2018 and 2019.

[9] Refer to Exhibit 3 of filing EB-2020-0061 for further explanation of load forecast equation and variables]

The tables below illustrate the Wholesale Predicted kWh Purchases for 2018 and 2019 from the Applicant's load forecast and the effect of weather-sensitive consumption by removing HDD and CDD:

Figure 19: 2018 Weather Sensitive Load (kWh)

	Predicted Purchases **with HDD**	Predicted Purchases **without HDD**	HDD%	Predicted Purchases **with CDD**	Predicted Purchases **without CDD**	CDD %
Jan-18	10,048,519	7,988,853	20%	10,048,519	10,048,519	0%
Feb-18	8,803,125	7,193,630	18%	8,803,125	8,803,125	0%
Mar-18	9,528,337	7,887,670	17%	9,528,337	9,528,337	0%
Apr-18	8,888,832	7,549,231	15%	8,888,832	8,888,832	0%
May-18	8,675,875	8,364,159	4%	8,675,875	8,365,636	4%
Jun-18	8,176,046	8,055,256	1%	8,176,046	7,886,017	4%
Jul-18	8,522,480	8,493,906	0%	8,522,480	7,741,322	9%
Aug-18	9,035,782	9,020,976	0%	9,035,782	8,218,245	9%
Sep-18	8,319,904	8,091,571	3%	8,319,904	7,854,039	6%
Oct-18	8,970,269	8,090,450	10%	8,970,269	8,890,435	1%
Nov-18	9,099,632	7,621,837	16%	9,099,632	9,099,632	0%
Dec-18	8,708,086	7,087,940	19%	8,708,086	8,708,086	0%
	106,776,885	**95,445,480**		**106,776,885**	**104,032,223**	

Figure 20: 2019 Weather Sensitive Load (kWh)

	Predicted Purchases **with HDD**	Predicted Purchases **without HDD**	HDD%	Predicted Purchases **with CDD**	Predicted Purchases **without CDD**	CDD %
Jan-19	10,085,439	7,880,566	22%	10,085,439	10,085,439	0%
Feb-19	8,864,590	7,072,221	20%	8,864,590	8,864,590	0%
Mar-19	9,562,280	7,811,149	18%	9,562,280	9,562,280	0%
Apr-19	8,642,505	7,570,981	12%	8,642,505	8,642,505	0%
May-19	8,451,208	7,861,415	7%	8,451,208	8,441,102	0%
Jun-19	7,847,343	7,664,989	2%	7,847,343	7,681,613	2%
Jul-19	8,604,315	8,587,171	0%	8,604,315	7,669,554	11%
Aug-19	8,429,884	8,364,683	1%	8,429,884	8,093,370	4%
Sep-19	8,048,752	7,812,627	3%	8,048,752	7,915,359	2%
Oct-19	8,643,889	7,880,703	9%	8,643,889	8,622,667	0%
Nov-19	8,878,569	7,380,253	17%	8,878,569	8,878,569	0%
Dec-19	8,678,176	6,996,727	19%	8,678,176	8,678,176	0%
	104,736,951	**92,883,486**		**104,736,951**	**103,135,224**	

The percentages (%) are calculated using predicted total purchases as the denominator as opposed to actual total purchases. The "Predicted" kWh total purchases are derived from the Applicant's Load Forecast which have been weather-normalized. If the "Actual" total purchases were used, there may be risk of using isolated instances of unseasonal weather temperatures which may skew results if an LDC was reliant on using only 1 year of demand data.

For example, in Ontario in September 2018, the province experienced an "Indian summer" or "late summer" with several days registering higher temperatures than July and August. Air-conditioning in residential properties in September 2018 increased energy demand above normal seasonal levels typically seen in July and August. By using the predicted total purchases, the data is normalized thus removing these isolated instances.

The resulting HDD% and CDD% values for each month were used to estimate the non-weather-sensitive (NWS) load for each hour by:

$$\text{HDD Adj}_{\text{Month N, Day, N, Hour N}} = \text{Actual Load}_{\text{Month N, Day N, Hour N}} * \text{HDD\%}_{\text{Month N}}$$

$$\text{CDD Adj}_{\text{Month N, Day, N, Hour N}} = \text{Actual Load}_{\text{Month N, Day N, Hour N}} * \text{CDD\%}_{\text{Month N}}$$

$$\text{NWS Load}_{\text{Month N, Day N, Hour N}} = (\text{Actual Load - HDD Adj - CDD Adj})_{\text{Month N, Day N, Hour N}}$$

Add Weather-Normal Load

For 2018, the daily HDD values for the 10-year HDD data 2010-2019 period were sorted from highest to lowest by each month. Once sorted, averages of each ranked day were considered to be weather-normal values for HDD. The table below illustrates the methodology applied:

Figure 21: 10 Year HDD Weather-Normal Adjustment

			January 2010 - Sorted					*January 2011 - Sorted*					*January 2018 - Sorted*				
Date	**10-Yr Avg HDD**	**10 Yr Avg to 2019**	**Date/Time**	**Year**	**Month**	**Day**	**Heat Deg Days (°C)**	**Date/Time**	**Year**	**Month**	**Day**	**Heat Deg Days (°C)**	**Date/Time**	**Year**	**Month**	**Day**	**Heat Deg Days (°C)**
31-Jan-19	36.33	0.96	1/29/2010	2010	1	29	35.10	1/23/2011	2011	1	23	38.70	1/6/2018	2018	1	6	39.60
30-Jan-19	35.60	0.94	1/30/2010	2010	1	30	34.60	1/31/2011	2011	1	31	37.50	1/5/2018	2018	1	5	39.20
20-Jan-19	33.97	0.93	1/2/2010	2010	1	2	33.70	1/24/2011	2011	1	24	33.40	1/1/2018	2018	1	1	35.60
21-Jan-19	32.98	0.91	1/9/2010	2010	1	9	32.90	1/22/2011	2011	1	22	32.90	1/13/2018	2018	1	13	34.00
19-Jan-19	31.79	0.95	1/3/2010	2010	1	3	31.60	1/20/2011	2011	1	20	32.50	1/4/2018	2018	1	4	33.80
28-Jan-19	30.88	0.94	1/28/2010	2010	1	28	29.70	1/30/2011	2011	1	30	32.50	1/30/2018	2018	1	30	32.20
26-Jan-19	30.39	0.93	1/10/2010	2010	1	10	29.50	1/16/2011	2011	1	16	32.30	1/3/2018	2018	1	3	31.60
27-Jan-19	29.41	0.94	1/4/2010	2010	1	4	29.20	1/21/2011	2011	1	21	30.20	1/14/2018	2018	1	14	31.30
11-Jan-19	29.03	0.93	1/8/2010	2010	1	8	29.00	1/13/2011	2011	1	13	30.10	1/2/2018	2018	1	2	30.40
22-Jan-19	28.23	0.92	1/5/2010	2010	1	5	27.60	1/19/2011	2011	1	19	29.60	1/7/2018	2018	1	7	29.80
13-Jan-19	27.65	0.94	1/31/2010	2010	1	31	27.50	1/7/2011	2011	1	7	29.40	1/24/2018	2018	1	24	29.10
17-Jan-19	27.32	0.94	1/12/2010	2010	1	12	27.40	1/9/2011	2011	1	9	29.30	1/17/2018	2018	1	17	28.50
10-Jan-19	26.95	0.94	1/11/2010	2010	1	11	27.00	1/17/2011	2011	1	17	29.30	1/15/2018	2018	1	15	28.40
29-Jan-19	26.63	0.93	1/21/2010	2010	1	21	26.30	1/8/2011	2011	1	8	29.00	1/16/2018	2018	1	16	27.90
25-Jan-19	26.08	0.92	1/6/2010	2010	1	6	26.10	1/10/2011	2011	1	10	28.60	1/25/2018	2018	1	25	26.90
12-Jan-19	25.61	0.91	1/20/2010	2010	1	20	25.90	1/29/2011	2011	1	29	28.50	1/18/2018	2018	1	18	26.70
16-Jan-19	24.83	0.93	1/1/2010	2010	1	1	25.50	1/5/2011	2011	1	5	27.50	1/29/2018	2018	1	29	25.80
14-Jan-19	24.28	0.93	1/7/2010	2010	1	7	25.50	1/12/2011	2011	1	12	27.40	1/31/2018	2018	1	31	24.10
18-Jan-19	23.62	0.90	1/27/2010	2010	1	27	24.50	1/6/2011	2011	1	6	26.90	1/9/2018	2018	1	9	22.40
2-Jan-19	22.98	0.89	1/13/2010	2010	1	13	23.20	1/14/2011	2011	1	14	26.20	1/19/2018	2018	1	19	21.30
1-Jan-19	22.45	0.96	1/19/2010	2010	1	19	21.80	1/11/2011	2011	1	11	26.00	1/8/2018	2018	1	8	20.70
9-Jan-19	22.08	0.98	1/18/2010	2010	1	18	21.60	1/15/2011	2011	1	15	25.00	1/28/2018	2018	1	28	20.60
6-Jan-19	21.55	0.98	1/26/2010	2010	1	26	21.30	1/28/2011	2011	1	28	25.00	1/23/2018	2018	1	23	20.40
15-Jan-19	20.97	0.95	1/17/2010	2010	1	17	21.10	1/3/2011	2011	1	3	24.50	1/12/2018	2018	1	12	19.80
24-Jan-19	20.39	0.94	1/22/2010	2010	1	22	20.80	1/2/2011	2011	1	2	24.40	1/10/2018	2018	1	10	18.30
8-Jan-19	19.89	0.93	1/23/2010	2010	1	23	20.80	1/25/2011	2011	1	25	23.80	1/26/2018	2018	1	26	18.30
3-Jan-19	19.28	0.93	1/16/2010	2010	1	16	20.70	1/27/2011	2011	1	27	23.50	1/20/2018	2018	1	20	17.50
4-Jan-19	18.75	0.92	1/14/2010	2010	1	14	20.30	1/26/2011	2011	1	26	22.80	1/21/2018	2018	1	21	17.40
7-Jan-19	18.02	0.90	1/15/2010	2010	1	15	18.20	1/4/2011	2011	1	4	22.10	1/22/2018	2018	1	22	15.80
5-Jan-19	16.86	0.86	1/25/2010	2010	1	25	16.60	1/18/2011	2011	1	18	21.40	1/27/2018	2018	1	27	15.20
23-Jan-19	14.86	0.84	1/24/2010	2010	1	24	16.50	1/1/2011	2011	1	1	16.20	1/11/2018	2018	1	11	10.30

The above table shows:

- HDD data for January 2010 sorted by largest to smallest.
- HDD data for January 2011 sorted by largest to smallest.
- HDD data for January 2012 to 2019 was also collected and sorted - not illustrated in table above).

- By sorting the HDD data, these dates are now in order of the January 2019 HDD data sorted by largest to smallest. In the table above, January 31 was the coldest day during January 2019.
- The "10 Yr Avg HDD" is the 10-year average HDD. Each month (January in this instance) of each year has been sorted by HDD largest to smallest. The average of the 10 highest HDD values for January 2010 to 2019 was considered to be the weather-normal HDD value for the coldest day in January. In this example, the coldest HDD was 36.33.
- The "10 Yr Avg to 2019" calculates the 10-year average HDD divided by the 2019 HDD. In this instance, for January 31st 2019 the calculation is 36.33 / 37.90 = 0.96. The purpose of this calculation is to adjust the 2018 Demand Profile data for each day (in this example January 31st) by this factor to weather normalize the demand data.

The same sorting and averaging process was repeated to determine weather-normal CDD values.

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 2010 to 2019; and
- 2019 is derived from the 10-year period of 2010 to 2019[10].

(As the Applicant has also collected hourly demand data for 2019, the same approach described above has been used using 10-year HDD and CDD daily data for years 2010 to 2019.)

The estimated weather-normal (WN) load for each hour was then calculated by:

WN HDD Adj $_{\text{Month N, Sorted Day N, Hour N}}$

= HDD Adj $_{\text{Month N, Sorted Day N, Hour N}}$ multiplied by (WN HDD / Actual HDD) $_{\text{Month N, Sorted Day N}}$

WN CDD Adj $_{\text{Month N, Sorted Day N, Hour N}}$

= CDD Adj $_{\text{Month N, Sorted Day N, Hour N}}$ multiplied by (WN CDD / Actual CDD) $_{\text{Month N, Sorted Day N}}$

WN Load $_{\text{Month N, Sorted Day N, Hour N}}$

= (NWS Load + WN HDD Adj + WN CDD Adj) $_{\text{Month N, Sorted Day N, Hour N}}$

[10] In EB-2020-0061 Interrogatories 7-VECC-49 and OEB Staff (Interrogatory 7-Staff-72) viewed that the "same" 10-year average period of 2010 to 2019 should be used to define weather normal for the load profiles of both 2018 and 2019

The tables below illustrates the effect of weather normalization:

Figure 22: 2018 Weather Normalization (kWh)

Rate Class	Demand Profile	Weather Normalization	*Effect*
Residential	25,345,905	24,839,344	*-2.00%*
General Service <50 kW	11,582,140	11,344,503	*-2.05%*
General Service 50-999 kW	18,316,320	17,918,406	*-2.17%*
General Service 1,000-4,999 kW	43,913,956	43,913,956	*0.00%*
Street Lights	691,015	691,015	*0.00%*
Sentinel Lighting	19,673	19,673	*0.00%*
Unmetered Scattered Load	6,801	6,801	*0.00%*

Figure 23: 2019 Weather Normalization (kWh)

Rate Class	Demand Profile	Weather Normalization	*Effect*
Residential	25,242,540	24,852,891	*-1.54%*
General Service <50 kW	11,109,758	10,935,590	*-1.57%*
General Service 50-999 kW	18,739,595	18,434,747	*-1.63%*
General Service 1,000-4,999 kW	42,766,148	42,766,148	*0.00%*
Street Lights	652,367	652,367	*0.00%*
Sentinel Lighting	19,673	19,673	*0.00%*
Unmetered Scattered Load	6,344	6,344	*0.00%*

Rate classes General Service 1,000-4,999 kW, Street Lights, Sentinel Lighting and Unmetered Scattered Load (USL) are not weather-sensitive and therefore the hourly demand for these rate classes were not weather normalized. Customers or connections in these rate-classes do not adjust their electricity demand due to weather temperature fluctuations, for instance:

a) A manufacturing company in rate-class GS 1,000-4,999 kW will continue to operate plant machinery despite warmer than normal summer temperatures; and
b) Street lights will still come on in the winter despite of cooler than normal temperatures.

After weather-normalizing the hourly load profiles for each rate class for 2018 to 2019, the data was re-sorted in chronological in order.

Scaling to Test Year Load Forecast (Wholesale Purchases)

As WNP's load forecast is by wholesale predicted kWh purchases, the weather normalized data was scaled to match the Test Year Load Forecast. In essence, this takes the daily demand weather normalized profile (or shape) for each rate class and adjusts it to match the Test Year predicted Load Forecast for each rate class using the formula:

$$= \frac{\text{Daily Weather Normalized Load}}{\text{Annual Weather Normalized Load}} \times \text{Test Year Load Forecast}$$

The tables below illustrate the change between the rate class hourly demand data (annualized) as collected by the LDC, the impact of weather normalization on the hourly demand data (annualized) and the Test Year Load Forecast:

Figure 24: 2018 Weather Normalization (kWh) & Test Year Load Forecast

Rate Class	**Demand Profile**	**Weather Normalization**	*Test Year Load Forecast*	*Test Year Load Forecast Compared to Actual Demand*
Residential	25,345,905	24,839,344	25,765,404	*1.7%*
GS <50 kW	11,582,140	11,344,503	11,136,665	*-3.8%*
GS 50-999 kW	18,316,320	17,918,406	18,284,534	*-0.2%*
GS 1,000-4,999 kW	43,913,956	43,913,956	42,766,148	*-2.6%*
Street Lights*	691,015	691,015	229,833	*-66.7%*
Sentinel Lighting	19,673	19,673	19,673	*0.0%*
USL	6,801	6,801	6,288	*-7.5%*

Figure 25: 2019 Weather Normalization (kWh) & Test Year Load Forecast

Rate Class	**Demand Profile**	**Weather Normalization**	*Test Year Load Forecast*	*Test Year Load Forecast Compared to Actual Demand*
Residential	25,242,540	24,852,891	25,765,404	*2.1%*
GS <50 kW	11,109,758	10,935,590	11,136,665	*0.2%*
GS 50-999 kW	18,739,595	18,434,747	18,284,534	*-2.4%*
GS 1,000-4,999 kW	42,766,148	42,766,148	42,766,148	*0.0%*
Street Lights*	652,367	652,367	229,833	*-64.8%*
Sentinel Lighting	19,673	19,673	19,673	*0.0%*
USL	6,344	6,344	6,288	*-0.9%*

Note:
In Quarter 4 of 2019, WNP replaced all high-pressure sodium (HPS) lights used in the streetlights with light-emitting diodes (LEDs). The above tables show the actual demand profile for 2018 and 2019 streetlights with the HPS lights (pre-LED conversion); whereas the Test Year Load Forecast is based on calculated demand with streetlights with LED lights. This LED conversion explains the significant variance between the Demand Profile and Test Year Load Forecast for the streetlights rate class.

Once the data has been scaled to the Test Year Load Forecast, it is now possible to calculate the required NCP and CP values for input to Tab I8 of the OEB's Cost Allocation Model.

Determine NCP and CP Values

After calculating weather-normalized load profiles by rate class for each year of 2018 to 2019, the monthly non-coincident peak demand was identified for each rate class, and the 1NCP, 4NCP and 12 NCP were determined from these peak demand values.

To determine CP values, the weather-normalized load profiles by rate class were combined to calculate a total-system hourly load profile. The hour in each month during which WNP's system demand peaked was identified, and the demand for each rate class during these 12 monthly system peak hours was tabulated to determine 1CP, 4CP and 12 CP values.

Averaging of Annual NCP and CP Values

The various NCP and CP values for each year (2018 and 2019) were averaged for the purpose of determining the demand allocator inputs to Tab I8 of the OEB's Cost Allocation Model, as shown in the following tables:

Figure 26: Non-Coincident Peak: 2018, 2019 and Average of 2018 & 2019

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Lighting	Sentinel Lighting	USL
2018 Values:							
1 NCP	6,080	2,200	3,338	7,264	53	6	2
4 NCP	21,940	8,494	13,078	28,664	211	23	8
12 NCP	59,043	23,560	37,756	82,518	633	56	18
2019 Values:							
1 NCP	5,718	2,226	3,316	7,508	56	6	2
4 NCP	21,295	8,527	12,904	29,250	223	23	7
12 NCP	56,819	22,680	36,885	83,616	639	56	18
Average of 2018 and 2019 values:							
1 NCP	5,899	2,213	3,327	7,386	54	6	2
4 NCP	21,617	8,510	12,991	28,957	217	23	7
12 NCP	57,931	23,120	37,320	83,067	636	56	18

Figure 27: Coincident Peak: 2018, 2019 and Average of 2018 & 2019

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Lighting	Sentinel Lighting	USL
2018 Values:							
1 CP	4,258	1,984	2,963	6,990	0	0	0
4 CP	15,952	8,005	12,469	26,134	0	0	0
12 CP	44,714	22,072	35,459	78,571	105	7	4
2019 Values:							
1 CP	5,149	1,912	2,632	6,513	56	3	1
4 CP	18,674	7,528	10,918	25,114	152	11	4
12 CP	44,144	20,595	33,210	79,235	193	15	5
Average of 2018 and 2019 values:							
1 CP	4,704	1,948	2,798	6,751	28	2	1
4 CP	17,313	7,767	11,693	25,624	76	6	2
12 CP	44,429	21,333	34,335	78,903	149	11	4

The NCP and CP derived from the average of years 2018 and 2019 have been inputted into worksheet “I8 Demand Data” of the OEB’s Cost Allocation Model that was filed WNP’s application EB-2020-0061.

Appendix B – Feedback of USF's Demand Profile Methodology

In its' 2021 Cost of Service application (EB-2020-0061), WNP received interrogatory questions specific to the "USF Demand Profile Methodology". Below are the interrogatory questions and responses as provided by WNP.

(WNP acknowledges the support of the USF Demand Profile Working Group in drafting responses to the questions.)

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:

   Assumptions Applied:

   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."*[11]

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.

a) As requested, please see schedule below relating to monthly and annual values for Heating Degree Day (HDD) and Cooling Degree Day (CDD):

		Heating Degree Day												
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
	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 initial application).

[11] OEB Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Application, section "2.7.1 Cost Allocation Study Requirements", page 54

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.

Appendix C – USF Demand Profile Methodology: User Friendly

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."*[12]

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.

Set-out below are components that the USF Demand Profile Working group considered:

1) Weather-Normalizing Each Hour of a Particular Day

The USF working group did explore taking each hour of every day and performing hourly HDD and CDD regression for each rate class. In principle, this would look like:

Figure 28: Plotting of Hourly HDD and CDD Regression

		HDD						CDD						Dummy Variable					
Day	Hour	Hr 1	Hr 2	Hr 3	Hr 4	Hr 23	Hr 24	Hr 1	Hr 2	Hr 3	Hr 4	Hr 23	Hr 24	Hr 1	Hr 2	Hr 3	Hr 4	Hr 23	Hr 24
1-Jan	Hr 1	HDD						CDD						1					
	Hr 2		HDD						CDD						1				
	Hr 3			HDD						CDD						1			
	Hr 4				HDD						CDD						1		
	Hr23					HDD						CDD						1	
	Hr24						HDD						CDD						1
2-Jan	Hr 1	HDD						CDD						1					
	Hr 2		HDD						CDD						1				
	Hr 3			HDD						CDD						1			
	Hr 4				HDD						CDD						1		
	Hr23					HDD						CDD						1	
	Hr24						HDD						CDD						1

[12] OEB Filing Requirements for Electricity Distribution Rate Applications – 2020 Edition for 2021 Rate Application, section "2.7.1 Cost Allocation Study Requirements", page 54

Then take the output (i.e. HDD Hr 1) to run regression to calculate a coefficient for each hour which would be used to adjust the actual rate class demand for that hour for that particular day:

Figure 29: Illustration of Adjusted Demand using Hourly Coefficient

Day	Hour	HDD	CDD	Dummy	Result Coefficient for the hour	Actual Residential Demand	Adjusted Demand Coefficient x Actual Demand
1-Jan	Hr 1	Hr 1	Hr 1	1	x1	5.42	4.72
2-Jan	Hr 1	Hr 1	Hr 1	1	y1	5.11	4.45
3-Jan	Hr 1	Hr 1	Hr 1	1	z1	4.83	4.20
4-Jan	Hr 1	Hr 1	Hr 1	1	a1	5.56	4.84
5-Jan	Hr 1	Hr 1	Hr 1	1	b1	5.27	4.58
6-Jan	Hr 1	Hr 1	Hr 1	1	c1	4.93	4.29
				1			
1-Jan	Hr 2	Hr 2	Hr 2	1	x2	5.53	4.81
2-Jan	Hr 2	Hr 2	Hr 2	1	y2	5.21	4.53
3-Jan	Hr 2	Hr 2	Hr 2	1	z2	4.93	4.29
4-Jan	Hr 2	Hr 2	Hr 2	1	a2	5.67	4.93
5-Jan	Hr 2	Hr 2	Hr 2	1	b2	5.38	4.68
6-Jan	Hr 2	Hr 2	Hr 2	1	c2	5.03	4.37

In order to perform the above, the USF working group determined the following:

- Software limitations:
  In order to produce the HDD and CDD for each hour, 72 variables are required (i.e. HDD variable count = 24; CDD variable count = 24; and dummy variable count = 24).
  (Microsoft Excel has a limit of 16 variables.)

- Expertise and Use of a third-party:
  Obtaining information at a granular level of hourly weather-normalized by each rate class is extremely complex. LDC's would very likely need to outsource this activity to a third-party specialist (e.g. Elenchus as used in application EB-2017-0039). A third-party would have access to sophisticated software to produce this information.
  Citing WNP as an example LDC, we would need to outsource this activity to a third-party which, in our opinion, would mean the LDC would probably lose value of the importance or reasoning of this demand allocator data.

- "Black-box":
  By using a third-party to produce this information, the onus to standby the validity, accuracy and evidence would likely shift from the LDC (Applicant) to a third-party expert. Consequently, the LDC may have very limited knowledge about the output or its relevance in their rate application. In its essence, the rate application is "telling their story to the OEB/Intervenor" based on the LDC's experience, customer-preference and RRFE outcomes rather than the output from a "black box" solution.

- Costs versus benefit?

  The primary goal of the USF Working group was to develop a useable and understandable methodology that LDCs could use to produce the demand allocators input into the OEB's Cost Allocation model worksheet "I8. Demand" using latest customer demand data.

  In WNP's opinion, our rate-payers would not be satisfied with incurring additional costs for retaining a third-party to produce "demand allocator data" that has limited significance or bearing in the overall rate application. Our customers' trust us to manage a safe, reliable and cost-effective distribution system.

  For an LDC the size of WNP, retaining a third party to produce demand allocator data is estimated to result in a cost per customer of approx. $100.

- Availability of Hourly HDD/CDD weather data

  There has been no validation to confirm that the proportion of load due to HDD and CDD is equal in every hour of each given month. For its load forecast, WNP used the weather station located at Mount Forest[13], Ontario which is in the utility's service territory. 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; however this station is approx. 90 kilometers south-east from Mount Forest and its' weather conditions are likely to be different to those of WNP's service territory. For instance, on the evening of March 24th and into the early hours of March 25th 2016, there was a major ice storm that resulted in two-thirds of WNP's customers losing power (a weather event, not loss of supply) – on the same dates, there were no ice-storms reported in the Toronto region or surrounding areas. Notwithstanding the significant complexity associated with hourly regression analysis (see response to c) below), the USF working group was concerned that using a more distant weather station to refine HDD and CDD coefficients for each hour of the day could introduce further inaccuracies in all of the coefficients.

2) Individual Rate Class Load Forecast

The Applicant, WNP, did create individual load forecasts for each rate class based on 10-years of metered data. For each rate class load forecast, WNP removed HDD and CDD to determine the effect of weather-sensitive consumption for the predicted kWh purchases for 2018.

The results of the HDD% and CDD% for each metered rate-class are shown in the chart on the following page. This chart demonstrates that rate-classes GS50-999kW and GS1000-4999kW show minimal or no effect due to weather.

[13] Station: Mount Forest (ID 7844). Latitude 43°59'00.000" N; Longitude: 80°45'00.000" W; Elevation 414.50 m

The individual rate class load forecasts produced some poor regression results as summarized below:

Figure 30: Rate Class Load Forecast Rsq Results

Rate Class	Adjusted $R_{sq.}$
Residential	91%
GS<50kW	82%
GS 50-999kW	34%
GS 1000-4999kW	62%

(Note: The same set of coefficient variables of HDD, CDD, # of days in month, # of peak hours, CPI and regional employment were used in each rate-class forecast. The regression output results in negative coefficients.)

Due to poor regression results for some rate-classes, WNP has decided to revert back to the Wholesale Purchase data for its' Load Forecast as tried and tested in previous Cost of Service applications and accepted by both OEB Staff and Intervenors. Similarly, in consideration of the poor regression results at a rate class level, WNP was unable to validate class-specific weather sensitivity with a high degree of confidence and instead used the wholesale HDD and CDD coefficients for the purpose of weather normalizing historical load profiles.

Figure 31: Rate Class Load Forecast Predicted kWh Purchases for 2018 and the Effect of Weather-Sensitive Consumption by Removing HDD and CDD.

Residential

	Predicted Purchases with HDD	Predicted Purchases without HDD	% Var		Predicted Purchases with CDD	Predicted Purchases without CDD	% Var
Jan-18	2,643,598	2,215,169	19%	Jan-18	2,643,598	2,565,820	3%
Feb-18	2,189,387	2,165,897	1%	Feb-18	2,189,387	2,133,642	3%
Mar-18	2,372,177	2,300,011	3%	Mar-18	2,372,177	2,359,406	1%
Apr-18	2,142,399	2,213,653	-3%	Apr-18	2,142,399	2,158,426	-1%
May-18	1,786,753	2,080,904	-14%	May-18	1,786,753	1,781,354	0%
Jun-18	1,619,856	2,013,621	-20%	Jun-18	1,619,856	1,647,844	-2%
Jul-18	1,954,392	1,810,559	8%	Jul-18	1,954,392	1,709,598	14%
Aug-18	1,980,135	1,729,871	14%	Aug-18	1,980,135	1,711,735	16%
Sep-18	1,821,979	1,940,176	-6%	Sep-18	1,821,979	1,740,484	5%
Oct-18	2,023,697	2,067,181	-2%	Oct-18	2,023,697	2,090,336	-3%
Nov-18	2,281,979	2,024,152	13%	Nov-18	2,281,979	2,288,207	0%
Dec-18	2,424,627	2,192,938	11%	Dec-18	2,424,627	2,446,883	-1%
Total	**25,240,977**	**24,754,133**		**Total**	**25,240,977**	**24,633,737**	

General Service <50kW

	Predicted Purchases with HDD	Predicted Purchases without HDD	% Var		Predicted Purchases with CDD	Predicted Purchases without CDD	% Var
Jan-18	1,167,215	1,039,092	12%	Jan-18	1,167,215	1,145,476	2%
Feb-18	1,012,615	1,014,591	0%	Feb-18	1,012,615	996,904	2%
Mar-18	1,076,200	1,067,093	1%	Mar-18	1,076,200	1,072,342	0%
Apr-18	1,005,830	1,041,154	-3%	Apr-18	1,005,830	1,009,959	0%
May-18	887,695	994,825	-11%	May-18	887,695	885,677	0%
Jun-18	825,076	959,883	-14%	Jun-18	825,076	832,447	-1%
Jul-18	908,246	872,134	4%	Jul-18	908,246	839,277	8%
Aug-18	921,950	851,599	8%	Aug-18	921,950	846,305	9%
Sep-18	856,874	901,996	-5%	Sep-18	856,874	833,560	3%
Oct-18	954,270	977,276	-2%	Oct-18	954,270	972,275	-2%
Nov-18	1,041,141	968,227	8%	Nov-18	1,041,141	1,042,205	0%
Dec-18	1,051,078	986,060	7%	Dec-18	1,051,078	1,056,684	-1%
Total	**11,708,191**	**11,673,930**		**Total**	**11,708,191**	**11,533,112**	

General Service 50-999kW

	Predicted Purchases with HDD	Predicted Purchases without HDD	% Var		Predicted Purchases with CDD	Predicted Purchases without CDD	% Var
Jan-18	1,721,186	1,637,084	5%	Jan-18	1,721,186	1,716,925	0%
Feb-18	1,539,817	1,538,840	0%	Feb-18	1,539,817	1,536,514	0%
Mar-18	1,671,712	1,661,344	1%	Mar-18	1,671,712	1,670,566	0%
Apr-18	1,593,576	1,611,300	-1%	Apr-18	1,593,576	1,593,882	0%
May-18	1,519,491	1,583,159	-4%	May-18	1,519,491	1,518,795	0%
Jun-18	1,448,619	1,531,072	-5%	Jun-18	1,448,619	1,449,759	0%
Jul-18	1,433,724	1,403,675	2%	Jul-18	1,433,724	1,421,529	1%
Aug-18	1,526,683	1,475,162	3%	Aug-18	1,526,683	1,513,575	1%
Sep-18	1,453,091	1,476,213	-2%	Sep-18	1,453,091	1,449,246	0%
Oct-18	1,604,577	1,611,196	0%	Oct-18	1,604,577	1,608,060	0%
Nov-18	1,640,313	1,583,075	4%	Nov-18	1,640,313	1,640,870	0%
Dec-18	1,574,187	1,520,699	4%	Dec-18	1,574,187	1,575,579	0%
Total	**18,726,973**	**18,632,819**		**Total**	**18,726,973**	**18,695,302**	

General Service 1000-4999kW

	Predicted Purchases with HDD	Predicted Purchases without HDD	% Var		Predicted Purchases with CDD	Predicted Purchases without CDD	% Var
Jan-18	3,799,020	3,818,187	-1%	Jan-18	3,799,020	3,804,075	0%
Feb-18	3,519,570	3,522,465	0%	Feb-18	3,519,570	3,523,282	0%
Mar-18	3,734,120	3,739,380	0%	Mar-18	3,734,120	3,735,779	0%
Apr-18	3,574,539	3,572,341	0%	Apr-18	3,574,539	3,573,762	0%
May-18	3,912,383	3,902,404	0%	May-18	3,912,383	3,913,285	0%
Jun-18	3,779,084	3,763,716	0%	Jun-18	3,779,084	3,777,435	0%
Jul-18	3,587,573	3,591,805	0%	Jul-18	3,587,573	3,600,634	0%
Aug-18	3,976,322	3,986,516	0%	Aug-18	3,976,322	3,991,653	0%
Sep-18	3,612,565	3,606,788	0%	Sep-18	3,612,565	3,616,760	0%
Oct-18	3,826,416	3,823,347	0%	Oct-18	3,826,416	3,822,346	0%
Nov-18	3,600,325	3,607,605	0%	Nov-18	3,600,325	3,599,099	0%
Dec-18	3,007,642	3,010,983	0%	Dec-18	3,007,642	3,004,223	0%
Total	**43,929,560**	**43,945,539**		**Total**	**43,929,560**	**43,962,335**	

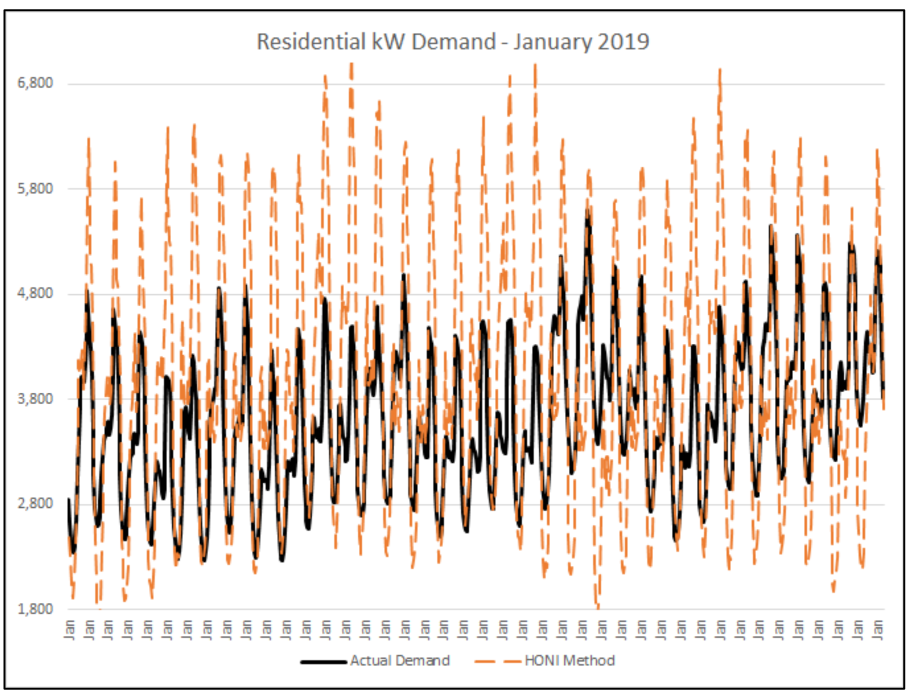
Appendix D – The Traditional HONI Method to Determine NCP and CP

The "USF Demand Profile Working Group" reviewed the Hydro One Networks Inc. (HONI) method as used in many rate applications since the 2006 EDR process. This method relies on 2004 interval LDC data based on work that was coordinated by the OEB and completed by Hydro One Networks Inc. in 2006. Upon reviewing the methodology applied by HONI, the "USF Demand Profile Working Group's" opinion was:

- The model was provided to each LDC and was hard-coded meaning that data or calculations could not be changed.
- The demand profile (or shape) has remained constant and has not been revised to account for events such as:
  - Energy conservation and use of energy efficient appliances or machinery;
  - Customers load-shifting their energy usage (using a washing a machine after 7pm (Off-Peak) rather than earlier in the day);
  - Increased use of technology and phantom power – i.e. more labour-saving technology devices being purchased by consumers; leaving phone chargers and devices plugged-in during the day.

The chart below illustrates WNP's Residential rate class actual hourly demand (not weather normalized) for the month of January 2019 overlaid with the hourly demand data weather-normalized using the HONI's demand profile shape:

Figure 32: Residential Demand (Jan 2019): Actual Demand versus HONI Method Weather-Normalized



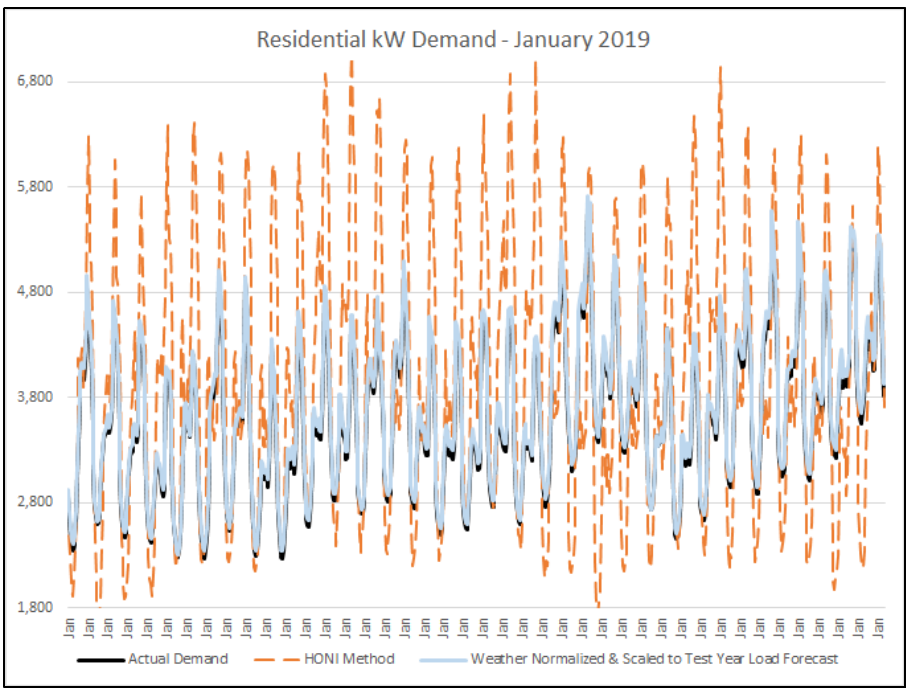
WNP acknowledges that the actual Residential Demand Data has not been weather-normalized; however, it is clear from the above chart that:

a) The HONI method, in this instance, has an exaggerated (stretched) demand profile (the dashed red line) extending beyond the actual demand not weather-normalized (black line) for the vast majority of days in January 2019.
b) For January 2019 actual Residential demand (the black-line) is typically lower than the HONI method (dashed red line).

The chart below illustrates WNP's Residential rate class actual hourly demand data for January 2019 by:

1) Actual hourly demand (not weather normalized) for the month of January 2019 (black-line);
2) Hourly demand data weather-normalized using HONI's method of 2004 data to create the demand profile shape and scaled to using the Test Year Load Forecast (dashed red line); and
3) Hourly demand data weather-normalized using the USF working group's methodology of weather normalizing actual January 2019 demand data and scaled to using the Test Year Load Forecast (blue line).

Figure 33: Residential Demand (Jan 2019): Actual Demand versus HONI Method Weather-Normalized and USF Hourly Weather-Normalized Method



The above chart shows:

a) Significant variance between the weather-normalized data between the HONI method and the USF's working group method. The HONI method (dashed red line) extends well beyond the actual demand weather-normalized (black line) for the majority of days in January 2019.
b) The weather normalized demand (blue line) has a very good resemblance (i.e. overlays near perfectly) to the actual demand (black line).

WNP did update the "HONI 2004 method" using the same methodology as applied in the Applicant's previous Cost of Service rate applications (e.g. EB-2015-0110). The table below shows the outcome of this approach using the latest actual data (2019) scaled to the Test Year Load Forecast:

Figure 34: HONI Method: Coincident Peak & Non-Coincident Peak Using 2019 Actual Data

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Lighting	Sentinel Lighting	USL
1 NCP	7,078	1,989	3,222	6,995	53	6	1
4 NCP	26,573	7,683	12,358	27,643	210	22	3
12 NCP	66,598	20,543	33,193	80,488	629	55	9
1 CP	6,175	1,237	2,181	6,866	53	5	1
4 CP	24,444	5,014	10,328	24,980	209	15	3
12 CP	60,771	12,511	28,229	77,529	471	39	9

The tables below illustrate the traditional "HONI Method" Non-Coincident Peak and Coincident Peak Results compared to the "USF Method":

Figure 35: Comparison of Methods: Non-Coincident Peak with 2019 Data

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Light	Sentinel Light	USL
HONI Method:							
1 NCP	7,078	1,989	3,222	6,995	53	6	1
4 NCP	26,573	7,683	12,358	27,643	210	22	3
12 NCP	66,598	20,543	33,193	80,488	629	55	9
USF Method:							
1 NCP	5,718	2,226	3,316	7,508	56	6	2
4 NCP	21,295	8,527	12,904	29,250	223	23	7
12 NCP	56,819	22,680	36,885	83,616	639	56	18
Variance:							
1 NCP	19%	-12%	-3%	-7%	-6%	-5%	-169%
4 NCP	20%	-11%	-4%	-6%	-6%	-5%	-149%
12 NCP	15%	-10%	-11%	-4%	-2%	-2%	-108%

Figure 36: Comparison of Methods: Coincident Peak with 2019 Data

	Residential	General Service <50 kW	General Service 50-999 kW	General Service 1,000–4,999 kW	Street Light	Sentinel Light	USL
HONI Method:							
1 CP	6,175	1,237	2,181	6,866	53	5	1
4 CP	24,444	5,014	10,328	24,980	209	15	3
12 CP	60,771	12,511	28,229	77,529	471	39	9
USF Method:							
1 CP	5,149	1,912	2,632	6,513	56	3	1
4 CP	18,674	7,528	10,918	25,114	152	11	4
12 CP	44,144	20,595	33,210	79,235	193	15	5
Variance:							
1 CP	17%	-55%	-21%	5%	-6%	24%	-58%
4 CP	24%	-50%	-6%	-1%	27%	28%	-25%
12 CP	27%	-65%	-18%	-2%	59%	62%	43%

In producing the above information, WNP used latest actual data (2019) scaled to the Test Year Load Forecast.

In reviewing the above tables, the Applicant notes that the traditional "HONI method" for determining both the Non-Coincident Peak and Coincident Peak calculates:

- Higher demand quantities for the Applicant's Residential customer class for 1CP, NCP and 12CP as well as 1NCP, 4NCP and 12NCP.
- Lower demand quantities for the Applicant's business rate classes (General Service <50kW; General Service 50-999kW and General Service 1000-4999kW) for 1CP, 4CP and 12CP as well as 1NCP, 4NCP and 12NCP.

One can assume from this analysis that electricity usage behaviour, particularly for Residential customers in the Applicant's service territory, has changed since the HONI 2004 profile was established. Perhaps this demand profile shift is a consequence of Smart meters whereby customers have shifted their energy usage to avoid On-Peak energy prices as much as possible.

Conclusion:

WNP believes that the USF's working group methodology provides a more realistic demand profile for its rate-classes based on recent demand data, weather data (HDD and CDD) averaged over 10-years and scaled to the Test Year forecast as per the load forecast used in the Application. Using a simpler approach (compared to methods used in other recent rate applications) that is supported by the load forecast used WNP's Application EB-2020-0061 will mean communicating how the USF's working group methodology is more understandable to all parties (OEB, Intervenors and rate-payers) and is reasonable in the calculation of demand allocators for use in the Cost Allocation Model's worksheet tab "I8 Demand Data".

Appendix E – Alternative Demand Profile Methods Considered

Demand Profiles Models used in Rate Applications

The "USF Demand Profile Working Group" also reviewed demand profile models included in recent rate applications, namely:

a) EB-2017-0039 Essex Powerlines Corp. application for 2018 rates.
b) EB-2017-0038 Erie Thames Powerlines application for 2018 rates.

In rate applications EB-2017-0039 and EB-2017-0038 the LDCs retained the third-party services of Elenchus Research Associates ("*Elenchus*") to complete a review of the Demand Allocators required in Tab I8 of the Cost Allocation model.

Upon reviewing the methodology applied by Elenchus, the USF working group's opinion was:

- The Elenchus model requires regression analysis software to perform regression analysis modelling using 72 variables per day (i.e. 24 hours per day with HDD, CDD and a dummy variable). (Microsoft Excel is limited to handling 16 variables per workbook).
- In the proceedings in which it was used, it appeared parties found it very difficult to understand. There were numerous questions from Intervenors about the methodology and it appeared to have complications that were difficult to explain.
- Included in the OEB's Decision & Order EB-2017-0039 for Essex Powerlines Corporation the Settlement Proposal noted that:

  > *"…in terms of the load profiles used, while Parties agree to accept the demand allocators proposed by EPLC for purposes of settlement as they are reasonable, there is no agreement that the methodology used to derive the values is appropriate"*[14]

From this statement, the USF working group assumes the OEB did not conclusively accept the model as presented by Elenchus.

[14] EB-2017-0039 Decision and Order, page 38, issued August 23rd 2018

Attachment 7-B

2017 Demand Profile Model (Excel Model Only)

Attachment 7-C

2018 Demand Profile Model (Excel Model Only)

Attachment 7-D

2019 Demand Profile Model (Excel Model Only)

Attachment 7-E

Cost Allocation Model (Excel

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Sheet I6.1 Revenue Worksheet - V1 - includes placeholders

Total kWhs from Load Forecast	928,196,629
Total kWs from Load Forecast	1,474,981
Deficiency/sufficiency (RRWF 8. cell F51)	- 4,397,115
Miscellaneous Revenue (RRWF 5. cell F48)	1,067,032

			1	**2**	**3**	**7**	**8**	**9**	**10**	**11**
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**	**Back-up/Standby Power**
Billing Data										
Forecast kWh	**CEN**	928,196,629	293,509,087	77,363,528	503,997,167	7,775,272	154,391	1,502,728	43,894,456	-
Forecast kW	**CDEM**	1,474,981	-	-	1,348,962	22,948	462		102,609	-
Forecast kW, included in CDEM, of customers receiving line transformer allowance		839,810			737,201.08				102,609	
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-								
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	878,272,205	293,509,087	77,363,528	497,967,199	7,775,272	154,391	1,502,728	-	-
Existing Monthly Charge			$24.35	$31.88	$245.54	$1.50	$4.39	$13.59	$375.73	
Existing Distribution kWh Rate				$0.0084				$0.0095		
Existing Distribution kW Rate					$2.9683	$6.2997	$21.0374		$2.0852	$2
Existing TOA Rate			$0.60	$0.60	$0.60	$0.60	$0.60	$0.60	$0.60	
Additional Charges										
Distribution Revenue from Rates		$18,886,568	$11,006,554	$1,790,407	$5,503,569	$248,442	$34,790	$79,829	$222,977	$0
Transformer Ownership Allowance		$503,886	$0	$0	$442,321	$0	$0	$0	$61,565	$0
Net Class Revenue	**CREV**	$18,382,682	$11,006,554	$1,790,407	$5,061,249	$248,442	$34,790	$79,829	$161,412	$0

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Sheet I6.2 Customer Data Worksheet - V1 - includes placeholders

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor	11 Back-up/Standby Power
Billing Data										
Bad Debt 3 Year Historical Average	BDHA	$634,490	$479,586	$72,215	$82,536	$0	$153	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$273,618	$ 202,419.78	$ 22,617.35	$ 48,162.16	$0	$ 41.59	$ 376.98	$0	
Number of Bills	CNB	499,221	452,015	35,776.44	6,106.72	12.00	475.73	4,823.62	12	
Number of Devices	CDEV					10,296	476	402		
Number of Connections (Unmetered)	CCON	6,649				5,771	476	402		
Total Number of Customers	CCA	42,039	37,668	2,981	509	1	476	402	2	-
Bulk Customer Base	CCB	42,039	37,668	2,981	509	1	476	402	2	
Primary Customer Base	CCP	42,893	37,668	2,981	509	855	476	402	2	
Line Transformer Customer Base	CCLT	42,814	37,668	2,973	440	855	476	402	-	
Secondary Customer Base	CCS	42,010	37,668	2,980	483	1	476	402	-	
Weighted - Services	CWCS	41,734	37,668	3,382	684	-	-	-	-	-
Weighted Meter -Capital	CWMC	14,993,176	10,927,690	2,408,439	1,657,046	-	-	-	-	-
Weighted Meter Reading	CWMR	40,875	37,667	2,874	334	-	-	-	-	-
Weighted Bills	CWNB	514,562	452,015	38,063	19,162	12	476	4,824	12	-

Bad Debt Data

		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
Historic Year:	2017	447,776	379,215	60,481	8,079	-	-	-	-	-
Historic Year:	2018	1,038,315	712,516	128,141	197,658	-	-	-	-	-
Historic Year:	2019	417,379	347,026	28,024	41,870	-	460	-	-	-
Three-year average		**634,490**	**479,586**	**72,215**	**82,536**	**-**	**153**	**-**	**-**	**-**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	37,668	327,211	37,668	327,211
Street Light	10,296	7,429	10,296	7,429

Street Lighting Adjustment Factors	
Primary	12.0388
Line Transformer	12.0388

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Sheet I8 Demand Data Worksheet - V1 - includes placeholders

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor	11 Back-up/Standby Power
		CP Sanity Check	Pass	Pass	Check 4CP and 12CP	Check 12CP	Check 12CP	Check 4CP and 12CP	Pass	Pass
CO-INCIDENT PEAK										
1 CP										
Transformation CP	TCP1	191,350	93,755	18,963	71,074	-	-	145	7,412	
Bulk Delivery CP	BCP1	191,350	93,755	18,963	71,074	-	-	145	7,412	
Total Sytem CP	DCP1	191,350	93,755	18,963	71,074	-	-	145	7,412	
4 CP										
Transformation CP	TCP4	699,923	304,835	65,443	301,043	-	-	589	28,013	
Bulk Delivery CP	BCP4	699,923	304,835	65,443	301,043	-	-	589	28,013	
Total Sytem CP	DCP4	699,923	304,835	65,443	301,043	-	-	589	28,013	
12 CP										
Transformation CP	TCP12	1,765,616	643,771	161,821	873,336	5,545	157	1,790	79,195	
Bulk Delivery CP	BCP12	1,765,616	643,771	161,821	873,336	5,545	157	1,790	79,195	
Total Sytem CP	DCP12	1,765,616	643,771	161,821	873,336	5,545	157	1,790	79,195	
NON CO_INCIDENT PEAK										
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP										
Classification NCP from Load Data Provider	DNCP1	226,674	100,804	22,329	91,051	1,857	39	259	10,334	
Primary NCP	PNCP1	226,674	100,804	22,329	91,051	1,857	39	259	10,334	
Line Transformer NCP	LTNCP1	203,934	100,803.82	22,268.97	78,705.83	1,857	39.25	259.24	-	
Secondary NCP	SNCP1	211,680	100,803.82	22,321.40	86,399.40	1,857	39.25	259.24	-	
4 NCP										
Classification NCP from Load Data Provider	DNCP4	795,610	327,211	72,455	351,639	7,429	157	984	35,735	
Primary NCP	PNCP4	795,610	327,211	72,455	351,639	7,429	157	984	35,735	
Line Transformer NCP	LTNCP4	712,003	327,211.04	72,260.48	303,960.87	7,429	156.99	984.26	-	
Secondary NCP	SNCP4	712,003	327,211.04	72,260.48	303,960.87	7,429	156.99	984.26	-	
12 NCP										
Classification NCP from Load Data Provider	DNCP12	2,006,842	737,809	181,325	965,985	22,144	471	2,572	96,537	
Primary NCP	PNCP12	2,006,842	737,809	181,325	965,985	22,144	471	2,572	96,537	
Line Transformer NCP	LTNCP12	1,137,315	737,808.91	72,260.48	303,960.87	22,144	156.99	984.26	-	
Secondary NCP	SNCP12	1,137,315	737,808.91	72,260.48	303,960.87	22,144	156.99	984.26	-	

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Sheet O1 Revenue to Cost Summary Worksheet - V1 - includes placeholders

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9	10	11
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
crev	Distribution Revenue at Existing Rates	$18,382,682	$11,006,554	$1,790,407	$5,061,249	$248,442	$34,790	$79,829	$161,412	$0
mi	Miscellaneous Revenue (mi)	$1,067,032	$741,392	$85,526	$198,965	$22,835	$3,044	$4,628	$10,643	$0
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	$19,449,714	$11,747,946	$1,875,932	$5,260,213	$271,277	$37,835	$84,457	$172,055	$0
	Factor required to recover deficiency (1 + D)	1.2392								
	Distribution Revenue at Status Quo Rates	$22,779,797	$13,639,308	$2,218,670	$6,271,893	$307,869	$43,112	$98,924	$200,022	$0
	Miscellaneous Revenue (mi)	$1,067,032	$741,392	$85,526	$198,965	$22,835	$3,044	$4,628	$10,643	$0
	Total Revenue at Status Quo Rates	$23,846,829	$14,380,700	$2,304,195	$6,470,858	$330,704	$46,156	$103,552	$210,664	$0
	Expenses									
di	Distribution Costs (di)	$3,441,815	$2,262,959	$295,746	$775,786	$47,021	$7,900	$7,534	$44,870	$0
cu	Customer Related Costs (cu)	$4,056,953	$3,451,429	$350,356	$230,171	$56	$2,426	$22,458	$56	$0
ad	General and Administration (ad)	$6,571,860	$4,908,251	$569,143	$966,956	$47,696	$9,945	$25,805	$44,064	$0
dep	Depreciation and Amortization (dep)	$4,019,354	$2,330,650	$395,157	$1,146,151	$70,331	$11,478	$10,899	$54,688	$0
INPUT	PILs (INPUT)	$608,487	$341,167	$56,114	$186,332	$11,508	$1,926	$1,830	$9,611	$0
INT	Interest	$1,873,131	$1,050,228	$172,738	$573,593	$35,426	$5,928	$5,633	$29,585	$0
	Total Expenses	$20,571,600	$14,344,683	$1,839,254	$3,878,988	$212,038	$39,603	$74,158	$182,875	$0
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$3,275,229	$1,836,358	$302,038	$1,002,945	$61,943	$10,365	$9,849	$51,731	$0
	Revenue Requirement (includes NI)	$23,846,829	$16,181,041	$2,141,292	$4,881,933	$273,981	$49,968	$84,008	$234,606	$0
		Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$106,132,405	$60,095,855	$10,026,452	$31,833,443	$2,004,805	$326,662	$310,180	$1,535,008	$0
gp	General Plant - Gross	$25,534,463	$14,280,430	$2,345,051	$7,857,556	$504,657	$82,199	$77,976	$386,595	$0
accum dep	Accumulated Depreciation	($29,354,945)	($17,160,784)	($2,979,304)	($8,201,635)	($480,666)	($79,082)	($75,369)	($378,105)	$0
co	Capital Contribution	($12,314,899)	($6,783,807)	($1,100,243)	($3,900,839)	($309,993)	($43,900)	($41,229)	($134,887)	$0
	Total Net Plant	$89,997,024	$50,431,694	$8,291,955	$27,588,525	$1,718,802	$285,879	$271,558	$1,408,611	$0
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$95,013,587	$31,702,332	$8,318,484	$53,505,028	$834,409	$16,569	$161,266	$475,498	$0
	OM&A Expenses	$14,070,628	$10,622,639	$1,215,245	$1,972,913	$94,773	$20,272	$55,797	$88,990	$0
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$109,084,215*	*$42,324,971*	*$9,533,729*	*$55,477,941*	*$929,182*	*$36,840*	*$217,063*	*$564,488*	*$0*
	Working Capital	$8,181,316	$3,174,373	$715,030	$4,160,846	$69,689	$2,763	$16,280	$42,337	$0
	Total Rate Base	$98,178,340	$53,606,066	$9,006,985	$31,749,370	$1,788,490	$288,642	$287,838	$1,450,948	$0
		Rate Base Input equals Output								
	Equity Component of Rate Base	$39,271,336	$21,442,427	$3,602,794	$12,699,748	$715,396	$115,457	$115,135	$580,379	$0
	Net Income on Allocated Assets	$3,275,229	$36,016	$464,942	$2,591,870	$118,666	$6,553	$29,393	$27,790	$0
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$3,275,229	$36,016	$464,942	$2,591,870	$118,666	$6,553	$29,393	$27,790	$0
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	88.87%	107.61%	132.55%	120.70%	92.37%	123.26%	89.80%	0.00%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($4,397,115)	($4,433,095)	($265,359)	$378,280	($2,704)	($12,134)	$449	($62,551)	$0
		Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($1,800,342)	$162,904	$1,588,925	$56,723	($3,812)	$19,544	($23,941)	$0
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.34%	0.17%	12.91%	20.41%	16.59%	5.68%	25.53%	4.79%	0.00%

Ontario Energy Board

2021 Cost Allocation Model

EB-2020-XXXX

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - V1 - includes placeholders

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9	10	11
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**	**Back-up/Standby Power**
Customer Unit Cost per month - Avoided Cost	$4.24	$6.74	$13.80	$0.00	$0.16	$2.04	-$6.48	0
Customer Unit Cost per month - Directly Related	$7.60	$11.14	$26.88	$0.00	$0.34	$3.90	-$5.41	0
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$25.96	$33.16	$91.77	$3.11	$8.74	$14.17	$2.61	0
Existing Approved Fixed Charge	$24.35	$31.88	$245.54	$1.50	$4.39	$13.59	$375.73	$0.00

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M	
1608	Franchises and Consents	Other Distribution Assets	gp				
1805	Land		dp	DDCP			
1805-1	Land Station >50 kV		dp	TCP	TCP4		
1805-2	Land Station <50 kV		dp	DCP	DCP4		
1806	Land Rights		dp	DDCP			
1806-1	Land Rights Station >50 kV		dp	TCP	TCP4		
1806-2	Land Rights Station <50 kV		dp	DCP	DCP4		
1808	Buildings and Fixtures		dp	DDCP			
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP4		
1808-2	Buildings and Fixtures < 50 KV		dp	DCP	DCP4		
1810	Leasehold Improvements		dp	DDCP			
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP4		
1810-2	Leasehold Improvements <50 kV		dp	DCP	DCP4		
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP4		
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP4		
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	DCP	DCP4		
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4		
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			CEN	
1825	Storage Battery Equipment		dp	DDCP			
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP4		
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP4		
1830	Poles, Towers and Fixtures		dp	DDNCP			
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP4		
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x
1835	Overhead Conductors and Devices		dp	DDNCP			
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP4		
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
1840	Underground Conduit		dp	DDNCP			
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP4		
1840-4	Underground Conduit - Primary	Land and Buildings	dp	PNCP	PNCP4	CCP	x
1840-5	Underground Conduit - Secondary	Land and Buildings	dp	SNCP	SNCP4	CCS	x
1845	Underground Conductors and Devices	Land and Buildings	dp	DDNCP			
1845-3	Underground Conductors and Devices - Bulk Delivery	TS Primary Above 50	dp	BCP	BCP4		
1845-4	Underground Conductors and Devices - Primary	DS	dp	PNCP	PNCP4	CCP	x
1845-5	Underground Conductors and Devices - Secondary	Other Distribution Assets	dp	SNCP	SNCP4	CCS	x
1850	Line Transformers	Poles, Wires	dp	LTNCP	LTNCP4	CCLT	x
1855	Services	Services and Meters	dp			CWCS	
1860	Meters	Services and Meters	dp			CWMC	
1905	Land	Land and Buildings	gp				
1906	Land Rights	Land and Buildings	gp				
1908	Buildings and Fixtures	General Plant	gp				
1910	Leasehold Improvements	General Plant	gp				
1915	Office Furniture and Equipment	Equipment	gp				
1920	Computer Equipment - Hardware	IT Assets	gp				
1925	Computer Software	IT Assets	gp				
1930	Transportation Equipment	Equipment	gp				
1935	Stores Equipment	Equipment	gp				
1940	Tools, Shop and Garage Equipment	Equipment	gp				
1945	Measurement and Testing Equipment	Equipment	gp				
1950	Power Operated Equipment	Equipment	gp				
1955	Communication Equipment	Equipment	gp				
1960	Miscellaneous Equipment	Equipment	gp				
1970	Load Management Controls - Customer Premises	Other Distribution Assets	gp				
1975	Load Management Controls - Utility Premises	Other Distribution Assets	gp				
1980	System Supervisory Equipment	Other Distribution Assets	gp				
1990	Other Tangible Property	Other Distribution Assets	gp				
1995	Contributions and Grants - Credit	Contributions and Grants	co		Break out	Breakout	
2005	Property Under Capital Leases	Other Distribution Assets	gp				
2010	Electric Plant Purchased or Sold	Other Distribution Assets	gp				
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Accumulated Amortization	accum dep		Break out	Breakout	
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Accumulated Amortization	accum dep		Break out	Breakout	

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
3046	Balance Transferred From Income	Equity	NI				
	blank row						
4080	Distribution Services Revenue	Distribution Services Revenue	CREV				
4082	Retail Services Revenues	Other Distribution Revenue	mi				
4084	Service Transaction Requests (STR) Revenues	Other Distribution Revenue	mi				
4086	SSS Admin Charge	Other Distribution Revenue	mi				
4090	Electric Services Incidental to Energy Sales	Other Distribution Revenue	mi				
4205	Interdepartmental Rents	Other Distribution Revenue	mi				
4210	Rent from Electric Property	Other Distribution Revenue	mi				
4215	Other Utility Operating Income	Other Distribution Revenue	mi				
4220	Other Electric Revenues	Other Distribution Revenue	mi				
4225	Late Payment Charges	Late Payment Charges	mi				
4235	Miscellaneous Service Revenues	Specific Service Charges	mi				
4235-1	Account Set Up Charges	Specific Service Charges	mi				
4235-90	Miscellaneous Service Revenues - Residual	Specific Service Charges	mi				
4240	Provision for Rate Refunds	Other Distribution Revenue	mi				
4245	Government Assistance Directly Credited to Income	Other Distribution Revenue	mi				
4305	Regulatory Debits	Other Income & Deductions	mi				
4310	Regulatory Credits	Other Income & Deductions	mi				
4315	Revenues from Electric Plant Leased to Others	Other Income & Deductions	mi				
4320	Expenses of Electric Plant Leased to Others	Other Income & Deductions	mi				
4325	Revenues from Merchandise, Jobbing, Etc.	Other Income & Deductions	mi				
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Other Income & Deductions	mi				
4335	Profits and Losses from Financial Instrument Hedges	Other Income & Deductions	mi				
4340	Profits and Losses from Financial Instrument Investments	Other Income & Deductions	mi				
4345	Gains from Disposition of Future Use Utility Plant	Other Income & Deductions	mi				
4350	Losses from Disposition of Future Use Utility Plant	Other Income & Deductions	mi				
4355	Gain on Disposition of Utility and Other Property	Other Income & Deductions	mi				
4360	Loss on Disposition of Utility and Other Property	Other Income & Deductions	mi				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
4365	Gains from Disposition of Allowances for Emission	Other Income & Deductions	mi				
4370	Losses from Disposition of Allowances for Emission	Other Income & Deductions	mi				
4375	Revenues from Non-Utility Operations	Other Income & Deductions	mi				
4380	Expenses of Non-Utility Operations	Other Income & Deductions	mi				
4390	Miscellaneous Non-Operating Income	Other Income & Deductions	mi				
4395	Rate-Payer Benefit Including Interest	Other Income & Deductions	mi				
4398	Foreign Exchange Gains and Losses, Including Amortization	Other Income & Deductions	mi				
4405	Interest and Dividend Income	Other Income & Deductions	mi				
4415	Equity in Earnings of Subsidiary Companies	Other Income & Deductions	mi				
4705	Power Purchased	Power Supply Expenses (Working Capital)	cop				
4708	Charges-WMS	Power Supply Expenses (Working Capital)	cop				
4710	Cost of Power Adjustments	Power Supply Expenses (Working Capital)	cop				
4712	Charges-One-Time	Power Supply Expenses (Working Capital)	cop				
4714	Charges-NW	Power Supply Expenses (Working Capital)	cop				
4715	System Control and Load Dispatching	Other Power Supply Expenses	cop				
4716	Charges-CN	Power Supply Expenses (Working Capital)	cop				
4730	Rural Rate Assistance Expense	Power Supply Expenses (Working Capital)	cop				
4750	Charges-LV	Power Supply Expenses (Working Capital)	cop				
4751	Charges - Smart Metering Entity	Power Supply Expenses (Working Capital)	cop			4751 C	
5005	Operation Supervision and Engineering	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x
5010	Load Dispatching	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x
5012	Station Buildings and Fixtures Expense	Operation (Working Capital)	di	1808 D	1808 D	1808 C	
5014	Transformer Station Equipment - Operation Labour	Operation (Working Capital)	di	1815 D	1815 D	1815 C	
5015	Transformer Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1815 D	1815 D	1815 C	

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
5016	Distribution Station Equipment - Operation Labour	Operation (Working Capital)	di	1820 D	1820 D	1820 C	
5017	Distribution Station Equipment - Operation Supplies and Expenses	Operation (Working Capital)	di	1820 D	1820 D	1820 C	
5020	Overhead Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835 I	1830 & 1835 C	x
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835 I	1830 & 1835 C	x
5030	Overhead Subtransmission Feeders - Operation	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835 I	1830 & 1835 C	
5035	Overhead Distribution Transformers- Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x
5040	Underground Distribution Lines and Feeders - Operation Labour	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845 I	1840 & 1845 C	x
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845 I	1840 & 1845 C	x
5050	Underground Subtransmission Feeders - Operation	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845 I	1840 & 1845 C	
5055	Underground Distribution Transformers - Operation	Operation (Working Capital)	di	1850 D	1850 D	1850 C	x
5065	Meter Expense	Operation (Working Capital)	cu			CWMC	
5070	Customer Premises - Operation Labour	Operation (Working Capital)	cu			CCA	
5075	Customer Premises - Materials and Expenses	Operation (Working Capital)	cu			CCA	
5085	Miscellaneous Distribution Expense	Operation (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x
5090	Underground Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1840 & 1845 D	840 & 1845 I	1840 & 1845 C	x
5095	Overhead Distribution Lines and Feeders - Rental Paid	Operation (Working Capital)	di	1830 & 1835 D	830 & 1835 I	1830 & 1835 C	x
5096	Other Rent	Operation (Working Capital)	di				
5105	Maintenance Supervision and Engineering	Maintenance (Working Capital)	di	1815-1855 D	1815-1855 D	1815-1855 C	x
5110	Maintenance of Buildings and Fixtures - Distribution Stations	Maintenance (Working Capital)	di	1808 D	1808 D	1808 C	
5112	Maintenance of Transformer Station Equipment	Maintenance (Working Capital)	di	1815 D	1815 D	1815 C	
5114	Maintenance of Distribution Station Equipment	Maintenance (Working Capital)	di	1820 D	1820 D	1820 C	
5120	Maintenance of Poles, Towers and Fixtures	Maintenance (Working Capital)	di	1830 D	1830 D	1830 C	x
5125	Maintenance of Overhead Conductors and Devices	Maintenance (Working Capital)	di	1835 D	1835 D	1835 C	x
5130	Maintenance of Overhead Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C	
5135	Overhead Distribution Lines and Feeders - Right of Way	Maintenance (Working Capital)	di	1830 & 1835 D	830 & 1835 I	1830 & 1835 C	x

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
5145	Maintenance of Underground Conduit	Maintenance (Working Capital)	di	1840 D	1840 D	1840 C	x
5150	Maintenance of Underground Conductors and Devices	Maintenance (Working Capital)	di	1845 D	1845 D	1845 C	x
5155	Maintenance of Underground Services	Maintenance (Working Capital)	di	1855 D	1855 D	1855 C	
5160	Maintenance of Line Transformers	Maintenance (Working Capital)	di	1850 D	1850 D	1850 C	x
5175	Maintenance of Meters	Maintenance (Working Capital)	cu	1860 D	1860 D	1860 C	
5305	Supervision	Billing and Collection (Working Capital)	cu			CWNB	
5310	Meter Reading Expense	Billing and Collection (Working Capital)	cu			CWMR	
5315	Customer Billing	Billing and Collection (Working Capital)	cu			CWNB	
5320	Collecting	Billing and Collection (Working Capital)	cu			CWNB	
5325	Collecting- Cash Over and Short	Billing and Collection (Working Capital)	cu			CWNB	
5330	Collection Charges	Billing and Collection (Working Capital)	cu			CWNB	
5335	Bad Debt Expense	Bad Debt Expense (Working Capital)	cu			BDHA	
5340	Miscellaneous Customer Accounts Expenses	Billing and Collection (Working Capital)	cu			CWNB	
5405	Supervision	Community Relations (Working Capital)	ad				
5410	Community Relations - Sundry	Community Relations (Working Capital)	ad				
5415	Energy Conservation	Community Relations - CDM (Working Capital)	ad				
5420	Community Safety Program	Community Relations (Working Capital)	ad				
5425	Miscellaneous Customer Service and Informational Expenses	Community Relations (Working Capital)	ad				
5505	Supervision	Other Distribution Expenses	ad				
5510	Demonstrating and Selling Expense	Other Distribution Expenses	ad				
5515	Advertising Expense	Advertising Expenses	ad				
5520	Miscellaneous Sales Expense	Other Distribution Expenses	ad				
5605	Executive Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
5610	Management Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad				
5615	General Administrative Salaries and Expenses	Administrative and General Expenses (Working Capital)	ad				
5620	Office Supplies and Expenses	Administrative and General Expenses (Working Capital)	ad				
5625	Administrative Expense Transferred Credit	Administrative and General Expenses (Working Capital)	ad				
5630	Outside Services Employed	Administrative and General Expenses (Working Capital)	ad				
5635	Property Insurance	Insurance Expense (Working Capital)	ad				
5640	Injuries and Damages	Administrative and General Expenses (Working Capital)	ad				
5645	Employee Pensions and Benefits	Administrative and General Expenses (Working Capital)	ad				
5650	Franchise Requirements	Administrative and General Expenses (Working Capital)	ad				
5655	Regulatory Expenses	Administrative and General Expenses (Working Capital)	ad				
5660	General Advertising Expenses	Advertising Expenses	ad				
5665	Miscellaneous General Expenses	Administrative and General Expenses (Working Capital)	ad				
5670	Rent	Administrative and General Expenses (Working Capital)	ad				
5675	Maintenance of General Plant	Administrative and General Expenses (Working Capital)	ad				
5680	Electrical Safety Authority Fees	Administrative and General Expenses (Working Capital)	ad				
5685	Independent Market Operator Fees and Penalties	Power Supply Expenses (Working Capital)	cop				
5705	Amortization Expense - Property, Plant, and Equipment	Amortization of Assets	dep	PRORATED	Break out	Breakout	
5710	Amortization of Limited Term Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout	
5715	Amortization of Intangibles and Other Electric Plant	Amortization of Assets	dep	PRORATED	Break out	Breakout	
5720	Amortization of Electric Plant Acquisition Adjustments	Other Amortization - Unclassified	dep	PRORATED	Break out	Breakout	
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	Amortization of Assets	dep				

Uniform System of Accounts - Detail Accounts:					Classification and Allocation		
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint
5735	Amortization of Deferred Development Costs	Amortization of Assets	dep				
5740	Amortization of Deferred Charges	Amortization of Assets	dep				
6005	Interest on Long Term Debt	Interest Expense - Unclassifed	INT				
6105	Taxes Other Than Income Taxes	Other Distribution Expenses	ad				
6110	Income Taxes	Income Tax Expense - Unclassified	Input				
6205-1	Sub-account LEAP Funding	Charitable Contributions	ad				
6210	Life Insurance	Insurance Expense (Working Capital)	ad				
6215	Penalties	Other Distribution Expenses	ad				
6225	Other Deductions	Other Distribution Expenses	ad				

Attachment 7-F

Letter to Energy+ - Embedded Distributor Communication

Sarah Hughes, CPA, CA

Chief Financial Officer
Energy+ Inc.

April 14, 2021

Sent Via Email

Dear Ms. Hughes,

As you are aware, Brantford Power Inc. (BPI) is preparing its Cost of Service Rate Application for distribution rates proposed to be effective on January 1, 2022. Under Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, BPI is required to consult with its embedded distributor regarding the inputs to its cost allocation model.

We have summarized the below inputs related to the Embedded Distributor classification, in which Energy+ is the sole customer. BPI has also attached the most recent Cost Allocation model for your review.

Load Forecast Assumptions:

	kW	kW/kWh ratio	kWh		Number of Connections Billed
2020 Actual	100,587		43,029,562	Actual	2
2021 Forecast (1% YOY growth)	101,593	0.00259	39,217,963	Forecast	2
2022 Forecast (1% YOY growth)	102,609	0.00259	39,610,143	Forecast	2
Growth Rates					
2021/2020	*1.01*				*1.00*
2022/2021	*1.01*				*1.00*
Transformer Allowance Application	*100%*				
Transformer Allowance kW (2022)	102,609				

Load growth of 1% was assumed based on input received from Energy+ regarding the forecast for 64M27 provided on July 20, 2020. This annual growth rate was applied to the Embedded Distribution kW for the last historic actuals (2020). The kW forecast was then multiplied by the 2020 relationship between kWh and kW for the GS >50 Class to achieve the kWh forecast; however as you know BPI does not bill Energy+ for any kWh related rates and charges.

Cost Allocation Inputs:

Please see the attached Cost Allocation model for a review of the cost allocation inputs used.

Please note, BPI has included a proposed update to its Load Profiles with its Application, as an input into the Cost Allocation Model, tab I8 (Demand Data). Hourly historic interval data from Energy+'s connection points for 2018 and 2019 were input into this model and were used to ascertain the embedded distributor usage patterns input into Cost Allocation model tab.

I note the current revenue to cost ratio calculated in the Cost Allocation model based on these inputs is 98%. Consistent with past practice, BPI has proposed a revenue to cost ratio adjustment to bring this to 100% in the rate proposals outline in the section below, so that there is no cross-subsidization between the rate payers of BPI and Energy+ as a result of these rates.

Distribution Rates Proposed:

BPI's rate proposals are summarized in the table below.

	Current 2021		Proposed 2022	
Distributioni Rates	**Monthly Per Connection**	**Per kW**	**Monthly Per Connection**	**Per kW**
Embedded Distributor	$ 375.73	$ 2.0852	$ 463.83	$ 2.4334
ICM Rate Rider	$ 1,096.22	$ -	$ -	$ -
Transformer Allowance	0	-$0.60	$ -	-$0.60

In accordance with the Filing Requirements, BPI requires a statement indicating whether its embedded distributor supports its proposal. Can you please provide us with a statement whether Energy+ supports the proposed cost allocation?

Thank you in advance,

Oana Stefan

Oana Stefan
Manager, Regulatory Affairs | Brantford Power Inc.
150 Savannah Oaks Drive, P.O. Box 308, Brantford, Ontario N3T 5N8
Office: 519-751-3522 ext. 5477
ostefan@brantford.ca | www.brantfordpower.com |

Attachment 7-G

Communication to Unmetered Customers

August 17, 2020

«name»
«mail_addr1»
«mail_addr2»
«mail_city», «mail_province» «mail_postal_zip»

Re: Brantford Power Rate Filing – Unmetered Sentinel Lights Account number: «Account»

Dear Customer:

This letter is to advise you that Brantford Power Inc. is preparing a Cost of Service application to the Ontario Energy Board to update its distribution rates effective January 1, 2022.

The application will include comprehensive updates on Brantford Power's costs to provide service to its customers and on the electricity loads on Brantford Power's distribution system.

As part of our Cost of Service application, Brantford Power will submit a cost allocation study to support the distribution rates proposed for each customer class, reflecting the electricity load of each class on the distribution system. Cost Allocation studies are typically performed every five years. As per the Ontario Energy Board and our Conditions of Service, we are required to advise all Unmetered Account customers prior to a cost allocation study.

As an Unmetered Account—Sentinel Lights customer, your monthly bill is based on an estimate of your electricity consumption, determined by the wattage of your equipment and estimated amount of time that they are in use each month. Brantford Power is currently using the following factors to calculate your billable consumption each month.

ACCOUNT NUMBER	RATE CATEGORY	# OF CONNECTIONS ON FILE	MONTHLY KW	MONTHLY KWH
«Account»	«bill_type_code»	«sentinel_lights»		«kWh_Usage»

If the information listed above is not accurate, or if you have made changes such as installing new equipment, please email us at customerservices@brantfordpower.ca by September 14, 2020, to provide updated information. Also, please let us know if you intend to update or change your equipment in the near future. If we do not hear from you by September 14, 2020, we will proceed based on our current monthly estimate.

You may contact us at any time to update information about the number of devices or wattage of your devices, which may affect your bill in the future. Verified updates may result in an adjustment to your monthly invoice. They will not affect Brantford Power's rate structure until the next Cost of Service application to the Ontario Energy Board.

If you have any concerns or questions, please contact our Customer Care Department at 519-751-3522 or by email at customerservices@brantfordpower.ca.

Sincerely,

Brantford Power Customer Care
Box 308
Brantford, Ontario
N3T 5N8