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Our File No. 161232

October 23, 2017

VIA RESS, EMAIL AND COURIER

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attention: Kirsten Walli,
Board Secretary

Dear Ms. Walli:

Re: OEB, Regional Planning and Cost Allocation Review
Board File No.: EB-2016-0003

Please find enclosed herewith BOMA's Written Comments on the Proposed TSC and DSC.

Yours truly,

FOGLER, RUBINOFF LLP

Tom Brett per D.

Thomas Brett
TB/dd
Encl.
cc: Chris Cincar, OEB *(via email)*
Marion Fraser, Fraser & Company *(via email)*

ONTARIO ENERGY BOARD

Proposed Amendments to The Transmission System Code and The Distribution System Code to Facilitate Regional Planning

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Written Submissions of

Building Owners and Managers Association of Greater Toronto (BOMA)

October 23, 2017

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The Ontario Energy Board (OEB) has given notice under section 70.2 of the Ontario Energy Board Act, 1998 of proposed amendments to the Transmission System Code (TSC) and the Distribution System Code (DSC).

Background

On January 7, 2016, the OEB issued a letter initiating a policy consultation aimed at ensuring the cost responsibility provisions for load customers in the OEB's TSC and DSC are aligned and facilitate the implementation of regional plans.

A primary reason for initiating this consultation was a leave to construct (LTC) application – Supply to Essex County Transmission Reinforcement (SECTR) – which was filed with the OEB by Hydro One Networks Inc. (Hydro One) in January 2014. That LTC application included a proportional benefit approach to cost apportionment that involved apportioning some transmission connection asset costs to all ratepayers.

Hydro One's SECTR application included a proposal to allocate upstream transmission connection costs to distribution-connected customers (including embedded distributors) in a manner that was not consistent with the current cost responsibility rules in the DSC.

1. *BOMA is pleased that the OEB determined that cost allocation issues should be reviewed from a policy perspective, which allows for consideration of the issues from a broader point of view and provides the opportunity for a more holistic review of the cost responsibility provisions in the TSC and the DSC to ascertain if other issues needed to be addressed.*

2. *BOMA is supportive of the guiding policy principles articulated by the OEB.*

    - Optimal Infrastructure Solution – Optimal solutions are infrastructure investments that meet regional needs at the lowest cost; i.e., most cost-effective solution. The optimal infrastructure investment will be identified in a Regional Infrastructure Plan (RIP) and will typically be supported by an Integrated Regional Resource Plan (IRRP)
    - Beneficiary Pays – Beneficiaries of an infrastructure investment will contribute to the cost of an investment. Cost allocation will be determined based on the customer's proportional use of the connection asset set out in a regional plan. Costs should not be allocated to any load customer (consumer or distributor) or generator that will not benefit from the investment.
    - Open, Transparent and Inclusive – The process used to determine the cost of an infrastructure investment and the appropriate allocation of those costs to the beneficiaries should be transparent and include all affected parties.

3. *BOMA suggests that another principle should be added which recognizes that all customer loads should be treated the same by transmitters, distributors and embedded distributors.*

1. BOMA Comments on Proposed TSC Amendments

Approaches to Apportion Transmission Connection Investment Costs to the Network Pool

One of the two major issues raised in the SECTR proceeding is whether it is appropriate to allow for a portion of the costs associated with a transmission connection investment that is triggered by the specific customer(s) to be recovered from all ratepayers.

Under the current TSC, the costs associated with transmission connection (line and transformation) investments are recovered from a load customer or group of load customers that caused the need for the investment while the costs associated with transmission network investments are recovered from all ratepayers since presumably all Ontario consumers benefit.

4. *BOMA suggests that not all ratepayers benefit equally from transmission network investments in multi circuit areas. Those investments clearly benefit customers who are served by multi circuit transmission systems more than those who are served by single circuit systems. BOMA addresses this issue later in this submission.*

5. *BOMA supported the OEB`s removal of a previous provision in the TSC (section 6.3.6) which allowed for apportionment of connection asset costs to the network rate pool for two reasons.*

   - Allowing apportionment of 100% of the cost to all ratepayers was inconsistent with the beneficiary pays principle.
   - Allowing the transmitter planning investments to connect transmission customers including distributors without obtaining input from those customers was incompatible with the OEB's approach to regional infrastructure planning.

6. *BOMA supports the OEB`s position that a specific customer should not be required to pay all costs associated with a connection investment where the investment also addresses a broader network system need (e.g., reliability). This is consistent with the beneficiary pays principle, since both the customer(s) that caused the need for the investment and the broader system benefit.*

While the OEB is generally supportive of recovering a portion of the costs in such cases from all ratepayers, the OEB has some concerns related to implementation within the context of ensuring fair and equitable apportionment. For example, there is a potential incentive to apportion more than the appropriate amount to all ratepayers (i.e., network pool).

7. *BOMA supports addressing the apportionment of connection costs to the network pool if it is premised on a transmitter making incremental transmission connection investments that exceed the capacity needs of those customer(s) because the transmitter would avoid a more expensive upstream transmission network asset upgrade (i.e., avoided cost methodology) and incremental connection investment costs would be apportioned to the network pool (like the avoided network investment costs would have been). This would reduce the amount apportioned to the applicable network pool (i.e., all ratepayers) relative to the cost of the network solution.*

8. *BOMA also agrees that it is consistent with the OEB's goal for regional planning – the lowest cost wires solution that addresses the need and recognizes that proportional benefit methodology could also be used for apportionment addressing capacity needs and such integrated solutions must be reflected in all regional plans.*

9. *BOMA understands that the non-wires solutions are paid for through the Global Adjustment Mechanism whether conservation, contracts for generation. However, BOMA would like the OEB to keep in mind that apportionment of those costs should also be considered, particularly for conservation and distribution connected generation.*

10. *Nevertheless, now, BOMA supports the OEB proposal to amend the TSC by adding sections 6.13A and 6.13B to allow costs associated with transmitter-owned connection investments to be apportioned between the customer(s) that caused the need for the connection investment and all ratepayers, based on the proportional benefit between the connecting customer(s) and the overall system.*

11. *BOMA supports the identified need for an OEB adjudicative process to review requests for such apportionment, on a case by case basis, to ensure there is not an over-allocation to the network pool (i.e., all consumers).*

12. *BOMA agrees that a case by case application approach is necessary as the apportionment would change based on specific circumstances relying on a proxy to estimate the cost to address each need as the basis for apportionment. The OEB should articulate the principles that will be used in each case. Such applications should be supported by three documents:*

    - a regional infrastructure plan (RIP),
    - an integrated regional resource plan (IRRP), where applicable, and
    - an independent assessment by the IESO.

13. *BOMA suggests that the beneficiary pays principle should also be applied to customers who are served with multi circuit delivery points which is about 70% of all delivery points in the province accounting for 85% of the electricity transmitted in Ontario. The remainder of the transmission system features single circuit delivery points. According to the Auditor General 2015 report [1]:*

    > *The difference in reliability between areas serviced by single or multiple lines was significant. As shown in Figure 2, single-circuit areas averaged 217.5 minutes in outages per year from 2010 to 2014, and the number of minutes varied significantly between years. In comparison, multi-circuit areas averaged 9.9 minutes in outages per year. Similarly, the number of outages averaged 3.22 per year per delivery point for the single-circuit transmission system compared to only 0.31 per year for the multi-circuit transmission system. We found 47% of transmission outages from 2010 to 2014 occurred in Northern Ontario, even though this is where fewer than 20% of Hydro One's delivery points are located. In Northern Ontario, 86% of the delivery points are single circuit supplied. As it is costly to build additional towers and lines, Hydro One does not attempt to convert rural single-circuit delivery points that serve fewer, or smaller, customers to multi-circuit delivery points because it does not consider it cost effective to do so, even if it would improve system reliability for these customers.*

14. *BOMA suggests that the beneficiary pays principle should apply to transfer some transmission charges from single circuit customers such as Northern Ontario to multi circuit customers in Southern Ontario.*

2. BOMA Comments on Proposed TSC and DSC Amendments: Approaches to Apportion Upstream Transmission Connection Investments

Upstream Transmission Connection Investments – Treatment of Embedded Distributors

In the TSC, a transmission connected distributor is treated like all directly connected transmission customers and must provide a capital contribution (based on an economic evaluation) to the transmitter in relation to a connection investment where it is the beneficiary. However, the DSC does not allow a host distributor that provided the capital contribution to the transmitter to, in turn, require a capital contribution from an embedded distributor where the latter is also a beneficiary of the same upstream transmission connection investment. Therefore, the customers of the host distributor subsidize the customers of the embedded distributor under the status quo.

[1] http://www.auditor.on.ca/en/content/annualreports/arreports/en15/3.06en15.pdf

15. *BOMA supports the idea that the beneficiary pays principle should apply to all distributors, regardless of whether they are connected to the transmission system or embedded within a distribution system, and the allocation of the costs should reflect the extent each distributor (and its customers) caused the need for and benefit from a connection facility investment. In other words, all distributors should be treated the same in terms of cost responsibility, with the costs apportioned based on the relative capacity needs of the host and embedded distributor(s) that benefit from the connection investment.*

16. *BOMA agrees with the amendment to section 3.2.4 of the DSC so that embedded distributors are no longer exempt from providing a capital contribution and the amendment to Section 3.2.4 to change "may" to "shall" to further ensure consistent treatment of customers across distributors. BOMA agrees that all distributors apply the beneficiary pays principle.*

Upstream Transmission Connection Investments – Treatment of Load Customers

The proposed amendment is based on the idea that the same concept described above applies to all large load customers (e.g., industrial). While BOMA agrees that all large load customers should be treated the same in terms of cost responsibility and virtually all other regulations whether they are connected to the system of a transmitter, host distributor or embedded distributor, BOMA is concerned about the lack of precision in referring to these customers as "industrial" creates a two-tiered system for loads of a similar size.

17. *BOMA agrees it is not practical nor appropriate for distributors to require a capital contribution from all load customers (e.g., residential, small business) related to upstream transmission connection investments. BOMA agrees with the OEB view that a materiality threshold for 'large' load customers of distributors required. BOMA is concerned that the suggested cut off, 3 MW or greater is inconsistent with the recent changes to the definition of class A customers2. BOMA suggests that consistency in treatment of customers of a similar size is also an important principle especially as both instances are based on the lowest cost principle even if Class A is programmatic and the TSC is regulatory.*

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[2] http://www.ieso.ca/sector-participants/settlements/global-adjustment-class-a-eligibility

> ***Quote from IESO Website:*** *Ontario's electricity system is built to meet the highest demand periods of the year. By reducing demand during peak periods, participants can both reduce their global adjustment costs and help defer the need for investments in new electricity infrastructure that would otherwise be needed. Effective January 1, 2017, the Government of Ontario expanded the ICI to include all electricity users with an average monthly peak demand over 1 MW. In addition, NAICS code requirements have been removed for customers with an average monthly peak demand above 1 MW. Effective April 13, 2017, the amended regulation now includes:*
>
> - *consumers in the manufacturing and industrial sectors, including greenhouses (with NAICS codes commencing with the digits "31", "32", "33" or "1114") with an average monthly peak demand of greater than 500 kW and equal or less than 1 MW are eligible to opt-in to the ICI.*
> - *Existing Class A customers who participated in one or more of the programs specified in Reg. 429/04 and dropped below the peak demand threshold during a base period for an adjustment period that began on or after July 1, 2016 may be eligible to opt back into the initiative.*

Consumer group representatives and distributors both advised OEB staff that 3 MW seemed the most appropriate. It was noted that customers with demand below that level (e.g., 500 kW, 1 MW) may *contribute to* the need for an upgrade, as residential customers similarly do, but they would *not drive* (i.e., cause) the need for an upstream transmission investment.

18. *BOMA suggests that the proposed 3 MW threshold for other purposes: bypass compensation, capital contribution true-ups and capital contribution (and expansion deposit) refunds should also be reconsidered to match the Class Definition based on the principle of consistency.*

3. BOMA Comments on Proposed TSC and DSC Amendments: Approaches to Apportioning Costs for End-Of-Life Connection Replacements and Multi- Distributor Regional Solutions

Replacement of End-of-Life Transmission Connection Assets: Not Like-for-Like

The TSC includes a provision that addresses when an upstream transmission connection asset reaches its end-of-life (EOL) and needs to be replaced with a like-for-like connection asset (i.e., same capacity). That provision is section 6.7.2 of the TSC. Under that section, the transmitter must replace the asset at no cost to the distributor or commercial[3] customer since the cost of

[3] BOMA is concerned about the imprecision of this terminology. Loads should be identified by demand not by

the asset has been recovered through the rates they have paid. During the Working Group process, the IESO suggested a change to the TSC related to cases where a connection asset reaches its EOL but the customer does *not* want a like- for-like replacement. Instead, the customer requires an *upgrade* (e.g., additional capacity) to replace the EOL connection asset. Currently, the customer pays 100% of the cost where it involves an upgrade. The IESO suggested the customer should only be required to pay the *incremental* cost (i.e., amount that exceeds the cost of a like-for- like replacement) to the transmitter.

19. *BOMA agrees that a change to the TSC to implement this approach would result in greater fairness among all load customers as they would be treated the same – all load customers would essentially receive a credit equal to the cost of a like-for-like replacement asset which could be applied to the cost whether it is the same capacity (fully offset) or an upgraded connection (partially offset).*

20. *BOMA agrees if the customer requests the replacement of a connection asset that has not reached its EOL, the customer should pay, but the amount they pay should be limited to the remaining net book value (NBV) – not the full cost – since the asset being replaced remains 'used and useful' but it has also been partially (or fully) paid for by that customer through rates. This NBV-approach is consistent with the OEB's current approach to Bypass Compensation (i.e., NBV approach), in the TSC, which is discussed below.*

Currently, the standard industry practice is for the transmitter to replace it with a like-for-like connection asset. The outcome, in such cases, would be an over-investment in capacity since some of it would no longer be needed. As noted above, the customer does not pay for a like-for-like connection asset replacement at its EOL. Instead, all ratepayers pay through the applicable connection pool and, in this instance, they would pay for anover-investment.

21. *BOMA agrees that the Codes should reflect the evolution of both the transmission and distribution systems and agrees where a customer's load has materially declined from the time the connection facility initially went into service to when it reached its EOL, and there is an expectation that the customer's load will not grow in the future, the transmitter would apply the appropriate judgment and replace the EOL asset with a new connection asset that meets the lower forecast need of the customer at its EOL (i.e., right-sized). This approach would reduce the cost allocated to all Ontario consumers and result in a more efficient transmission system by avoiding an investment in unnecessary capacity.*

22. *BOMA disagrees with the OEB not proposing to include a code requirement to right-size to a lower capacity but appreciates that the TSC will be amended to*

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sector.

make it clear that a lower capacity replacement connection asset is a potential outcome given that a transmitter has a natural bias to increase its rate base.

23. *BOMA agrees with the OEB is proposal that section 6.7.2 of the TSC be amended to include three subsections that address all three EOL scenarios discussed above: (1) like-for-like, (2) additional capacity, and (3) lower capacity and to further amend section 6.7.2 of the TSC to require the transmitter to consult with their customers – distributors and commercial – that are served by a facility before the transmitter replaces it.*[4]

24. *BOMA agrees with the OEB's intent to update the transmission filing requirements to ensure transmission system plans that involve the replacement of EOL connection assets include evidence of the assessment of alternatives (i.e., wires and non-wires) in meeting future customer demands on the system. The OEB expects that this approach will ensure replacement decisions and all EOL scenarios are adequately addressed in transmitter planning.*

Major changes have taken place in the industry since the TSC and DSC were introduced. Increased efficiencies and conservation have lowered the average customer's electricity consumption. The falling cost of distributed generation has encouraged customers to install load displacement generation to reduce their total cost of energy. Technology is also evolving quickly which will provide more choice to consumers in terms of their ability to manage demand through various approaches, including generating and storing energy, to better manage their energy costs. These factors are resulting in many distributors experiencing lower customer consumption levels and lower maximum peak demands. EOL conditions provide an opportunity to take that evolution into account in relation to appropriately right-sizing the assets being replaced.

25. *BOMA notes that these changing trends are important but notes that a major issue result from these trends has not been addressed in these proposed amendments. According to the 2016 -2017 Energy Conservation Annual Report Volume 2, Every Joule Counts, "in 2015 there was an increase of more than 15% of electricity produced from embedded generation (i.e., distributed energy, connected to the distribution systems instead of the high voltage grid), from 5.1 TWh in 2014 to 6 TWh in 2015, the biggest increase being solar." However, every kWh sold attracts transmission charges even without making use of the transmission system. To be consistent with the principle of beneficiary pays, these customers should not be charged transmission fees on the portion of their bills making use of distributed generation. It is unclear*

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[4] BOMA is concerned that the imprecision created by both the term "industrial" and in this case "commercial" could result in some customers being disadvantaged.

who benefits from these over-charges but BOMA suggests that the OEB might consider changes to address this problem in the current review of these two codes. Not charging transmission fees on distribution connected generation would increase the acceptance of local generation.

Replacement of End-of-Life Distribution Connection Assets

Unlike the TSC, the DSC does not address cost responsibility in relation to the replacement of a distributor-owned connection asset that has reached its EOL. At the same time, changes in customer expectations and demands on the electricity system, and the evolution of technology are even more pronounced at the distribution system level. The OEB understands it is standard industry practice not to charge the customer when it involves a like-for-like replacement (i.e., continuation of same level of service) at EOL. The OEB is of the view that is how it should be.

26. *BOMA supports the OEB proposal to add new section 3.17 to the DSC that aligns with the proposed amendments to section 6.7.2 of the TSC. The proposed new section would capture all three scenarios discussed above involving the replacement of EOL transmission connection assets, to ensure consistency between the two codes. BOMA supports the proposed TSC and DSC amendments related to the replacement of EOL assets and agree they would achieve the following outcomes*[5]*:*

- Ensure each EOL replacement asset is the most cost-effective solution that meets the customer's needs
- Better recognize the evolution of the distribution system which is resulting in lower customer consumption levels due to factors such as the introduction of new technologies, higher penetration of distribution generation and an increased emphasis on conservation
- Increase regulatory certainty for customers
- Ensure all customers in Ontario are treated the same regardless of:
  - Which distributor serves them
  - Whether they are connected to the distribution system or the transmission system

Regional Distribution Solution – LDC Feeder Transfer

During the Working Group process, the IESO proposed a distribution solution involving more than one distributor that would avoid a higher cost upstream transmission connection upgrade, to further leverage regional planning. The IESO referred to this proposal as LDC Feeder Transfer. The following is the example that was provided to the Working Group. One distributor

[5] BOMA maintains it concern about the definition of large customers (3 MW and above), as noted above.

– LDC (A) – that requires more transmission connection capacity would make an investment to connect to a distribution line of another distributor – LDC (B) – which has excess capacity and no significant future growth is expected. This approach would be taken to avoid a costlier upstream transmission connection investment. The OEB will refer to LDC (A) as the connecting distributor and LDC (B) as the facilitating distributor below.

27. *BOMA supports the OEB`s proposed amendment to the DSC to add section 3.1.8. Under this proposed amendment, the non-beneficiary (facilitating distributor) would be compensated by the beneficiary (connecting distributor) to the extent the facilitating distributor had to make any investments and/or incurred additional costs in the future to facilitate such a solution. The OEB would expect that the two distributors would reach an agreement that would ensure the customers of the facilitating distributor were not negatively affected in any way, including from a reliability perspective.*

28. *BOMA supports that if this proposed amendment is adopted, a joint application involving the connecting distributor and the facilitating distributor for approval of the proposed investment and the compensation to the facilitating distributor would be the appropriate approach. This would confirm the distributors agree and all investments proposed by the distributors have been taken into consideration. The joint application should also include a regional infrastructure plan (RIP), an integrated regional resource plan (IRRP), where applicable, and an independent assessment by the IESO.*

29. *BOMA agrees that the OEB require that the two distributors demonstrate that there is an adequate amount of excess capacity on the transmission connection facility – connecting the 'facilitating' distributor to the transmission network – to meet the forecast needs of both distributors. The OEB would look to the IESO to take that potential outcome into account as part of its assessment.*

30. *BOMA also suggests that this opportunity may not be limited to two distribution utilities, but ensure that the codes are worded to include multiple utilities in any region.*

4. BOMA Comments on Proposed TSC and DSC Amendments: Facilitating Regional Plan Implementation and Mitigating Electricity Bill Impacts

Distributor incremental load growth vs. lumpy transmission connection investments

The transmission connection upgrades discussed above are lumpy in nature, while any load growth or decline within a distribution system tends to be gradual. Load growth (i.e., demand) and the assets to supply it or not are therefore rarely aligned. As a result, when a connection asset upgrade associated with a distributor is implemented, there is often much excess capacity.

The disconnect noted above is a concern to the OEB because it can result in significant bill impacts for the customers of distributors and a barrier to the implementation of regional plans due to the capital contribution that must be provided by the distributor to the transmitter. That capital contribution is a one-time lump sum amount representing the shortfall between the revenues to be paid by customers through transmission rates and the total cost of the facility. The capital contribution also reflects both the incremental capacity required by the distributor to meet its near-term needs, as well as excess capacity since these investments cannot be sized to exactly match the distributor's forecast needs.

The focus tends to be line connections when this issue is raised, as they come in only two discrete sizes – 115 kV and 230 kV – in Ontario.12 A 230 kV line accommodates about 400 MW of load, while a 115 kV line accommodates only about 150 MW of load – a 250 MW differential. As a consequence, if a 115 kV line comes close but falls short of meeting a distributor's forecast needs, a 230 kV line would be required which would include much excess capacity under such circumstances. The capital contribution would be substantial in such a case since the distributor would not recover any transmission rate revenues on that excess capacity.

Due to the issue discussed above, stakeholders have noted that many distributors in Ontario may not implement the 'optimal' transmission connection investments identified in regional plans. In those cases, the primary reason for that is the current approach can result in distributor financing issues and significant customer bill impacts. Consequently, concerns have been expressed that the following undesirable outcomes may result:

- Sub-optimal investments being made by distributors within the distribution system to avoid an upstream transmission connection investment
- Existing transmission connection facilities being overloaded to avoid a necessary upstream investment (which reduces the useful life of a connection asset)
- Regional plans cannot be implemented
- Reliability may be impacted

31. *BOMA supports the proposed implementation of all three funding approaches through code amendments and/or changes to other regulatory instruments. Providing for alternative approaches to fund capital contributions related to connection assets will increase the effectiveness of regional planning by avoiding the unintended consequences noted above.*

5. BOMA's Comments on Proposed TSC And DSC Amendments: Addressing Inconsistencies and Gaps

Utility Discretion – Cost Responsibility Code Provisions

The DSC provides much more discretion to distributors than the TSC provides to transmitters within the context of allocating costs associated with connection asset investments. For example, in the TSC, it notes the transmitter "shall" require a capital contribution from load customers that cause the need for and benefit from a connection investment. In contrast, the DSC provides distributors with the discretion to recover such costs via a capital contribution from the load customer or through its revenue requirement (i.e., from all its customers). There are several sections where that is the case.

As discussed earlier, the evolution of a distribution system is resulting in it operating in a similar way to a transmission system. As a result, the OEB now believes the DSC needs to be revised to achieve greater consistency with the TSC to ensure that all customers are treated equitably (i.e. beneficiary pays), whether they are connected to a transmission or distribution system. With about 70 distributors in the province, the OEB also expects that some distributors are applying the beneficiary pays principle (i.e., requiring a capital contribution), while other distributors are not. To the extent that is the case, there is inconsistent treatment of load customers across the province.

32. *BOMA supports the OEB's proposed amendments to the DSC to be consistent with the TSC by replacing "may" with "shall" in all sections of the DSC related to cost responsibility (including expansion deposit provisions). In doing so, it will ensure a consistent approach in relation to distributors allocating costs and therefore consistent treatment of all load customers in Ontario.*

Capital Contribution Refund/Rebate to Initial Customer(s)

Both Codes require a refund. However, there is an inconsistency between the TSC and DSC in terms of the timeframe for the refund requirement. The TSC was amended, in 2013, to increase the timeframe from five (5) to 15 years for the transmitter to require a capital contribution from the subsequent customer(s) that are assigned capacity to provide the refund to the initial customer. That change was made due to 'gaming' concerns, as five years is a relatively short timeframe.

Those gaming concerns are equally applicable at the distribution level. However, the timeframe currently remains at five years in the DSC. The OEB is therefore proposing to amend section 3.2.27 of the DSC to increase the timeframe to 15 years, subject to the threshold condition discussed below. This change would better align the DSC with the TSC, which the OEB believes is appropriate given the increasing similarity between the two systems. The OEB notes that distributors have a much larger number of customers than transmitters and the majority are relatively small compared to those connected to the transmission system. It would therefore be a significant administrative burden for distributors to track all customers for 15 years and, for most, the refund would be immaterial.

The OEB therefore proposes that section 3.2.27 of the DSC be further amended to include a materiality threshold of 3 MW, where the 15-year timeframe would apply. For customers below that materiality threshold, the OEB proposes that the status quo of five (5) years would be maintained. This would include developers of residential subdivisions since none would remain for 15 years. The OEB is also proposing to amend that section to make the DSC more user-friendly and clear for stakeholders by including the reference to 15 years directly in section 3.2.27 rather than referring to a separate document (Appendix B). As a result, references to the customer connection horizon "as defined in Appendix B" would be replaced with the number of years whether the timeframe is changed or not. The OEB is also proposing to add clarity by changing the various references to the *same* term ("parties") to identify *different* types of customers – generator and load.

Due to the proposed changes above, there would also be a need to revise section of the DSC and Appendix B. Section 3.2.23 sets out the process for returning the expansion deposit collected from customers in the case of a distribution system expansion. The annual calculation for returning the expansion deposit must be done for the duration of the connection horizon as defined in Appendix B. Since the OEB is proposing to amend section 3.2.27 to make specific reference to the applicable timeframes – rather than Appendix B – section 3.2.23 would similarly be amended to directly reflect the different number of years (five or 15) based on the proposed materiality threshold. This change would affect only new projects where a capital contribution is required after the date the DSC amendments come into force.

Appendix B defines a maximum customer connection horizon of five (5) years, calculated from the energization date of the facilities. It would similarly be amended to make a change that is consistent with section 3.2.27, as explained above. The TSC already references the timeframes directly in the applicable sections.

> 33. *BOMA agrees with the proposed changes to the DSC and TSC in the interests of consistency. However, consistency is also required with cutoff point with respect to the Class A designation as outlined earlier.*

Capital Contribution True-Ups and Load Forecasts

One factor that contributes to the amount of a capital contribution that a customer must provide to a transmitter or a distributor is a load forecast. For example, if the load forecast is higher than the customer's actual load, the capital contribution would have been too low because the lower actual consumption results in a shortfall of revenues for the distributor. If the load forecast is too low, the outcome is the opposite.

Consequently, the TSC includes true-up provisions to address this issue by ensuring the capital contribution reflects the customer's actual load and is therefore consistent with the beneficiary pays principle. This is particularly important where multiple customers are connected to the same connection facility and share the cost. The true-up requirements ensure all customers pay their fair share (i.e., one customer does not subsidize another). It also removes the inappropriate incentive to provide a higher load forecast to reduce the capital contribution that must be provided to the transmitter.

The DSC contains its own true-up mechanism in the form of an expansion deposit as set out in sections 3.2.20 to 3.2.26. Section 3.2.20 currently states, for customer expansions that require a capital contribution, a distributor may require the customer to provide an expansion deposit for up to 100% of the present value (PV) of the forecasted revenues as described in Appendix B. For customer expansions that do not require a capital contribution, a distributor may require the customer to provide an expansion deposit for up to 100% of the PV of the projected capital costs and on-going maintenance costs of the expansion project.

The DSC permits the distributor to require an expansion deposit even where no capital contribution is required because the distributor can still be at risk if the customer does not deliver on the forecast revenue. To cover the distributor's risk, the DSC permits them to require an expansion deposit, until it is demonstrated that the customer is going to deliver on the revenue. That said, since no capital contribution is required, the OEB considers the risk to be lower and is proposing to maintain "may" in this instance.

Section 3.2.23 provides direction related to how the distributor is to return the expansion deposit to the customer. The distributor must annually return a percentage in proportion to the actual connections (for residential developments) or actual demand (for commercial and industrial developments[6]) that materialized in that year (i.e., if 20% of forecasted connections or demand materialized in that year, the distributor is required to return 20% of the deposit). Currently, this annual calculation is only done for five years. As noted, the OEB is proposing to introduce a 3 MW materiality threshold. The return of the expansion deposit would therefore be extended to 15 years for those over that threshold.

The OEB is proposing to amend the sections of the DSC related to expansion deposits to be consistent with the TSC by replacing "may" with "shall", except for the one instance noted above. This applies to sections 3.2.20 and 3.2.24. All other sections related to expansion deposits already use the term "shall". This proposed amendment is consistent with the OEB's view that there is a need for greater consistency between the DSC and TSC, given that distribution systems and transmission systems are becoming more similar in the nature.

> 34. *BOMA agrees with the proposed changes to the DSC and TSC in the interests of consistency. However, consistency is also required with cutoff point with respect to the Class A designation as outline earlier.*

Mix of load and generator customers on a connection asset

The TSC and the DSC are not consistent in their approach to cost responsibility in cases where a connection asset involves both load and generator customers. In the TSC, costs are allocated based on a trigger pays approach. For example, if a load customer connects first and a generator customer subsequently connects, the generator customer does not pay a capital contribution refund to the initial load customer. On the other hand, if the subsequent customer was a load customer, they would be required to pay a refund to the initial load customer.

In contrast, in the DSC refund provision, costs are allocated based on the beneficiary pays principle where a load customer connects first and a generator customer subsequently connects. In other words, regardless of the type of customer that subsequently connects, the DSC requires the provision of a capital contribution and the initial customer receives a refund. The apportioned benefit is determined considering factors such as the relative name-plate rated capacity (generator customer) and the relative load level (load customer). The OEB believes this approach is more appropriate. The initial customer should be compensated for the capacity they paid for and do not need, regardless of what type of customer connects after

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[6] Load customers should be referred to by demand, not by undefined sectors. The phraseology in this sector ignores the public sector and the cut-off should be consistent with the Class A Definition.

them.

Given the OEB's shift in emphasis from the trigger pays to the beneficiary pays approach in relation to cost responsibility, the OEB is proposing to amend section 6.16 of the TSC to be consistent with section 3.2.27 of the DSC. The OEB believes this proposed change to the TSC would achieve the following desirable outcomes:

- Better ensure that all transmission customers are treated the same (i.e., all beneficiaries pay)
- Eliminate the potential for cross-subsidization between load and generator customers
- Result in a consistent approach to cost responsibility between the TSC (transmission level) and DSC (distribution level) in this regard

The OEB is proposing to create new section 3.1.9 in the DSC, since section 3.2.27 is specific to refunds. Unlike the TSC, the DSC does not currently contemplate a scenario where load and generator customers connect at the same time to a new connection facility. This new section would combine the positive attributes of both sections – 3.2.27 (DSC) and 6.16 (TSC). For example, use the beneficiary pays approach in the DSC. On the other hand, the terminology in section 3.2.27 of the DSC refers to "relative load level" while the TSC is much more specific in referring to "respective non-coincident incremental peak load requirements" for apportioning costs. It is the "peak" load requirements that drive the need and size of the investment, and best reflects the relative benefits. The "relative load level" can also be interpreted differently by distributors (e.g., average, peak, etc.). The OEB is therefore also proposing to amend section 3.2.27 of the DSC to add "non-coincident peak" before "load". The OEB is proposing to replicate the proposed wording for the DSC in the TSC; i.e., current wording in section 6.1.6 would be replaced.

Under the OEB's proposed approach, the result would be the same wording in both Codes.

35. BOMA agrees with the OEB's proposed changes and additions.

Bypass Compensation

Under the TSC and the DSC, transmitters and distributors construct a load customer's connection facility based on the customer's load forecast. Where the load customer subsequently constructs its own connection facility to supply existing load before the utility-owned connection facility reaches its end-of-life, it is considered bypass because the dedicated connection asset becomes stranded. Unlike a shared network asset, a dedicated connection asset cannot be used by other customers. If the customer disconnects and does not compensate the utility for the bypass, the stranded cost must be borne by all the other ratepayers in the connection pool that remain connected to the system of the utility. The customer that disconnected would be the only beneficiary but they would not pay.

Bypass compensation from a load customer to a transmitter is therefore required under section 6.7.7 of the TSC in certain circumstances to ensure all consumers are not required to pay the stranded cost when a load customer bypasses a transmitter-owned connection facility. Bypass compensation is calculated based on the remaining net book value (NBV) associated with the connection facility in the TSC. Where the NBV is zero, the connection facility is fully depreciated.

There is only one circumstance in the TSC where existing load can be shifted from a transmitter-owned connection asset without triggering bypass compensation to the transmitter; that is where the existing connection facility is overloaded, since overloading any facility reduces the economic efficiency of the transmission system and should be avoided. However, in such cases, only the overload portion of existing load does not constitute bypass.

The DSC is not consistent with the TSC. It does not require bypass compensation under any circumstances. The OEB believes that is a gap in the DSC that should be addressed. A key reason for that is related to changes in how the distribution system is being used. For many years, consumers were largely passive and the distribution system was used almost exclusively to deliver power to consumers. However, like the transmission system, consumers have recently become more active in terms of undertaking various measures that are resulting in customers of distributors reducing their use of the distribution system (i.e., distribution assets that were put in place to specifically serve them). As the distribution system evolves into an extension of the transmission system, the need for alignment between the DSC and TSC has become much more evident, in this regard.

The OEB is therefore proposing to add sections 3.5.1 and 3.5.3 to the DSC to identify the circumstances where bypass compensation should be required and to identify how it should be determined (i.e., based on NBV of bypassed capacity). The bypass provisions in the TSC have been used to amend the DSC.

Like the TSC, the OEB is not proposing that bypass compensation be provided to the distributor due to all actions that result in a load reduction. The OEB is therefore also proposing to add new section 3.5.2 to the DSC to specify the circumstances under which a customer of a distributor could act to reduce the amount of electricity it withdraws from the distribution system without triggering the need to provide bypass compensation – embedded renewable generation (e.g., rooftop solar), energy conservation, energy efficiency, or load management activities (e.g., net metering).

The OEB is not proposing any material changes to the provisions in the TSC related to bypass compensation. However, the OEB does see an opportunity to make the TSC more user-friendly for stakeholders. Bypass compensation is currently addressed in two separate sections of the TSC – section 6 and section 11. The OEB is proposing to consolidate all bypass compensation related provisions under section 11.2, which is entitled "Bypass Compensation". Current sections 6.7.5 to 6.7.11 would be moved to become new sections 11.4 to 11.10. Any changes to the wording would be limited to affected cross references between sections.

Except for cases where proposed section 3.5.2 would apply, the OEB is of the view that the customer that chooses to bypass and benefits from reduced or no distribution charges should be solely responsible for the related stranded costs – not all other consumers, who have no control over that decision and do not benefit. The OEB believes the proposed changes to the DSC set out above would achieve that outcome.

36. *BOMA supports these changes with respect to bypass except for the 3 MW cutoff point for the reasons outlined above.*

Relocation of Connection Assets

The DSC does not address cost responsibility where a distribution asset connecting a customer is relocated at the customer's request. Most distributors therefore have provisions in their Conditions of Service that require the customer to pay for relocation.

However, in some cases, it is the OEB's understanding that some distributors do not apply a relocation charge. In such cases, all customers of the distributor – not the requesting customer – are responsible for the cost. The OEB does not believe that outcome is appropriate.

Unlike the DSC, the TSC includes a section (6.7.3) that addresses this issue and identifies that the transmitter must recover the cost of relocating the connection facility solely from that requesting customer.

To achieve consistency between the DSC and the TSC and to ensure all customers in the province are treated the same, the OEB is proposing to add section 3.1.10 to the DSC that would achieve the same outcome as section 6.7.3 of the TSC; i.e., allocate the full cost of relocating a connection asset to the customer where the customer requested the relocation. That proposed change would eliminate the potential for the customer requesting the relocation to be subsidized by other consumers. The OEB is also proposing to add section 3.1.11 to clarify the customer does not pay where they do *not* request the relocation – the distributor pays.

37. *BOMA supports the proposed changes based on consistency.*

Definition of "Customer"

The definition of "customer" is different in the TSC and the DSC. The definition in the DSC is less specific and could be interpreted differently for cost responsibility purposes. The TSC specifically refers to each type of customer – *"generator, consumer, distributor or unlicensed transmitter"* – whereas the DSC is more general in referring to *"a person"*.

The OEB is proposing to amend the DSC to be more specific and clear like the TSC so that the definition of "customer" is not open to different interpretations. The OEB believes this will provide greater regulatory certainty to distributors and their customers, particularly within context of allocating costs.

38. *BOMA supports the proposed changes based on consistency.*

Community desire for more than 'optimal' solution in regional plan – No mechanism in place to fund Local Choices

The IESO has established a local advisory committee (LAC) in each region where it has been determined that an Integrated Regional Resource Plan (IRRP) is required. LACs are comprised of stakeholders from the affected local community. One purpose of the LACs is to provide input related to the local preferences in terms of the solution to meet a regional need.

Therefore, there may be instances where a community desires a premium solution that is preferred, but is not necessary (i.e., higher cost than the optimal solution). For example, the undergrounding of transmission wires for aesthetic reasons. Currently, neither code (TSC or DSC) addresses how costs should be allocated in relation to such premium wires solutions.

The OEB believes that, where such unnecessary premium wires solutions are desired, the incremental cost of the investment should be funded through other means, rather than through distribution rates (e.g., by the municipal shareholder through municipal property taxes like the approach recently used in Ottawa). This approach is consistent with the optimal infrastructure solution principle discussed above, as the premium solution would not be the optimal solution identified in the regional infrastructure plan.

While the OEB is of the view that only the costs associated with the optimal wires solution (as identified in a regional plan) should be recoverable in rates, the OEB considers that the issue identified by the Working Group should be addressed on a case by case basis, in an adjudicative process, rather than through a change to the Codes.

The distributor or transmitter would need to justify any proposed investment that deviates from the optimal solution identified in the regional infrastructure plan as part of a rate or LTC application.

> 39. *BOMA supports the proposed changes based on consistency as well as the adjudication process which should be broadened to include investments by more than one distributor and by non-municipal shareholders.*

6. Out of Scope

Non-Wires Solutions – No Mechanism for Local Cost Recovery

An issue raised during the Working Group process is that the costs associated with wires (i.e., distribution solutions) are recovered locally through the distribution rate approved by the OEB. On the other hand, it was suggested that where a non-wires option (e.g. distributed generation or CDM) represents the optimal solution, there is no mechanism to similarly allocate costs locally (via distribution rates) to the same group of customers in relation to much of the generation that is procured in Ontario. Instead, it is recovered provincially (i.e., allocated to all consumers) through the Global Adjustment charge.

The OEB notes that there is a mechanism in place in relation to some non-wires options where they defer the need for wires investments; specifically, in 2014, the OEB made changes to its CDM Guidelines which provides distributors with the ability to fund certain non-wires investments (e.g., storage, eligible generation) in distribution rates. However, the OEB has not yet received an application from a distributor to include such generation in rate base.

The OEB believes the most cost-effective solution in a regional plan should be implemented regardless of the solution (i.e., wires or non-wires). That is one of the reasons for the above noted change to the CDM Guidelines and the OEB's intent to further consider this issue as part of a separate initiative to implement optimal investment planning decisions by distributors and transmitters. That future initiative is intended to assess the need for regulatory reforms which support the evolution of the sector (e.g., technological innovation).

40. *BOMA supports the OEB view of this matter but suggests that the issue of distributors paying for non-wires solutions should be addressed as soon as possible to better align costs and benefits citing the principle of beneficiary pays and reduce the amount of costs in the Global Adjustment Mechanism.*