Alternative GS Distribution Rate Analysis Appendix B

- **Results and Approach for Model 2A Rates and Bill Impacts**
- **DG Scenario Revenue Comparison Analysis.**

Prepared for:

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1. INTRODUCTION

In late 2016, Navigant was engaged by the Ontario Energy Board to support Board staff's analysis of general service distribution rates, and, in particular, the potential impact on customer bills of alternative rate structures. Since that time, Navigant has continued to provide support to Board staff as the Board has explored different rate structures and used different sets of local distribution company (LDC) anonymized customer data to analyze them.

This Appendix B covers two key components of the work performed by Navigant:

1. **Section 1: Model 2A.** This section of Appendix B describes the analysis performed by Navigant in:
    a. Splitting the GS<50 rate class into two smaller sub-classes (GS<10 and GS 10 – 50);
    b. Assessing an alternative revenue-neutral rate for these classes; and,
    c. Calculating the potential impact of such a rate transition on individual customers.
2. **Section 2: Distributed Generation and a Capacity Reserve Charge**. This section of Appendix B quantifies the potential impact on distribution revenue under certain OEB-specified assumptions of distributed generation (DG) uptake, and tests the effectiveness of a remedial "capacity reserve charge" at recovering the full revenue required for revenue neutrality.

2. SECTION 1: MODEL 2A

This section of Appendix B provides a summary of the analysis Navigant has applied to GS < 50 customer data from a number of different Ontario LDCs for the OEB. Specifically, this section of Appendix B summarises the approach and findings of Navigant's application of the "Model 2A" pricing structure.

Section 1 of Appendix B is divided into two sub-sections:

- **Approach.** This outlines the key data used by Navigant for the analysis, and how they were applied to deliver the final results.
- **Results.** This section provides a summary of the final rates developed as part of this analysis. Key data and graphical outputs may be found in the accompanying appendices A (an Excel spreadsheet), and B (a .pdf file).

Navigant was engaged in December of 2016 by the Ontario Energy Board to develop a set of alternative distribution rates based on PowerStream[1] individual customer data and existing distribution rates. The key requirements of the analysis were:

1. To develop a set of alternative, revenue-neutral, distribution rates based on a sample of customer hourly usage data.
2. To quantify the distribution of bill impacts on that sample of customers as a result of the new, alternative, rate structure, assuming no customer behaviour changes as a result of the change in rate structure.

Over the course of 2017, the OEB requested that Navigant apply the same logic to status quo distribution rates and twelve months of customer demand data from four utilities: Entegrus, Hydro One (rural and urban customer classes[2]), Orangeville Hydro, and Toronto Hydro.

This memo summarizes the approach used to develop "Model 2A", and some of the key outputs of that analysis. The structure of the Model 2A rate is applied only to customers in the status quo GS<50 classes. Model 2A divides these customers into two new class:

- **GS<10.** Customers in the status quo GS<50 class were assigned to this new class if their average monthly peak demand was less than 10 kW
- **GS 10 to 50.** After the new GS<10 customers are removed from the GS<50 sample, all remaining customers in that group were assigned to this class

2.1 Approach

The approach for this analysis may be summarized in the following five steps:

1. Split status quo customers into new rate classes.
2. Calculate the sample revenue requirement (SRR) – i.e., the total distribution revenue generated by customers in the sample. This is calculated by new class (i.e., the SRR for GS<10 customers is different from that of GS 10 – 50 customers).
3. Develop a new set of revenue-neutral rates based on the SRR and customer consumption data..
4. Apply the new rates to the sample consumption data. This delivers a counterfactual distribution cost for each customer (i.e., what each customer would have paid in distribution costs had the

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[1] In early 2017 Enersource, Horizon Utilities and PowerStream Inc. officially became known collectively as "Alectra Utilities". For the purposes of this analysis Navigant will refer to "PowerStream" as that was the name of the utility at the outset of this analysis, and makes clear that the customer data used are all from Alectra's legacy PowerStream territory.

[2] NB, for the mechanics of this analysis, rural and urban Hydro One customers are effectively treated as being from two separate LDCs.

new rate regime been in place during the sample period assuming no changes in customer behaviour).

5. Calculate individual customer bill impacts. For each individual customer, subtract new, alternative charges from the status quo charges to deliver individual customer distribution cost bill impacts.

2.1.1 Data

The OEB provided Navigant with customer hourly demand data for each of the LDCs, divided by rate class. A single year of data were provided for each group. For each customer, Navigant developed a monthly series of energy consumption and non-coincident peak demand values. These monthly data form the basis of Navigant's analysis.

All customers with any negative demand values were removed from the sample, as were any GS < 50 customers with any peak demand values exceeding 700 kW, and any customers with an average monthly consumption more than 100 times the median monthly consumption for the given LDC and rate class.

Error! Reference source not found. below provides some key summary statistics for the base data, including the original number of customers in the sample, the number once the outlier values (see above) were removed, the calendar year from which the sample data were drawn, and the average monthly energy consumption and non-coincident peak demand of the group of customers included in the analysis.

Table 1: Sample Summary Statistics of the Customer Demand Data Set

LDC	Status Quo Rate Class	# Cust in Original Sample	# Cust in Analysis Sample	Data Year	Mean Monthly Consumption (kWH)	Mean Peak Demand (kW)
Entegrus	GS < 50	3,804	3,802	2015	2,433	9
Hydro One (Rural)	GS < 50	70,319	70,280	2014	1,877	7
Hydro One (Urban)	GS < 50	9,267	9,260	2014	2,336	8
Orangeville	GS < 50	1,000	998	2015	3,771	12
PowerStream	GS < 50	17,427	17,384	2014	2,488	9
Toronto Hydro	GS < 50	1,415	1,414	2012	1,759	7

2.1.2 Pricing Information

The distribution rates applied to each LDC's customers for the purposes of calculating the sample revenue requirement were the most recently approved rates available at the time the analysis began for that LDC.

For PowerStream and Hydro One (analysis begun in late 2016) distribution rates effective January 1, 2016 were used. For Toronto Hydro, distribution rates effective January 1, 2017 were used. For Entegrus and Orangeville Hydro, distribution rates effective May 1, 2017 were used. The status quo rates applied in this analysis are summarised in Table 2 below.

The SRR was calculated by applying these rates, and only these rates, to the customers' monthly energy data referenced above. No adjustment was made for losses, and no rate riders were applied.

Table 2: Status Quo Distribution Rates

LDC	Status Quo Rate Class	Service Charge ($/cust/month)	Energy Charge ($/kWh/month)
Entegrus	GS < 50	$31	$0.010
Hydro One (Rural)	GS < 50	$28	$0.056
Hydro One (Urban)	GS < 50	$22	$0.025
Orangeville	GS < 50	$33	$0.010
PowerStream	GS < 50	$27	$0.014
Toronto Hydro	GS < 50	$33	$0.030

2.1.3 Setting Alternative Rates

For GS<10 customers, the specified alternative rate to be tested was a fully fixed rate: i.e., a flat $/customer charge to be applied uniformly within the LDC every month. Rates were set by calculating the SRR for that group of customers, by LDC. This total annual revenue requirement was then divided by the twelve months of the year and the number of customers from which it was derived, to deliver a single fixed monthly rate for this group.

For GS 10 to 50 customers, the specified alternative rate to be tested was one that maintained the existing service charge ($/customer per month), but converted the distribution energy charge to a non-coincident peak demand charge. The alternative variable charge in the following manner: the total revenue delivered by the status quo service charge was subtracted from the SRR of this group. The residual was then divided by the sum of these customers' monthly non-coincident peak demand to deliver a $/kW demand rate.

2.1.4 Bill Impact Calculation

One of the key outputs of this analysis is the distribution of bill impacts as a result of the alternative modeled rates on the individuals included in the sample. These summaries are generated in the following manner:

- Monthly bill impacts are calculated for each participant as the "new" distribution cost (under the alternative rate) minus the customer's distribution cost under the status quo rate.
- Monthly non-distribution costs are calculated for each participant, based on:
    - Commodity charges (the current TOU rates[3])
    - Regulatory charges:
        - Wholesale Market Service Rate
        - Capacity Based Recovery[4]
        - Rural or Remote Electricity Rate Protection Protection Charge
        - Standard Supply Service Administrative Charge
- Monthly percentage bill impacts are calculated by dividing the monthly bill impact by the sum of the status quo distribution cost and the commodity and regulatory costs (these values are identical under both the alternative and the status quo distribution rate).
- Percentage and level bill impacts are then averaged across all 12 months for each individual.
- Impacts are then averaged across individuals to obtain a decile distribution of bill impacts.

[3] Note that the TOU rates – the commodity charge – include the global adjustment.

[4] Included for Toronto Hydro, Entegrus, and Orangeville Hydro only. The rate riders available at the time the other LDCs' analyses were conducted did not include this charge.

Note that one result of this approach is the fact that it is perfectly possible for a given grouping of customers to have a negative percentage bill impact (i.e., a bill decrease), but an average level bill impact that is positive (a bill increase). An illustrative example, shown in Table 3 makes clear how this is possible.

Table 3: Illustrative Example of How Average Percentage and Absolute Bill Impact With Different Signs

Account	Status Quo Bill	Bill Under Alternative Dx Rates	Level Impact ($)	Percentage Impact
Cust 1	$500	$510	$10	2%
Cust 2	$100	$96	-$4	-4%
		Average:	**$3**	**-1%**

The impact of the alternative distribution rate, expressed as a percentage of the total bill, was based on TOU commodity rates as of July 1, 2017, and regulatory charges drawn from the same OEB Orders as used to deliver status quo distribution charges.

Finally, it should be noted that the average bill impact across all customers within a given utility will be zero. This is by construction, since alternative rates are set using customer data to recover exactly the calculated SRR.

2.2 Results

Table 4, below, provides a summary of the new, revenue-neutral within class, rates developed as part of this analysis. This table also provides some key summary statistics for each LDC and new rate-class combination.

Note that the revenue-neutral (assuming no behaviour change) approach to rate-setting means that, within each unique LDC and class (GS<10, GS 10 – 50) the average monthly bill impact is the same under the status quo and the new alternative rate, although of course bill impacts vary considerably across individuals.

Table 4: Alternative Rates and Summary Statistics by New Rate Classes

LDC	New Class	# of Customers in Sample	Monthly Service Charge ($/customer/month)	Demand Charge ($/kW/month)	Mean Monthly Peak Demand (kW)	Mean Monthly Consumption (kWh)
Entegrus	GS<10	2,672	$39.57	$0.00	4.1	935
Hydro One (Rural)	GS<10	54,378	$75.50	$0.00	3.6	845
Hydro One (Urban)	GS<10	6,738	$47.76	$0.00	4.1	1,011
Orangeville	GS<10	722	$43.70	$0.00	4.5	1,106
PowerStream	GS<10	12,110	$42.78	$0.00	4.7	1,143
Toronto Hydro	GS<10	1,136	$64.68	$0.00	4.4	1,058
Entegrus	GS 10 - 50	1,130	$30.53	$2.90	20.6	5,944
Hydro One (Rural)	GS 10 - 50	15,902	$27.94	$16.30	18.7	5,405
Hydro One (Urban)	GS 10 - 50	2,522	$22.28	$7.94	18.6	5,875
Orangeville	GS 10 - 50	276	$32.71	$3.57	30.1	10,729
PowerStream	GS 10 - 50	5,274	$26.55	$3.92	20.2	5,576
Toronto Hydro	GS 10 - 50	278	$32.68	$9.26	15.1	4,622

Revenue-neutral rate design is, by construction, a zero-sum game. GS<10 customers that operate seasonal businesses, are vacant properties, or otherwise use very little electricity experience bill increases, whereas the GS<10 customers with the highest electricity consumption experience bill decreases. Within the GS 10 – 50 classes, the customers experiencing the highest bill increases are those with the lowest load factor[5] while those with high load factors – those customers with relatively flat load profiles – see bill decreases.

[5] i.e., those customers for whom the ratio of average demand to peak demand is lowest – the "peakiest" customers.

3. SECTION 2: DISTRIBUTED GENERATION AND CAPACITY RESERVE CHARGE

During the course of Navigant's analysis of alternative rate impacts, Board staff tasked Navigant with quantifying the potential impact of distributed generation on system revenue under two alternative assumed scenarios:

- When 10% of customers in a given rate class acquired sufficient distributed generation to satisfy 75% of their energy and monthly non-coincident peak demand requirements.
- When 10% of customers in a given rate class acquired sufficient distributed generation to satisfy all (100%) of their energy and monthly non-coincident peak demand requirements.

Further, in addition to quantifying the potential lost revenue under the two scenarios, Board staff requested that Navigant explore the impact on revenue of the implementation of a "capacity reserve charge" (CRC) that would apply to DG installed capacity. This analysis was applied only to GS>50 and Large customer classes.

Section 2 of Appendix B is divided into two sub-sections:

- **Approach**. This describes the assumed scenarios in greater detail, status quo rate assumptions, and how these assumptions were applied to the data in hand to drive the analysis.
- **Results.** This sub-section describes the key findings of this analysis, highlighting the manner in which these flow from the assumptions imposed.

3.1 Approach

Navigant was tasked with two key goals:

1. Quantifying the impact on revenue of 10% of the customers in a given rate-class and LDC deploying substantial amounts of DG.
2. Quantifying the remedial impact of a CRC.

More specifically, Navigant was to calculate the revenue short-fall (below the SRR) and remedial revenue recovery under two scenarios in which 10% of customer of customers deployed DG:

- Scenario A: DG participants deployed sufficient DG that their monthly energy and peak demands fell by 75%.
- Scenario B: DG participants deployed sufficient DG that their monthly energy and peak demands fell by 100%

3.1.1 DG Revenue Impacts

To avoid any potential sampling bias, Navigant performed this analysis 10 times, each time randomly[6] sampling (without replacement[7]) 10% of the given rate class and LDC combination's customers for inclusion in the DG group.

For each iteration of the analysis, customers randomly allocated to the DG group had their monthly energy and peak demand values set reduced by 75% (Scenario A) or 100% (Scenario B). The revenue for these customers was then added to the status quo revenue of the remaining 90% of (non-DG) customers in the given class/LDC grouping.

The total impact on revenue (i.e., the short-fall of SRR) was simply calculated as the average of the revenue impact across the ten randomly allocated groups.

3.1.2 CRC Revenue Impacts

CRC revenue impacts were calculated using the same iterative re-sampling approach as DG revenue impacts. The CRC applied was 90% of the given rate class's demand charge. The CRC is a monthly charge intended to be applied to the nameplate capacity of a given customer's installed DG. For the purposes of this analysis, the nameplate capacity of installed DG was assumed to be equivalent to the maximum monthly peak demand reduction achieved by the customer as a result of DG installation.

So, for example, if a given customer's highest monthly non-coincident peak demand was 100 kW, then under Scenario A that customer would be charged the CRC based on an assumed installed DG capacity of 75 kW and under Scenario B that customer would be charged the CRC based on an assumed installed DG capacity of 100 kW.

3.2 Results

The results of the analysis are summarized in Table 5 (Scenario A, 10% of customers acquire sufficient DG to supply 75% of their monthly energy and non-coincident peak demand) and in Table 6 (Scenario B, 10% of customers acquire sufficient DG to supply 100% of their monthly energy and non-coincident peak demand).

Both tables present, by customer class and LDC, the:

- status quo SRR;
- average annual revenue under the scenario-specific DG assumptions (i.e., revenue when a certain proportion of demand is assumed to be served by DG);
- average annual revenue under the scenario-specific DG assumptions *and* after the remedial effects of the assumed CRC are accounted for.

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[6] Random allocation was performed using a random number generator with a specified seed, allowing for the same random numbers to be replicated at a later date.

[7] Sampling without replacement in this context simply means that if a given customer is included in sample group 1 (i.e., is assumed to deploy DG), then that same customer will not be included in any of the remaining 9 sample groups.

The final two columns present the DG scenario, and the DG scenario with remedial CRC, revenues as a percentage of the SRR.

Table 5: Scenario A (75%) Impact on Revenue of DG and CRC

Class	LDC	Status Quo SRR	Revenue w/ DG	Revenue w/ DG and CRC	Revenue w/ DG as % of SRR	Revenue w/ DG and CRC as % of SRR
Scenario A (75% of Energy and Peak kW Supplied by DG)						
GS > 50	Entegrus	$3,613,125	$3,375,469	$3,644,534	93.4%	100.9%
GS > 50	Hydro One (Rural)	$25,493,057	$23,633,535	$25,861,364	92.7%	101.4%
GS > 50	Hydro One (Urban)	$3,027,269	$2,808,882	$3,048,075	92.8%	100.7%
GS > 50	PowerStream	$15,882,766	$14,770,728	$15,957,059	93.0%	100.5%
GS > 50	THESL	$67,197,633	$62,255,269	$67,735,073	92.6%	100.8%
Large	PowerStream	$19,180,233	$18,168,088	$19,199,042	94.7%	100.1%

Table 6: Scenario B (100%) Impact on Revenue of DG and CRC

Class	LDC	Status Quo SRR	Revenue w/ DG	Revenue w/ DG and CRC	Revenue w/ DG as % of SRR	Revenue w/ DG and CRC as % of SRR
Scenario B (100% of Energy and Peak kW Supplied by DG)						
GS > 50	Entegrus	$3,613,125	$3,296,250	$3,655,004	91.2%	101.2%
GS > 50	Hydro One (Rural)	$25,493,057	$23,013,694	$25,984,133	90.3%	101.9%
GS > 50	Hydro One (Urban)	$3,027,269	$2,736,086	$3,055,010	90.4%	100.9%
GS > 50	PowerStream	$15,882,766	$14,400,048	$15,981,823	90.7%	100.6%
GS > 50	THESL	$67,197,633	$60,607,815	$67,914,220	90.2%	101.1%
Large	PowerStream	$19,180,233	$17,830,707	$19,205,311	93.0%	100.1%

Two key impacts are immediately observable:

1. As expected, substantial uptake of DG reduces distribution revenues.
2. A CRC applied based on the status quo demand charge and customer installed capacity is likely to over-collect.

The first result is trivially obvious: reducing the value of billing determinants will reduce revenue collected. The second finding requires a bit more explanation.

The over-collection is a result of the assumptions imposed:

- The CRC is set to be 90% of the status quo demand rate.
- The CRC is applied to the assumed nameplate capacity of the DG

- Nameplate capacity is assumed to be equivalent to the maximum level of demand avoided by the individual customer, or, effectively 75% of a customer's annual peak demand (Scenario A) or 100% of their annual peak demand.