EB-2016-0069

ONTARIO ENERGY BOARD

Oshawa PUC Networks Inc.

Application for electricity distribution rates beginning January 1, 2018 and January 1, 2019

Final Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

23 November 2017

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1.0 The Application

1. In 2015 OPUCN applied for rates to be set under a 5 year Custom Incentive Rate Plan. In the event the Board approved distribution rates on a final basis for 2015 to 2017, but on an interim basis for 2018 and 2019. The latter year rates are be adjusted for a number of factors:

- Forecast of new customer connections and consumption;
- The amount and timing of its capital expenditures, specifically from :
  a) the cost and schedule of the MS9 substation and the proposed Hydro One Enfield TS, as well as any related capital contributions to Hydro One by Oshawa PUC.
  b) regional planning; and,
  c) third party requests for relocation of OPUCN plant;
- Updating of the Cost of capital parameters
- Updated forecast for the cost of power

2. In its 2015 Decision the OEB also directed that OPUCN in its next (this) application make a number of comparisons:

- comparison of the OEB-approved to actual capital expenditures for 2015-2017;
- comparisons of the approved forecasts for the 2018 and 2019 that are used to set the interim rates in EB-2014-0101 and updated forecasts for 2018 and 2019: and,
- comparison of the interim rates for 2018 and 2019 set in EB-2014-0101 and the rates flowing from the updated forecast.

3. The Board further noted that "[T]*he comparisons should provide information, including on financial performance, sufficient for the OEB to determine whether rate adjustments are warranted*."[1]

4. In the result of the OPUCN's proposed rate adjustments factors are shown below[2]:

Year	Interim Base Revenue Requirement ($000s)	Updated Base Revenue Requirement ($000s)	Interim Residential Rate	Final Residential Rate
2018	$24,975	$23,741	$17.93 Fixed/Month $0.0078 per kWh	$17.35 Fixed/Month $0.0078 per kWh
2019	$26,406	$24,974	$21.55 Fixed/Month $0.0041 per kWh	$20.97 Fixed/Month $0.0041 per kWh

[1] Reason For Decision EB-2014-0101, November 15, 2015, pg.10
[2] Exhibit A/pg. 4

5. The application also includes proposals for disposition of Group 1 (power) deferral and variance accounts and flow-through Retail Transmission Service rates and other reporting requirements. However, The Board has limited cost awards to those for issues related to capital expenditures, the working capital allowance and the load forecast.[3] VECC takes these items to form the issues list and has therefore made argument on only those matters.

2.0 Capital Adjustment

<u>OPUCN 's Application</u>

6. Below VECC has summarized the detailed capital expenditure as approved and as updated in 1-Staff-3. To ease comparisons we have summed both the 3 year actual years and the remaining two year forecast and shown the 5 year totals

7. As required by the Board Decision and in response to a Board Staff interrogatory OPUCN provided a comparison the actual 2015 to 2017 capital expenditures, which were $28.985 million (11480/15+8467/16,+9038/17) as compared to the forecast approved amount of $29.869 million (12370/15+977/16+7722/17). Or a difference of $884,000.[4]

	2015	2016	2017	2018	2019	5 Yr	5 Yr		2015	2016	2017	2018	2019
		UPDATED		('000)		Total	Total			BOARD APPROVED		('000)	
System Access Total	2,872	1,675	1,854	3,458	2,698			**System Access Total**	3,684	2,285	2,075	2,340	2,350
3/2YR TOTAL			**6,401**		**6,156**	**12,557**	**12,734**	**3/2YR TOTAL**			**8,044**		**4,690**
System Renewal Total	6,719	4,029	4,647	4,761	4,561			**System Renewal Total**	5,943	4,932	4,472	4,761	4,851
3/2YR TOTAL			**15,395**		**9,322**	**24,717**	**24,959**	**3/2YR TOTAL**			**15,347**		**9,612**
System Services Total	801	1,229	1,082	10,580	15,548			**System Services Total**	1,068	1,380	420	25,145	4,050
3/2YR TOTAL			**3,112**		**26,128**	**29,240**	**32,063**	**3/2YR TOTAL**			**2,868**		**29,195**
General Plant Total	1,088	1,534	1,455	730	510			**General Plant Total**	1,675	1,180	755	730	510
3/2YR TOTAL			**4,077**		**1,240**	**5,317**	**4,850**	**3/2YR TOTAL**			**3,610**		**1,240**
Five year total comparison					Updated	**71,831**	**74,606**	Approved					

[3] See Notice of Application
[4] 1-Staff-3

VECC's Submission

8. In VECC's submission OPUCN must adjust its 2018 opening rate base balance for the actual 2015-2017 capital expenditures. This is clear from the Board's EB-2014-101 Decision with Reason which states "[T]*he comparisons should provide information, including on financial performance, sufficient for the OEB to determine whether rate adjustments are warranted*."

9. Since the Board has explicitly required comparison of actuals capital expenditures to forecast it follows that it intended for 2018 opening rate base to be based on the best information available at the time of the mid-term review. To argue otherwise (as OPUCN has done) begs the question as to why then the Board would ask for a comparison of forecast to actual capital expenditures. In this case the variance is material and therefore the adjustment of 884k should be made.

10. The second question that arises is whether and how the remaining 2018-2019 capital forecast should be adjusted for known changes since the original rate setting. In this regard the Board was also very specific. It asked that three items be examined: the MS9 project, the Hydro One Enfield project and the amounts for relocated plant. All three items were, in our submission singled out because of the known risk at the time for significant variation. In our view this does not preclude a consideration of the other capital expenditure variations from forecast.

11. In the event, OPIUM has indicated that the MS9 project costs are substantially on target and no adjustment is required. In our submission there is no evidence to refute this position.

12. With respect to Enfield it appears to us that there has been a significant broadening or adjustment of scope of the project. The adjusted costs, moving from the original filed to the Board approved in EB-2014-0101, to the current amount are shown in the table below:[5]

Asset Description	Original DSP	Decision on Custom IR	Mid Term Application
Enfield TS Contributions	$6,500	$13,500	$4,000
MS9 Substation	$7,000	$7,000	$7,000
MS9 Overhead Feeders	2,000	$7,500	$7,500
Overhead Feeder Enfield TS Egress and Load Transfer	Nil	Nil	$6,500
Total	**$15,500**	**$28,000**	**$25,000**

13. OPUCN's notes that the projects were itemized based upon the regional planning process which was in the early stages of development when the OEB issued their decision in November 2015. Overhead feeders for Enfield TS egress and load transfer

[5] Undertaking JT1.4

requirements were subsequently identified as part of the regional planning process. In our view OPUCN has provided sufficient information for the Board to incorporate the revised scope and requested additional Enfield Feeder project. However, the revised project scope costs are not supported by any business case. As such it is difficult to ascertain the veracity of the estimated costs. In our submission the significant adjustments made to this project argue for the establishment of a variance account to capture the revenue requirement impacts of both cost and timing variations from the Board approved forecast.

14. With respect to the issue of plant relocations. It is OPUCN's position that "[C]*umulative total capital expenditures related to plant relocations is expected to be approximately $2.4 million below plan at the end of 2017 due mainly to the pace of construction being slower than anticipated. However, based on City and Regional planning and the completion of infrastructure for the 407 ETR extension, OPUCN expects the total planned capital for third-party requested plant relocations for the five year period to be spent*[6]."

15. We think this unlikely. Nor do agree that in 2018 and 2019, OPUCN will spend, as it suggests, the planned capital for these years in the remaining two which would be in addition to what it originally anticipated in the final years[7]. In our submission the Board should reduce the Applicant's proposal for this adjustment and substitute for it the first two year's forecast spending. That is, it should treat the underspending as simply a delay of two years in the original forecast.

16. Finally, with respect to the remainder of the capital expenditures we note that OPUCN is 467k in excess of general plant investments. In our view such investments are largely discretionary but relatively small in their impact on rates.

3.0 Load Forecast, Cost Allocation and Rate Design

OPUCN's Application

17. In its EB-2014-0101 Decision[8] regarding OPUCN's 2015-2019 CIR Application the Board approved an annual customer growth rate of 1.5% for 2015, 2016 and 2017 and a 3.0% growth rate for 2018 and 2019. It also indicated that Oshawa PUC would have the opportunity to update the forecast growth rate for 2018 and 2019 based on actual results to date at the mid-term review. To this end it directed that the mid-term review application include evidence of customer connections and consumption[9].

[6] Exhibit A, page. 17
[7] Ibid, page 17
[8] Page 30
[9] Page 9

18. In the current Application, OPUCN has updated the forecast customer growth for each of 2018 and 2019 to 1.8%[10], as opposed to the 3% included in the interim rates approved for the two years. For purposes of forecasting 2018 and 2019 customer/connection counts for the Residential and General Service classes:

- The historic (geometric mean) growth rate to the actual 2016 counts, by customer class, to determine the 2017 forecast customer count and, then,
- The 1.8%/annum increase was applied to the 2017 forecast customer count to derive the values for 2018 and 2019.

The basis for the 1.8% was the Durham Regional Official Plan[11].

19. For the remaining customer classes, the 2018 and 2019 customer/connection counts were forecast by applying the historic (geometric mean) growth rate to the actual 2016 counts, except for the Large User class where the customer count was held constant at one[12].

20. In preparing the Application, OPUCN also updated the purchased power model used in the EB-2014-0101 Application by re-estimating the model using actual data up to March 2017[13]. OPUCN then compared the predicted values for the period to the actuals and concluded that there was growing variance between actual versus predicted values (with predicted being higher than actual). This led OPUCN to propose an alternative projection for purchased power based on the historical trend between 2006 and 2016. The resulting purchased power projections for 2018 and 2019 were then allocated to customer classes using the same approach as was used for EB-2014-0101. Adjustments were then made to account for the higher (1.8%) than historic customer growth rate, again using the same approach as in EB-2014-0101[14].

21. Finally, OPUCN also updated its CDM adjustments for 2018 and 2019 to reflect its current view as to the impact of 2017-2019 CDM programs[15]. However, OPUCN did not update the associated LRAMVA baseline amounts as it considered that to be "out of scope"[16].

22. The resulting billed energy forecast by customer class is set out in Exhibit A, Table 8.

[10] Note: While Exhibit A, page 5 of the Application indicates the forecast growth rate is 1.82%, page 12 quotes a growth rate of 1.8% and this is the value actually used in the load forecast model.
[11] Exhibit A, page 12
[12] Load Forecast Model, City Expansion Tab
[13] Load Forecast Model, Purchased Power Model Tab
[14] See Load Forecast Model, Customer Energy Model and City Expansion Tabs
[15] See Load Forecast Model, CDM Summary Tab
[16] VECC 4 d)

VECC's Submissions

23. VECC has a number of issues with OPUCN's proposed load forecast. They have been grouped below under three general headings: i) Board Update Direction, ii) Proposed Purchase Power Forecast Methodology, and iii) Customer Class Forecasts (including CDM Adjustment).

Board Update Direction

24. In its EB-2014-0101 Decision the Board rejected OPUCN's original proposal to annually update various aspects of its 2015-2019 CIR Plan, including updating the load forecast to account for updated customer connection and volume forecasts. Instead, the Board opted for a mid-term review and indicated that "the mid-term review will have a narrow scope with a limited number of 2016 actual and forecast updates"[17]. In the case of the load forecast, the Board indicate that the review include evidence of customer connections and consumption.

25. In VECC's view there were a number of different approaches that OPUCN could have taken in terms of it evidentiary update regarding the load forecast that would have been consistent with the Board's Decision:

- OPUCN could have utilized the purchased power model and forecast developed for EB-2014-0101; updated the customer counts/connections for actuals through to 2016; developed a new forecast of customer counts/connections for 2017 – 2019 and then revised the consumption forecast using the same approach as in the original 2015 CIR Application. In other words, only update the forecast customer count for 2018 and 2019 and adjust the consumption forecast accordingly.

- OPUCN could have used the purchased power model developed for EB-2014-0101; updated the forecasts for the various explanatory variables; updated the purchase power forecast for 2017-2019 accordingly; developed a new forecast of customer counts/connections for 2017 – 2019 and then revised the consumption forecast using the same approach as in the original 2015-2019 CIR Application. In other words, update the customer count forecast and the forecast for explanatory variables used in the EB-2014-0101 load forecast model. but also update the EB-2014-0101 load forecast model to incorporate more recent historic data.

- OPUCN could have re-estimated the power model using actual data up to 2016; updated the forecasts for the various explanatory variables; updated the purchase power forecast for 2017-2019 accordingly; developed a new forecast of customer counts/connections for 2017 – 2019 and then revised the consumption forecast using the same approach as in the original 2015 CIR Application. In other words, update the customer count forecast and the forecast for explanatory variables used in the EB-2014-0101 load forecast model, but also update the EB-2014-0101 load forecast

[17] EB-2014-0101 Decision, page 9

model itself to incorporate more recent historic data. Indeed, this is what OPUCN initially did, except that while it updated the HDD and CCD values used in forecast for 2017-2019 it did not update the unemployment rate forecast.

26. In VECC's view any of the above approaches would have been a reasonable interpretation of the Board's EB-2014-0101 Decision that the mid-term review will have "a limited number of 2016 actual and forecast updates[18]". However, under the approach initially used by OPUCN it would have been appropriate to also update the unemployment rate forecast.

27. The problem is that OPUCN did not ultimately adopt any of these approaches for its current Application. Rather it has chosen to adopt a totally different approach to forecasting purchased power than what the original 2015-2019 CIR Application was based on. In VECC's submission, this goes well beyond what can reasonably be considered an "update" as envisioned by the Board's Decision. The concern in EB-2014-0101 that led to the Board permitting a "limited number" of updates was the uncertainty regarding future customer growth. In VECC's view the intent of Board was to address this uncertainty by allowing OPUCN to revise its load forecast based on 2016 actual (and updated forecasts for) customer counts. It was not meant to provide an opportunity for OPUCN to fundamentally change its load forecast methodology.

28. VECC submits that the Board should reject OPUCN's load forecast update as being inconsistent with it intent in permitting limited updates during the CIR period.

OPUCN's Proposed Purchase Power Forecast Methodology

29. OPUCN alternative approach to forecasting purchased power for 2018 and 2019 is to apply a simple trend analysis to the actual purchased power values for 2006-2016. There are a number of problems with this approach.

30. First, the Board expects the load forecast used for purposes of setting rates to be weather normalized[19]. In its analysis OPUCN uses actual purchases, such that the results are not reflective of weather normalized purchases.

31. Second, the Board's filing guidelines makes reference to two types of forecasting models that are generally used to for load forecast purposes[20], neither of which is the trend analysis approach put forward by OPUCN. Indeed, VECC is unaware of any Ontario distributor who has used this methodology, let alone an instance where its use has been approved by the Board. In VECC's view, a mid-term review which is meant to be of limited scope is not the time to be introducing a fundamentally different approach to load forecasting.

[18] EB-2014-0101 Decision page 9
[19] Chapter 2 Filing Guidelines, pages 26-27
[20] Chapter 2 Filing Guidelines, page 26

32. Further compounding this issue is the fact that OPUCN did not provide the revised load forecast “model” in its initial Application. In fact, it was only provided in response to specific information requests[21]. In VECC’s view the subsequent “teleconference” provided inadequate opportunity to understand/test the basis for OPUCN’s new load forecast and whether there were other alternatives available.

33. Finally, the trend analysis approach implicitly includes additional CDM savings in the years 2017-2019 and therefore making explicit adjustments for 2017-2019 CDM programs (OPUCN has done[22]) results in a double counting of CDM savings. The Load Forecast model provided by OPUCN indicates[23] that the actual CDM savings in 2006 were 4.362 GWh (annualized). Furthermore by the end of 2016 the cumulative savings persisting in that year (annualized) from 2006-2016 CDM programs are 61.248 GWh as shown in the following table:

CDM Program Years	Impact on 2016 Load	Source
2006-2010	18.946 GWh	CDM Summary Tab , O40
2011-2013	9.904 GWh	CDM Summary Tab, O45+O46+O47
2014	5.379 GWh	2011-2014 Verified Results, 2014 Results (with a 97.1% adjustment for persistence)
2015	6.328 GWh	2016 Verified Results
2015 CHP Initiative	9 GWh	Not included in 2016 Verified Results, per VECC 4 b). 9 GWh reported during teleconference
2016	11.689 GWh	2016 Verified Results
Total	**61.246 GWh**	

34. Even after allowing for the ½ year rule the impact of CDM programs over the 2006-2016 period used to determine the “trend” is over 5 GWh per year[24]. Extrapolating historic purchases out 2 and 3 years respectively by means of a trend line to estimate

[21] Staff 4 a) and VECC 4 a).
[22] Load Forecast Model, CDM Summary Tab
[23] CDM Summary Tab, cell E26.
[24] The starting 2014 value would be 2.181 GWh (½ of 4.362 GWh) and the CDM impact in 2016 would be 55.402 GWh (61.246 less ½ of 11.689 GWh). The difference is 53.221 GWh over 10 years.

2018 and 2019 purchased power means that an additional 11 GWh and 16.5 GWh[25] of CDM program savings is being included in 2018 and 2019 respectively. Thus, making a separate adjustment for the impact of 2017-2019 (as OPUCN has done) results in a double counting of the impact of post-2016 CDM programs.

35. What is also worth noting is that the trend analysis undertaken by OPUCN leads to an annual reduction in purchased power of 4.526 GWh in 2018 over 2017 and in 2019 over 2018[26]. This value is less than the annual impact of CDM suggesting that under OPUCN's approach the trend in power purchases is upwards (i.e., growing) prior to any adjustment for CDM. In contrast, OPUCN's approach applies a CDM adjustment to a purchased power forecast value that is already lower than that for the previous year.

36. Overall, VECC submits that OPUCN's alternative approach to forecasting purchased power for 2018 and 2019 (prior to CDM adjustments) is fundamentally flawed and would be totally inappropriate even if the Board was dealing with a full cost-of-service based test year application.

37. For purposes of the current Application, it is VECC's view that the Board should direct OPUCN to use the purchased power forecasts for 2018 and 2019 based on its updated version of the load forecast model developed and accepted as part of the EB-2014-0101 Decision (i.e., the third approach discussed in the preceding section). Customer class forecasts can then be developed using the same methodology and in EB-2014-0101 and updated CDM adjustments incorporated based results to date and the most recently approved CDM plans.

38. This may result in an over forecasting of 2018 and 2019 purchased power. However, in VECC's view this is part of the risk that OPUCN accepted in opting for a CIR-based Application in EB-2014-0101. Defaulting to this approach is also one of the consequences of OPUCN not being transparent at the start of the current process in terms of its proposed changes in load forecast methodology. Such transparency would have allowed a more fulsome exploration of the forecast and possible alternatives.

Customer Class Forecasts (Including CDM Adjustment)

39. As noted previously, OPUCN allocated its 2018 and 2019 purchased power forecast to customer classes using the same methodology as in EB-2014-0101. The Company then adjusted the Residential and General Service customer class forecasts to account for the higher than historic customer/connection growth forecast for those years. VECC has no issues with either of these steps nor with the updated customer growth (1.8%/annum) proposed by OPUCN.

[25] The CDM savings are based on customer delivered energy and would need to be also marked-up for losses.
[26] Load Forecast Model, Power Purchased Model Tab, cells C225 and C226.

40. However, VECC does have issues with the CDM adjustment that OPUCN proposes for 2018 and 2019. Set out below is the "starting point" for OPUCN's CDM adjustments[27].

CDM Projected Program Results

#	Program Year	Results Status	2014	2015	2016	2017	2018	2019
1	2014 Programs	Forecast	6,464,441	6,464,441	6,464,441	6,464,441	6,464,441	6,464,441
2	2015 Programs	Forecast	0	17,441,800	17,424,328	17,347,217	17,313,658	17,302,100
3	2016 Programs	Forecast	0	0	8,870,268	9,230,108	9,230,108	9,230,108
4	2017 Programs	Forecast	0	0	0	19,300,418	18,640,298	18,640,298
5	2018 Programs	Forecast	0	0	0	0	13,551,112	12,425,992
6	2019 Programs	Forecast	0	0	0	0	0	9,524,448

41. VECC's issue is the fact that the 2016-2019 program savings as set out above do not match those provided in either the initial IESO approved CDM Plan[28], the more recent May 2017 IESO approved CDM Plan or the August 2017 CDM Plan recently submitted by OPUCN to the IESO[29]. Undertaking JT1.3 purportedly explains how the CDM savings values were determined. However, after reviewing the IESO tool provided with JT1.3 it is still not at all clear to VECC which of the aforementioned "plans" were the basis for the CDM adjustment or why the values used differ from those in provided in any of the plans. Again, VECC attributes this in large part to the lack of transparency in the initial Application as to how the updated forecast was developed which subsequently led to inadequate opportunity for discovery.

42. However, in this case, the impacts will eventually be trued up through the LRAMVA process. The existence of the "true-up" coupled with the fact that the proposed CDM adjustments are reasonably close to the annual savings in the more recent plans means that the values can be used for forecasting purposes with two provisos:

- The purchased power forecast must be based on the same methodology as used in EB-2014-0101 – otherwise there will be double counting of the impacts.
- The LRAMVA baselines consistent with the CDM adjustment used must be clearly documented so as to facilitate any future LRAMVA claim.

43. The CDM adjustments included by OPUCN for the impact of 2017, 2018 and 2019 programs were based on the annual results set out above but were refined to reflect the "½ year" rule and to reflect better information regarding the likely impact of the street lighting LED retrofit program[30]. The following table sets out the first year impact assumed for the programs in each of these years and the corresponding "annualized" impact that would be appropriate for the LRAMVA baseline. Also shown, for

[27] Load Forecast Model, CDM Summary Tab
[28] Posted on the IESO web-site: http://www.ieso.ca/sector-participants/conservation-delivery-and-tools/cdm-plans
[29] JT1.1
[30] JT1.2

comparison purposes are the annualized programs savings for 2017-2019 from the May 2017 and August 2017 CDM plans submitted to the IESO.

CDM Program Year	1st Year Impact (kWh)	Annualized Impact (kWh)	May 2017 CDM Plan (kWh)	August 2017 Plan (kWh)
2017 Programs	7,257,964	14,515,928	16,420,000	15,131,100
2018 Programs	6,871,041	13,742,081	13,137,000	14,653,800
2019 Programs	4,857,709	9,715,418	9,489,000	10,506,400

Sources: a) 1st Year Impact – Load Forecast Model, CDM Summary Tab, Cells M14, N15, and O16
b) Annualized Impact – Twice first year impact

44. VECC submits that if the Board adopts OPUCN's proposed CDM adjustments then it should also approve the annualized Impact values set out above as the corresponding LRAMVA baseline contributions from 2017, 2018 and 2019 programs. Similarly, if the Board chooses to approve a different level of CDM adjustment, VECC submits it is equally important that the corresponding LRAMVA baseline values be clearly documented.

45. Finally, VECC notes that OPUCN has not included in its CDM adjustments any impacts from 2016 CDM programs. In principle this adjustment would reflect ½ of the impact from 2016 CDM programs. However, since the 2016 results have already been "verified", unless there are future adjustments to the results any future true-up would effectively be zero.

4.0 Working Capital Allowance

46. VECC has no specific submissions with respect to the working capital allowance adjustment other than those changes flowing from the above submissions.

5.0 Costs Incurred

47. 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 costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED