EXHIBIT 7 – COST ALLOCATION

2021 Cost of Service

Wellington North Power Inc.
EB-2020-0061

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7.1 COST ALLOCATION STUDY REQUIREMENTS

7.1.1 OVERVIEW OF COST ALLOCATION

WNP is submitting cost allocation informational filing consistent with the utility's understanding of the Directions and Policies in the Board's Reports of November 28, 2007 Application of Cost Allocation for Electricity Distributors, and March 31, 2011 Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) (the "Cost Allocation Reports") and all subsequent updates.

The main objectives of the original informational filing in 2006 were to provide information on any apparent cross-subsidization among a distributor's rate classifications and to support future rate applications. This information is updated to reflect new parameters and inputs and then used to adjust any cross-subsidization in the proposed rates.

7.1.2 PREVIOUSLY APPROVED COST ALLOCATION STUDY (2016)

The Previously Board Approved ratios are presented as a point of reference to the proposed Test Year (2021) ratios. As part of its last Cost of Service Rate Application[1], WNP updated the cost allocation revenue to cost ratios with 2016 base revenue requirement information. The revenue to cost ratios from the 2016 application are presented below:

Table 1 - Previously Approved Ratios (2016 COS)

Customer Class Name	2016 Approved Revenue to Cost Ratio
Residential	92.49
General Service < 50 kW	119.07
General Service 50 to 999 kW	119.61
General Service 1,000 to 4,999 kW	99.68
Unmetered Scattered Load	114.76
Sentinel Lights	79.87
Street Lighting	119.96

[1] EB-2015-0110 Wellington North Power Inc. 2016 Cost of Service application, Settlement Proposal Table 23, page 48

7.1.3 NEW CUSTOMER CLASS

WNP notes that there have been no changes in its class composition since 2016. [2] The utility is not proposing to introduce any new customer classes.

7.1.4 ELIMINATION OF A CUSTOMER CLASS

WNP is not proposing to eliminate any customer rate classes. [3]

[2] MFR - New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS

[3] MFR - New customer class or eliminated customer class - rationale and restatement of revenue requirement from previous CoS

7.2 PROPOSED COST ALLOCATION STUDY (2021)

The Cost Allocation Study for 2021 allocates the Test Year 2021 costs (i.e. the 2021 forecasted revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class and customer counts.

WNP has used the latest OEB published Cost Allocation Model (issued May 14, 2020, version 1) and followed the instructions provided by the OEB to enter the 2021 data into this model.[4]

Below is a summary of the process that WNP applied in completing the 2021 Cost Allocation Model.

7.2.1 TRIAL BALANCE INPUT

WNP populated the information in worksheet "I3, Trial Balance Data" with the 2021 forecasted data, Target Net Income, PILs, interest on long term debt, and the targeted Revenue Requirement and Rate Base.

The Applicant confirmed that the values balanced with the Revenue Requirement and the Rate Workform as per the Revenue Requirement Workform.

7.2.2 BREAK-OUT OF ASSETS

In worksheet "I4, Break-out of Assets", WNP updated the allocation of the accounts based on Test Year 2021 values.

The Applicant confirmed that all items balanced as per the Cost Allocation model.

WNP referred to the OEB's "Cost Allocation Information Filing Guidelines for Electricity Distributors" to confirm the understanding of bulk assets and definitions of primary and secondary assets.[5]

[4] MFR - If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters

[5] Cost Allocation Information Filing Guidelines for Electricity Distributors issued November 15, 2006, Section 6.2.2

7.2.3 MISCELLANOUES DATA

In worksheet "I5.1, Miscellaneous data", WNP inputted:

- Structure kilometers of 92km. This is consists of the utility having 71km of primary overhead, 15km of primary underground and 6km of secondary along roads where there is no primary distribution line. WNP referred to the OEB's "Cost Allocation Information Filing Guidelines for Electricity Distributors" to confirm the definition of km.[6]
- The deemed equity component of 40% of the rate base.
- A working capital allowance of 7.5%.
- The proportion of pole rental revenue from secondary poles / distribution lines.

7.2.4 WEIGHTING FACTORS

As instructed by the Board, in worksheet "I5.2, Weighting Factors", WNP has used LDC specific factors rather than continue to use OEB approved default factors. The utility has applied service and billing & collecting weightings for each customer classification.

These weightings are based on a review of time and costs incurred in servicing its' customer classes.

The table below summarizes the weighting factors assigned to the customer classes for (a) Services Account 1855 and (b) billing and collecting:

Table 2 - Weighting Factors

	1	2	3	5	7	8	9
	Residential	GS <50 kW	GS 50-999 kW	GS 1000-4999 kW	Streetlight	Sentinel	Unmetered Scattered Load
Insert Weighting Factor for Services Account 1855	1.0	0.4					
Insert Weighting Factor for Billing and Collecting	1.0	1.0	1.8	1.5	0.7	0.5	0.7

[6] Cost Allocation Information Filing Guidelines for Electricity Distributors issued November 15, 2006, section 7.4.2.4

Proposed Services Account 1855 Weighting Factors[7]

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

Proposed Billing and Collecting Weighting Factors[8]

- *Residential:* weighting factor set as "1" per Cost Allocation instruction sheet.
- *General Service <50 kW*: weighting factor is "1" as WNP believes that no more time, attention and costs are spent on these customers as the residential class. Although the GS<50 kW customers are periodically monitored to assess if their kVA demand means that they qualify to move into the GS50 – 999 kW class, this is off-set by WNP printing fewer bills and receiving fewer calls from customers in this rate class when compared to the Residential Class.
- *General Service 50-999 kW:* weighting factor "1.8" is proposed because these customers are periodically monitored to assess if their kVA demand to determine whether the customers should be moved to another General Service rate class. Also, there is additional staff time required to prepare and validate each bill to ensure monthly consumption data aligns to the settlement data for the period. However, collection costs are lower than those incurred when dealing with General Service <50 kW customers.
- *General Service 1,000-4,999 kW:* weighting factor "1.5" is proposed because each bill is individually validated to ensure monthly consumption data aligns to the settlement data for the period; however this manual validation is not time-consuming because there are only a few customers in this class and therefore, this should not influence the weighing factor. Also, there are no collection costs or bad debt expenses for this customer class.

[7] MFR - Description of weighting factors, and rationale for use of default values (if applicable)
[8] MFR - Description of weighting factors, and rationale for use of default values (if applicable)

- *Street Lighting:* weighting factor "0.7" is proposed as this customer class does not give rise to collection activity so no collection costs have been allocated. The weighting factor reflects the extremely low volume of bills issued. WNP discusses and confirms load profile data and bill impact with the Township when new rates and charges are introduced.
- *Sentinel Lighting:* weighting factor "0.5" is proposed because, similar to Street Lighting, this class does not give rise to collection costs. The weighting factor reflects that relatively fewer bills are issued to this customer class.
- *Unmetered Scattered Load:* weighting factor "0.7" is proposed because, similar to Sentinel Lighting, weighting factor reflects that relatively fewer bills are issued to this customer class. WNP discusses unmetered load profile data and bill impact with USL customers when new rates and charges are introduced.

A derivation of the billing and collecting weighting factors for the rate class is illustrated in the table below.

Table 3 – Breakdown of Weighting Factors

Year: 2017	**Billing**	**USoA**	**Residential**	**GS<50**	**GS 50-999**	**GS 1000-4999**	**Sentinel Lighting**	**Street Lights**	**USL**
	FileNexus (Loris Technologies)	*5310*	$11,273	$1,643	$122	$17			
	Settlement & AMI Hosting (Utilismart)	*5310*	$24,582	$3,582	$265	$38		$23	
	Settlement Metering - MIST meters (Utilismart)	*5310*			$2,166	$309			
	ODS (Savage)	*5310*	$6,189	$902					
	Elster	*5310*	$16,540	$2,410	$178	$25			
	Harris CIS (NorthStar Computer Corp) + WNP Labour	*5315*	$79,906	$11,644	$862	$123	$345	$74	$49
A	Total		$138,490	$20,180	$3,592	$513	$345	$97	$49
B	Average # of Accounts		3,246	473	35	5	14	3	2
C = B x 12	Number of Bills per year (Accounts x 12)		38,952	5,676	420	60	168	36	24
D = A / C	**Billing Cost per Bill**		**$3.56**	**$3.56**	**$8.55**	**$8.55**	**$2.05**	**$2.68**	**$2.05**
	Collecting								
E	Collecting	*5320*	$94,869	$13,824	$1,023		$409		$58
F = E / C	**Collection Cost per Bill**		**$2.44**	**$2.44**	**$2.44**	**$0.00**	**$2.44**	**$0.00**	**$2.44**
Year: 2018		**USoA**	**Residential**	**GS<50**	**GS 50-999**	**GS 1000-4999**	**Sentinel Lighting**	**Street Lights**	**USL**
	FileNexus (Loris Technologies)	*5310*	$15,886	$2,277	$165	$24			
	Settlement & AMI Hosting (Utilismart)	*5310*	$26,175	$3,752	$271	$40		$24	
	Settlement Metering - MIST meters (Utilismart)	*5310*			$2,226	$327			
	ODS (Savage)	*5310*	$6,431	$922					
	Elster	*5310*	$12,342	$1,769	$128	$19			
	Harris CIS (NorthStar Computer Corp) + WNP Labour	*5315*	$93,370	$13,383	$968	$142	$399	$85	$57
A	Total		$154,205	$22,103	$3,758	$553	$399	$109	$57
B	Average # of Accounts		3,279	470	34	5	14	3	2
C = B x 12	Number of Bills per year (Accounts x 12)		39,348	5,640	408	60	168	36	24
D = A / C	**Billing Cost per Bill**		**$3.92**	**$3.92**	**$9.21**	**$9.21**	**$2.37**	**$3.04**	**$2.37**
	Collecting								
E	Collecting	*5320*	$91,071	$13,054	$944		$389		$56
F = E / C	**Collection Cost per Bill**		**$2.31**	**$2.31**	**$2.31**	**$0.00**	**$2.31**	**$0.00**	**$2.31**
Year: 2019		**USoA**	**Residential**	**GS<50**	**GS 50-999**	**GS 1000-4999**	**Sentinel Lighting**	**Street Lights**	**USL**
	FileNexus (Loris Technologies)	*5310*	$16,019	$2,280	$170	$24			
	Settlement & AMI Hosting (Utilismart)	*5310*	$28,246	$4,020	$299	$43		$26	
	Settlement Metering - MIST meters (Utilismart)	*5310*			$2,195	$314			
	ODS (Savage)	*5310*	$6,470	$921					
	Elster	*5310*	$17,286	$2,460	$183	$26			
	Harris CIS (NorthStar Computer Corp) + WNP Labour	*5315*	$94,856	$13,502	$1,005	$144	$402	$86	$57
A	Total		$162,877	$23,184	$3,852	$550	$402	$112	$57
B	Average # of Accounts		3,302	470	35	5	14	3	2
C = B x 12	Number of Bills per year (Accounts x 12)		39,624	5,640	420	60	168	36	24
D = A / C	**Billing Cost per Bill**		**$4.11**	**$4.11**	**$9.17**	**$9.17**	**$2.39**	**$3.11**	**$2.39**
	Collecting								
E	Collecting	*5320*	$84,957	$12,093	$901		$360		$51
F = E / C	**Collection Cost per Bill**		**$2.14**	**$2.14**	**$2.14**	**$0.00**	**$2.14**	**$0.00**	**$2.14**
	3-year Average (2017, 2018 & 2019)								
	Average Billing Cost per Bill		$3.86	$3.86	$8.98	$8.98	$2.27	$2.94	$2.27
	Average Collection Cost per Bill		$2.30	$2.30	$2.30	$0.00	$2.30	$0.00	$2.30
	Total Average		**$6.16**	**$6.16**	**$11.28**	**$8.98**	**$4.57**	**$2.94**	**$4.57**
	Weighting Factor for CA Model		**1.0**	**1.0**	**1.8**	**1.5**	**0.7**	**0.5**	**0.7**
				Calculated by taking Total Average for each class and dividing by Residential Total Average amount of $6.16					

The above table shows:

a) The annual costs to produce an electricity bill including, but not limited to, vendor maintenance fees for Customer Information Systems, bill-print scanning solutions for document management and e-billing, collecting meter readings and interval data, bill data validation and labour time to calculate, print and validate bills. Costs are allocated based on the number of accounts and whether the expense is unique to a certain rate class (e.g. MIST meter costs relate to class GS50-999 and GS1000-4999 kW only.)

b) Collection costs relate to WNP labour only as the utility does not out-source to collection agencies.

7.2.5 REVENUE

In worksheet “I6.1 – Revenue”, WNP has inputted the 2021 Test Year load forecast data (kWh and kW), the proposed revenue deficiency and miscellaneous revenue as well as current rates (derived from the LDC’s 2019 IRM rate application – EB-2019-0073: Final Rate Order, October 8, 2020). This is illustrated in the table below:

Table 4 - Worksheet “I6-1 Revenue” of the Cost Allocation Model[9]

EB-2020-0061

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	99,677,917
Total kWs from Load Forecast	146,002
Deficiency/sufficiency (RRWF 8. cell F51)	- 350,116
Miscellaneous Revenue (RRWF 5. cell F48)	135,330

			1	2	3	5	7	8	9
Billing Data	**ID**	**Total**	**Residential**	**GS <50**	**GS 50-999kW**	**GS 1000-4999kW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Forecast kWh	CEN	99,677,917	26,503,100	11,455,522	18,697,353	42,766,148	229,833	19,673	6,288
Forecast kW	CDEM	146,002			52,425	92,890	632	55	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		10,607			10,607				
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	99,677,917	26,503,100	11,455,522	18,697,353	42,766,148	229,833	19,673	6,288
Existing Monthly Charge			$36.39	$43.75	$289.38	$2,365.10	$1.68	$7.75	$29.71
Existing Distribution kWh Rate				$0.0188					$0.0163
Existing Distribution kW Rate					$2.7600	$3.1994	$1.8527	$28.6379	
Existing TOA Rate					$0.60				
Additional Charges									
Distribution Revenue from Rates		$2,652,609	$1,465,096	$461,076	$262,898	$439,097	$19,800	$3,707	$934
Transformer Ownership Allowance		$6,364	$0	$0	$6,364	$0	$0	$0	$0
Net Class Revenue	CREV	$2,646,244	$1,465,096	$461,076	$256,534	$439,097	$19,800	$3,707	$934

[9] MFR - Hard copy of sheets I-6, I-8, O-1 and O-2 (first page)

7.2.6 CUSTOMER DATA

Worksheet "I6.2 Customer Data" has been updated with the required Bad Debt and Late Payment revenue data as well as the 2021 Test Year forecasted number of customers, connections and number of devices. WNP reviewed Navigant's report "*Cost Allocation to Different Types of Street Lighting Configurations*" (issued June 12, 2015) as well as the Board's letter dated June 12, 2015, "*Review of Cost Allocation Policy for Unmetered Loads – EB-2012-0383*" and has inputted the number of devices and connections for its' Street Lighting class.) Below is a summary of worksheet "I6.2 – Customer Data":

Table 5 - Worksheet "I6-2 Customer Data" of the Cost Allocation Model[10]

			1	2	3	5	7	8	9
	ID	Total	Residential	GS <50	GS 50-999kW	GS 1000-4999kW	Street Light	Sentinel	Unmetered Scattered Load
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$70,312	$53,437	$12,656	$4,219	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$25,836	$19,635	$4,650	$1,550				
Number of Bills	CNB	46,621	40,261	5,616	408	60	36	216	24
Number of Devices	CDEV						924		
Number of Connections (Unmetered)	CCON	914					889	23	2
Total Number of Customers	CCA	3,884	3,355	468	34	5	3	18	1
Bulk Customer Base	CCB	-							
Primary Customer Base	CCP	3,914	3,355	468	34	5	33	18	1
Line Transformer Customer Base	CCLT	3,912	3,355	468	32	5	33	18	1
Secondary Customer Base	CCS	3,884	3,355	468	34	5	3	18	1
Weighted - Services	CWCS	3,547	3,355	192	-	-	-	-	-
Weighted Meter -Capital	CWMC	1,076,093	671,000	332,280	63,478	9,335	-	-	-
Weighted Meter Reading	CWMR	4,155	3,355	702	85	13	-	-	-
Weighted Bills	CWNB	46,859	40,261	5,616	747	87	27	103	18
Bad Debt Data									
Historic Year:	2017	56,923	43,261	10,246	3,415	-	-	-	-
Historic Year:	2018	93,722	71,228	16,870	5,623	-	-	-	-
Historic Year:	2019	60,292	45,822	10,853	3,618	-	-	-	-
Three-year average		**70,312**	**53,437**	**12,656**	**4,219**	**-**	**-**	**-**	**-**

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	3,355	22,056	3,355	22,056
Street Light	924	217	924	217

Street Lighting Adjustment	
Primary	27.9811
Line Transformer	27.9811

[10] MFR - Hard copy of sheets I-6, I-8, O-1 and O-2 (first page)

7.2.7 METER CAPITAL & METER READING

WNP has updated the capital cost per meter information in worksheet "I7.1 Meter Capital" and the meter reading information in worksheet "I7.2 Meter Reading".

7.2.8 DEMAND DATA

For previous WNP Cost of Service applications (e.g. EB-2015-0110 and EB-2011-0249), the Applicant relied on load profiles produced by Hydro One Networks Inc., (HONI) which were based on sample data from 2004. The coincident peak and non-coincident peak values populated in worksheet I8 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 has 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 to input into worksheet "I8 Demand Data" of the OEB's 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 Appendix 7A. In addition, WNP has filed excel copies of supporting information as listed in the Appendices of this Exhibit.

By January 2018, WNP had completed installation of MIST[11] meters for all customers in its' General Service 50-999 kW rate classes. Therefore, WNP was able to compile hourly consumption data for each of its' metered rate classes, beginning with January 2018, and has used this data to update load profiles for all of its' rate classes, in accordance with Section 2.7.1 of the Filing Requirements.

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)

[11] "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)

and Coincident Peak for each year. The CP and NCP Demand Data inputted into worksheet "I8 Demand Data" of the Cost Allocation model is based on the average of CP and NCP demand data for the two years of 2018 and 2019 weather-normalized data and scaled to the Applicant's 2021 Test Year Load Forecast using Wholesale kWh purchases.

The tables below summarize the NCP and CP demand values for years 2018 and 2019 by customer class as well as the average NCP and CP for years 2018 and 2019 which are used in the Cost Allocation model:

Table 6 - Non-Coincident Peak: 2018, 2019 and Average of 2018 & 2019

	Non-Coincident Peak						
2018	**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
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	6,088	2,283	3,560	7,386	54	6	2
4NCP	22,056	8,740	13,712	28,957	217	23	7
12NCP	59,264	23,704	38,653	83,067	636	56	18

Table 7 - Coincident Peak: 2018, 2019 and Average of 2018 & 2019

	Coincident Peak						
2018	**Residential**	**General Service <50kW**	**General Service 50-999kW**	**General Service 1000-4999kW**	**StreetLights**	**Sentinel Lights**	**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
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	4,810	2,121	2,735	6,494	28	2	1
4CP	18,038	7,873	11,623	25,648	76	6	2
12CP	47,016	21,704	34,398	78,325	149	11	4

The table below shows the Demand Data as used in WNP's 2016 Cost of Service application (EB-2015-0110):

Table 8 - Demand Data for 2016 Test Year (adjusted to 2016 Load Forecast)

EB-2015-0110

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

Customer Classes		Total	1 Residential	2 GS <50	3 General Service 50 - 999 kW	5 General Service 1000 - 4999 kW	7 Street Light	8 Sentinel Lighting	9 Unmetered Scattered Load
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	17,455	6,232	1,317	1,609	8,126	166	5	0
Bulk Delivery CP	BCP1	17,455	6,232	1,317	1,609	8,126	166	5	0
Total Sytem CP	DCP1	17,455	6,232	1,317	1,609	8,126	166	5	0
4 CP									
Transformation CP	TCP4	67,869	24,672	5,337	7,620	29,563	658	18	1
Bulk Delivery CP	BCP4	67,869	24,672	5,337	7,620	29,563	658	18	1
Total Sytem CP	DCP4	67,869	24,672	5,337	7,620	29,563	658	18	1
12 CP									
Transformation CP	TCP12	185,237	60,968	13,651	20,756	88,323	1,487	46	4
Bulk Delivery CP	BCP12	185,237	60,968	13,651	20,756	88,323	1,487	46	4
Total Sytem CP	DCP12	185,237	60,968	13,651	20,756	88,323	1,487	46	4
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	20,090	7,144	2,117	2,377	8,278	166	7	0.4
Primary NCP	PNCP1	20,090	7,144	2,117	2,377	8,278	166	7	0.4
Line Transformer NCP	LTNCP1	11,812	7,144	2,117	2,377	-	166	7	0.4
Secondary NCP	SNCP1	20,090	7,144	2,117	2,377	8,278	166	7	0.4
4 NCP									
Classification NCP from Load Data Provider	DNCP4	77,523	26,821	8,179	9,117	32,715	663	26	1
Primary NCP	PNCP4	77,523	26,821	8,179	9,117	32,715	663	26	1
Line Transformer NCP	LTNCP4	44,807	26,821	8,179	9,117	-	663	26	1
Secondary NCP	SNCP4	77,523	26,821	8,179	9,117	32,715	663	26	1
12 NCP									
Classification NCP from Load Data Provider	DNCP12	210,886	67,219	21,868	24,489	95,257	1,984	65	4
Primary NCP	PNCP12	210,886	67,219	21,868	24,489	95,257	1,984	65	4
Line Transformer NCP	LTNCP12	115,629	67,219	21,868	24,489	-	1,984	65	4
Secondary NCP	SNCP12	210,886	67,219	21,868	24,489	95,257	1,984	65	4

The table below shows the Demand Data for this 2021 Cost of Service application:

Table 9 - Demand Data for 2021 Test Year (adjusted to 2021 Load Forecast)

Ontario Energy Board

2021 Cost Allocation Model

EB-2020-0061

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

Customer Classes		Total	1 Residential	2 GS <50	3 GS 50-999kW	5 GS 1000-4999kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
		CP Sanity Check	Pass	Pass	Check 4CP and 12CP	Check 12CP	Pass	Pass	Pass
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	16,190	4,810	2,121	2,735	6,494	28	2	1
Bulk Delivery CP	BCP1	16,190	4,810	2,121	2,735	6,494	28	2	1
Total Sytem CP	DCP1	16,190	4,810	2,121	2,735	6,494	28	2	1
4 CP									
Transformation CP	TCP4	63,265	18,038	7,873	11,623	25,648	76	6	2
Bulk Delivery CP	BCP4	63,265	18,038	7,873	11,623	25,648	76	6	2
Total Sytem CP	DCP4	63,265	18,038	7,873	11,623	25,648	76	6	2
12 CP									
Transformation CP	TCP12	181,607	47,016	21,704	34,398	78,325	149	11	4
Bulk Delivery CP	BCP12	181,607	47,016	21,704	34,398	78,325	149	11	4
Total Sytem CP	DCP12	181,607	47,016	21,704	34,398	78,325	149	11	4
NON CO_INCIDENT PEAK									
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP									
Classification NCP from Load Data Provider	DNCP1	19,379	6,088	2,283	3,560	7,386	54	6	2
Primary NCP	PNCP1	19,379	6,088	2,283	3,560	7,386	54	6	2
Line Transformer NCP	LTNCP1	9,154	6,088	2,283	720		54	6	2
Secondary NCP	SNCP1	16,540	6,088	2,283	720	7,386	54	6	2
4 NCP									
Classification NCP from Load Data Provider	DNCP4	73,713	22,056	8,740	13,712	28,957	217	23	7
Primary NCP	PNCP4	73,713	22,056	8,740	13,712	28,957	217	23	7
Line Transformer NCP	LTNCP4	33,819	22,056	8,740	2,774		217	23	7
Secondary NCP	SNCP4	62,775	22,056	8,740	2,774	28,957	217	23	7
12 NCP									
Classification NCP from Load Data Provider	DNCP12	205,397	59,264	23,704	38,653	83,067	636	56	18
Primary NCP	PNCP12	205,397	59,264	23,704	38,653	83,067	636	56	18
Line Transformer NCP	LTNCP12	91,498	59,264	23,704	7,821		636	56	18
Secondary NCP	SNCP12	174,565	59,264	23,704	7,821	83,067	636	56	18

WNP notes that in the 2021 Demand Date, the sanity checks for CP for customer classes GS50-999 kW and GS 1,000-4999 kW flagged a “check error message”; however the demand data for all other classes and NCP data all passed the sanity check. The Applicant attempted using the following options to try to resolve the sanity check warnings for these particular classes:

a) Used 2018 weather-normalized demand data and scaled to the Applicant’s 2021 Test Year Load Forecast using Wholesale kWh purchases and inputted the CP data (i.e. not using the average of 2018 and 2019 demand data, but solely using the single year of 2018). The result is shown below:

Table 10 – 2018 CP Demand Data for 2021 Test Year (adjusted to 2021 Load Forecast)

3	5
GS 50-999kW	GS 1000-4999kW
Check 4CP and 12CP	Check 4CP and 12CP
2,778	6,475
2,778	6,475
2,778	6,475
12,081	26,182
12,081	26,182
12,081	26,182
35,482	77,856
35,482	77,856
35,482	77,856

b) Used 2019 weather-normalized demand data and scaled to the Applicant’s 2021 Test Year Load Forecast using Wholesale kWh purchases and inputted the CP data (i.e. not using the average of 2018 and 2019 demand data, but solely using a single year of 2019). The result is shown below:

Table 11 – 2019 CP Demand Data for 2021 Test Year (adjusted to 2021 Load Forecast)

3	5
GS 50-999kW	GS 1000-4999kW
Check 4CP and 12CP	Check 4CP and 12CP
2,778	6,475
2,778	6,475
2,778	6,475
12,081	26,182
12,081	26,182
12,081	26,182
35,482	77,856
35,482	77,856
35,482	77,856

In both attempts, the sanity check warning message continued to appear. The sanity check occurs when the 4CP demand data is more than 4 times the 1CP value and / or the 12CP demand data is more than 12 times the 1CP value.

WNP has checked and re-checked the data and confirms it is correct. The demand data for customer class GSS50-999 kW and GS1,000-4,999 kW is actually used to bill customers in these rate classes, the only difference here is that the data has been scaled to the 2021 Load Forecast. In the GS GS1,000-4,999 kW, there are six (6) customers all of whom have opted into the IESO's "Industrial Conservation Initiative" since July 2018; in the GS50-999 kW class, there are 35 accounts of which one (1) account, which has the largest monthly kW demand of the rate class, has also opted into the IESO's "Industrial Conservation Initiative" since July 2018. Therefore, the LDC can only assume that these customers have been actively managing their electricity demand under the ICI program to minimize their resulting peak demand factor (PDF) when it is calculated for the following program period.

WNP also ran the "traditional" 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. WNP applied 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 2019 actual data scaled to the Test Year 2021 Load Forecast:

Table 12 – "Traditional HONI Method" Demand Data for 2021 Test Year

Ontario Energy Board

2021 Cost Allocation Model

EB-2020-0061

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

Customer Classes		Total	1 Residential	2 GS <50	3 GS 50-999kW	5 GS 1000-4999kW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
		CP Sanity Check	Pass	Check 4CP	Check 4CP and 12CP	Pass	Pass	Pass	Pass
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	16,778	6,352	1,272	2,230	6,866	53	5	1
Bulk Delivery CP	BCP1	16,778	6,352	1,272	2,230	6,866	53	5	1
Total Sytem CP	DCP1	16,778	6,352	1,272	2,230	6,866	53	5	1
4 CP									
Transformation CP	TCP4	66,069	25,144	5,157	10,561	24,980	209	15	3
Bulk Delivery CP	BCP4	66,069	25,144	5,157	10,561	24,980	209	15	3
Total Sytem CP	DCP4	66,069	25,144	5,157	10,561	24,980	209	15	3
12 CP									
Transformation CP	TCP12	182,295	62,511	12,869	28,867	77,529	471	39	9
Bulk Delivery CP	BCP12	182,295	62,511	12,869	28,867	77,529	471	39	9
Total Sytem CP	DCP12	182,295	62,511	12,869	28,867	77,529	471	39	9
NON CO_INCIDENT PEAK									
		NCP Sanity Check	Pass	Pass	Pass	Pass	Pass	Pass	Pass
1 NCP									
Classification NCP from Load Data Provider	DNCP1	19,676	7,281	2,046	3,295	6,995	53	6	1
Primary NCP	PNCP1	19,676	7,281	2,046	3,295	6,995	53	6	1
Line Transformer NCP	LTNCP1	10,053	7,281	2,046	667		53	6	1
Secondary NCP	SNCP1	17,048	7,281	2,046	667	6,995	53	6	1
4 NCP									
Classification NCP from Load Data Provider	DNCP4	75,753	27,334	7,903	12,637	27,643	210	22	3
Primary NCP	PNCP4	75,753	27,334	7,903	12,637	27,643	210	22	3
Line Transformer NCP	LTNCP4	38,029	27,334	7,903	2,557		210	22	3
Secondary NCP	SNCP4	65,672	27,334	7,903	2,557	27,643	210	22	3
12 NCP									
Classification NCP from Load Data Provider	DNCP12	204,759	68,505	21,131	33,942	80,488	629	55	9
Primary NCP	PNCP12	204,759	68,505	21,131	33,942	80,488	629	55	9
Line Transformer NCP	LTNCP12	97,196	68,505	21,131	6,868		629	55	9
Secondary NCP	SNCP12	177,685	68,505	21,131	6,868	80,488	629	55	9

WNP notes that using the "traditional HONI method", the data in the above table also shows the sanity checks messages for 4CP appears for rate class GS50-999 kW as well as 4CP and 12CP for rate class GS 50-999 kW. The exercise of running the "traditional HONI method", is encouraging because under this method and the "USF Demand Profile Working Group" method, the sanity check warning messages in the Cost Allocation model worksheet "I8 Demand Data" appeared for certain rate class and only under the Coincident Peak Demand (CP) data.

The Applicant believes that the "USF Demand Profile Working Group" method 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 (2021) forecast as per the load forecast used in the application. For more information, please refer to the evidence provided in Appendix 7A as well, as the supporting excel data files (Appendix 7B, Appendix 7C, Appendix 7D and Appendix 7E) submitted with this application.

WNP has inputted the NCP and CP values derived from the "USF Demand Profile Working Group" method into worksheet "I8 Demand Data" of the OEB's Cost Allocation Model.

WNP confirms the following:

- The Applicant proposes to use the CP and NCP data, as calculated under the "USF Demand Profile Working Group" method instead of using the "traditional HONI method".
- The Applicant has filed the Cost Allocation model, as a live excel file, with this application.[12]
- The Applicant has populated sheets 11 and 12 of the Revenue Requirement Workform.[13]
- The Applicant confirms that the inputs to the model are consistent with the test year load forecast, changes to customer classes and load profiles. [14]

[12] MFR – Completed cost allocation study using the OEB-approved methodology or a comparable model must be filed reflecting future loads and costs and be supported by appropriate explanations and live Excel spreadsheets

[13] Sheets 11 and 12 of the RRWF must also be completed

[14].. Model must be consistent with test year load forecast, changes to customer classes and load profiles

7.2.9 DIRECT ALLOCATION

WNP confirms that no Direct Allocations were entered in worksheet “I9. Direct Allocation”

The revenue to cost ratios calculated in worksheet “O1 Revenue to Cost|RR” of the Cost Allocation model updated for the Test Year 2021 is presented in the table below:

Table 13 – Worksheet O1 – Revenue to Cost Ratios of the Cost Allocation Model [15]

			1	2	3	5	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS 50-999kW	GS 1000-4999kW	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$2,646,244	$1,465,096	$461,076	$256,534	$439,097	$19,800	$3,707	$934
mi	Miscellaneous Revenue (mi)	$135,330	$86,284	$18,231	$5,120	$18,423	$6,985	$255	$32
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	**$2,781,574**	**$1,551,380**	**$479,307**	**$261,653**	**$457,520**	**$26,784**	**$3,962**	**$967**
	Factor required to recover deficiency (1 + D)	1.1323							
	Distribution Revenue at Status Quo Rates	$2,996,360	$1,658,939	$522,079	$290,475	$497,193	$22,419	$4,197	$1,058
	Miscellaneous Revenue (mi)	$135,330	$86,284	$18,231	$5,120	$18,423	$6,985	$255	$32
	Total Revenue at Status Quo Rates	**$3,131,690**	**$1,745,223**	**$540,311**	**$295,594**	**$515,616**	**$29,404**	**$4,453**	**$1,090**
	Expenses								
di	Distribution Costs (di)	$525,000	$258,443	$64,155	$56,533	$134,233	$10,682	$849	$105
cu	Customer Related Costs (cu)	$585,500	$463,966	$90,674	$13,725	$1,727	$14,149	$1,096	$163
ad	General and Administration (ad)	$822,000	$521,731	$114,629	$55,804	$110,415	$17,830	$1,398	$193
dep	Depreciation and Amortization (dep)	$500,023	$227,628	$81,511	$59,889	$125,090	$5,392	$451	$62
INPUT	PILs (INPUT)	$0	$0	$0	$0	$0	$0	$0	$0
INT	Interest	$279,927	$120,956	$39,202	$35,765	$80,077	$3,593	$293	$40
	Total Expenses	**$2,712,450**	**$1,592,724**	**$390,171**	**$221,717**	**$451,542**	**$51,646**	**$4,087**	**$563**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$419,241	$181,153	$58,712	$53,565	$119,929	$5,381	$439	$61
	Revenue Requirement (includes NI)	$3,131,690	$1,773,877	$448,883	$275,282	$571,471	$57,027	$4,526	$624
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$13,005,445	$5,784,004	$1,877,244	$1,597,353	$3,559,520	$171,773	$13,677	$1,874
gp	General Plant - Gross	$2,168,239	$953,716	$302,983	$270,190	$609,361	$29,345	$2,326	$319
accum dep	Accumulated Depreciation	($3,437,206)	($1,562,523)	($540,717)	($410,243)	($878,766)	($41,124)	($3,372)	($461)
co	Capital Contribution	($494,496)	($311,184)	($65,393)	($23,533)	($78,321)	($15,128)	($833)	($104)
	Total Net Plant	**$11,241,982**	**$4,864,013**	**$1,574,117**	**$1,433,766**	**$3,211,793**	**$144,866**	**$11,798**	**$1,628**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$12,196,563	$3,258,800	$1,401,889	$2,282,931	$5,221,711	$28,062	$2,402	$768
	OM&A Expenses	$1,932,500	$1,244,140	$269,458	$126,062	$246,375	$42,662	$3,343	$461
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$14,129,063***	***$4,502,940***	***$1,671,347***	***$2,408,993***	***$5,468,085***	***$70,724***	***$5,745***	***$1,228***
	Working Capital	**$1,059,680**	**$337,721**	**$125,351**	**$180,674**	**$410,106**	**$5,304**	**$431**	**$92**
	Total Rate Base	**$12,301,661**	**$5,201,734**	**$1,699,468**	**$1,614,441**	**$3,621,900**	**$150,170**	**$12,229**	**$1,720**
		Rate Base Input equals Output							
	Equity Component of Rate Base	**$4,920,665**	**$2,080,693**	**$679,787**	**$645,776**	**$1,448,760**	**$60,068**	**$4,892**	**$688**
	Net Income on Allocated Assets	**$419,241**	**$152,499**	**$150,140**	**$73,877**	**$64,074**	**($22,243)**	**$366**	**$527**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$419,241**	**$152,499**	**$150,140**	**$73,877**	**$64,074**	**($22,243)**	**$366**	**$527**
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**98.38%**	**120.37%**	**107.38%**	**90.23%**	**51.56%**	**98.38%**	**174.73%**
	EXISTING REVENUE MINUS ALLOCATED COSTS	($350,116)	($222,496)	$30,424	($13,629)	($113,951)	($30,243)	($564)	$343
		Deficiency Input equals Output							
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($28,654)	$91,428	$20,312	($55,855)	($27,624)	($73)	$466
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.52%	7.33%	22.09%	11.44%	4.42%	-37.03%	7.48%	76.61%

[15] MFR - Hard copy of sheets I-6, I-8, O-1 and O-2 (first page)

7.3 CLASS REVENUE REQUIREMENTS

7.3.1 REVENUE TO COST

The table below is taken from the OEB Cost Allocation model worksheet "O-2 – Fixed Charge |Floor |Ceiling" and illustrates the minimum and maximum level for the Monthly Fixed Charge for each rate class.

Table 14 - Sheet O-2 of the Cost Allocation Model[16]

	1	2	3	5	7	8	9
Summary	**Residential**	**GS <50**	**GS 50-999 kW**	**GS 50-999 kW**	**Street Lighting**	**Sentinel**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$10.07	$19.03	$39.93	$25.93	$1.30	$2.98	$4.17
Customer Unit Cost per month - Directly Related	$16.55	$29.36	$62.76	$47.87	$2.25	$5.16	$7.22
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$32.18	$43.85	$83.15	$63.37	$5.02	$16.28	17.96
Existing Approved Fixed Charge	$36.39	$43.75	$289.38	$2,365.10	$1.68	$7.75	$29.71

[16] MFR - Hard copy of sheets I-6, I-8, O-1 and O-2 (first page)

7.3.2 CLASS REVENUE ANALYSIS

The table below shows the results from the previous Cost Allocation study from the 2016 Test Year as approved in WNP's 2016 Cost of Service rate application (EB-2016-0110):

Table 15 – 2016 Test Year Results of the Cost Allocation Study (EB-2015-0110)

Cost Allocation Results	REVENUE ALLOCATION (sheet O1)							CUSTOMER UNIT COST PER MONTH (sheet O2)		
Customer Class Name	Service Rev Req (row40)		Misc. Revenue (mi) (row19)		Base Rev Req (row80)		Revenue to Cost Expenses %	Avoided Costs (Minimum Charge)	Directly Related	Minimum System with PLCC * adjustment
Residential	1,559,734	58.43%	88,239	67.82%	1,471,495	57.95%	89.78%	$8.65	$14.31	$28.25
General Service < 50 kW	404,332	15.15%	20,347	15.64%	383,984	15.12%	119.66%	$19.75	$31.04	$46.15
General Service > 50 to 999 kW	199,789	7.49%	6,554	5.04%	193,235	7.61%	151.49%	$27.65	$46.02	$81.80
General Service 1,000 to 4,999kW	481,194	18.03%	14,002	10.76%	467,192	18.40%	78.44%	($1.01)	$43.97	$204.32
Unmetered Scattered Load	260	0.01%	19	0.01%	241	0.01%	114.67%	$4.83	$8.36	$21.16
Sentinel Lighting	5,988	0.22%	415	0.32%	5,572	0.22%	62.23%	$2.89	$5.07	$16.75
Street Lighting	17,882	0.67%	528	0.41%	17,354	0.68%	563.95%	($0.63)	$2.80	$180.52
TOTAL	**2,669,178**	**100.00%**	**130,105**	**100.00%**	**2,539,073**	**100.00%**				

The table below shows the results from the latest 2021 Test Year Cost Allocation study. These results are used to compare and analyze the distribution costs under each option and help the utility determine its' 2021 proposed ratios.

Table 16 - Results of the Cost Allocation Study

Cost Allocation Results	REVENUE ALLOCATION (sheet O1)							CUSTOMER UNIT COST PER MONTH (sheet O2)		
Customer Class Name	Service Rev Req (row40)		Misc. Revenue (mi) (row19)		Base Rev Req		Rev2Cost Expenses %	Avoided Costs (Minimum Charge)	Directly Related	Minimum System with PLCC * adjustment
Residential	1,773,877	56.64%	86,284	63.76%	1,687,592	56.32%	98.38%	$10.07	$16.55	$32.18
General Service < 50 kW	448,883	14.33%	18,231	13.47%	430,652	14.37%	120.37%	$19.03	$29.36	$43.85
General Service 50 - 999 kW	275,282	8.79%	5,120	3.78%	270,163	9.02%	107.38%	$39.93	$62.76	$83.15
General Service 1000 - 4999 kW	571,471	18.25%	18,423	13.61%	553,048	18.46%	90.23%	$25.93	$47.87	$63.37
Unmetered Scattered Load	624	0.02%	32	0.02%	592	0.02%	174.73%	$4.17	$7.22	$17.96
Sentinel Lighting	4,526	0.14%	255	0.19%	4,271	0.14%	98.38%	$2.98	$5.16	$16.28
Street Lighting	57,027	1.82%	6,985	5.16%	50,043	1.67%	51.56%	$1.30	$2.25	$5.02
TOTAL	**3,131,690**	**100.00%**	**135,330**	**100.00%**	**2,996,360**	**100.00%**				

The table below shows the allocation percentage and base revenue requirement allocation under the three scenarios of (a) existing rates, (b) cost allocation results and (c) proposed 2021 proposed allocation.

Table 17- Base Revenue Requirement Under 3 Scenarios

	Proposed Base Revenue Requirement					
Customer Class Name	**Cost Allocation Results**		**Existing Rates**		**Proposed Allocation**	
Residential	56.32%	$1,687,592	55.37%	$1,658,939	52.65%	$1,577,450
General Service < 50 kW	14.37%	$430,652	17.42%	$522,079	17.37%	$520,438
General Service 50 to 999 kW	9.02%	$270,163	9.69%	$290,475	9.69%	$290,475
General Service 1,000 to 4,999 kW	18.46%	$553,048	16.59%	$497,193	18.46%	$553,038
Unmetered Scattered Load	0.02%	$592	0.04%	$1,058	0.02%	$716
Sentinel Lighting	0.14%	$4,271	0.14%	$4,197	0.14%	$4,197
Street Lighting	1.67%	$50,043	0.75%	$22,419	1.67%	$50,045
TOTAL	**100.00%**	**$2,996,360**	**100.00%**	**$2,996,360**	**100.00%**	**$2,996,360**

The table below shows the revenue offset allocation which resulted from Cost Allocation Study (Sheet O1).

Table 18 - Revenue Offset Allocation as per Cost Allocation Study

	Revenue Offsets	
Customer Class Name	**%**	**$**
Residential	63.76%	$86,284
General Service < 50 kW	13.47%	$18,231
General Service 50 to 999 kW	3.78%	$5,120
General Service 1,000 to 4,999 kW	13.61%	$18,423
Unmetered Scattered Load	0.02%	$32
Sentinel Lighting	0.19%	$255
Street Lighting	5.16%	$6,985
TOTAL	**100.00%**	**$135,330**

The table below shows the allocation of the service revenue requirement under the same three scenarios.

Table 19 - Service Revenue Requirement Under 3 Scenarios

	Service Revenue Requirement $		
Customer Class Name	**Existing Rates**	**Cost Allocation**	**Rate Application**
Residential	$1,745,223	$1,773,877	$1,663,735
General Service < 50 kW	$540,311	$448,883	$538,669
General Service 50 to 999 kW	$295,594	$275,282	$295,594
General Service 1,000 to 4,999 kW	$515,616	$571,471	$571,461
Unmetered Scattered Load	$1,090	$624	$749
Sentinel Lighting	$4,453	$4,526	$4,453
Street Lighting	$29,404	$57,027	$57,030
TOTAL	**$3,131,690**	**$3,131,690**	**$3,131,690**

7.4 REVENUE-TO-COST RATIOS

The results of a 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 that are being subsidized and those that are 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.

In the "Review of Electricity Distribution Cost Allocation Policy - EB-2010-0219" report (issued March 31, 2011), the Board established what it considered to be the appropriate ranges of revenue to cost ratios. The ranges are Residential 0.85 to 1.15 and all other classes 0.80 to 1.20.

7.4.1 COST ALLOCATION RESULTS AND ANALYSIS

The table below shows WNP's proposed Revenue to Cost ratios for 2021 Test Year for each customer class:

Table 20 – Proposed Revenue Allocation

				Target Range	
Customer Class Name	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Variance**	**Floor**	**Ceiling**
Residential	98.38	93.79	4.59	0.85	1.15
General Service < 50 kW	120.37	120.00	0.37	0.80	1.20
General Service 50 to 999 kW	107.38	107.38	0.00	0.80	1.20
General Service 1,000 to 4,999 kW	90.23	100.00	-9.77	0.80	1.20
Unmetered Scattered Load	174.73	120.00	54.73	0.80	1.20
Sentinel Lighting	98.38	98.38	0.00%	0.80	1.20
Street Lighting	51.56	100.00	-48.44%	0.80	1.20

The table on the following page shows the completed worksheet "11. Cost Allocation" from the OEB's 2021 Revenue Requirement Workform. This table provides information on previously approved Revenue to Cost ratios and proposed ratios.

Table 21 - OEB Rev Reqt Workform: worksheet "11. Cost Allocation"

Stage in Application Process: *Initial Application*

A) ***Allocated Costs***

	Name of Customer Class [3]		Costs Allocated from Previous Study [1]	%		Allocated Class Revenue Requirement [1] (7A)	%
	From Sheet 10. Load Forecast						
1	Residential	$	1,559,734	58.43%	$	1,773,877	56.64%
2	General Service<50kW	$	404,332	15.15%	$	448,883	14.33%
3	General Service 50-999kW	$	199,789	7.49%	$	275,282	8.79%
4	General Service 1000-4999kW	$	481,194	18.03%	$	571,471	18.25%
5	Unmetered Scattered Load	$	260	0.01%	$	624	0.02%
6	Sentinel Lights	$	5,988	0.22%	$	4,526	0.14%
7	Street Lights	$	17,882	0.67%	$	57,027	1.82%
	Total	$	2,669,178	100.00%	**$**	**3,131,690**	100.00%
				Service Revenue Requirement (from Sheet 9)	**$**	**3,131,690.45**	

B) ***Calculated Class Revenues***

	Name of Customer Class		Load Forecast (LF) X current approved rates (7B)		LF X current approved rates X (1+d) (7C)		LF X Proposed Rates (7D)		Miscellaneous Revenues (7E)
1	Residential	$	1,465,096	$	1,658,939	$	1,577,450	$	86,284
2	General Service<50kW	$	461,076	$	522,079	$	520,438	$	18,231
3	General Service 50-999kW	$	256,534	$	290,475	$	290,475	$	5,120
4	General Service 1000-4999kW	$	439,097	$	497,193	$	553,038	$	18,423
5	Unmetered Scattered Load	$	934	$	1,058	$	716	$	32
6	Sentinel Lights	$	3,707	$	4,197	$	4,197	$	255
7	Street Lights	$	19,800	$	22,419	$	50,045	$	6,985
	Total	$	2,646,244	$	2,996,360	$	2,996,360	$	135,330

C) ***Rebalancing Revenue-to-Cost Ratios***

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2016 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	92.49%	98.38%	93.79%	85 - 115
2	General Service<50kW	119.07%	120.37%	120.00%	80 - 120
3	General Service 50-999kW	119.61%	107.38%	107.38%	80 - 120
4	General Service 1000-4999kW	99.68%	90.23%	100.00%	80 - 120
5	Unmetered Scattered Load	114.76%	174.73%	120.00%	80 - 120
6	Sentinel Lights	79.87%	98.38%	98.38%	80 - 120
7	Street Lights	119.96%	51.56%	100.00%	80 - 120

(D) ***Proposed Revenue-to-Cost Ratios***

	Name of Customer Class	Proposed Revenue-to-Cost Ratio			Policy Range
		Test Year	Price Cap IR Period		
		2021	2022	2023	
1	Residential	93.79%	93.79%	93.79%	85 - 115
2	General Service<50kW	120.00%	120.00%	120.00%	80 - 120
3	General Service 50-999kW	107.38%	107.38%	107.38%	80 - 120
4	General Service 1000-4999kW	100.00%	100.00%	100.00%	80 - 120
5	Unmetered Scattered Load	120.00%	120.00%	120.00%	80 - 120
6	Sentinel Lights	98.38%	98.38%	98.38%	80 - 120
7	Street Lights	100.00%	100.00%	100.00%	80 - 120

The information below addresses the method and logic used to update the revenue to cost ratios from the Cost Allocation study to determine the proposed ratios.

The table below illustrates WNP's proposed Revenue to Cost reallocation based on an analysis of the proposed results from the Cost Allocation Study vs. the Board's floor and ceiling ranges.

Table 22 – 2021 Allocation[17]

Customer Class Name	**Calculated R/C Ratio**	**Proposed R/C Ratio**	**Variance**	**Target Range** **Floor**	**Ceiling**
Residential	98.38	93.79	4.59	0.85	1.15
General Service < 50 kW	120.37	120.00	0.37	0.80	1.20
General Service 50 to 999 kW	107.38	107.38	0.00	0.80	1.20
General Service 1,000 to 4,999 kW	90.23	100.00	-9.77	0.80	1.20
Unmetered Scattered Load	174.73	120.00	54.73	0.80	1.20
Sentinel Lighting	98.38	98.38	0.00	0.80	1.20
Street Lighting	51.56	100.00	-48.44	0.80	1.20

* Ratios highlighted in yellow fell outside of the floor to ceiling range under the Cost Allocation Model.

The proposed Revenue to Cost ratio is adjusted by changing the allocation percentage for each class. The utility reviews and assesses the bill impacts for each class before adjusting the Revenue to Cost ratios. [18]

In reviewing the calculated revenue to cost results from the Cost Allocation study, there are three customer classes that are outside of the Board's floor/ceiling parameters. WNP has applied the same methodology as used in both the Applicant's 2016 Cost of Service application (EB-2015-0110) and 2012 Cost of Service application (EB-2011-0249) for adjusting revenue-to-cost ratio, namely:

- For General Service <50 kW and Unmetered Scattered Load, WNP adjusted the revenue-to-cost ratio to 120% to meet the ceiling limit set by the Board;

[17] MFR - If R:C ratios outside deadband based on model - distributors must include cost allocation proposal to bring them within the OEB-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rates of any particular class or classes is significant.

[18] MFR - To support a proposal to rebalance rates, the distributor must provide information on the revenue by class that would apply if all rates were changed by a uniform percentage. Ratios must be compared with the ratios that will result from the rates being proposed by the distributor.

- For Street Lighting, WNP adjusted the revenue-to-cost ratio to 100%. Based on the output of the 2021 Cost Allocation model, the revenue to cost ratio is 51.56% for the Streetlight customer class. This indicates that this rate class, since the last re-basing in 2016 (WNP 2016 Cost of Service application EB-2015-0110) has not been paying its' equitable share of revenue to cover the utility's costs. As an outcome of the 2016 Cost of Service application, the Monthly Service Charge per connection fell from $7.12 *(2015's charge)* to $1.68 *(2016's charge)* and the distribution volumetric rate reduced from $7.9283/kW *(2015's rate)* to $1.7664/kW *(2016's rate).* [19]. Therefore, WNP is proposing to adjust the revenue to cost ratio to 100% in order for this particular rate class pays its "fair share" moving forward. (The bill impact implications are discussed in detail in Exhibit 8).

WNP is also proposing the following:

- For General Service 1,000 to 4,999 kW customer class, the 2021 Cost Allocation model produced a revenue to cost ratio of 90.23. The utility has adjusted this to 100.00 in the Test Year 2021 because the five customers in this rate class receive additional services that are not charged by WNP, for example:
    - During a power outage, the customers in this rate class contact WNP's CEO / President on his company cell phone for information, day or night. The CEO / President of the utility personally provides updates to the customers about cause of the outage and restoration times. This information helps large customers make informed critical operational decisions regarding staffing, for instance like shift cancellations or special staffing call-ins and production planning changes.
    - There are 5 customers in this rate class and each has the direct company cell number for the CEO/President of WNP.
    - The CEO / President and the Regulatory Manager are frequently requested to attend meetings to assist with capacity requirements/changes and energy programs specific to large customers like the Industrial Conservation Initiative. Also

[19] Comparing OEB-approved rates for WNP: OEB Decision & Rate Order, March 19, 2015 (EB-2014-0121) for distribution rates effective May 1, 2015 versus OEB Decision & Order, corrected April 6, 2016 (EB-2015-0110) for distribution rates effective May 1, 2016

the CEO / President has been requested to attend special meeting regarding energy storage.

As a result of applying a revenue to cost ratio of 100.00 for this customer class, WNP projects the total bill impact, including Rate Riders for disposition of Deferral / Variance accounts is a 3.30% above current monthly bill.

It should be noted that WNP has not adjusted the revenue to cost ratio for any customer classes in its' annual IRM rate applications. Each IRM application has applied the same cost-to-revenue ratios that were approved in WNP's 2016 Cost of Service application.

WNP is proposing to adjust the revenue to cost ratios over the period of the 2021 Test Year and recommends that these ratios are held constant over the years of 2022 and 2023, as illustrated below:

Table 23 – Revenue to Cost Ratios 2021, 2022 and 2023

Customer Class Name	**Proposed R/C Ratio**	**2021 Test Year**	**2022**	**2023**
Residential	93.79	93.79	93.79	93.79
General Service < 50 kW	120.00	120.00	120.00	120.00
General Service 50 to 999 kW	107.38	107.38	107.38	107.38
General Service 1,000 to 4,999 kW	100.00	100.00	100.00	100.00
Unmetered Scattered Load	120.00	120.00	120.00	120.00
Sentinel Lighting	98.38	98.38	98.38	98.38
Street Lighting	100.00	100.00	100.00	100.00

Also, WNP wish to note that in determining the proposed cost-to-revenue ratio adjustments, the LDC has considered the bill impact for each rate class. In WNP's opinion, these ratios do not result in a bill impact change of more than 10% for each rate class (with the exception of Street Lights with a bill impact of 86.5% for reasons as discussed above). For further details about the class specific bill impacts, please refer to Exhibit 8.

7.4.2 HOST DISTRIBUTOR

WNP is not a Host Distributor therefore evidence of consultation with embedded distributors is not applicable. [20]

7.4.3 UNMETERED LOADS

On June 12, 2015, the OEB released their report 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" is 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. WNP implemented these changes in its' 2016 Cost of Service application (EB-2015-0110) and has continued to follow this policy in this 2021 Cost of Service application.

WNP has informed its' Street Lighting customers that the utility is filing a rate application that proposes an increase of approximately 86.5% above the current rates charged. As of October 2020, there has been no feedback or objections received by the utility from the streetlight customers.[21]

WNP has not communicated with Unmetered Scattered Load or Sentinel Lighting customers because the bill impact is not in excess of the Board's 10% total bill impact threshold for rate mitigation consideration.[22]

[20] MFR - Host Distributor - evidence of consultation with embedded Dx
[21] MFR - Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges
[22] MFR - Confirmation of communication with unmetered load customers when proposing changes to the level of the rates and charges or the introduction of new rates and charges

7.4.4 MICROFIT CLASS

WNP is proposing no change to the MicroFIT Monthly Service Charge of $15.69 - a non-provincial-wide rate that was approved in the LDC's 2016 Cost of Service rate application (EB-2015-0110).

In its' 2016 Cost of Service rate application, EB-2015-0110, WNP explained in Exhibit 3 the utility incurred third-party settlement costs of $10.00 per MicroFIT account per month that specifically related to MicroFIT customers. During interrogatories, the LDC used the OEB's Cost Allocation model, worksheet "O3.6 MicroFIT Charge" to demonstrate the impact of this third-party settlement cost that is specifically related to MicroFIT accounts.[23] WNP continues to incur this third-party settlement cost of $10.00 per MicroFIT account per month.

WNP does not record specific costs related to MicroFIT meters separately. However, assuming that cost-structure for MicroFIT meters is similar to that of a Residential metered customer, using the data in worksheet "O3.6 - MicroFIT Charge" in the Cost Allocation model, then the calculated MicroFIT Monthly Unit Cost for 2021 would be $16.33 per account per month as illustrated below:

Table 24 – "O3.6 – MicroFIT Charge" Including MicroFIT Meters to Residential Base

Description	Residential	Monthly Unit Cost	*Monthly Unit Cost including MicroFIT*
Customer Premises - Operations Labour (5070)	$ 42,145.04	$ 1.05	$ 1.04
Customer Premises - Materials and Expenses (5075)	$ 10,536.26	$ 0.26	$ 0.26
Meter Expenses (5065)	$ 37,413.12	$ 0.93	$ 0.92
Maintenance of Meters (5175)	$ 21,824.32	$ 0.54	$ 0.54
Meter Reading Expenses (5310)	$ 54,106.39	$ 1.34	$ 10.00
Customer Billing (5315)	$ 90,215.25	$ 2.24	$ 2.23
Amortization Expense - General Plant Assigned to Meters	$ 4,798.11	$ 0.12	$ 0.12
Admin & General Expenses allocated to O&M expenses for meters	$ 47,334.50	$ 1.18	$ 1.17
Allocated PILS (general plant assigned to meters)	$ -	$ -	$ -
Interest Expense	$ 828.51	$ 0.02	$ 0.02
Income Expenses	$ 1,240.84	$ 0.03	$ 0.03
Total Cost	**$310,442.35**	**$ 7.71**	**$ 16.33**
Number of Residential Customers (forecast year-average for 2021)	3,355		
Number of MicroFIT accounts *(as at Dec 31 st 2019)*	22		
Number of Residential accounts + MicroFIT accounts	3,377		

[23] EB-2015-0110 WellingtonNorth_IR_20160127 Applicant's response to IR 3-VECC-21 – page 130

In the above table, WNP has added the 22 MicroFIT connection accounts to the 2021 forecasted number of Residential customer accounts. Dividing the total cost by a revised meter count of 3,377 plus adding the $10.00 per month for settlement provider costs (highlighted above) results in a MicroFIT monthly unit cost of $16.33[24]. WNP used this approach in its' 2016 Cost of Service application as evidence to adjust its' MicroFIT Monthly Service from the province-wide rate, which was accepted by all intervening parties.

The calculated monthly unit cost presented in the table above of $16.33 is above WNP's current OEB-approved MicroFIT Monthly Service Charge. The Applicant is proposing to maintain the current rate of $15.69 for the MicroFIT Monthly Service Charge.

7.4.5 STANDBY RATES

The utility is not seeking Standby Rates in this application. [25]

[24] MFR - As per OEB letter "Review of Fixed Monthly Charge for microFIT Generator Service classification" (February 24, 2020), any distributor that applies for a distributor-specific charge will be required to support its costs with evidence

[25] MFR - Standby Rates - if seeking approval on final basis, provide evidence that affected customers have been advised. If seeking changes to standby charges, provide rationale and evidence that affected customer have been advised.

APPENDICES

List of Appendices

Appendix 7A	USF Demand Profile Methodology Paper
Appendix 7B	2018 Demand Profile Model (excel file)
Appendix 7C	2019 Demand Profile Model (excel file)
Appendix 7D	Information Workbook (excel file)
Appendix 7E	HONI Demand Profile Method (excel file)

APPENDIX 7A USF DEMAND PROFILE METHODOLOGY PAPER

USF Demand Profile Methodology Paper

August 2020

Purpose:

Supporting Evidence for Exhibit 7 – Cost Allocation, section 7.2.8 of Wellington North Power Inc.'s 2021 Cost of Service application EB-2020-0061

Contents

Supporting Excel Workbooks:

The following excel models have been filed as Appendices to "Exhibit 7 – Cost Allocation" of Wellington North Power Inc.'s 2021 Cost of Service application (EB-2020-0061):

- Appendix 7B: 2018 Demand Profile Model. (filed as
- Appendix 7C: 2019 Demand Profile Model.
- Appendix 7D: Information Workbook.
- Appendix 7E: HONI Demand Profile Method.

1. Background

For previous cost of service rate applications (e.g. EB-2015-0110 and EB-2011-0249) for Wellington North Power Inc. (WNP), the Applicant relied on load profiles produced by Hydro One Networks Inc., (HONI) which were based on sample data from 2004. The coincident peak and non-coincident peak values populated in worksheet I8 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 will be using the "USF Demand Profile Working Group" methodology as described in this document, the "USF Demand Profile Methodology Paper", using 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 has used this data to update load profiles for all of its rate classes, in accordance with Section 2.7.1 of the Filing Requirements.

The methodology described in detail in Appendix A and used in this Cost of Service rate 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

[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.

peak (CP) values from the years 2018 and 2019 were input in Tab I8 of the OEB's Cost Allocation Model.

Note: Copies of the 2018 and 2019 demand models as separate excel workbooks have been filed with this application containing the data and calculations.

[Reference: "2018 Demand Profile Model" and "2019 Demand Profile Model"].

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:

Demand Profiles using 2018 Demand Data

	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
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

[Reference: Tab “4. CP & NCP” of “2018 Demand Profile Model” workbook.]

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:

Demand Profiles using 2019 Demand Data

	Demand Profile with 2019 Demand Data						
	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
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

[Reference: Tab “4. CP & NCP” of “2019 Demand Profile Model” workbook.]

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:

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

	Non-Coincident Peak						
2018	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
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	6,088	2,283	3,560	7,386	54	6	2
4NCP	22,056	8,740	13,712	28,957	217	23	7
12NCP	59,264	23,704	38,653	83,067	636	56	18

[Reference: Tab "3a. (USF) NCP – 2018 & 2019" of "Information Workbook".]

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

	Coincident Peak						
2018	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	StreetLights	Sentinel Lights	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
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	4,810	2,121	2,735	6,494	28	2	1
4CP	18,038	7,873	11,623	25,648	76	6	2
12CP	47,016	21,704	34,398	78,325	149	11	4

[Reference: Tab "3b. (USF) CP – 2018 & 2019" of "Information Workbook".]

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 has been filed with this 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:

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

	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	Street Lights	Sentinel Lights	Unmetered Scattered Load
1NCP	7,144	2,117	2,377	8,278	166	7	0.40
4NCP	26,821	8,179	9,117	32,715	663	26	1
12NCP	67,219	21,868	24,489	95,257	1,984	65	4
1CP	6,232	1,317	1,609	8,126	166	5	0.35
4CP	24,672	5,337	7,620	29,563	658	18	1
12CP	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.

Weather Sensitive Rate Classes Demand Allocators Approved in EB-2015-0110 Application

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

[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.

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 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 <u>not</u> 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:

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	6,256	2,280	3,370	11,906
4NCP	**22,084**	**8,685**	**13,277**	**44,046**
12NCP	60,247	24,050	38,381	122,678
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	5,880	2,275	3,377	11,532
4NCP	**21,910**	**8,761**	**13,151**	**43,822**
12NCP	58,240	23,196	37,575	119,011
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	6,293	2,276	3,729	12,298
4NCP	**22,208**	**8,709**	**14,228**	**45,146**
12NCP	60,082	24,078	39,589	123,749
Allocation of 4NCP	49%	19%	32%	100%

	2019 Actual Demand **After** Weather Normal Adj			
	Non-Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1NCP	5,882	2,290	3,391	11,563
4NCP	**21,904**	**8,771**	**13,195**	**43,871**
12NCP	58,446	23,329	37,718	119,493
Allocation of 4NCP	50%	20%	30%	100%

[References: Tab “4a. 2018 bef Weather Adj”; Tab “4b. 2019 bef Weather Adj”; and Tab “4c. Shift between Rate Classes” of “Information Workbook”.]

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

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	4,155	2,100	3,294	9,549
4CP	**17,139**	**8,120**	**12,167**	**37,426**
12CP	46,808	22,275	35,654	104,738
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	5,324	1,976	2,704	10,004
4CP	**18,761**	**7,989**	**11,196**	**37,946**
12CP	47,468	21,239	33,253	101,961
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	4,324	2,276	2,778	9,378
4CP	**16,868**	**8,002**	**12,081**	**36,951**
12CP	47,319	22,434	35,482	105,235
Allocation of 4CP	46%	22%	33%	100%

	2019 Actual Demand **After** Weather Normal Adj			
	Coincident Peak			
	Residential	General Service <50kW	General Service 50-999kW	Total
1CP	5,296	1,967	2,692	9,955
4CP	**19,208**	**7,744**	**11,164**	**38,116**
12CP	46,713	20,974	33,315	101,002
Allocation of 4CP	50%	20%	29%	100%

[References: Tab “4a. 2018 bef Weather Adj”; Tab “4b. 2019 bef Weather Adj”; and Tab “4c. Shift between Rate Classes” of “Information Workbook”.]

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.

4NCP Demand Allocator Comparison

	Residential	General Service <50kW	General Service 50-999kW	Total
2016 CoS - "HONI Method"	26,821	8,179	9,117	44,117
% of Total	61%	19%	21%	100%
2019 Data - HONI Method	27,334	7,903	12,637	47,874
% of Total	57%	17%	26%	100%
2018 - **Not** Weather Normalized	22,084	8,685	13,277	44,046
% of Total	50%	20%	30%	100%
2018 - Weather Normalized	22,208	8,709	14,228	45,146
% of Total	49%	19%	32%	100%
2019 - **Not** Weather Normalized	21,910	8,761	13,151	43,822
% of Total	50%	20%	30%	100%
2019 - Weather Normalized	21,904	8,771	13,195	43,871
% of Total	50%	20%	30%	100%

4CP Demand Allocator Comparison

	Residential	General Service <50kW	General Service 50-999kW	Total
2016 CoS - "HONI Method"	24,672	5,337	7,620	37,629
% of Total	66%	14%	20%	100%
2019 Data - HONI Method	25,144	5,157	10,561	40,862
% of Total	62%	13%	26%	100%
2018 - **Not** Weather Normalized	17,139	8,120	12,167	37,426
% of Total	46%	22%	33%	100%
2018 - Weather Normalized	16,868	8,002	12,081	36,951
% of Total	46%	22%	33%	100%
2019 - **Not** Weather Normalized	18,761	7,989	11,196	37,946
% of Total	49%	21%	30%	100%
2019 - Weather Normalized	19,208	7,744	11,164	38,116
% of Total	50%	20%	29%	100%

[References: Tab "4e NCP and 4CP Comparison" of "Information Workbook".]

Observations

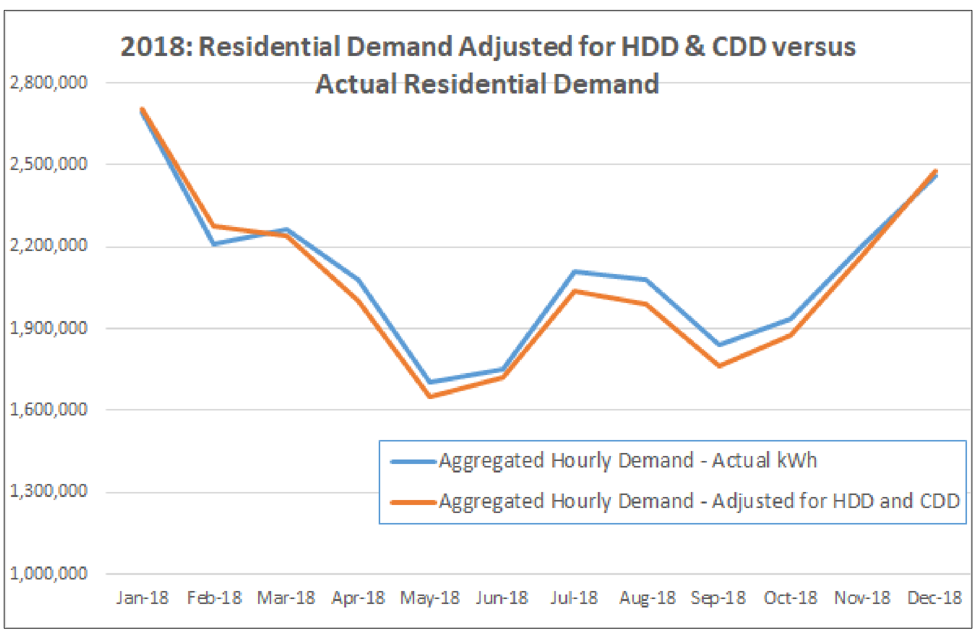
The following observations can be made from this analysis:

i. The traditional "HONI method", as applied in WNP's 2016 Cost of Service application (EB-2015-0110) and 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.

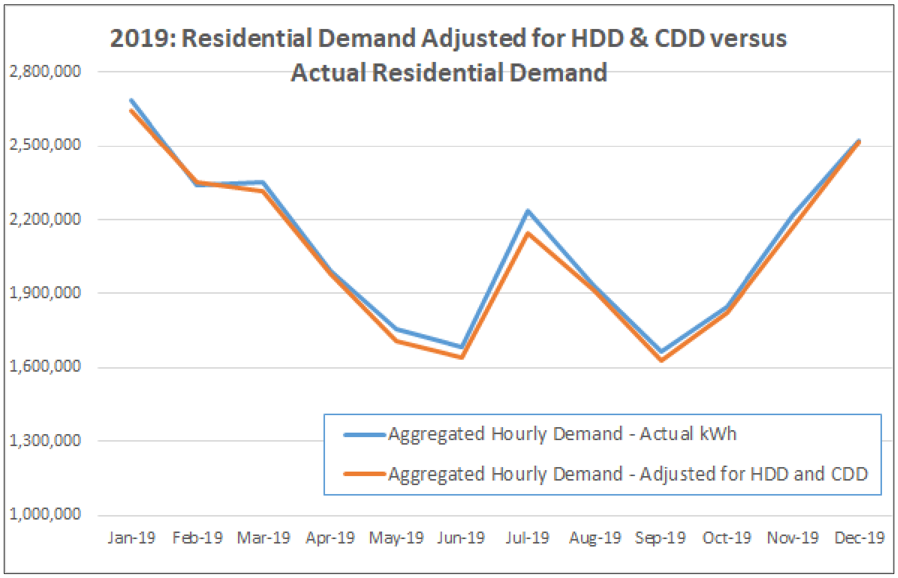
The graph below shows 2018 Actual Demand for WNP's Residential customers overlaid with the Weather Adjusted Demand:



[Reference: Tab "5. Graph" in "2018 Demand Profile Model" workbook.]

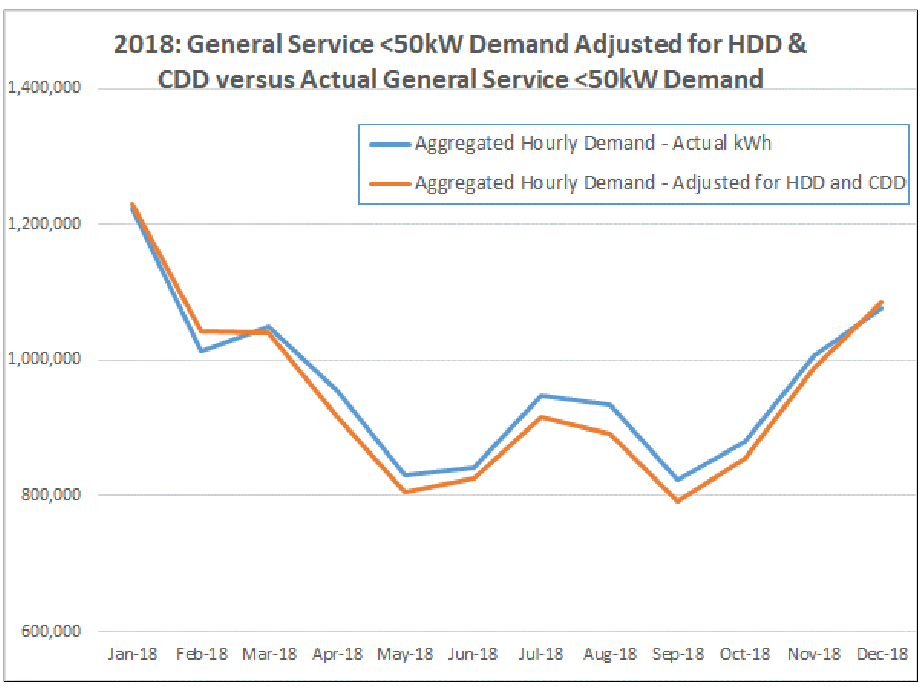
[6] The Applicant acknowledges this method is based on the data available at the time of the 2016 Cost of Service application and, by no means, is criticizing the traditional method that OEB and HONI developed

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



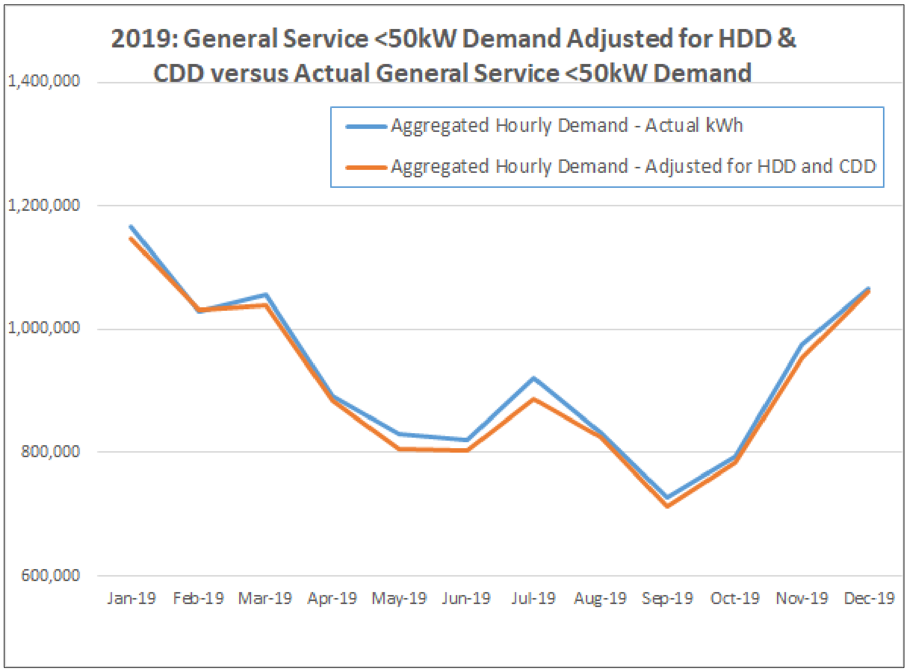
[Reference: Tab "5. Graph" in "2019 Demand Profile Model" workbook.]

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



[Reference: Tab "5. Graph" in "2018 Demand Profile Model" workbook.]

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



[Reference: Tab "5. Graph" in "2019 Demand Profile Model" workbook.]

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 and this demand pattern change is not a result from the weather normalization process; and
b) 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 of the OEB's Cost Allocation Model that has been filed with this application.

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 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.

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

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.:

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

Year: 2018 – Annual kWh

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

[Reference: Tabs “3a. Resi – Hourly Demand Data” column G; “3b. GS<50kW – Hourly Demand Data” column G; “3c. GS50-999kW – Hourly Demand Data” column G; and “3d. Not Weather Sensitive” in “2018 Demand Profile Model” workbook.]

Year: 2019 – Annual kWh

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

[Reference: Tabs “3a. Resi – Hourly Demand Data” column G; “3b. GS<50kW – Hourly Demand Data” column G; “3c. GS50-999kW – Hourly Demand Data” column G; and “3d. Not Weather Sensitive” in “2019 Demand Profile Model” workbook.]

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

[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.

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 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.

<u>Remove Actual Weather-Sensitive Load</u>

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

[References: Tab "1a. Load Forecast" of "Information Workbook".]

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 & 2019 from the Applicant's load forecast and the effect of weather-sensitive consumption by removing HDD & CDD:

2018 & 2019 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**	

[References: Tab "1a. Load Forecast" of "Information Workbook".]

[Reference: Tab "1. Load Forecast Output" in "2018 Demand Profile Model" workbook.]

	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**	

[References: Tab "1a. Load Forecast" of "Information Workbook".]

[Reference: Tab "1. Load Forecast Output" in "2019 Demand Profile Model" workbook.]

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. Airconditioning 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:

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

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

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

<u>Add Weather-Normal Load</u>

For 2018, the daily HDD values for the 10-year HDD data 2009-2018 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:

10 Year HDD Weather-Normal Adjustment

			January 2009 - Sorted					January 2010 - Sorted					January 2018 - Sorted				
Date/Time	10-Yr Avg HDD	10 Yr Avg to 2018	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)
6-Jan-18	36.42	0.92	15-Jan-09	2009	1	15	38.80	29-Jan-10	2010	1	29	35.10	6-Jan-18	2018	1	6	39.60
5-Jan-18	35.70	0.91	14-Jan-09	2009	1	14	38.70	30-Jan-10	2010	1	30	34.60	5-Jan-18	2018	1	5	39.20
1-Jan-18	33.76	0.95	20-Jan-09	2009	1	20	34.40	2-Jan-10	2010	1	2	33.70	1-Jan-18	2018	1	1	35.60
13-Jan-18	32.77	0.96	16-Jan-09	2009	1	16	34.30	9-Jan-10	2010	1	9	32.90	13-Jan-18	2018	1	13	34.00
4-Jan-18	31.79	0.94	24-Jan-09	2009	1	24	33.40	3-Jan-10	2010	1	3	31.60	4-Jan-18	2018	1	4	33.80
30-Jan-18	30.88	0.96	17-Jan-09	2009	1	17	32.90	28-Jan-10	2010	1	28	29.70	30-Jan-18	2018	1	30	32.20
3-Jan-18	30.28	0.96	26-Jan-09	2009	1	26	31.60	10-Jan-10	2010	1	10	29.50	3-Jan-18	2018	1	3	31.60
14-Jan-18	29.42	0.94	21-Jan-09	2009	1	21	31.30	4-Jan-10	2010	1	4	29.20	14-Jan-18	2018	1	14	31.30
2-Jan-18	29.01	0.95	25-Jan-09	2009	1	25	30.90	8-Jan-10	2010	1	8	29.00	2-Jan-18	2018	1	2	30.40
7-Jan-18	28.21	0.95	1-Jan-09	2009	1	1	30.60	5-Jan-10	2010	1	5	27.60	7-Jan-18	2018	1	7	29.80
24-Jan-18	27.76	0.95	27-Jan-09	2009	1	27	30.60	31-Jan-10	2010	1	31	27.50	24-Jan-18	2018	1	24	29.10
17-Jan-18	27.42	0.96	9-Jan-09	2009	1	9	30.20	12-Jan-10	2010	1	12	27.40	17-Jan-18	2018	1	17	28.50
15-Jan-18	27.05	0.95	13-Jan-09	2009	1	13	29.70	11-Jan-10	2010	1	11	27.00	15-Jan-18	2018	1	15	28.40
16-Jan-18	26.73	0.96	10-Jan-09	2009	1	10	29.60	21-Jan-10	2010	1	21	26.30	16-Jan-18	2018	1	16	27.90
25-Jan-18	26.22	0.97	11-Jan-09	2009	1	11	29.60	6-Jan-10	2010	1	6	26.10	25-Jan-18	2018	1	25	26.90
18-Jan-18	25.71	0.96	30-Jan-09	2009	1	30	29.10	20-Jan-10	2010	1	20	25.90	18-Jan-18	2018	1	18	26.70
29-Jan-18	25.05	0.97	3-Jan-09	2009	1	3	28.90	1-Jan-10	2010	1	1	25.50	29-Jan-18	2018	1	29	25.80
31-Jan-18	24.51	1.02	19-Jan-09	2009	1	19	28.40	7-Jan-10	2010	1	7	25.50	31-Jan-18	2018	1	31	24.10
9-Jan-18	23.81	1.06	31-Jan-09	2009	1	31	28.00	27-Jan-10	2010	1	27	24.50	9-Jan-18	2018	1	9	22.40
19-Jan-18	23.20	1.09	8-Jan-09	2009	1	8	27.90	13-Jan-10	2010	1	13	23.20	19-Jan-18	2018	1	19	21.30
8-Jan-18	22.79	1.10	18-Jan-09	2009	1	18	26.70	19-Jan-10	2010	1	19	21.80	8-Jan-18	2018	1	8	20.70
28-Jan-18	22.48	1.09	12-Jan-09	2009	1	12	26.60	18-Jan-10	2010	1	18	21.60	28-Jan-18	2018	1	28	20.60
23-Jan-18	21.97	1.08	29-Jan-09	2009	1	29	26.30	26-Jan-10	2010	1	26	21.30	23-Jan-18	2018	1	23	20.40
12-Jan-18	21.37	1.08	28-Jan-09	2009	1	28	26.00	17-Jan-10	2010	1	17	21.10	12-Jan-18	2018	1	12	19.80
10-Jan-18	20.75	1.13	6-Jan-09	2009	1	6	25.20	22-Jan-10	2010	1	22	20.80	10-Jan-18	2018	1	10	18.30
26-Jan-18	20.26	1.11	4-Jan-09	2009	1	4	25.00	23-Jan-10	2010	1	23	20.80	26-Jan-18	2018	1	26	18.30
20-Jan-18	19.66	1.12	23-Jan-09	2009	1	23	24.60	16-Jan-10	2010	1	16	20.70	20-Jan-18	2018	1	20	17.50
21-Jan-18	19.11	1.10	22-Jan-09	2009	1	22	24.00	14-Jan-10	2010	1	14	20.30	21-Jan-18	2018	1	21	17.40
22-Jan-18	18.41	1.17	5-Jan-09	2009	1	5	23.90	15-Jan-10	2010	1	15	18.20	22-Jan-18	2018	1	22	15.80
27-Jan-18	17.14	1.13	2-Jan-09	2009	1	2	22.30	25-Jan-10	2010	1	25	16.60	27-Jan-18	2018	1	27	15.20
11-Jan-18	15.28	1.48	7-Jan-09	2009	1	7	21.90	24-Jan-10	2010	1	24	16.50	11-Jan-18	2018	1	11	10.30

[Reference: Tab “2b. HDD Sorted + 10yr Avg” in “2018 Demand Profile Model” workbook.]

The above table shows:

- HDD data for January 2009 sorted by largest to smallest.
- HDD data for January 2010 sorted by largest to smallest.
- HDD data for January 2018 sorted by largest to smallest.
- (HDD data for January 2011 to 2017 was also collected and sorted - not illustrated in table above).

- As this is information is to be applied to the 2018 Hourly Demand data, to the left, the 2018 dates for January are used. These dates are in order of the January 2018 HDD data sorted by largest to smallest – January 6 was the coldest day during January 2018.
- 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 2009 to 2018 was considered to be the weather-normal HDD value for the coldest day in January. In this example, the coldest HDD was 36.42.
- The "10 Yr Avg to 2018" calculates the 10-year average HDD divided by the 2018 HDD. In this instance, for January 6th 2018 the calculation is 36.42 / 39.60 = 0.92. The purpose of this calculation is to adjust the 2018 Demand Profile data for each day (in this example January 6th) by this factor to weather normalize the demand data.

The same sorting and averaging process was repeated to determine weather-normal CDD values. [Reference: Tab "2c. CDD Sorted + 10yr Avg" in "2018 Demand Profile Model" workbook.]

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[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:

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

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

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

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

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

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

[Reference: Tabs "3a. Resi – Hourly Demand Data" column S; "3b. GS<50kW – Hourly Demand Data" column S; "3c. GS50-999kW – Hourly Demand Data" column S; and "3d. Not Weather Sensitive" in "2018 Demand Profile Model" workbook.]

[Same Reference applies for 2019 in 2019 Demand Profile Model" workbook.]

[10] If OEB Staff and Intervenors view that the "same" time periods are acceptable, then the method and model could adapted to incorporate this feedback

The tables below illustrates the effect of weather normalization:

2018 Weather Normalization (kWh)

Rate Class	Demand Profile	Weather Normalization	Effect
Residential	25,345,905	24,922,053	-1.7%
GS <50kW	11,582,140	11,388,935	-1.7%
GS 50-999kW	18,316,320	17,995,259	-1.8%
GS 1,000-4,999kW	43,913,956	43,913,956	0.0%
Street Lights	691,015	691,015	0.0%
Sentinel Lighting	19,673	19,673	0.0%
USL	6,801	6,801	0.0%

[Reference example: Tab “3a. Resi – Hourly Demand Data” column G total shows Demand Profile and column S shows Weather Normalization total in “2018 Demand Profile Model” workbook]

2019 Weather Normalization (kWh)

Rate Class	Demand Profile	Demand Profile	Effect
Residential	25,242,540	24,852,891	-1.5%
GS <50kW	11,109,758	10,935,590	-1.6%
GS 50-999kW	18,739,595	18,434,747	-1.6%
GS 1,000-4,999kW	42,766,148	42,766,148	0.0%
Street Lights	652,367	652,367	0.0%
Sentinel Lighting	19,673	19,673	0.0%
USL	6,344	6,344	0.0%

[Reference example: Tab “3a. Resi – Hourly Demand Data” column G total shows Demand Profile and column S shows Weather Normalization total in “2019 Demand Profile Model” workbook]

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:

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

[Reference: Tab "4. CP & NCP" "2018 Demand Profile Model" workbook]

[Reference: Tab "4. CP & NCP" "2019 Demand Profile Model" workbook]

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:

2018 Weather Normalization (kWh) & Test Year Load Forecast

Rate Class	Demand Profile	Weather Normalization	Test Year Load Forecast	Test Year Compared to Actual Demand
Residential	25,345,905	24,922,053	26,503,100	4.6%
GS <50kW	11,582,140	11,388,935	11,455,522	-1.1%
GS 50-999kW	18,316,320	17,995,259	18,697,353	2.1%
GS 1,000-4,999kW	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%

[Reference: Tab "5. Summary Tables" of "Information Workbook".]

2019 Weather Normalization (kWh) & Test Year Load Forecast

Rate Class	Demand Profile	Weather Normalization	Test Year Load Forecast	Test Year Compared to Actual Demand
Residential	25,242,540	24,852,891	26,503,100	5.0%
GS <50kW	11,109,758	10,935,590	11,455,522	3.1%
GS 50-999kW	18,739,595	18,434,747	18,697,353	-0.2%
GS 1,000-4,999kW	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%

[Reference: Tab "5. Summary Tables" of "Information Workbook".]

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.

[Reference: Tab "4. CP & NCP" "2018 Demand Profile Model" workbook]

[Reference: Tab "4. CP & NCP" "2019 Demand Profile Model" workbook]

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:

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

	Non-Coincident Peak						
2018	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
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	6,088	2,283	3,560	7,386	54	6	2
4NCP	22,056	8,740	13,712	28,957	217	23	7
12NCP	59,264	23,704	38,653	83,067	636	56	18

[Reference: Tab "3a. (USF) NCP – 2018 & 2019" of "Information Workbook".]

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

	Coincident Peak						
2018	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	StreetLights	Sentinel Lights	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
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	4,810	2,121	2,735	6,494	28	2	1
4CP	18,038	7,873	11,623	25,648	76	6	2
12CP	47,016	21,704	34,398	78,325	149	11	4

[Reference: Tab “3b. (USF) CP – 2018 & 2019” of “Information Workbook”.]

The NCP and CP derived from the average of years 2018 and 2019 have been inputted into Tab I8 of the OEB’s Cost Allocation Model that has been filed with this application.

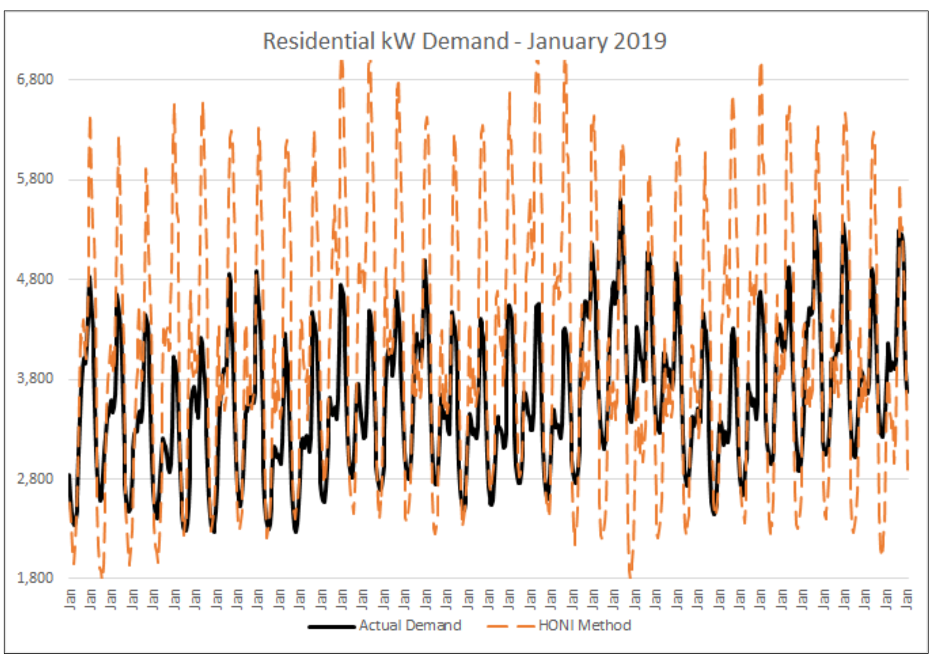
Appendix B – The Traditional HONI Method to Determine NCP and CP

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:

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



[Reference: Tab "6. Example – January 2019" of "Information Workbook".]

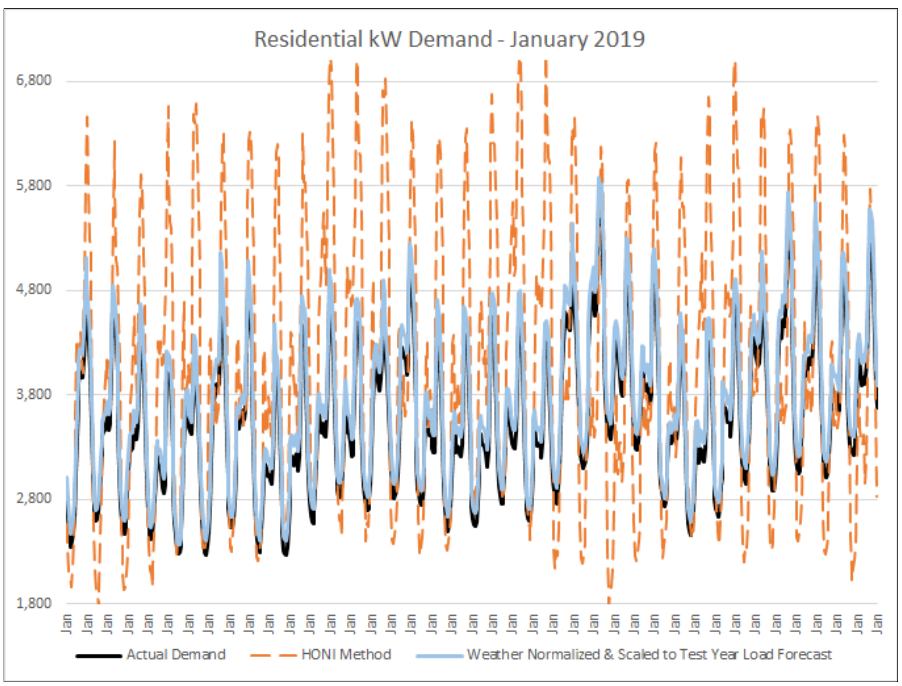
The applicant acknowledges that the actual Residential Demand Data has not been weather-normalized; however, it is clear from the above chart that:

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).

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



[Reference: Tab "6a. Example – January 2019" of "Information Workbook".]

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:

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

HONI 2004 Method							
	Non-Coincident Peak						
2019 Data	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	StreetLights	Sentinel Lights	USL
1NCP	7,281	2,046	3,295	6,995	53	6	1
4NCP	27,334	7,903	12,637	27,643	210	22	3
12NCP	68,505	21,131	33,942	80,488	629	55	9
	Coincident Peak						
2019 Data	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	StreetLights	Sentinel Lights	USL
1CP	6,352	1,272	2,230	6,866	53	5	1
4CP	25,144	5,157	10,561	24,980	209	15	3
12CP	62,511	12,869	28,867	77,529	471	39	9

[Reference: Tab “6c. HONI NCP & CP” of “Information Workbook”.]

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

Comparison of Methods: Non-Coincident Peak with 2019 Data

	HONI Method - **Non-Coincident Peak**						
2019 Data	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	StreetLights	Sentinel Lights	USL
1NCP	7,281	2,046	3,295	6,995	53	6	1
4NCP	27,334	7,903	12,637	27,643	210	22	3
12NCP	68,505	21,131	33,942	80,488	629	55	9
	USF Method - **Non-Coincident Peak**						
2019 Data	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
	Variance: HONI Method Compared to USF Method						
	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	StreetLights	Sentinel Lights	USL
1NCP	19%	-12%	-3%	-7%	-6%	-5%	-169%
4NCP	20%	-11%	-4%	-6%	-6%	-5%	-149%
12NCP	15%	-10%	-11%	-4%	-2%	-2%	-108%

[Reference: Tab “6d. HONI v USF” of “Information Workbook”.]

Comparison of Methods: Coincident Peak with 2019 Data

	HONI Method - **Coincident Peak**						
2019 Data	**Residential**	**General Service <50kW**	**General Service 50-999kW**	**General Service 1000-4999kW**	**StreetLights**	**Sentinel Lights**	**USL**
1CP	6,352	1,272	2,230	6,866	53	5	1
4CP	25,144	5,157	10,561	24,980	209	15	3
12CP	62,511	12,869	28,867	77,529	471	39	9
	USF Method - **Coincident Peak**						
2019 Data	**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
	Variance: HONI Method Compared to USF Method						
	Residential	**General Service <50kW**	**General Service 50-999kW**	**General Service 1000-4999kW**	**StreetLights**	**Sentinel Lights**	**USL**
1CP	17%	-55%	-21%	5%	-6%	24%	-58%
4CP	24%	-50%	-6%	-1%	27%	28%	-25%
12CP	25%	-63%	-15%	-2%	59%	62%	43%

[Reference: Tab “6d. HONI v USF” of “Information Workbook”.]

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:

The Applicant 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 Elenchus) that is supported by the load forecast used in this rate application 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 tab I8.

Appendix C – Alternative Demand Profile Methods Considered

1) 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"*[11]

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

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

2) 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:

		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

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:

					Result	Actual	Adjusted Demand
Day	Hour	HDD	CDD	Dummy	Coefficient for the hour	Residential 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[12], 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

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

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.

3) 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.

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

Rate Class Load Forecast R_{sq} 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.

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 7B 2018 DEMAND PROFILE MODEL

The 2018 Demand Profile Model has been filed as an excel file as part of this Application.

APPENDIX 7C 2019 DEMAND PROFILE MODEL

The 2019 Demand Profile Model has been filed as an excel file as part of this Application.

APPENDIX 7D INFORMATION WORKBOOK

The "Information Workbook" that supports Appendix 7A has been filed as an excel file as part of this Application.

APPENDIX 7E HONI DEMAND PROFILE METHOD

A copy of WNP's 2019 Demand Profile using the HONI Demand Profile method has been filed as an excel file as part of this Application.