Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Attn: Ms. K. Walli
Board Secretary

September 20, 2018

Dear Ms. Walli:

Re: EB-2016-0003 – Revised Proposed Amendments to the Transmission System Code and the Distribution System Code to Facilitate Regional Planning

The Electricity Distributors Association (EDA) is writing to provide comments in the above-named matter. They are set out in this Covering Letter and the Attachment thereto.

Regional Planning is a demanding task that has far reaching implications. The key objective of regional planning is to ensure ongoing customer access to a system that can safely and reliably deliver power and energy to them. Cost Allocation for Regional Planning is the process that quantifies an accurate and appropriate price signal in a timely manner, suitable for the needs of many parties such as decision makers, investors, consumers, government planners and prospective supply chain participants. Under the existing "trigger" pays rules some Regional Planning costs are socialized because they were included in the Transmitter's Network Pool while others were recovered from certain identifiable parties. The proposed amendments are intended to replace the principle of "trigger" pays with the "beneficiary" pays.

These amendments operationalize the "beneficiary pays" principle. The tangible outcomes are expected to be:

- An increase in the "beneficiaries" who will be responsible for a greater proportion of the costs (and by implication a lowering of the proportion that will be recovered through Network Transmission Charges); and
- An increase in the eligible beneficiaries charge parameters.

While these outcomes result in a lower level of socialized cost responsibility they also increase the charge parameters used to assign cost responsibility for the non-socialized costs and,

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implicitly, mitigates rate shock. If this is indeed the OEB's driver it may, or may not, align with the industry's need for policies that will put all parties on a balanced playing field.

The Independent Electricity System Operator's Market Renewal Program (MRP) has been underway since November 2016. The EDA notes that the MRP is expected to impact the need for incremental transmission and/or distribution infrastructure as well as the configuration of existing infrastructure. The EDA suggests that the OEB consider co-ordinating the proposed "Coming into Force" of any Code amendments focused on the Cost Allocation of Regional Planning with the MRP's timelines.

LDCs have a long track record of making investment decisions so that customers can have ongoing access to distribution services at a fair price. They invest to be able to accommodate new supply points (e.g., to provide feeders downstream of transmission stations or transmission connections), to address reliability (e.g., to network feeders rather than rely on radial infrastructure), to attach new customers.

LDCs expect to apply fair policies and fair rules that will result in fair outcomes for the affected stakeholders in the majority of cases. EDA members have reviewed the Board's proposed code amendments through this lens for consistency with existing regulatory policy and for an underlying Framework. LDCs note that the OEB's adoption of the 5MW threshold, versus the 3MW previously proposed, aligns with LDCs rate class structure. Our members look forward to a framework suitable for allocating costs to either emerging technologies or innovative connection configurations, and that can be confidently applied to scenarios other than those scoped in the proposed code amendments, as this was not discernable in the proposed code amendments. The EDA observes that the Board has provided special cases (e.g., End-of-Life scenarios) and that at least two of the special cases (newly attaching >5MW loads, two LDCs connecting to the same transmission infrastructure) occur so infrequently that it does not appear to be appropriate to codify them.

The EDA believes that the proposed code amendments must be "fit for purpose". The Board has articulated that it expects similar customers to experience similar outcomes. The EDA has some reservations as to why the Board has focused on achieving similar outcomes for similar customers. The Board's legislated mandate is silent on this expectation. The legislation is consistent with achieving the principal objective of economic regulation, which is setting just and reasonable rates. The EDA notes that each LDC has its unique service area, unique cost structure, and specific system constraints such that the best realization of this objective appears to be that the rules will be applied consistently and that differences between LDCs will be data driven.

Further, LDCs are concerned that it is foreseeable that the proposed amendments will result in similar customers of an individual LDC experiencing differing outcomes depending on where in the service area they choose to site their facility or the state of the distribution infrastructure. Consider the example of a large load (e.g., a server farm, a marijuana greenhouse operator, a large car park with charging infrastructure for hundreds of electric vehicles) that seeks to attach to the same LDC and is evaluating 3 different locations that will be referred to as A, B and C:

- If location A is a "green field" site the customer can expect to pay a financial contribution based on their load and the infrastructure costs, where the customer has no ability to control the infrastructure costs.
- If location B is in an area where the existing distribution infrastructure has not attained its end-of-life the customer may still be required to remit a financial contribution to support the LDCs investment in appropriately sized infrastructure as well as to remit bypass compensation because the existing, otherwise under sized infrastructure has not attained its End-of-Life. In this situation, not only will the customer have no ability to control the infrastructure costs they will also have no ability to control the quantum of the bypass charge as it is rooted in decisions made by the LDC in a prior period.
- If location C has distribution infrastructure that is inadequate to serve the projected load then the customer will be expected to remit a different amount of financial contribution to support the LDC's investment in appropriately sized infrastructure. Again, the amount to be remitted will depend on decisions made by the LDC in prior periods and where the newly attaching load customer has no ability to control the costs of the newly expanded/enhanced distribution infrastructure.

The above analysis raises a concern that the proposed amendments may not result in stable or predictable outcomes for the customer.

The EDA repeats a submission made in November 2017 on the need for worked examples (EB-2016-0003, EDA comments, Attachment A, page 4). The EDA seeks worked examples of the anticipated application of the proposed code amendments so that LDCs know they are applying the rules correctly, so that customers will know that the LDC is transparently abiding by the rules and so that all parties are equally informed of the expected outcomes. These worked examples can also be used to test whether the OEB's objectives will be achieved and may foreshadow the impact to today's customers, specifically for whether advantages they enjoy today will persist. As was also observed in the November 2017 comments, unlike transmitters LDCs engage in Regional Planning issues and considerations infrequently (EB-2016-0003, EDA comments, Attachment A, page 4). The EDA seeks provisions that will place LDCs on equal footing versus the transmitter - provisions that will provide LDCs with the ability to access appropriately skilled and experienced individuals who can readily evaluate the proposed regional plan and the associated allocation of costs. This is expected to support all parties understanding and to prepare the LDC to respond to their customer's enquiries in the future.

LDCs note the OEB's focus on beneficiaries and seek to better understand its scope so that they correctly operationalize the term. For example, is "beneficiary" synonymous with "user"? does "beneficiary" refer to parties who will experience indirect benefits or will connect in the future? Distribution systems are not static, and neither are the parties they serve. Orienting the analysis on beneficiaries is expected to address any concerns of benefits being obtained by free riders. The proposed "Coming Into Force" provision contemplates that the OEB will apply rules consistent with the beneficiary pays principle on a go forward basis - except for the Supply to Essex County Transmission Reinforcement (SECTR). The EDA notes that the key decisions on the SECTR project were made using the existing rules that are not based on beneficiaries. However, its costs are to be allocated using the eventual 2018 cost allocation rules. This contrasts with the treatment of all other projects that were either committed to or that were entered into service before the contemplated "Coming Into Force" date. The Board is also proposing additional powers to deem some customers to be beneficiaries of regional planning investments and to evaluate some of the outcomes of regional planning using proxy cost data. The EDA suggests that the Board adjudicate projects that rely on or are informed by the use of proxy data or that could result in impacts to deemed customers so that LDCs appropriately operationalize these concepts. The EDA proposes that the Board either not codify provisions that use deemed customers or proxy data or that it defers the "Coming Into Force" of these provisions.

The EDA anticipates that operationalizing the proposed amendments related to Bill Impact Mitigation will be difficult. LDCs understand that the effect of the installment option is to smooth the bill impact to consumers and thereby avoid undue rate shock. LDCs are unclear as to whether the mitigation is intended to result in predictable bill impacts to specific line items, whether it is to mitigate the "lumpiness" of significant capital investments over time, or whether it is intended to constrain bill increases below a threshold value. If the intention is to achieve predictable bills then there is a follow on issue of inter-generational inequities that should be explicitly contemplated and addressed. If, however, the intention is to mitigate "lumpiness" there may be cross subsidies between customer classes. LDCs acknowledge that good rate making requires that these cross subsidies not be so high as to be considered undue. LDCs also expressed that there is a risk of an unintended and undesirable consequence of this provision with respect to debt management and borrowing capacity. LDCs point out that a situation could emerge where an LDC may be off-side of the Board's hypothetical capital structure through the combined effect of material non-discretionary distribution system relocations and the operation of the Annual Installment Option. The EDA expects that the Board will be open to considering such a situation, should it be realized.

The EDA observes that stranded debt is a significant and emerging issue and suggest that it is better dealt with through a dedicated and focused issue specific proceeding. It is undesirable to simply import a provision from another regulatory instrument. LDCs recognize that while it is helpful to understand the Board's thinking on the recovery of bypass compensation, it is not robustly rooted in an analysis of the fundamental underlying issue of stranded debt and stranded costs. LDCs need clear regulatory policy so that they can responsibly manage their resources and be able to provide service on an ongoing basis. Customers need a clear policy that demonstrates how the Board will maintain a financially viable industry that supports its fulfillment of one of its legislated objectives and delivers a key outcome of economic regulation.

The counter case to bypass compensation is asset overloading. LDCs monitor their distribution systems and gather data to discern which assets have been overloaded, the magnitude and duration of the overloading and so on. They use this data in combination with other data and resourcing considerations to manage their portfolio of assets. Overloading is not a clear-cut sign of poor asset management, rather it is an indicator that further probing is necessary. At the extreme, overloading can degrade an asset's ability to serve for its intended life or when operated at design parameters. It is important to incorporate the inherent flexibility of the infrastructure when assessing overloading. LDCs acknowledge that chronic overloading over successive periods that is not recognized is inappropriate and may be unacceptable. LDCs note that the evidence filed in the SECTR proceeding included a chart of the chronic and persistent overloading of Hydro One's Kingsville TS that has existed since the 1990's. LDCs acknowledge that there are rate making tools available that can address the drivers of overloading (e.g., curtailable rates, interruptible rates) and policy alternatives (e.g., conservation, deployment of Distributed Energy Resources). There are administrative tools also, such as financial penalties, technical audits, more frequent and more intrusive reporting requirements. The EDA recognizes that customers and the OEB expect LDCs to be good asset managers, and that all these stakeholders expect the transmitter to also be a good asset manager. Because there is a range of circumstances that give rise to overloading and a range of responses, the EDA believes the proposed rules on overloading may be premature. Instead, LDCs suggest that the OEB adjudicate an application on planned investments intended to address overloading.

The proposed code amendments raise practical implementation questions such as:

- changes to distribution rates to align with the proposed revisions to Basic Connection infrastructure;
- clarification of implications for ownership and ongoing maintenance obligations of Basic Connection infrastructure;
- revisions to all LDCs Conditions of Service.

Our members seek regulatory accounting guidance from the Board on issues such as:

- the appropriate treatment of bypass compensation;
- the methodology to use to compute and record the impact to the Net Book Value of the bypassed infrastructure if the assets are accounted for on a pooled basis;
- recording contributions charged to one entity and remitted by another; and
- how to account for bypass compensation if the affected asset is to be used to provide distribution service in a future period.

As the Board is well aware, all LDCs are engaged in the provision of a public good at commercial conditions and terms. One of the outcomes of the OEB's Renewed Regulatory Framework is a sharpened focus on customer interests. LDCs have in the past and will continue to respond to all customers interests - including those of local area governments, whether they desire to create economic growth to benefit their inhabitants (e.g., employment in for-profit firms) or to provide essential public services such as health care.

The EDA seeks OEB clarification on the appropriate implementation of the OEB's proposed "Coming into Force" provisions from the perspective of fairness. The EDA recognizes that the projects that have either been initiated or completed since the SECTR project will be caught by the existing rules. It appears that only SECTR, by virtue of the OEB authorized deferral account, could experience a different outcome. This different outcome is not a forgone conclusion. The EDA recognizes that the key decisions leading up to the design and construction of the SECTR project were made under the existing rules and that there is a principal-based argument in favour of applying those rules. If the Board were to proceed in this manner it would have the flexibility to potentially socialize such costs by authorizing their recovery through Transmission – Network charges, or, that it could phase the recovery in over time to address concerns of rate shock.

Whatever Code amendments the OEB authorizes, it will result in some parties understanding that they have, in prior periods, underpaid while others will understand that they have overpaid. It is advisable to identify and prepare for the effects of this transparency at the earliest opportunity.

Essex Powerlines, Entegrus Powerlines and ELK Energy are the three LDCs engaged in the SECTR proceeding that gave rise to the proposed code amendments. As stated earlier, the EDA raises the question of the fairness and appropriateness of applying the proposed code amendments to the SECTR project and that it will create out of chronological sequence differences. The EDA contends that, with the passage of time, their specific concerns will be recognized as generic concerns. Since the OEB adjourned the SECTR proceeding for an indefinite period these three

LDCs have lacked clear and objective data and their ability to responsibly invest capital and to respond to questions from their customers has been hindered. The OEB's timely adjudication of the costs of SECTR will provide the decisions, clarification and direction that they – and the industry – need. If the OEB declines to adjudicate on SECTR by hearing final submissions or re-opening the evidentiary portion of the proceeding it risks leaving the E3 LDCs in an uncertain situation as to the next steps including how to administer the discovery of new data and the available forms of recourse. It also raises questions about the appropriate consumer protection for the LDC when it is a consumer being served by a transmitter.

From the customer's perspective it appears that the industry and the regulator have not progressed from the situation as it existed in 2015. This is an unfortunate outcome. Furthermore, with the passage of time new investment needs have emerged. The Board needs to take steps to deal with specific investments and to simultaneously provide rules and policies. Customers need all this and expect no less.

Please refer any questions or comments to Kathi Farmer, the EDA's Senior Regulatory Affairs Advisor at kfarmer@eda-on.ca or at 905.265.5333.

Sincerely

J Rangooni

Justin Rangooni
Vice President, Policy & Government Affairs

Encl.

1. General and Administrative Provisions

1.2 Definitions

The EDA suggests that the OEB:

- define “advancement costs”, “beneficiary”, “benefit” and “facility”;
- refine its definition of “embedded distributor” or refine its rules that apply to embedded distributors to ensure consistency;
- amend the definition of “distributor-owned asset” to reflect that some distribution customers own transformation infrastructure.

The EDA notes that OEB definitions assist in achieving consistency among all LDCs and help to educate customers and temper their expectations.

3. Connections and Expansions

3.1 Connections

3.1.5

LDCs assume that basic connection infrastructure is to be dedicated to serving a single customer, either because it can be demonstrated (e.g., by inspection) as being dedicated to serving the customer, as is the case with a service line, or because a portion of it can be allocated to serve a specific customer, as is the case with the last stage of transformation.

There are two immediate issues arising from the implementation of this proposed amendment:

- distribution rates will need to be adjusted; and
- each LDC’s Conditions of Service will need to be revised.

Our members observe that the Coming Into Force of this provision should be co-ordinated with these associated regulatory activities. LDCs acknowledge that they will need to engage with their customers, for example to educate on whether they have new responsibilities, to educate on the associated changes to rates, by providing written notice of the proposed changes to their respective Conditions of Service as is required under section 2.4.8 of the DSC. The timing of the changes to distribution rates should be co-ordinated with other planned rate changes, such as updates to Regulated Price Plan levels or to distribution rates through the IRM or other rate setting mechanisms.

Each LDC will be a party to the regulatory process that will adjust distribution rates. Our members seek clarity as to the regulatory accounting of the costs incurred to participate in and of the rate making treatment of the costs recorded.

3.1.17

Our LDC members understand the appropriateness of directly recovering the costs attributable to a specific, identifiable customer from that customer in order to avoid undue cross subsidization. They also anticipate that the affected customer will need to understand the appropriateness of recovering these costs from them. The EDA's proposal that the OEB define "beneficiary" will assist in achieving this understanding and will benefit customers who are engaged through the application of deeming rules.

LDCs note that because their systems are dynamic, over time there is a strong likelihood that the replacement infrastructure funded by contributed capital could become common use infrastructure such that the costs would be eligible for recovery through OEB approved distribution rates.

The EDA is encouraged that the OEB's recent proposed Code amendments align with distributors rate structure and rely on a 5MW threshold. We inspected the OEB's 3 most recently issue Statistical Yearbooks and observe that LDCs infrequently attach customers >5MW. While the consultation is not expected to be problematic LDCs are unclear as to how the OEB expects the LDC to use the results of the consultation. Our members wonder whether it is advisable to consult with large user and other affected customers in those situations where the infrastructure that is at end-of-life is not to be replaced on a like-for-like basis; they note that it may be more beneficial to those customers to be educated on the merits, drivers and other issues of investing in alternative infrastructure.

3.1.17A

The EDA acknowledges that this provision provides a level of financial protection (e.g., from the consequences of capital investment decisions that prove to have a shorter economic life than technical life). We also observe that the effect of this provision could result in two similar customers having to pay different amounts to the LDC in order to be served through appropriately sized and appropriately configured infrastructure only because of where they locate in the service area (e.g., a newly developing part of the system versus a recently constructed portion of the system). This outcome differs from the OEB's express objective of achieving similar outcomes for similar customers; please see the EDA's Covering Letter for its comments on this objective. Should the proposed amendment be made, LDCs will be expected to explain to customers that as a result of the customer's choice of location they become financially responsible for decisions made in a prior period.

3.1.18

According to our previous comments, (EB-2016-0003, EDA Comments, Attachment B, page 3 of 10, November 2017) the EDA believes that the connection configuration outlined in Section 3.1.18 is relatively uncommon. Since the Board intends to adjudicate these situations, the EDA suggests that the proposed Code amendment may be better suited for inclusion in the Board's Minimum Filing Requirements. Alternatively, the Board could adjudicate them individually and thereby gain insight into the embedded LDCs specific interests and consequential impacts. OEB adjudication is expected to benefit embedded LDCs by providing clarity on how to facilitate customer connection and how to responsibly allocate costs. In general, OEB adjudication can inform parties of the appropriate balancing of the interests (for example, when quantifying excess transmission capacity at a point in time, to clarify whether it is reserved or guaranteed or not).

This configuration of infrastructure raises a related rate making issue: should the facilitating LDC's costs be recovered through a wheeling rate? And if a wheeling rate is to be charged: should it be set at a level that recovers the costs of providing the infrastructure over its planned life and thereby overcome the need for an upfront financial contribution? LDCs acknowledge that a new connection of this nature will require a new Settlement Point, either Wholesale or Retail, that will need to be settled using Board authorized distribution rates so that the facilitating LDC is kept financially whole. Distribution rates recover the ongoing costs incurred to provide service to a load customer; they are not clearly suitable for a connecting LDC (e.g., whereas a load customer presents a non-payment risk, a connecting LDC presents virtually none).

To be clear, our members assume that these rules are not to be applied when the LDC connects one of its customers. However, if this is the OEB's intention then LDCs seek clarity as to the application of this proposed Code amendment (e.g., with respect to the Coming into Force provisions).

3.1.19

Applying the Board's proposed definition of "distributor owned asset" (i.e., not the basic connection infrastructure) and recognizing that under this scenario many users will be served, implies that the costs incurred are ongoing costs of providing service to many customers. Put differently, it implies that these costs will be eligible for recovery through rates.

Assuming that this section is to be applied as written there is a risk that different customers will pay different amounts depending on the extent of the physical infrastructure that they require for service. While apportioning cost responsibility based on non-coincident peak aligns with the basis on which rates are set, apportioning costs based on distance does not. Consider the case of two customers, who will be referred to as A and B. In this example, customer A connects first and requires a lengthy connection; customer A remits the required Contribution computed using the Discounted Cash Flow (DCF) methodology. Customer B connects in a later period and requires a physically shorter connection than did A. What is the fair way to compute Customer B's level of cost responsibility - by using distance and peak load, or, by using peak load as the proposed amendment appears to suggest?

Whether a generator's peak output should be used raises a much larger policy issue.

3.1.20

No comments

3.1.21

This provision introduces another situation where two similar customers can incur different costs to connect to an LDC's distribution system depending on the configuration of distribution assets.

Our members observe that if the LDC decides to relocate infrastructure then the LDC is eligible to include these costs in rate base and to recover the associated revenue requirement through OEB approved rates.

3.2 Expansions

3.2.4 and 3.2.4A

Please see the comments provided at "Definitions" and at 3.1.18.

3.2.4A

The EDA considers our members as front line industry representatives, as they have an enduring relationship with the customer and that they have earned the customer's trust. LDCs neither concede nor concur that their responsibility to the customer should be transferred to another party.

Should the Board, nonetheless, make this Code amendment LDCs will expect that the transmitter will be fully engaged and be explicitly required to provide customer care and to communicate with the customer in an appropriate manner – in conjunction and co-ordination with the LDC.

The OEB should consider how LDC specific data required to fully quantify the customer's responsibility will need to be shared, and, that LDCs will benefit from insight into the transmitter's data and DCF methodology so that all calculations are appropriate. The LDC should expect that its Contribution to the transmitter will be known as it is determined based on the required infrastructure and the Board authorized Uniform transmission Rates.

All parties to the decision will benefit from a transition period or a deferred Coming Into Force date that will allow for the development of appropriate business and communications processes, and, for all parties to gain fluency with analytical tools, such as the DCF.

To be well prepared to respond to customers' potential inquiries LDCs will need to have ready access to and be supported by the transmitter responsible for running the DCF analysis.

3.2.5

LDCs note that since generators are deemed to have no load that, in the extreme situation of a single generator, the upshot of this provision is that the generator will be 100% responsible for the costs. LDCs also note that connecting entities may be indirectly incented to reveal their 'worst' case need for incremental capacity and disincented from revealing internal decisions or plans that may dampen or defer utilizing incremental capacity (e.g., if the connecting entity deploys behind-the-meter generation or storage).

The EDA suggests that this provision be carefully stakeholdered with the generator community for appropriateness and for whether a transition or phase in is considered appropriate.

3.2.20

Expansion deposits ensure that "growth pays for growth" and are a vital forecasting risk mitigation tool for LDCs that also guards against the potential for cross subsidization.

An unaddressed question is whether a municipality can finance a contribution or provide an expansion deposit. A municipality might be motivated to take such action in order to mitigate or avoid the negative economic development impact of the new contribution requirements on its community. If a municipality either finances a contribution or provides an expansion deposit it would not increase its equity position in the LDC and it would have access to a financial tool to support attracting employers to the municipality, and to create economic growth.

3.2.21

Please see the comments provided under 3.2.20.

3.2.23

No comments

3.2.24

Please see the comments made in connection with section 3.2.21.

3.2.27

No comments.

3.5 Bypass Compensation

3.5.1

The EDA observes that mandatory bypass compensation of stranded transmission assets protects the LDC from undesirable financial consequences, will make clear the customer's responsibility and will achieve consistency across all LDCs. The EDA refers to its November 2017 comments, specifically those that scope the potentially transient nature of by-passed infrastructure (EB-2016-0003, EDA Comments, Attachment A, page 2).

The EDA proposes that the OEB co-ordinate this provision with its Commercial and Industrial rate design initiative for common in scope issues such as bypass compensation.

Our members seek regulatory accounting guidance on the appropriate treatment of bypass compensation. For example, should it be held in a deferral account for a period of time until it is certain that the assets have been permanently bypassed? Should the pool of assets be adjusted when removing the bypassed infrastructure? Will the OEB use a sub-account of 1995? How will the Board set rates if the bypass compensation remitted is so material as to put the LDC off side of the Board's hypothetical capital structure?

LDCs are the face of the industry to the end user. Our members note that there is a possibility that both a financial Contribution and bypass compensation may be sought from the same customer. They also note that the Board's proposed amendments risk incompatible outcomes to otherwise similar customers depending on the configuration and vintage of distribution or transmission infrastructure. Consider the scenario where a customer can be served by either Transmission Station A which has unutilized capacity or Transmission Station B which lacks capacity to serve. In the latter case the customer may be charged bypass in a future period while in the former case the customer can expect to be asked to render a Contribution and still risks being charged bypass compensation in a future period.

LDCs look to the Board for insight into the fairness of asking a customer to be financially responsible for decisions they did not make and were not engaged in and, in many cases, were unaware of.

3.5.2

The proposed amendments risk treating similar entities in differing ways and LDCs anticipate struggling to make these distinctions compelling to the customers who are not engaged by them.

The rules on overloaded infrastructure may relieve a customer from bypass compensation – for reasons that the customer does not control, is not accountable for and has not authority over. While this is a benefit to the customer it doesn't address the LDCs need for protection against the associated stranded debt. LDCs anticipate that customers will believe they are being dealt with unfairly when the decision making factors are the state of the infrastructure and its utilization – both of which are beyond the control of the customer who will be required to remit bypass compensation.

Should the OEB make this proposed amendment, LDCs suggest that a transition period be provided so that customers can be appropriately educated. Customer education will benefit from the preparation of customer oriented materials, including worked examples that objectively conveys the impact to all affected stakeholders. The EDA suggests that transition periods be co-ordinated with the Coming Into Force proposals so that all customers are provided with consistent and comparable protections.

LDCs also note that it is not the customer's responsibility to find new loads, under any circumstances.

3.5.3

The EDA seeks accounting guidance and information on rate making considerations from the Board, e.g., how to calculate the NBV of pooled bypassed distributor-owned assets, whether LDC owned assets or other assets are affected, how the difference between bypass compensation and the NBV of Transmission assets is to be recovered over time, how to recover stranded costs and stranded debt resulting from customer islanding, the treatment of stranded costs and stranded debt when a customer transitions from being distribution connected to being transmission connected, of the application of bypass compensation to common use pooled assets.

9.7 Reporting Requirements for Embedded Distributors

9.7.1

The EDA suggests the entity responsible for fulfilling the obligation or expectation should also be the reporting entity; alternatively, the reported information should be provided to the regulator and to the entity being reported on.