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*via web portal – signed original to follow by regular mail*

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St
Toronto, ON M4P 1E4

Dear Ms. Walli:

**RE: EB-2007-0673: Further Consultation re Stretch Factor Rankings**

On November 21, the Board issued notice of further consultation on issues related to Stretch Factor Rankings for Third Generation Incentive Regulation (3GIRM), and invited submissions from interested parties. The submissions of Toronto Hydro-Electric System Limited (THESL) are set out below. At a general level, THESL also endorses the submissions of the EDA, Hydro Ottawa, and CEIRM, in that those submissions point to the importance of data integrity and model robustness in the exercise of setting stretch factors with real financial consequences. THESL's submissions are in four main areas: Definition of a Standard Distributor; LDC Entitlement to Supply; Econometric Results; and Relative versus Absolute Performance Rankings.

THESL has concerns around specific issues in the exercises of cost comparison and stretch factor setting; however, these should not be understood as opposition on THESL's part to the general incentive regulation approach.

## *The Need to Define a Standard Distributor*

Some of the concerns raised by distributors stem from the fact that for the purposes of distributor cost comparisons and stretch factor determination, there is no explicit definition of what a standard distributor is; or in different terms, what functions actually carried out by distributors are, and are not, within the scope of the benchmarking exercise. Although the function of distributors is superficially apparent, specific concerns have been raised around exceptional items such as LDC reliance on third party LV facilities as substitutes for plant that would usually be supplied and maintained by the LDC; and the presence in LDC operations of assets and costs usually associated with transmission, such as transmission stations and high voltage switchgear. These concerns have been described in detail in other submissions and will not be repeated here.

THESL suggests that the cost comparison analysis and its transparency would be substantially aided by an explicit definition of a standard distributor for purposes of cost comparison. With such a definition in hand, it would be possible to clearly identify and compensate for any departures from that definition in the case of an individual distributor. A closely parallel exercise was carried out for the purpose of 2006 EDR in defining what items would be included and excluded from the distribution revenue requirement. Some of the items that should be identified in the Standard Distributor definition include:

- Inclusion of responsibility (i.e., establishment and maintenance of assets) for transformation and distribution of all power within the LDC service area boundaries;
- Exclusion of responsibility for high-voltage assets including transmission stations and switchgear;
- The treatment, either inclusion or exclusion, of HV metering facilities;
- The treatment, either inclusion or exclusion, of CDM costs
- The treatment, either inclusion or exclusion, of Smart Metering;
- Exclusion of ancillary businesses such as multi-utility billing; and
- Other factors identified through industry consultation.

THESL emphasizes that establishment of a Standard Distributor would pertain only to the cost comparison exercise and would not otherwise bear on the actual conduct of LDCs or their regulation under code and legislation. However, a clear concept of a Standard Distributor would be greatly helpful in reducing confusion, adjusting distributor costs for the purpose of comparison, and improving comparability among distributors.

## *LDC Entitlement to Supply*

THESL submits that all LDCs are entitled to have power brought to their borders, and that the costs of upstream supply to distributors should be wholly excluded from the distribution costs subject to comparison. This exclusion should be maintained regardless of the manner of that upstream supply. Any utility may be supplied with wholesale power by means of the transmission system only; partly by transmission and partly by LV; or entirely by LV. In any case the existing configuration is a function of institutional history and cannot be affected by any utility; distributors neither choose the location of the communities they serve nor the location of the transmission or LV systems.

The proper responsibility of Local Distribution Companies is just that; local distribution. This means that LDCs should be entirely responsible for distribution of power within their service areas and should have costs attributed to them to the extent that they rely on the facilities of third parties, *within the LDC service area,* to distribute power to LDC customers. (THESL also supports the view that distribution within a service area should include transformation to distribution voltages, even if done outside the service area in the case of embedded LDCs.)

It also means that no LDC should be penalized by the attribution of supply costs incurred to bring power to the boundary of the LDC service area. The fact that an embedded distributor is supplied by LV does not mean that that distributor either has or should have responsibility for the LV system or costs thereof upstream of its service boundaries.

THESL therefore submits that the methodology used by Staff for correcting for LV costs is flawed, both for the reasons described in other submissions and because it improperly attributes upstream supply costs to embedded distributors. Much (but not all) of the LV system serves a quasi-transmission (i.e., upstream supply) function; as a result of including the total LV costs in the costs to be attributed to embedded distributors, Staff has begun with a quantity that is overstated, despite the other adjustments that are made to those costs.

## *Flawed Econometric Results*

The Board should be significantly concerned about the stability, accuracy, and reliability of the econometric results produced by PEG in light of the sensitivity analysis that was conducted after it was revealed that Renfrew Hydro had been misclassified as being ‘on-shield’.

In a report dated December 3, 2008, PEG presents on page 10 performance rankings based on econometric results that correct the results originally issued July 22. THESL uses this data as one point of reference.

The other point of reference is the PEG report released by the Board on November 21. The latter report presents the results of revising the value of one dummy variable for one distributor, i.e., the reassignment of Renfrew from shield to non-shield.

Theory indicates that the coefficient on the shield variable should be positive with respect to predicted costs: if a utility is on-shield, its operating costs should be higher all other things equal. As a result, designation as on-shield confers (or should confer) a ranking benefit to an LDC, since its predicted costs will be higher relative to any level of actual costs.

However, in comparing the results for Renfrew Hydro as between the November and the corrected July figures, the removal of the shield variable for Renfrew Hydro has actually increased its ranking from 11 to 6, with a corresponding decrease in Renfrew's actual-over-predicted costs from 0.807 to 0.752. In the absence of any indication to the contrary, THESL assumes that Renfrew's actual costs remained the same; consequently it must be the case that upon *removal* of the shield attribute, Renfrew's predicted costs increased.

This result means either that the sign of the shield coefficient has inexplicably changed, or that the model coefficients have changed significantly enough to improve Renfrew's ranking, or both. However, since the econometric results of the sensitivity analysis were not released, it is not possible at this stage for the parties affected to know what has changed. THESL requests that those results be released, and that PEG provide an explanation for this apparent anomaly.

If it is the case that the econometric results changed dramatically enough to produce a theoretically unsupportable outcome as a consequence of changing one value of one dummy variable among all those for approximately 80 utilities, the Board's confidence in the model *for ratemaking purposes* should certainly be shaken.

If it is the case that there is another explanation, possibly a further data error, then the Board should still be given pause and should institute measures to conduct stringent quality control on the results used for ratemaking purposes.

Finally in this regard, PEG's statement at page 5 of its November report misses the point. There PEG states "Our sensitivity tests show that *relatively few distributors* move from one efficiency cohort to another based on changes in accounting for LV charges or for whether or not Renfrew is classified as being on the Canadian shield." (emphasis added) This statement ignores the direct and possibly material effects that such changes have on individual utilities, and falls into the fallacy of averages. Ratemaking is done on the basis of individual utilities, not on the basis of averages. It would be totally unacceptable to rationalize overstating revenue requirements for half the LDCs and understating them for the other half by saying that on average it makes no difference. Similarly, to state that categories did not change for other distributors is irrelevant to the issue of whether the change in ranking for those utilities affected is warranted.

### *Relative versus Absolute Performance Measurements*

The revisions to econometric results and the flaws pointed out in other submissions concerning the peer grouping approach demonstrate that under a relative performance measurement approach such as that adopted here by the Board, it is possible for discrete financial benefits or penalties to be imposed on an individual utility as a result of events totally external to the operation and control of that utility. THESL submits that a system under which a utility's revenue requirement is affected by whether or not another utility is placed in its peer group or is the subject of a data error is intrinsically and apparently unfair, since the impact on the subject utility is made without reference to its own performance.

Nothing in the cost performance of Renfrew Hydro or Horizon Utilities, to take two concrete examples, changed between the July PEG report and the November PEG report. Yet as a result of a data error concerning Renfrew, which notably did not involve its actual costs, Horizon would be moved from a 0.2 stretch factor to a 0.4 stretch factor. Horizon management would then be left to explain to its Board of Directors and Shareholder why a small mistake concerning the characterization of a utility on the other side of the province should reduce Horizon's revenue requirement.

Some may raise the objection that the difference in Horizon's revenue requirement is not material. If so, why is the Board discriminating the stretch factors applied to different utilities? To support the approach it has taken, the Board must believe that differences between stretch factors are significant. In any event, to say that the change wouldn't matter is tantamount to advising a patient not to worry if the wrong medication is given, since not very much is administered.

Even without assuming that data errors skew results, the peer group approach cannot be statistically validated and is highly dependent on subjective judgements as to the discriminators underlying peer group formation. In this sense the approach provides a kaleidescopic view of distributor costs performance, since minor adjustments can produce quite different pictures.

Furthermore, the assumption underpinning the peer group approach is that utilities in a group share common values of a significant cost driver. The peer group approach is thought to 'correct' for differences in cost drivers between groups and therefore to put distributors on a (more) equal footing; specifically, to the degree that comparisons of cost performance across groups are meaningful. Under the current approach it is held to be possible to conclude that utilities with actual costs lower than average *for their group* exhibit better cost performance (and should get a higher ranking) than utilities with average performance in a different group.

This conclusion does not follow and cannot be relied on. Consider two groups discriminated on an arbitrary cost driver such as customer density. In the first group, cost performance on the underlying cost driver could be quite poor across the entire group, but nevertheless there could be utilities that have actual costs significantly lower than the *group average*. In the second group, cost performance on the underlying cost driver could be very good but without much variation between utilities in that group. Clearly, it is not possible to properly conclude that the best out of a bad lot in the first group has better cost performance than an average member of the second group.

To ‘further reduce the potential for misclassification’, the Board should move away from a relative performance system, especially during early days when it cannot have confidence in precise results that discriminate narrowly between utilities. Instead the Board should set stretch factors for individual utilities based only on their own cost performance. It would still be quite open to the Board to set standards based on consideration and quantification of the cost performance of all utilities, but after those standards were set, the stretch factor and revenue requirement outcomes for individual utilities would be determined only by reference to their own absolute performance against the standard.

An absolute performance approach is perfectly compatible with econometric benchmarking, and in fact would almost require it. It would also mean moving away from the peer grouping system, which by necessity is at best a rough approximation of factors which would be better measured directly through the econometric approach. While the Board may not be prepared to abandon peer groups in the short term, it should certainly move in the direction of improving the data and modelling underpinning the econometric approach so that the individual set of cost drivers facing each utility can be accurately and properly accounted for in setting cost performance standards for that utility.

Yours truly,

*[original signed by]*

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