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Toronto Hydro-Electric System Limited (Toronto Hydro) Application for 2020-2024 Rates EB-2018-0165

Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

August 28, 2019

On behalf of the
Vulnerable Energy Consumers Coalition

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1.0 Summary & Customer Engagement

1.1 The proposal of Toronto Hydro represents a significant increase in costs to be recovered from ratepayers as compared to the prior period plan. That plan represented a significant increase from the plan before it. Over the past 8 years Toronto Hydro ratepayers have been funding an extraordinary growth in capital assets. In our view part of the reason for this is a phenomena known as "gold-plating." The introduction of performance based regulation was, at least in part, introduced as a way to minimize the incentives of utilities to overbuild rate base as might occur under cost of service rate making. In our submission Toronto Hydro's proposal shows that the incentive plans of this Utility have largely failed to achieve this objective.

1.2 Similarly operating expenses, especially compensation expenses, continue to outstrip the trends in the economy as a whole. The result is that electricity costs continue on their trajectory of taking a larger portion of consumers' income. Were it not for the fact that the rate increases are in any given year a small portion of the overall bill and consumer's overall budget, we doubt this could continue.

1.3 Ultimately, it is our conclusion that there are no "incentives" to be found in the so called "custom incentive framework." In our submission the Board must reintroduce actual incentives. If not customers would be better off on rates determined on an annual cost of service basis.

1.4 In order to address these facts we recommend the following changes to the Applicant's proposal:

Rate Adjustment Formula:

- The addition of a 0.60% stretch factor;
- The elimination of the C factor in the plan, or in lieu of that, the application of a stretch factor of 0.60% to the capital factor;
- A 50/50 sharing of any earnings above the Board approved return on equity.

2020 Cost of Service Rates

- A reduction of 2020 capital in-service amounts to reflect the average of that achieved under the previous rate plan;
- A reduction of $9.5 million in 2020 operating expenses.

2020 Load Forecast and Other Revenues

- The gain on disposition of utility and other property is not reasonable and should be adjusted for historical averages;
- The RTSRs values need to be set using same reporting periods as for customers' consumption data and the UTR billing determinant period.

Customer Engagement

1.4 With respect to customer engagement we are of the view that the Utility has taken the necessary steps to satisfy the Board's filing requirements. In dozens of rebasing filings VECC has reviewed strikingly similar forms of engagement by a standard form of consultants (Innovative Research and/or Utility Pulse). The results are invariably similar. Customers want low prices and reliable service. Given the selective nature of information provided to them (cue a litany of old equipment, catastrophic equipment failures and post storm pictures); customers are found to be largely supportive of the capital program presented to them.

1.5 Invariably some discussion is put forward as to programs that have been eliminated or reduced based on these surveys and focus groups. On close examination much of what is put forward as adjustments due to customer concerns appear somewhat contrived. In this case there are detailed explanations on how a two-step process led to changes in the distribution system plan. While we are sceptical we acknowledge that Toronto Hydro went to some efforts to demonstrate its customer engagement had an impact on its capital plan. In our view this was done to address the Board criticism in the prior rate proceeding that the capital plan was not necessarily aligned with the interests of its customers[1].

1.5 In our submission the Board should re-examine the form of customer engagement that is being brought forward in this and other proceedings in order to either relief utilities of this costly burden or to make the exercise more meaningful. A case in point is the proposal in this case (as has been seen in other recent proceedings) on the issue of replacement of back lot plant with front lot underground. In this case customers were not told what the incremental costs of this form of replacement would be, or why plant which has existed often for 50 years or more in back lots could not just as well be replaced with like-for-like.[2] Instead they were provided the preferred capital plan of the Utility and no information to criticise that plan. While we accept that it is difficult for some projects to provide reasonable alternatives for surveyed customers to consider (which is demonstrative, we suggest, of the deficiency of the entire exercise) if when clear alternatives do present themselves and are then are ignored in customer engagement what does that say about the entire exercise - what insight is being gained?

1.6 Generally, the style of customer engagement presented in this case provides limited, if any insight as to the acceptability to customers of the rate plan or its capital program. This is not particularly a criticism of Toronto Hydro. We doubt frankly that such an exercise could be done. And while such exercises provide a politically acceptable means of being seen to being customer focused, they are expensive undertakings and more importantly they can provide a false sense of the real concerns of ratepayers. In our view the Board should eliminate these requirements. It is fallacy to hold that customers will inform optimal capital

[1] EB-2014-0116 Toronto Hydro-Electric System Limited, December 29, 2015, pg.6
[2] TC Vol. 7 July 9, 2019, pgs. 20-24

investment choices for multi-billion dollar utilities like Toronto Hydro. Even expert tribunals like the OEB are challenged in an environment of asymmetrical information to weigh the trade-off of investment alternatives, timing of those investments and the risk inherent in of both. Instead we believe the Utility should be encouraged to undertake their own outreach through such activities as transaction follow-ups or analysis of and developing strategies for, addressing customer complaints and enquiries. Ultimately it is our view that the $413,585[3] spent on the Innovative customer engagement exercise would have better been spent to support the real needs of low income customers under the LEAP program rather than to provide a simulated sense of a customer's satisfaction with the Utilities operations.

2.0 Custom Incentive Rate-setting

2.1 The only difference between the proposed rate adjustment formula in this proceeding from the current approved scheme is the introduction of a custom stretch factor based on econometric benchmarking.[4] Conceptually the revenue requirement is adjusted for inflation net of factors combining a productivity assumption and an incentive target (the stretch factor). To this is added a percentage increase for the assumption that existing rates do not fully recover cost of invested capital beyond the replaced value represented by depreciation and those additional s assets funded by incremental customer revenues. In practice the rate proposal amounts to a cost of service rate plan where the only uncertainty is the inflation rate to be applied in any given year. This is clearly seen by examining the provided revenue requirement table below[5].

Revenue Requirement	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
CRR	540.46	579.30	595.57	648.13	689.36	$3,052.83
Non-CRR	230.93	233.01	235.10	237.22	239.35	$1,175.61
Base RR	771.39	812.31	830.67	885.35	928.72	**$4,228.44**
I		1.20%	1.20%	1.20%	1.20%	
X		0.30%	0.30%	0.30%	0.30%	
Cn		5.03%	2.00%	6.33%	4.66%	
Scap		71.32%	71.70%	73.21%	74.23%	
G		0.20%	0.20%	0.20%	0.20%	
CPCI		4.88%	1.84%	6.15%	4.47%	
Revenue Requirement recovered in rates	**771.39**	**809.03**	**823.93**	**874.60**	**913.66**	**$4,192.61**
Rate Recovered RR annual increase		4.88%	1.84%	6.15%	4.47%	4.33%
Typical Residential Bill Impact (no rider) Staff Table 1		3.20%	2.50%	4.20%	3.90%	3.45%

[3] 1B-BOMA-119
[4] 1B-VECC-2
[5] Undertaking J1.8

* Capital Related Revenue Requirement

2.2 This shows that ratepayers fund the forecast amount of capital in the plan. The Applicant then relies on post facto productivity initiatives and micro analysis like the UMS unit cost benchmarking study to argue for the realization of progressive efficiency. We are unimpressed. The bottom line is that, like the 5 years before, in every year Toronto Hydro's revenue requirement and rate impacts will exceed inflation – and by significant amounts. That is not progression to anything other than ratepayers shelling out a greater portion of their income to pay for electricity distribution service. The fact is were it not for the "cost of service" like capital factor adjustment and the associated large capital expenditure forecasts this would not be the case.

2.3 We will not repeat the critique of Board Staff and other parties with respect to the UMS benchmarking study. We agree with the qualifications they raise about the specific study. More generally we would say that the Board should view with some skepticism studies commissioned by the Applicant, especially when the contracting party has a clear interest in maintaining a positive relationship with the utility or the industry at large. It does not require a conspiratorial or nefarious mind set to see how the multitude of judgmental decision embodied in such studies can have on its results. One need look no further than the PEG and PSE their competing studies on the appropriate X factors and benchmarking results. These two consulting firms use virtually identical methodologies but often find strikingly different results. With respect to unit benchmarking we believe the Board would find greater value if, as it has done for its incentive regulation policies, it retained its own experts to carry out these types of studies and among multiple Ontario LDCs.

Inflation Rate

2.4 VECC accepts the IPI inflation methodology, including annual updates, as proposed by Toronto Hydro is reasonable.

Growth Factor

2.5 In our submission the growth factor is calculated as 0.25% based on the Toronto Hydro's own calculations and should be properly rounded to the 2nd decimal point.

Productivity Factor

2.6 The Applicant has adopted the Board base productivity factor of 0%. While we are skeptical of the underlying logic of applying a post facto set of productivity measurements to determine future rates we accept this as the prevailing accepted methodology. In any event we disagree with Toronto Hydro (and their consultant) that the base productivity factor inherently includes an implicit stretch factor of 0.33%. Such a conclusion is based on a level of model specificity that does not exist. We also note that both consultants agree that there is a continuation of the decline in cost performance of Toronto Hydro which occurred during the first customer IR plan.[6]

Stretch Factor

2.7 We agree with PEG that setting the stretch factor on the basis of a cost forecast rather than actual achieved historical cost reduces the incentive to cut costs during the plan.[7] In our submission the Board has significant latitude to choose a reasonable proxy for the expected efficiency gains during the term of the plan. Furthermore this choice should be made with an eye to the past performance of the Utility. The possible numbers on the record are the Applicant`s proposal of 0.3%, the Staff`sponsored PEG proposed stretch factor of 0.45% and the pre-existing 0.6% in the current rate plan.

2.8 We have reviewed the arguments of Board Staff with respect to Total Cost Benchmarking and we have no disagreement with the points they make. In our view the addition of proxy variables like those for urban congestion extend a debate that is becoming largely academic in various recent proceedings of the Board on this issue. It is reminiscent of the prolonged and protracted arguments about how to best estimate a utility`s cost of equity. Various consultants (in this case all graduates of the same school) argue vociferously about the best models, correct variables, the right data and best time over which to measure and then imply results meaningful to the 3rd decimal point. Meanwhile outside the world of the regulation industry specific TFP studies are subject to some debate among academics as to their veracity[8].

2.9 It is also important to keep in mind that the exercise is using the past to forecast the future. This is not what happens in competitive markets where disruptive forces, technological change or aggressive competitors, force change. In using the benchmarking as a forecasting methodology one does the reverse and looks for `structural changes` in order to modify the model. The over reliance on methodologies like the TFP-benchmarking leads the regulator to the equivalent of hoping for the outcome of an automobile while modeling the behavior of horse drawn carriages.   We are not arguing that there are not insights to be had from these models. We are submitting that the Board should not surrender its discretion and the insights it garners from the application as a whole in determining an incentive factor for this plan.

2.10 In our submission the Board should continue to apply the 0.6% stretch factor. This would signal the expectation that Toronto Hydro needs to improve its overall performance. We also not that the 0.6% factor is similar to the Applicant`s own assessment of a .33% implicit stretch factor as added to its proposed Group III factor of .30.

[6] See for example, Exhibit M1, pg. 9
[7] Ibid, pg.9
[8] See for example, The Challenge of Total Factor Productivity Measurement, Erwin Diewert, Department of Economics, University of British Columbia, 2000 – CSLS Research Reports wwww.csls.ca

2.11 In our view 0.6% represents a reasonable objective for this Utility as it is achievable within its current revenue requirement framework and represents a reasonable expectation for improvements in cost efficiency. While the two consultants argue as between 0.30% and 0.45% we note that both outcomes are presented on the basis of an unwarranted degree of accuracy of the models. It is the very nature of econometric (or any other statistical based) modelling that it is inherently inaccurate. At best such exercises are directionally correct. The basis of the test of reasonableness the Board needs to apply does not lie in the choice of one or the other figure. Rather it is in the assessment of the resulting outcome and whether what is provided offers the utility with a reasonable opportunity to achieve the approved rate of return (which itself is subject to a question of reasonableness). Toronto Hydro has a revenue requirement in the order of $800M. Within that envelope it has a numerous opportunities to achieve its targeted rate of return. As noted by the table below Toronto Hydro was largely able to achieve and often exceed the Board allowed rate of return with a 0.60 stretch factor.[9]

Table 1: Achieved regulatory ROE and the Board deemed ROE

	2013	2014	2015	2016	2017	2018
Achieved regulatory ROE	7.10%	7.41%	10.71%	12.18%	9.08%	N/A
Board deemed ROE	9.58%	9.58%	9.30%	9.30%	9.30%	9.30%

The Capital Factor

2.12 The premise of the capital factor is to ensure Toronto Hydro is held whole for 100% of its capital investments during the rate period. As proposed it contains no incentives for the Utility to meet its investment needs efficiently or to optimize its capital to operating cost ratio. A modest a stretch factor be applied to this capital factor part of the formula at least partly ameliorates this.

2.13 However, applying an incentive variable to the capital factor does not address the main issue with respect to large capital investment proposed over the rate period. It is clear that in comparison to the prior period Toronto Hydro's capital program are excessively large. This represents the second plan with such large increases. Fundamentally the underlying premise of these extraordinary investments is based three premises. The first is that the asset base of the Utility is degrading in an exponential fashion. The second is that the high density nature of the City of Toronto causes higher than expected costs for both the replacement of existing plant and for new plant serving a growing population, the third is that weather in becoming more volatile and that "system hardening" is required.

2.14 Even if these propositions are in fact true and extraordinary capital investments are required then the question arises as to whether a capital factor adjustment is the best regulatory tool for

[9] 5-VECC-51

addressing such severe set of circumstances. A capital factor adjustment (subject to an incentive offset) *might* be appropriate in the case of a utility with a "normal" year-on-year capital investment portfolio. In these circumstances adjustments might be anticipated for one-time events or modest growth in investment requirements. In our assessment the Board's ACM/ICM framework was contemplated to address the issue of extraordinary capital requirements under incentive rate making. The ACM/ICM framework allow the Board to closely monitor rate recovery for extraordinary events and to ensure that ordinary capital investments do not escape the ambit of incentive rate making.

2.15 In our view the Board should address the issue first by introducing an incentive (stretch) factor to the capital adjustment part of the formula. Toronto Hydro can reasonably be called upon to meet the efficiency requirements embodied in a stretch factor of 0.6%. This is the same as we recommend be applied to the other aspects of the formula and similar to the ACM/ICM threshold figure of 0.64% as suggested by Board Staff.

2.16 The Utility should reduce its distribution system plan (DSP) to the average of its past 5 year plan and identifying those items which need to be addressed in a project specific ICM application.

Earning Sharing Mechanism (ESM)

2.17 Toronto Hydro is proposing a symmetrical ESM at 100 basis deadband from Board approved returns before sharing any earnings on a 50/50 basis. The Application describes it this way: "*Toronto Hydro's earnings sharing methodology (as described in part 1 a) is essentially a true-up of OM&A costs and revenue offsets between the: (i) amounts approved in base rates; and (ii) comparable actuals*."[10] This results in a symmetrical ESM which has the effect of eliminating any incentive aspects of the rate plan. As such the proposal is incompatible with the incentive framework policies of the OEB.

2.18 VECC agrees with the proposal of Board Staff with respect to the appropriate calculation and reporting of the ESM[11]. The ESM should be calculated on the total revenue requirement basis as is the standard approach.

2.19 VECC does not believe there should be a deadband applied to the ESM. The rate plan simply does not have sufficient existing incentives to justify such a figure. The capital factor, even with the application of a stretch factor, provides little incentive for efficient capital deployment. Combined with the variance accounting which tracks capital on a total basis there is very little accountability for meeting the stated distribution plan. It is our submission that this leaves ratepayers with little, if any upside during the term of the plan. As such it is our submission that all earnings over the Board approved amount should be shared with ratepayers on a 50/50 basis.

[10] 1B-Staff-25

[11] OEB Staff Submission, EB-2018-0165, August 21, 2019, pgs. 50-51; 147-148

Scorecard

2.20 Toronto Hydro has proposed 15 custom measures for addition to the Board's standardized scorecard. In our submission all of these are helpful in focusing measurement on outcomes especially those which focus on defective equipment metrics. We do remain concerned that in this Application, as with similar incentive rate plans, there is no connection between the outcome on the scorecard and the rates charged to customers. This means it provides no incentives. We are also of the view that the standardized distribution system plan implementation metric simply measure total numbers and in no way provides an assessment as between the plan and actual subsequent capital investments.

Table 1: Toronto Hydro's 44 Measures Mapped to Outcomes (RRFE & TH)

RRF Outcomes	Toronto Hydro Outcomes	OEB Reporting Categories	Measures
Customer Focus	Customer Service	Service Quality	1. New Residential/Small Bus. Connected on Time [Connection of New Services - Low Voltage]
			2. Connection of New Services - High Voltage
			3. Telephone Calls Answered on Time [Telephone Accessibility]
			4. Scheduled Appointments Met on Time [Appointments Met]
			5. Appointment Scheduling
			6. Rescheduling a Missed Appointment
			7. Telephone Call Abandon Rate
			8. Emergency Response – Urban
			9. Reconnection Performance Standards
		Customer Satisfaction	10. First Contact Resolution
			11. Billing Accuracy
			12. Written Responses to Enquiries
			13. Customers on eBills
			14. Customer Survey Satisfaction Results
Operational Effectiveness	Safety	Safety	15. Level of Public Awareness
			16. Compliance with Ontario Reg. 22/04
			17. Public Number of General Public Incidents
			18. Rate per 10, 100, 1000 km of Line
			19. Total Recorded Injury Frequency
			20. Box Construction Conversion
			21. Network Units Modernization
	Reliability	System Reliability	22. SAIDI
			23. SAIFI
			24. SAIDI - Defective Equipment
			25. SAIFI - Defective Equipment
			26. FESI-7 System
			27. FESI-6 Large Customers
		Asset Management	28. DSP Implementation Progress
			29. System Capacity
			30. System Health (Asset Condition) – Wood Poles
			31. Direct Buried Cable Replacement
Financial Performance	Financial	Cost Control	32. Efficiency Assessment (Ontario Distributors)
			33. Total Cost per Customer
			34. Total Cost per Km of Line
			35. Average Wood Pole Replacement Cost
			36. Vegetation Management Cost per Km

		Financial Ratios	37. Liquidity: Current Ratio
			38. Leverage: Total Debt to Equity Ratio
			39. Reg. ROE - Deemed vs. Achieved

RRF Outcomes	Toronto Hydro Outcomes	OEB Reporting Categories	Measures
Public Policy Responsive-ness	Public Policy	CDM	40. Net Cumulative Energy Savings
		Connection Renew. Gen.	41. Renewable Gen. CIAs Completed on Time
			42. Micro Gen. Fac. Connected on Time
	Environment		43. Oil Spills Containing PCBs
			44. Waste Diversion Rate

3.0 Rate Base and Capital Plan

3.1 With respect to the calculation of rate base VECC is in agreement with the proposal of Toronto Hydro with one exception. As argued by Board staff the more accurate and consistent method of calculating rate base is to use the average of monthly averages for both capital additions and depreciation expense. We accept Staff's calculation of the impact at $21 million for the duration of the rate plan.

<u>Copeland Station</u>

3.2 A number of parties have argued for a reduction in the Copeland Phase 1 costs. We note that Copeland station is a very complex undertaking. Some aspects, like the failure of the original contractor, are unusual. Other issues, like the change in requirements of Hydro One, would appear to be related to deficiencies in planning prior to the start of the project. However we are also cognizant that there are few transformation stations of such a magnitude built underground in Canada. The site is adjacent to heritage buildings (John Street Roundhouse), next to a major tourist and pedestrian traffic are (the Rogers Centre) and is bound on the south by major traffic arteries. As such the project presents unique challenges. We also note that the lessons learned from Phase I of this project will have an impact on Phase 2 of the project.[12]

Table 1: Copeland TS – Phase 2 – Cost Breakdown ($ Millions)

	Copeland TS – Phase 2										
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
EB-2014-0116					24.0	22.0					**48.0**
EB-2018-0165			0.5	1.8	7.8	8.9	29.7	38.8	1.0		**88.5**

Note 1: For EB-2018-0165 costs, 2015-2017 are actuals, 2018-2019 are bridge, and 2020-2024 are forecasts.

[12] 2B-Staff-93

3.3 Similar changes impacts are not, for example, shown in the Horner TS expansion[13]

Table 2: Horner TS Expansion – Cost Breakdown ($ Millions)

	Horner TS Expansion										
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**Total**
EB-2014-0116		12.0	20.0	20.0	20.0						**72.0**
EB-2018-0165	0.05	0.3	--	15.0	19.4	10.6	7.8	8.0	8.0		**69.15**

Note 1: For EB-2018-0165 costs, 2015-2017 are actuals, 2018-2019 are bridge, and 2020-2024 are forecasts.

3.4 Our conclusion is that cost overruns of Copeland are related to the unique aspects of the project. And while it is clear there are no strong incentives for Toronto Hydro to better manage its capital projects this does mean what results is imprudent behavior. We do however agree with Board staff that any subsequent awards or payments arising from settlement of contractor insolvency should accrue to ratepayers and that the necessary deferral account be established to capture any such costs.

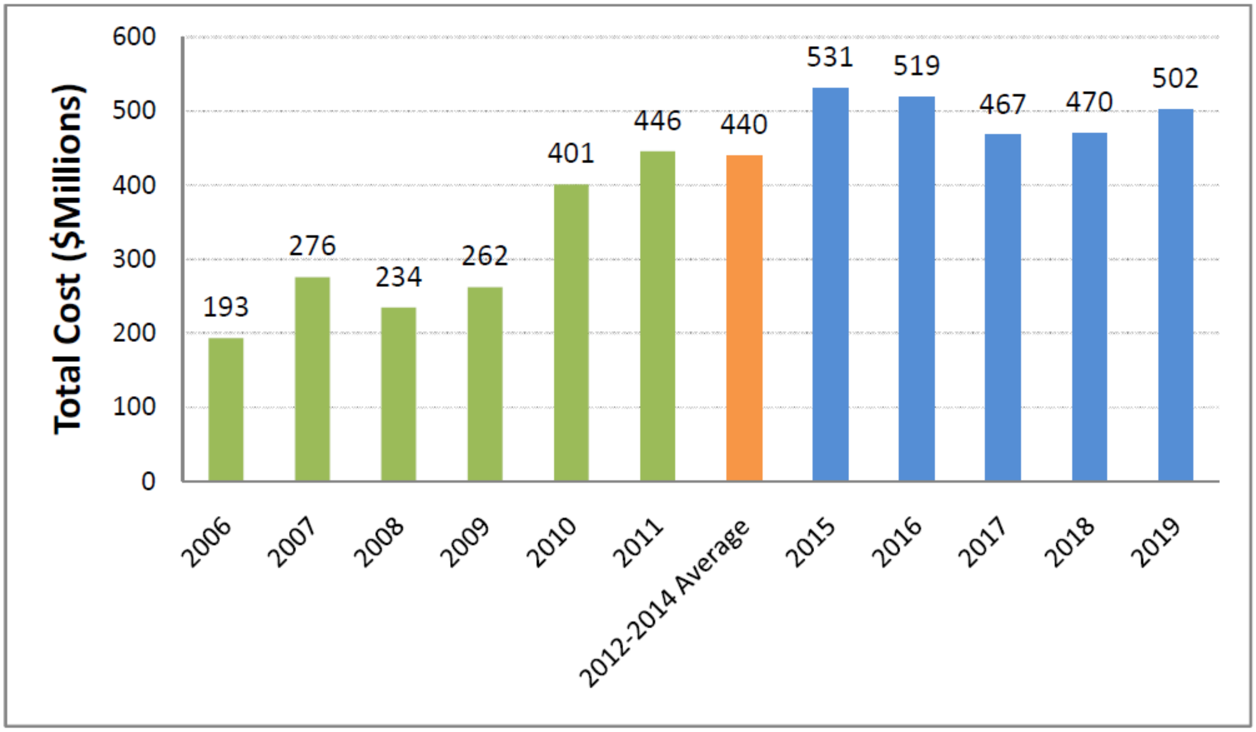
<u>Distribution System Plan</u>

3.5 One of the main criticisms of cost of service (rate of return) regulation is that is encourages over investment in capital. In economics this is known as the Averch-Johnson effect[14] and a primary objective of incentive rate regulation is to eliminate or at least reduce its effect. This is best achieved by decoupling rates from their underlying costs. However, in our submission Toronto Hydro's proposed rate plan, like its predecessor, is essentially cost of service with respect to capital investment recovery.

3.6 The impact of the current rate adjustment scheme on capital additions is clearly demonstrated by simply comparing the prior DSP with that proposed in this proceeding. This shows a clear an unending increase in capital investments and notwithstanding no evidence of reliability deficiencies and in fact improvement in the aspects of controllably reliability (defective equipment) over the same period.

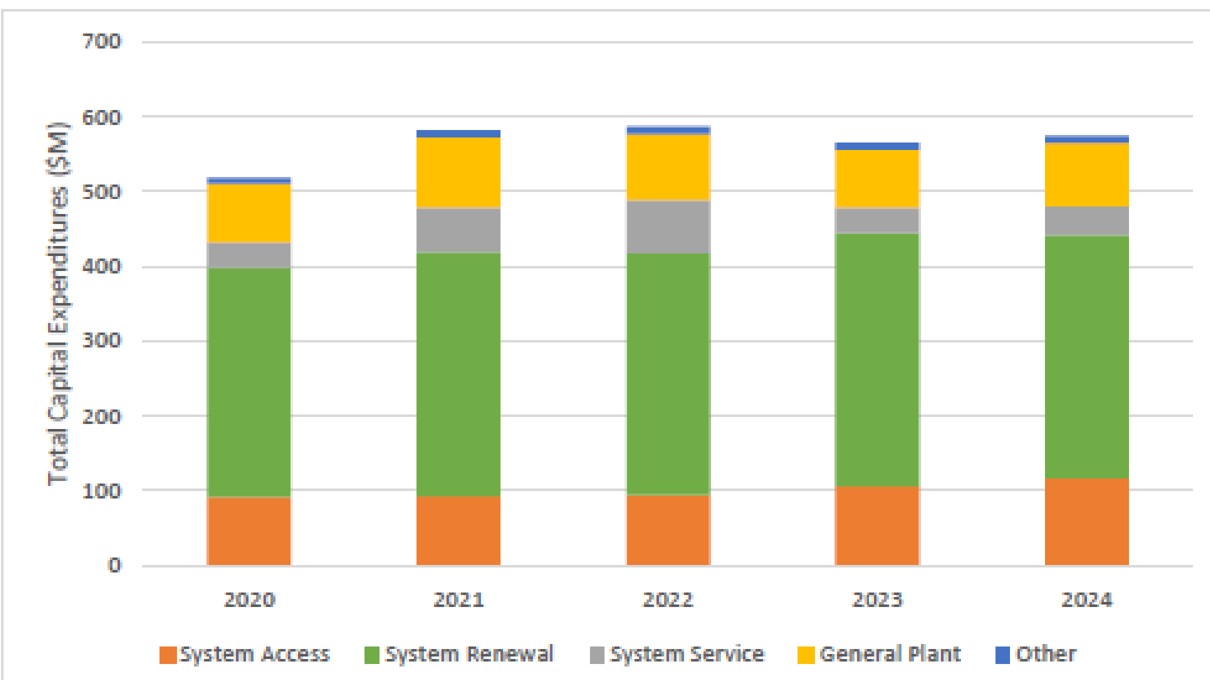
[13] Ibid

[14] Averch, H.A., and L.L. Johnson. 1962. Behavior of the firm under regulatory constraint. American Economic Review 52(5): 1052–1069.



Source: Decision and Order EB-2014-0016, December 29, 2015, pg. 20

Figure 2: 2020-2024 Capital Expenditure Plan by Investment Category



Source Exhibit 2B, Distribution System Plan, and pg.9

3.7 It is also interesting to observe that while overall the prior distribution plan was met (at least as measured by dollars) generally early years were underspend and the latter over spent[15].

Table 1: Historical Capital Expenditure Summary ($ Millions)

Category	Historical												Bridge		
	2015			2016			2017			2018			2019		
	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	Act.	Var.	Plan	For.	Var.
System Access	86.1	58.3	(32%)	95.3	79.0	(17%)	104.9	65.5	(38%)	95.8	88.0	(8%)	92.3	112.1	21%
System Renewal	251.7	304.1	21%	239.6	266.1	11%	256.2	250.3	(2%)	275.9	245.5	(11%)	287.3	244.2	(15%)
System Service	76.5	37.9	(50%)	70.7	53.3	(25%)	65.1	72.4	11%	52.6	31.0	(41%)	80.2	41.5	(48%)
General Plant	104.6	79.4	(24%)	101.5	109.5	8%	30.3	98.9	226%	34.2	58.4	71%	30.3	46.4	53%
Other	12.2	11.6	(5%)	11.6	3.7	(68%)	10.8	10.7	(1%)	11.5	12.7	10%	12.1	(1.3)	(111%)
Total CAPEX	**531.1**	**491.4**	**(7%)**	**518.8**	**511.6**	**(1%)**	**467.4**	**497.8**	**7%**	**470.0**	**435.6**	**(7%)**	**502.2**	**443.0**	**(12%)**
System O&M	128.8	116.1	(10%)	126.5			126.3			139.6			131.0		

3.8 As might be expected such a plan has let to large increases in rate base as shown below.[16] Over the past plan term net book values have risen by 45%. And while it is true that the franchise has seen customer growth the nature of high density urban growth is not in expensive to service single dwellings but rather in multi-unit high-rises which on a per customer measurement basis less expensive to serve.

Table 3: Gross and Net PP&E – Years Ending December 31 ($ Millions)

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Bridge	2020 Forecast
Land and Buildings	76.2	129.9	141.4	161.6	171.0	169.8
Other Distribution Assets	170.0	238.5	267.3	434.6	507.6	612.7
General Plant	127.7	185.2	247.5	240.1	241.4	243.0
TS Primary Above 50	5.8	6.0	36.9	37.9	38.9	39.1
Distribution System	149.9	156.8	184.5	213.5	233.9	277.9
Poles, Wires	2,172.2	2,430.6	2,663.8	2,876.9	3,132.8	3,426.9
Contributions and Grants	(58.2)	(90.5)	(118.0)	(156.6)	(235.2)	(322.6)
Line Transformers	412.4	465.3	515.4	566.7	640.8	714.2

[15] Exhibit U, Tab 2, Schedule 2, pg.3
[16] Exhibit U, Tab 2, Schedule 1, pg.4

Services and Meters	262.0	290.0	321.8	344.7	385.3	451.0
Equipment	61.5	100.4	120.8	131.3	140.5	145.9
IT Assets	27.3	47.2	58.7	66.8	74.2	89.0
Gross Assets	**3,406.8**	**3,959.4**	**4,440.1**	**4,917.5**	**5,331.0**	**5,846.8**
Accumulated Depreciation	(320.6)	(496.8)	(684.3)	(876.9)	(1,097.7)	(1,357.0)
Closing PP&E NBV (MIFRS)	**3,086.2**	**3,462.6**	**3,755.8**	**4,040.6**	**4,233.4**	**4,489.8**
Adjustments to Closing PP&E NBV						
Assets held for Sale	-	-	(8.7)	-	-	-
Monthly Billing	(0.7)	(0.6)	(2.3)	(1.7)	(1.1)	-
Closing PP&E NBV	**3,085.4**	**3,462.0**	**3,744.7**	**4,038.8**	**4,232.3**	**4,489.8**

3.9 In our view the inordinate growth in capital assets is indicative of the phenomena of over investment in capital. This notwithstanding continual improvements in the performance of asset. Outages related to defective equipment which has been trending downward as shown below[17]:

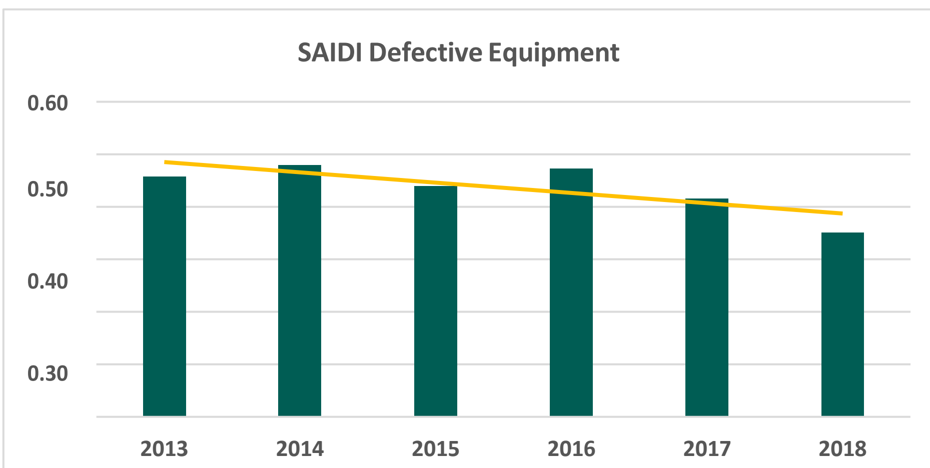


Figure 5: SAIDI (Defective Equipment) Performance 2013-2018

[17] Exhibit U, T1B, Schedule 1, pg.10

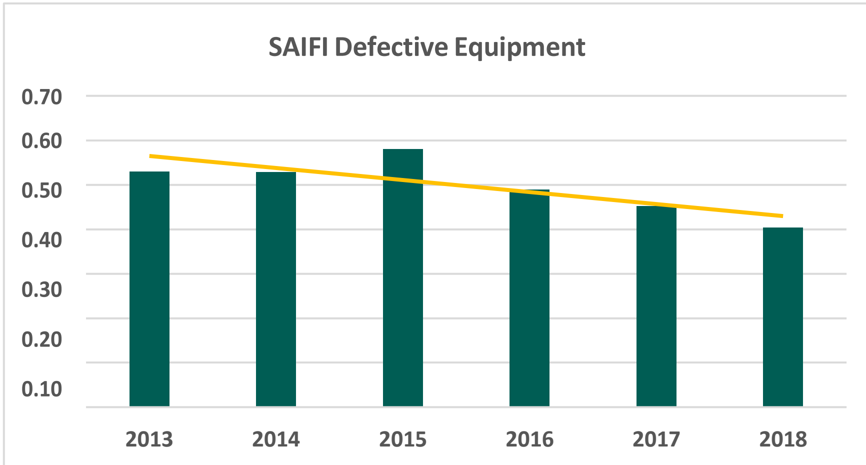


Figure 6: SAIFI (Defective Equipment) Performance 2013-2018

3.10 Inexplicably and notwithstanding historic spending Toronto Hydro is forecasting forecasting a decrease in reliability over the term of the plan

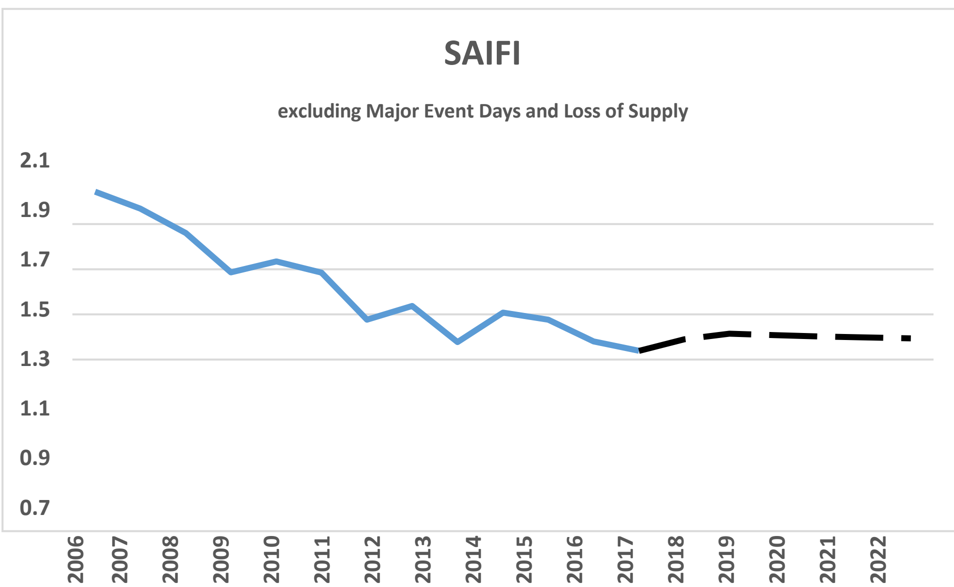


Figure 1: SAIFI Projections for 2019-2024 (excluding MED and LoS)

3.11 Since controllable related outages are declining the only way for reliability to deteriorate is for those uncontrollable events (adverse weather, human element, lightning etc.) to increase. It is proffered that this will occur notwithstanding the storm hardening proposals the utility has offered up as part of the reason for its greater capital expenditure.

3.12 This is simply not a credible scenario. Certainly it is true that in the actual event the Utility may have more or less outages and the duration of these outages may be greater or less than in the past. But this is due to the inherent uncertainty of weather. Toronto Hydro postulates that this will happen due to a greater number and severity of storms attributable to climate change. However there is no evidence that climate change will have this effect. Again serve storms are certain –and in micro climates along Lake Ontario ice storms are certainly possible. Whether there is a trend toward more such storms is not yet possible do determine. Severe weather outcomes of climate change also include other phenomenal like drought which would not likely have a detrimental effect on utility plant. In any event, a large part of the proposed incremental plant increase is related to underground plant which is presumably largely immune to weather other than severe flooding.

3.13 The other main driver for the increased capital requirements in this case is the new asset condition assessment methodology. The Common Network Asset Indices Methodology (CNAIM) is imported from the United Kingdom. It is clear that this new methodology drives the argument for a much larger capital investment plan.[18] Contrary to Toronto Hydro's claim the CNAIM algorithms is a less mature methodology than that it currently uses or is used by other distribution utilities in Ontario. [19]It is a new set of policies and procedures introduced by the British regulatory, Ofgem and has not been assessed, and is even resisted by some British utilities. Toronto Hydro did not do a comprehensive survey of other methodologies to understand what best practice was[20]. Toronto Hydro's outside review of its implementation of the methodology contains numerous recommendations and examples of difficulties in this particular iteration of implementing the methodology.[21] The objective of the CNAIM methodology in the UK is enabling "*Ofgem to be able to make direct comparison between each of the GB licence holders.*"[22] In sum, it is not apparently obvious that the methodology is intended to be used to provide forecasts as to the optimum capital planning.

3.14 Furthermore Toronto Hydro is implementing a limited version of the methodology. Significantly it does not provide the probability or consequence of failures. In the interim the risk based analysis performed by Toronto Hydro is individualistic to the management and planners of the different programs.

3.15 In our view the outcomes of the prior rate plan do not support an increase in capital expenditures as compared to the previous period. The methodology used by Toronto Hydro to support the larger increase is untested, incomplete in its implementation and yet to demonstrated to be a reasonable approach. The arguments for weather hardening investments are adhoc and unsupported by any data. Other parties have made detailed observations about specific parts of the proposed distribution plan. We think these arguments

[18] See Exhibit K1.2 SEC Compendium pg.46
[19] See 2B-AMPCO-41
[20] Transcript, Volume 4, July 4, 2019, pgs. 121- 122
[21] 2B-SEC-44, Appendix A
[22] 2b_SEC-44, Appendix A, pg. 2 of 4

provide insight into the areas under which Toronto Hydro could reasonably make reductions without impacting the service to ratepayers. We take an "envelope" approach similar to that taken for operating costs. A utility is always better placed than the regulatory and intervenors in prioritizing its investments and reacting to varying circumstances. In our submission the evidence does not support a capital plan that is in excess to the average capital expenditures over the past plan. We calculate that as an average of $476 million per year. On in-service additions basis the figure would be $504.6 million.[23]

3.16 In our submission the use of a lower on average capital/in-service investment profile in conjunction with the stretch factor of 0.6% would modify the Applicant's proposal sufficiently to be just and reasonable to both ratepayers and shareholders.

Implementation Date

3.17 Toronto Hydro filed its application over a year in advance of its proposed implementation date. In our submission the Applicant should be allowed to implement its rates January 1, 2020 irrespective of the actual date of any Board order.

4. Load and Other Revenue Forecast

Customer Count

4.1 Toronto Hydro's customer count forecasts are primarily based on either extrapolation models or the most recent actual values. The exception is the CSMUR class where the forecast is based on CHMC's forecast of housing starts for multi-unit developments in Toronto and internal estimates the market share that will be serviced by Toronto Hydro. The initial Application used historical data up to December 2017 while the updated forecast was revised to incorporate actual data for 2018[24].

4.2 A summary of the initial and revised customer count forecasts is set out in Exhibit U, Tab 3, Schedule 1, page 5. For all customer classes except the GS<50 kW the updated customer count forecast by 2024 was lower than or equal to that in the original Application.

4.3 VECC's primary concern with Toronto Hydro's customer count forecast is its use of extrapolation models, particularly linear trend models. These models do not incorporate any considerations as to the projected economic conditions and, in some instances, lead to counterintuitive results.

4.4 First, the models are simple linear trend models[25] and do not incorporate any considerations as to the projected economic conditions. The GDP forecast used by Toronto Hydro in its

[23] See Exhibit U, Tab 2, Schedule 1, Appendix A, page 1 of 1
[24] Exhibit U, Tab 3, Schedule 1, pages 4-5 and U-VECC-72, 73 & 74
[25] U-VEE-76

updated load forecast includes higher growth over the period 2018-2024 than its initial GDP forecast[26]. Intuitively this would lead one to expect a higher growth in customer counts over the same period. However, for the GS 50-999 class this is not the case as demonstrated in Exhibit K7.1, Tab 1. While there may not be as close a link one might expect the higher growth rate for GDP to lead to a higher growth for the Residential class. Again, this is not the case. For the Residential class the 2018-2020 increase in customer count actually decreases from 1.6% to 1.5%[27].

4.5 VECC's other issue is with the trend models themselves. In the case of the GS 50-999 class the 2018 actual customer count is higher than the forecast value in the original Application. On this basis one would intuitively expect the new trend model which incorporated this higher value to produce a higher forecast through to 2024. However, this was not the result[28]. When asked about this during the oral proceeding Toronto Hydro's explanation was:

> *"So the particular values you are showing in here and the values we typically show for a spot year are the mid-year numbers, the June numbers, but if there is some kind of differences in the other months of that year, that would also be incorporated in a trend analysis which ultimately leads to the forecast update."[29].*

The anomaly was further explored by the Board Panel during its questioning:

> *MS. FRANK: What I am hoping is that there's going to be something that will show by using the monthly data that the, you know, the 1.3 percent looks like a reasonable increase in the -- for the GS under 50 and for the greater ones, the negative 2.1. So actually, I would appreciate if you would do something that doesn't make me do a lot of analysis, I can just look at it and say, oh, yes, that's obvious*.[30]

4.6 However, the undertaking response[31] provided by Toronto Hydro simply filed the monthly data used and the resulting trend lines that were derived from it. No explanation was provided as to why the 2024 count was now lower than in the original Application or why this result was reasonable from an intuitive perspective.

4.7 In VECC's view Toronto Hydro's customer count forecasts could be improved by using models that link customer counts to changes in economic and demographic conditions. VECC submits that the Board should direct Toronto Hydro to explore usefulness of such models for its next cost-of-service based application.

[26] Transcript Volume 7, page 2 and Exhibit K7.1, Tab 1
[27] Exhibit U, Tab 3, Schedule 1, Table 4
[28] Exhibit K7.1, Tab 1
[29] Transcript Volume 7, page 5
[30] Transcript Volume 8, page 73
[31] Undertaking J8.6

Volume Forecasts (Prior to CDM Adjustments)

4.8 In order to forecast energy use, Toronto Hydro has developed individual regression models for each of its rate classes. The models incorporate economic, demographic, calendar and weather variables that are statistically significant in explaining the energy use by rate class. The models used in the initial Application were based on actual data for the period July 2002 to December 31, 2017.

4.9 In Toronto Hydro's approach to load forecasting the impact of historical CDM programs is captured by i) adding the gross impact of past CDM programs back into the historical data used to estimate its load forecast models; ii) using these models to forecast future energy use (prior to any CDM reduction); and then iii) deducting the cumulative forecast gross impact of CDM programs in order to derive the energy load forecast (net of CDM) to be used in the Application. For those classes that are billed on a kW basis, forecast energy (prior to removing CDM) was converted to billing kW using the historic relationship between energy and billing demand and then the impacts of CDM were removed.

4.10 For purposes of the updated load forecast filed in April 2019 the load forecast's regression models were re-run using actual historical loads and input variables to the end of 2018. Furthermore, the models were re-tested to confirm the appropriateness of the explanatory variables used. All of the model specifications remained unchanged except for the GS 1-5 MW class. The initial load forecast models used verified CDM results for the years up to 2016 but unverified CDM results for 2017. In the updated forecast, verified 2017 CDM results were available and used but the 2018 CDM results used were unverified. More specific details regarding Toronto Hydro's treatment of CDM and VECC's submissions in that regard are set out in the next section.

4.11 VECC has no issues with respect to the Toronto Hydro's overall load forecast methodology used for its volume forecasts.

CDM Adjustments and Proposed LRAMVA Threshold

4.12 As noted in the preceding section, Toronto Hydro's approach is to forecast future delivered energy and billing demand prior to any CDM adjustments, including those related to CDM programs that were implemented over the historic period used to develop its load forecast models, and then remove the impact of CDM (both historic and future programs) from the forecasts produced by the models. Also, as noted above, the updated load forecast used the IESO-verified CDM results up to 2017 and unverified results for 2018. For the 2019-2024 forecast period, the CDM savings included in the forecast are based on the latest CDM plan submitted to the IESO regarding the programs to be implemented each year.

4.13 For purposes of including CDM impacts in its load forecast models the values used by Toronto Hydro differ from the verified net energy savings reported by the OPA/IESO in four ways: gross vs. net, persistence, realization rates and lines losses . The CDM values Toronto

Hydro uses in its load forecast models are the gross CDM results reported by the IESO (e.g., including free-riders) as opposed to net CDM result which are what electricity distributor CDM targets are based on . In terms of persistence, the values reported by the IESO are the savings that are directly attributable to the CDM program which are tied to the life of the program measure. However for load forecasts purposes, Toronto Hydro assumes that the measure will be replaced by a similar technology at the end of life and there is no loss in persistence. Realization rates refers to the fact the IESO reports annualized results and does not account for implementation effects during a program's first year. Line losses reflect the fact that Toronto Hydro's load forecast is at the purchased power level whereas the IESO reports savings at the end use level. It should be noted that: i) for purposes of the actual sales forecast used in the Application, Toronto Hydro removes lines losses and ii) recognition that first year impacts of CDM programs will be less than the annualized values is standard practice.

4.14 For purposes of the LRAMVA threshold applicable to the 2020-2024 period, Toronto Hydro has calculated the values based on the forecast savings from programs implemented in 2019-2024. For purposes of determining the LRAMVA threshold, Toronto Hydro has converted its forecast of gross CDM saving to net CDM savings and adjusted for its assumption regarding continued persistence of CDM savings.

4.15 In EB-2014-0116 the Board considered and accepted Toronto Hydro's use of gross (as opposed to net) CDM saving for purposes of developing its load forecast. The other key area of departure from simply using the verified results reported by the IESO is Toronto Hydro's assumption that there will be no loss in persistence of the impact of CDM programs over time. While this approach is unconventional, VECC accepts that the assumption the CDM measures will be replaced by a similar technologies at the end of their lives and there is no loss in persistence is not unreasonable.

4.16 If such an approach is adopted the critical concern is that for purposes of the LRAMVA threshold this persistence impact be removed as the LRAMVA values are calculated in comparison to the verified IESO reports – which do assume a loss in persistence. In this regard, Toronto Hydro has appropriately adjusted its proposed LRAMVA thresholds to exclude the impact of its assumptions regarding continued persistence. Toronto Hydro, in determining its LRAMVA threshold has also appropriately accounted for the fact that in its load forecast gross CDM impacts are used whereas the LRAMVA calculations are based on net CDM impacts.

4.17 Toronto Hydro has acknowledged that the CDM values in its load forecast have not been revised to account for the recent government announcements with respect to the discontinuation of certain CDM programs. However, Toronto Hydro has indicated that the discontinuation of certain CDM programs currently assumed in its load forecast will have a minimal impact on its load forecast.

4.18 Based on Toronto Hydro's evidence that the recent government changes to the province's CDM programs will have a minimal impact, VECC considers the adjustments Toronto Hydro has made to its load forecast to account for CDM to be reasonable.

4.19 In terms of the LRAMVA threshold, the adjustments that Toronto Hydro has made for the impact of 2018 CDM programs are not based on verified results. When asked why the 2018 program impacts were not included in the LRAMVA threshold determination, Toronto Hydro responded that it had been informed by the IESO that the IESO would not be issuing verified results for 2018 CDM savings . However, since then, the Board has released an addendum to the Chapter 2 Filing Guidelines and indicated that the IESO has made monthly Participation and Cost Reports available to electricity distributors from January 1, 2018 to March 31, 2019 and that the OEB will be relying on these reports as supporting documentation when assessing applications for lost revenues in relation to energy and demand savings from programs delivered under the CFF.

4.20 Given the 2018 CDM savings estimates used by Toronto Hydro were based on unverified results and the Board's recent Filing Requirements update, VECC submits that Toronto Hydro's LRAMVA thresholds for 2020-2024 should also include the impact of 2018 CDM programs.

<u>2020 Other revenue and shared services</u>

4.21 In its April 2019 update Toronto Hydro revised its 2020 forecast for Other Revenues from $47.7 M to $46.8 M in order to account for: i) a decrease in Specific Service Charges revenues of $3 M as a result of the removal of the Collection of Account and Install/Remove Load Control Devices charges as of July 1 in accordance with the OEB rate order dated March 14, 2019 and ii) an increase in Other Income and Deductions of $2 M due to lower merchandising and jobbing costs of $2 million as a result of capitalization of major assets related to accident claims[32].

4.22 In response to U-VECC 83 b) Toronto Hydro acknowledged that the updated forecast for 2020 Other Revenue had not captured the impact of the increase in Retail Service Charges approved by the Board in February 2019. After adjusting for this change, the forecast Other Revenue for 2020 is $47.07 M[33].

4.23 VECC's only concern regarding Toronto Hydro's Other Revenue forecast is the same as that raised by Board Staff which is that Toronto Hydro's forecast of zero revenues in 2020 from the gain on disposition of utility and other property (USOA 4355) in not reasonable.

[32] Exhibit U, Tab 3, Schedule 2, page 2 and U-Staff-178
[33] U-VECC 83, Appendix A

4.24 VECC notes that in its 2015 CIR Application (EB-2014-0116) Toronto Hydro was also forecasting zero gains on the disposition of utility property for 2015[34]. However, the actual gains in 2015 were over $4 M and the average over the years 2015-2018 has been $1.8 M with an additional $1.6 M forecast for 2019[35].

4.25 As a result, VECC supports Board Staff's submission that Other Revenue should be increased by $1.78 M in recognition of likely gains on the disposition of utility property in 2020.

5.0 OM&A, Depreciation and PILS

5.1 For the purpose of OM&A for the 2020 test year VECC has taken an envelope approach based on the principle that the prior rate plan was intended to provide the outcome of costs no larger than the going rate of inflation. Since for consumers the going rate of inflation is measure by CPI we have used the Bank of Canada's inflation calculator to make this comparison[36].

5.2 In 2015 the Board approved an envelope amount of $243.9 million. The negligible difference between actual spent and Board approved simplifies our analysis. If one were to inflate the 2015 approved/actual spending of $244 million to its 2019 equivalent (approximately June 2019) then the current OM&A would be $262.6. Inflating that amount for the remainder of 2019 and by 2% (the current inflation rate[37]) would add $5.2 million to this figure. The resulting in a 2020 cost of service OM&A figure of $267.8 million. This is similar to the last year of actual report of OM&A spending of $268.3 million.

5.3 Based on this analysis VECC submits that the OM&A to be included in rates should be reduced by $9.5 million. We note that this is very similar to Board staff's proposal of a $9.4 million reduction based on a more detailed program analysis.

5.4 The above analysis makes no adjustment for what should have productivity savings during the prior term. In the same way we make no adjustment for customer growth during the period which is under 5%[38] . In our view a detailed examination of Toronto Hydro operating cost, especially compensation costs, would argue for a much greater reduction[39].

5.5 The simple fact is that if OM&A in the new plan exceeds the rate of inflation for the past period then there is no compelling reason to continue on this form of "incentive" rate making. If

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[34] EB-2014-0116, Exhibit 3, Tab 2, Schedule 1, page 1

[35] U-VECC 83, Appendix A

[36] https://www.bankofcanada.ca/rates/related/inflation-calculator/ the calculator use the CPI to the most recent inflation which is about two months prior to the current calculation

[37] See for example https://www.inflation.eu/inflation-rates/canada/inflation-canada.aspx

[38] Exhibit 3, Tab 1, Schedule 1, pg. 1

[39] See for example the proposal of School Energy Coalition, pgs. 73-74 which seek an $18.3 million reduction

OM&A costs are not reduced significantly then the greater incentive and benefit to consumers will surely be found in setting rates on an annual cost of service basis.

5.6 We would draw the Board to one example of the failure of incentive rate making in this proceeding. Toronto Hydro has argued for a significant increase in bad debt costs in order to compensate for presumed higher costs due to imposed restriction on winter disconnection. Board staff has pointed out that the data does not support the argument.[40] But this seems to us beside the point. Toronto Hydro is just one of a number of utilities we have seen argue that a change in circumstance necessarily results in an increase in the cost to ratepayers (it seldom goes the other way). Yet if incentive regulation were working as expected – really working - the result of a change in circumstance like the moratorium on winter disconnection would entice an efficiency response. The utility would find ways to reduce and eliminate the cost of that new risk. Instead, and in true the fashion of cost of service regulation no innovation is demonstrated. Contrast that to a firm operating in a competitive market where it cannot simply add to the price of its service or product lest their more nimble competitor not do the same. Out of that equation come efficiencies which benefit all consumers. The issue of bad debt compensation is just one very small element of the cost of this Utility. But the response of Toronto Hydro to this challenge, like its every increasing demands for capital investment, point to a set of policies that are failing to bring the change in electricity distribution costs in line those of non-regulated services.

5.7 We have similar sentiments about compensation costs. Typical is the "Mercer Report" which ultimately compares the utility if not to precisely to the same type of utility – then to other highly compensated firms. The Board never examines whether there might be a disconnect between the average salary/wage of Ontario workers and the salary those firms or government in regulated or highly unionized sectors which are used to judge the reasonability of these costs. Inevitably this leads to a disconnect between the ratepayers who pay bills and those who charge them. The resentment caused by this is evident we think in the letters of comment and customer meetings that are part of the Board process.

<u>Payment in lieu of taxes (PILS)</u>

5.8 VECC adopts the argument of Board Staff on this issue. They are comprehensive and we think articulate accurately the interaction between the new CCA rules and the CRRRVA.

[40] Board Staff, pgs. 108-109.

6.0 Cost of Capital

6.1 VECC has no specific issues with the Applicant's calculation of the cost of capital component for the test year. Generically, however we are concerned that the Board has not revisited the appropriate setting of the cost equity or the appropriate deemed capital structure in light of the movement for a larger component of costs being recovered in the fixed rate. Taken in conjunction with overly generous custom rate plans and rebasing deferments being granted we believe there is a need to revisit how the equity component of a utility's rates are set.

7.0 Cost Allocation and Rate Design

Revenue-to-cost ratios

7.1 As part of the April 2019 Update Toronto Hydro filed an updated Cost Allocation Model that incorporated the updated load forecast and revenue requirement for 2020 as well as required corrections to the Model itself identified during the interrogatory process[41].

7.2 The status quo revenue to cost ratios produced by the updated Cost Allocation model and Toronto Hydro's proposed ratios for 2020 are as follows[42]:

Name of Customer Class	Previously Approved Ratios Most Recent Year: 2015 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
Residential	94.3%	103.2%	103.2%	85 - 115
Competitive Sector Multi-Unit Residenti	100.0%	102.2%	100.0%	80 - 120
GS <50	91.5%	88.9%	89.5%	80 - 120
GS - 50 to 999	119.0%	105.8%	105.8%	80 - 120
GS - 1000 to 4999	101.9%	90.8%	91.2%	80 - 120
Large Use >5MW	95.3%	88.2%	88.8%	85 - 115
Street Light	82.7%	108.9%	108.9%	80 - 120
Unmetered Scattered Load	90.5%	137.1%	120.0%	80 - 120

7.3 VECC has no issues with cost allocation methodology employed by Toronto Hydro. VECC notes that it is based on the latest model available from the Board at the time the Application was prepared[43]. VECC also notes that the direct allocations and the minimum system customer component employed by Toronto Hydro have both been approved previously by the Board in EB-2014-0116[44].

[41] Exhibit U, Tab 7, Schedule 1, page 1
[42] Based on the RRWF filed with the April 2019 Update, Tab 11
[43] Exhibit 7, Tab 1, Schedule 1, page 1
[44] Technical Conference, Volume 4, pages 124-126 and Exhibit 7, Tab 1, Schedule 1 page 3

7.4 With respect to the proposed revenue to cost ratio adjustments, VECC notes that: i) none of the customer class ratios are being moved further away from 100%; ii) for those classes outside the Board's policy range the ratios are being moved to the boundary of the policy range, iii) the ratio for CSMUR is being set at 100% in accordance with the Board's EB-2010-0142 Decision, and iv) to make up the revenue shortfall from (ii) and (iii) those customers with ratios below 100% are seeing an increase. With respect to the last point, VECC also notes that those classes whose ratios are the furthest away from (i.e., below) 100% are experiencing the largest adjustments. VECC has no issues with Toronto Hydro's proposed adjustments to the status quo revenue to cost ratios.

7.5 VECC appreciates that the results of the cost allocation may change as a result of the Board's final decisions regarding the load forecast and revenue requirement. However, VECC submits that the principles (as outlined above) used by Toronto Hydro in identifying and making any required adjustments to the status quo revenue to cost ratios are appropriate and should be endorsed by the Board.

<u>Rate design – Fixed variable split</u>

7.6 For the Residential and CSMUR classes, 2020 is the last year of transition to a fully fixed distribution charge . In both cases the increase in the monthly service charge is less than $4 and the total bill impacts are less than 10%.

7.7 For the other customer classes, Toronto Hydro proposes to maintain the existing fixed/variable split.

7.8 VECC has no issues with Toronto Hydro's proposed rate design for the Residential and CSMUR classes. Movement to a fully fixed service charge in 2020 is in line with Board policy providing the impacts are reasonable (i.e., increase in service charge due to the Board policy is not greater than $4 and the overall total bill impact is 10% or less).

7.9 VECC makes no submissions regarding the rate design applied to the other customer classes.

<u>Loss factors</u>

7.10 For the Large Use class Toronto Hydro commissioned Navigant to undertake a study which has estimated the class' primary loss factor to be 1.0025 . For the other customer classes the proposed loss factor is based on a five year history. For these classes the resulting loss factor is 1.0295 which is less than the currently approved loss factor of 1.0376.

7.11 VECC has no issues with Toronto Hydro's proposed loss factors.

Retail Transmission Service Rates (RTSRs)

7.12 Toronto Hydro's proposed 2020 RTSRs have been calculated using the Board's RTSR model. They are based on the current Uniform Transmission Rates (UTRs). However, Toronto Hydro has indicated that it will update the calculated rates prior to implementation based on the OEB approved UTRs at the time .

7.13 VECC's only submission with respect to Toronto Hydro's proposed RTSRs is in regards to the billing units used. In initial version of Board's RTSR model Toronto Hydro has used its initial 2020 load forecast as the basis for the billing units for each customer class . However, a revised version of the model was not filed when the 2020 load forecast was updated in April 2019. Further revisions will also be required if the 2020 load forecast approved by the Board differs from the April 2019 update.

7.14 In addition, the Board's RTSR model requires that the UTR billing determinants used be based on the same reporting period as the customer class billing determinants. As a result, Toronto Hydro will also need to update the UTR billing determinants used in the model to reflect the Board's final determinations regarding the 2020 load forecast. In the alternative, Toronto could elect to use the actual customer class billing determinants and UTR billing determinants for the most recent for which RRR data has been reported to the Board. In VECC's view this later approach is the more straight forward one particularly as Toronto Hydro has not documented how it determines the forecast UTR billing determinants.

Specific Service Charges

7.15 Toronto Hydro is requesting approval to remove the "Service Call – Customer Owned Equipment" charge from it Schedule of Rates and Charges . The rationale being the scope of the work that could be perceived to fall under the charge description is too broad and has a high degree of cost variation. Toronto Hydro intends to recover the costs for providing such services on a "cost basis".

7.16 The only other changes that Toronto Hydro is proposing to make to its Specific Service Charges arise as a result of Board policy and decisions. These include: i) the Specific Charge for Access to Power Poles (Wireline Attachments) which will be set at the standard province-wide rate , ii) Retail Service Charges which will be set in accordance with OEB Decision EB-2015-0304 , and iii) the Collection of Account and Install/Remove Load Control Devices charges which have been removed in accordance with EB-2017-0183.

7.17 VECC has no issues with Toronto Hydro's proposed changes to its Specific Service Charges.

Service charges

7.18 The only issue raised during proceeding with respect to customer service charges under Toronto Hydro's Conditions of Service was with regard to its person in attendance policy for vault access for customer-owned vaults. At the time of its original Application Toronto Hydro was proposing to change the policy such that instead of allowing the attendance of Toronto Hydro personnel for one vault entry per year free of charge there would be a charge for attendance time in excess of 2 hours.

7.19 During the course of the proceeding Toronto Hydro indicated that the conditions of service relating to this matter would remain as they currently are (i.e., one free inspection per year). This was confirmed in Toronto Hydro's Argument-in-Chief.

7.20 Given that Toronto Hydro's withdrawal of its proposed change to its person in attendance policy for vault access for customer-owned vaults, VECC has no submissions on this issue.

8.0 Accounting and Deferral and Variance Accounts

CRRRA

8.1 Toronto Hydro has proposed to continue its Capital Related Revenue Requirement Variance Account (CRRRA). Since the account only tracks gross capital spending and is not project specific it acts as a "slush" mechanism. Projects which run over budget are offset by those that are completed under budget or eliminated in their entirety. There is no specific accountability which brings this back to the distribution system plan filed as part of this Application. We submit that the account should be organized by the categories of the DSP.

Copeland Related DVA

8.2 VECC supports the establishment of the Carillion Insolvency Payments Receivable Account as set out by Board Staff.[45]

VECC respectfully submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred cost

-ALL OF WHICH IS RESPECTFULLY SUBMITTED -

[45] OEB Staff Submission, EB-2018-0185, August 21, 2019, pg. 146