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October 1, 2018

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL
A1A 5B2 Canada

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - Network Additions Policy

Procedural History

Newfoundland and Labrador Hydro ("Hydro") filed its 2018 Capital Budget Application with the Board of Commissioners of Public Utilities (the "Board") on July 28, 2017. The Board issued Order No. P.U. 43(2017) on December 22, 2017 approving the Application with the exception of the Muskrat Falls to Happy Valley Interconnection Project and the Hydraulic Generation Refurbishment and Modernization Project. For these projects, the Board requested Hydro file additional information – in effect deferring the Board's decision on these projects.

On March 16, 2018, Hydro filed its final reply with respect to the Muskrat Falls to Happy Valley Interconnection Project. The Board issued Order No. P.U. 9(2018) on March 23, 2018 directing the submission of a proposal in relation to the process and timelines for further consideration of the Muskrat Falls to Happy Valley-Goose Bay Interconnection project. As outlined in the Board's Findings in Order No. P.U. 9(2018), the Board required Hydro to provide further information, more specifically, the information should include an expansion study for the Labrador Interconnected system and "a network addition policy setting out how new customers will be treated in regards to their impact on the system and how costs will be allocated among customers for reliability, economic, transmission, and load upgrades, either in the cost of service or through contributions in aid of construction."

On April 30, 2018, Hydro submitted a response which outlined commitments to complete an expansion study for Labrador by October 31, 2018 and a network addition policy by October 1, 2018.

Background

Hydro's bulk transmission grid consists of two regions: the Island Interconnected System ("IIS") and the Labrador Interconnected System ("LIS"). The two systems are interconnected today, via the Labrador Island Link and Labrador Transmission Assets. Additionally, the IIS is interconnected with Nova Scotia via the Maritime Link.

Hydro's current approach to network additions treats assets as either common or specifically assigned. Common assets are those that benefit two or more customers and the costs for such are recovered from all customer classes. Specifically assigned assets are those assets that benefit only one customer and the costs for such are assigned directly to the benefitting customer. Hydro has always used the current approach with respect to network additions in preparation of its cost of service studies.

The breakdown of transmission costs between common and specifically assigned costs is a part of the functionalization process in the cost of service study. Costs that are determined to be common are classified between demand costs and energy costs and then allocated among customer classes based on approved demand and energy allocators. Common transmission costs are classified as demand related and are allocated using a load ratio share approach. Hydro uses the single coincident peak allocator for determining the transmission demand cost recovery approach among customer classes.

The treatment of a transmission asset as either fully common or fully specifically assigned can be contentious. There has been material evidence before the Board in the past concerning the treatment of the frequency converter serving the Corner Brook Pulp and Paper ("CBPP"). The Board ruled in 2001 that this asset should be treated as specifically assigned. With the approved sale of the CBPP frequency converter to CBPP, the functionalization of this asset is no longer an issue.

There is currently an issue on the Labrador Interconnected system with respect to the potential impact of network additions on customer rates. Hydro has experienced recent load growth in Labrador primarily due to the arrival of data centres/cryptocurrency mining sites to the region. While these technology-based customers may not necessarily request to be served at a transmission voltage, their arrival can require the addition of upstream network facilities. Under the current network addition approach, the costs resulting from such network additions are treated as common for recovery from all ratepayers on the LIS.

These technology-based customers also bring an additional level of uniqueness to service request considerations as the loads associated with these enterprises are potentially large and of uncertain permanency, further bringing the reasonableness of the current approach into question. Changes in the emerging block-chain technologies can lead to the unexpected, abrupt departure of these technology-based customers on relatively short notice, thus leaving stranded costs associated with the new transmission additions to be borne by the remaining customers.

Hydro has reviewed its network additions approach to determine the necessary changes required to ensure the goal of maintaining just and reasonable rates is achieved in dealing with new transmission additions.

Network Additions Policy Review

Hydro's Network Additions Policy Review is provided as Attachment 1 to this letter. As part of the review, Christensen Associates Energy Consulting, LLC ("CA Energy Consulting") was engaged to conduct an industry scan (Attachment 1, Appendix A – *Transmission Cost Allocation Methods to Account for Network Additions*) for use in Hydro's assessment of appropriate changes to its current practices in dealing with cost recovery for transmission network additions.

The industry review revealed that there is an emergence of the use of beneficiary pays approach in assessing cost responsibility for network additions in Canada and the United States. With the beneficiary pays approach, similar to Hydro's current approach, the utility reviews the driver of the network addition to assess the degree of customer benefits (i.e., between the requesting customer and ratepayers). However, unlike Hydro's approach, the beneficiary pays approach recognizes that it may not be reasonable for new network additions to be either 100 percent specifically assigned or 100 percent common. In this circumstance, an up-front contribution may be required from the customer prompting the network addition, thereby reducing the cost of the network addition to be treated as common and recovered from ratepayers.

The Ontario Energy Board ("OEB") recently undertook a comprehensive review of cost responsibility for network additions and released a *Notice of Proposal to amend its Transmission System Code and Distribution System Code.* Attachment 1, Appendix B provides the OEB review and the proposals resulting from their policy review. Additionally, some regional transmission organizations and independent system operators in the United States have applied the beneficiary pays approach over recent years.

The OEB review also provided recommendations on the treatment of large load distribution customers that materially contribute to the requirement for network additions. These customers would be required to pay up-front contributions to reduce the amount of common costs to be recovered through customer rates. This approach is consistent with the beneficiary pays approach. The basis of the beneficiary pays concept is that users should share in the costs of a transmission network addition according to their share of the benefits arising from it.

Hydro believes the principles of the beneficiary pays approach reflect sound regulatory practice and is conceptually similar to the distribution contribution in aid of construction policy that is applied in serving customers on the IIS and LIS. However, when considering the methodologies utilized elsewhere, the scale and nature of Hydro's system relative to these larger jurisdictions must be considered. The beneficiary pays methodology is primarily used in large multi-jurisdictional areas with active wholesale electricity markets, a market context unlike Hydro's system.

Implementing the beneficiary pays approach on a large scale for both the LIS and IIS has the potential to increase complexity relative to Hydro's existing approach. This is particularly true for complex projects that affect multiple transmission users, including those outside the Hydro service territory. For relatively simple projects, such as those that might arise in Labrador in response to a single customer's service application, the application of the beneficiary pays method should be practical to implement to deal with the current challenges to deal with load growth in Labrador.

Next Steps

Hydro has reviewed its current approach to the assignment of cost responsibilities for network additions and determined an enhancement to its current policy is warranted. Hydro plans to integrate the principles supporting the beneficiary pays approach in dealing with the assignment of cost responsibility for new network additions for the LIS and will file a proposal with the Board, subsequent to the submission of the LIS expansion study, by December 14, 2018.

Based on a review of Hydro's transmission plan for the IIS, Hydro is not proposing, at this time, any change in its approach to dealing with new network additions on the IIS. Hydro will inform the Board and stakeholders if fairness concerns arise with respect to the requirement for new network additions on the IIS.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

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Network Additions Policy Review

October 1, 2018

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1 Introduction

This report outlines Hydro's current practices with respect to cost responsibility for network additions and identifies revisions that are necessary to determine the changes required to ensure the goal of maintaining just and reasonable rates is achieved in dealing with new transmission additions.

There is currently an issue on the Labrador Interconnected System ("LIS") with respect to the potential impact of network additions on customer rates. Hydro has experienced recent load growth in Labrador primarily due to the arrival of data centres/cryptocurrency mining sites to the region. While these technology-based customers may not necessarily request to be served at a transmission voltage, their arrival can require the addition of upstream network facilities. Under the current network additions approach, the costs resulting from such network additions are treated as common for recovery from all ratepayers on the Labrador Interconnected System.

This report provides an option for consideration in light of the customer load requests in Labrador. Subsequent to the completion of Hydro's LIS expansion study, specific recommendations will be made to deal with new service requests. At this time, there are no major concerns with Hydro's current policy approach to network additions on the island. Should similar issues arise on the island, Hydro will address them from a policy perspective at that time.

In completing a review of its network additions policy, Hydro engaged Christensen Associates Energy Consulting, LLC ("CA Energy Consulting") to conduct an industry scan of network additions cost allocation practices in North America. Appendix A presents the findings. As part of this scan, a recent release by the Ontario Energy Board ("OEB") to amend its policy with respect to the cost responsibility of transmission network additions was also reviewed. The OEB's proposed amendments are attached as Appendix B.

The industry review revealed that there is an emergence of the use of beneficiary pays approach in assessing cost responsibility for network additions in Canada and the United States. The basis of the beneficiary pays concept is that users should share in the costs of a transmission network addition according to their share of the benefits arising from it. Hydro has reviewed the beneficiary pays concept and believes there is merit in applying its principles in dealing with the LIS network additions issues currently before the Board.

2 Current Network Addition Policy

The current practices with recovery of the costs of distribution network additions and transmission network additions reflect Hydro approved regulations, Contribution in Aid of Construction Policy for distribution assets and the cost of service methodology approved by the Board.

2.1 Distribution Investment

In general, distribution investments to serve residential customers are treated as common assets in the determination of customer rates. However, where the cost of facilities required to serve new customer load exceeds a fixed asset investment as approved by the Board in the Residential Contribution in Aid of Construction ("CIAC") Policy, the customer requesting service leading to the additional investment is required to contribute the additional cost of the new facilities. This approach reduces the impact on customer rates arising from capital investment in distribution service extensions to serve new residential customers.[1]

As well, a General Service customer that requires a capital investment in distribution assets which is not supported by future revenues from that customer is required to pay a contribution to offset the required additional investment. Such contributions are required by the utility's General Service CIAC Policy for distribution extensions and upgrades. These practices in the assignment of costs to a customer who derives all the benefits of the investment are consistent

[1] Operationally, the criterion for cost assignment is based on length of line: customer connections requiring line longer than the benchmark amount absorb the full extra cost of the line. That extra line is deemed to provide benefits to the specific customer exclusively.

with the beneficiary pays approach since the payment system is consistent with matching costs to benefits.[2]

Newfoundland Power applies the same CIAC Policy as Hydro, except that Hydro's CIAC Policy does not provide for underground service. At Newfoundland Power, customers that request underground service are required to pay the incremental cost of providing underground service relative to overhead service as underground service is not the least-cost option and the benefits of such a service primarily accrue to the customer requesting it.

The concept of betterment,[3] as it relates to charging customers for investment in distribution assets, is also consistent with the beneficiary pays concept. A betterment credit is applied to reduce the amount charged to a customer for an asset upgrade if the new asset is providing benefit to both the customer requesting the system modification and the general customer population. The application of a betterment credit is also common in the administration of the CIAC Policy in determining customer charges for distribution plant extensions and distribution upgrades.

However, the cost of replacement of common assets upon the end of life does not require a CIAC from the original customers. The CIAC Policy also requires the utility to monitor new customer connections to distribution facilities for which a contribution was required; a refund is provided to the original customer if a new customer connects within ten years of the original customer connection.

On occasion, new service requests on the distribution system can also require modifications, such as feeder upgrades and substation modifications. The requirement to pay for such a system modification has been dependent on the nature of the load addition (i.e., whether the load is temporary or permanent) and whether the system modifications are of primary benefit

[2] The same CIAC Policy is applied to the customers of Hydro and Newfoundland Power.

[3] Reflected in the Schedule of Rates, Rules and Regulations that applies to customers of Hydro and Newfoundland Power

to the requesting customer or to other ratepayers served in the area. The utility also considers its five-year capital plan when determining whether the investment cost should be borne by the customer requesting service or by all customers (through customer rates). If a customer load request prompts a system modification that is already included in the five-year capital plan, the customer may not be charged for the upstream system modifications.

A certain amount of judgment must be employed in determining which customers incur the cost of upstream network additions that result from customer load requests. This reflects the varied benefit impact of transmission investment applications. The principles and practices currently followed in determining cost responsibility in administering the CIAC Policy are consistent with the beneficiary pays approach since the policy imposes costs and provides benefits to both the customers requesting service and the existing customers. Approval by the Board is required for contributions from customers when the capital cost of asset upgrades or additions is in excess of $50,000. As a result, there is transparency in the process in determining the contribution from a customer when upstream network additions are required, as such projects would generally cost in excess of that threshold.

2.2 Transmission Investment

The current practice at Hydro with respect to transmission network additions is to functionalize the addition either as common or specifically assigned assets. Common assets are those that benefit two or more customers. Costs for common assets are allocated to all customers on the system and recovered through published rates. Specifically assigned assets benefit only one customer and costs are attributed to, and recovered from, the customer to whom the facilities are assigned.

As a matter of policy, a contribution is required from customers to offset the capital investment in specifically assigned assets.[4] The customer is also responsible for the costs related to

[4] Hydro has some specifically assigned assets that have been in service for many years for which a contribution in aid of construction was not required. In these circumstances, the customer is required to pay Hydro depreciation expense and return through a specifically assigned charge.

sustaining capital and the replacement cost at the end of life of the asset. Hydro also recovers the estimated annual operating and maintenance ("O&M") costs related to the specifically assigned asset.[5]

Projections of load-based revenues are not used to reduce the funding contribution from the customer to which a transmission asset is specifically assigned. Hydro considers this as an appropriate approach, as revenues from load-based rates are determined to support cost recovery of common transmission assets.

As with additions to the distribution network, Hydro considers its approach to cost recovery of specifically assigned transmission assets to be consistent with the beneficiary pays approach; customer-assigned costs generally match customer benefits since the beneficiary is typically a single customer.

The determination of transmission assets or transmission upgrades as common currently results in the full cost being recovered from the published rates that apply to all customers. Within Hydro's current cost-of-service methodology, Hydro allocates the cost of the common existing transmission network according to the well-known load ratio share methodology. The justification for this approach is that transmission systems are planned to meet peak system demands.

The current methodology (i.e., transmission network costs being treated as either fully common or fully specifically assigned) does not recognize that the benefits provided by new transmission investment will not necessarily accrue exclusively to the initiating customer or, alternatively, entirely to the existing customer population as a group. As a result, the current method may not reflect a reasonable sharing of cost responsibility between the customer requesting service and the existing customers. The beneficiary pays approach offers the potential for a fairer balance among the interests of all parties.

[5] Operating and maintenance costs are recovered from the customer through a specifically assigned O&M charge.

3 Network Additions Policy Considerations

3.1 Policy Requirements

Given the potential for material customer rate impacts due to the requirement for transmission network additions on the Labrador Interconnected system in the near future, Hydro needs to revise its network additions policy to find a better balance between the benefits to the requesting customer requiring the network addition with the appropriate cost responsibility. Hydro believes the principles of the beneficiary pays approach reflect sound regulatory practice. This approach associates increased cost responsibility with benefits resulting from a transmission investment rather than with shares of peak demand. The beneficiary pays approach thus underpins the assignment of otherwise common costs to those who benefit substantially from those costs.

Any principles adopted reflecting the beneficiary pays approach will need to address the immediate needs for appropriate cost recovery from customers on the LIS and also be generally applicable in evaluating cost responsibilities for transmission network additions on both the LIS and IIS. The methodology also needs to be manageable and practical to apply as part of Hydro's transmission planning approach.

3.2 The Transmission Planning Process and the Beneficiary Pays Approach

Hydro has the responsibility to ensure that its system is planned to meet the utility's requirement to provide least-cost, reliable service to its customers. To this end, Hydro develops annual updates to its transmission plan, a task that includes the review of user applications for network additions. Hydro develops a capital plan that includes all transmission system reinforcements required to meet Hydro's ten-year load forecast. The transmission planning process extends over the course of a full-year planning period from November to October of the succeeding year.[6]

[6] Newfoundland and Labrador Hydro, *NL Transmission Planning* Process, last updated Dec. 1, 2017, Section 5.2, p. 4 of 10, and Appendix A.

The process occasionally deals with transmission service applications by prospective users. First, the utility conducts a system impact study to model the impact of the service request on the system over the life of the request. This involves determining whether the system, as presently constructed and planned, can accommodate the request. If the conclusion is that investment is required, Hydro then undertakes a facilities study to determine the nature of the investment and to estimate its cost.

Within this process, Hydro determines whether the request would result in a material impact on the capital plan. This review would consider if transmission system reinforcements were required or if any planned system reinforcements identified in Hydro's capital plan required advancement. If the request is not material, no further work is necessary and any costs are simply treated as common. In the event that the costs are material, the assignment of costs associated with new assets or asset advancement represent an opportunity for the application of fairness principles.

Hydro's review also identifies service applications with "local" implications only. Such an application might be for a new or expanded industrial customer service line or a small generator interconnection that clearly has no system implications and can be resolved by directly assigning all costs to the user. The customer is asked to pay its cost, typically in advance of project start-up.[7] There are no common costs remaining to be allocated to other customers.

The beneficiary pays method can come into play in the case of a material transmission service request that is likely to have multiple beneficiaries and impacts across the system. The method can be used on a project-by-project basis to determine the facilities costs, allocate costs to customers and rate classes and determine a method of recovery. The beneficiary pays approach takes into account the requirements associated with all network users who might be affected by a transmission investment. It can also be used to determine contributions from generators

[7] If multiple customers request a project and it is approved, then division of the costs is made by the customers themselves or simply on an even per-customer basis.

that require new transmission additions. Thus, the beneficiary pays approach is intended to be comprehensive in its methodology as part of the transmission planning process.

The experience of utilities and transmission organizations using the beneficiary pays methodology indicates that exact methods can vary from case to case. This is due to several factors. First, transmission projects are diverse in size, location, and complexity of effect on the grid. Second, these projects can have different objectives, not merely customer connection, but reinforcement to influence quality of service. Third, transmission users can have varying priorities and definitions of benefits. The beneficiary pays approach generally requires stakeholder engagement in defining benefits and methods of cost analysis.

3.3 Pricing Considerations of a Network Additions Policy

Currently, Hydro recovers costs from an individual customer through specifically assigned charges that can be applied in advance of project start-up or recovered in monthly customer-specific lump sum fees. The beneficiary pays method permits this same approach to be applied to costs that would otherwise be deemed common. The key is that the costs to be recovered from a specific customer are directly associated with the estimated benefits of the project. Hydro currently recovers dedicated transmission costs via specifically assigned charges and common transmission costs through rates recovering demand costs. For dedicated assets, the utility imposes pre-service or up-front contributions from customers at both the transmission and distribution service levels.

The use of the beneficiary pays approach can allow Hydro to more clearly define what proportion of the network addition should be treated as common. Hydro can use this approach to determine whether an up-front contribution is required. Contributions for transmission network additions based on the beneficiary pays approach should be subject to Board approval, consistent with the requirements of the distribution General Service CIAC Policy.

Potential impacts or issues resulting from applying the beneficiary pays approach can be addressed through Hydro's cost of service methodology review. However, any up-front contributions required from customers as a result of network additions will be deducted from the original cost of capital additions reflected in rate base.

Hydro will also consider the following attributes in its beneficiary pays proposal to be provided to the Board.

Retention of Approach to Recovery of Dedicated Transmission Costs

Hydro believes that it is reasonable that its network additions policy will continue to apply to recovery of costs related to specifically assigned assets. Under this policy, the customer with specifically assigned assets from which it alone benefits pays the full cost of the asset, including original and sustaining capital costs, replacement cost at the end of life, and estimated annual operating and maintenance costs.

Common Asset Replacement

Hydro believes that it is reasonable to continue to treat replacement of common transmission assets that reach the end of life as common assets with no up-front contribution from customers. Hydro does not believe it is practical to specifically assign a portion of annual O&M costs of common transmission assets to the customer that paid the original contribution. Therefore, Hydro believes it is reasonable to continue the current practice of allocating O&M costs for the full original cost of new transmission assets consistent with the approach approved in the cost of service study methodology.

Potential for Contribution Refunds for Originally Specifically Dedicated Facilities

Hydro believes it is reasonable to monitor new customer connections to previously specifically assigned transmission assets for a period of ten years to determine if the contribution initially paid by a customer should be revised through the provision of a contribution refund that reflects the addition of other customers making use of the investment. This practice is consistent with the distribution CIAC policy.

Sales Revenue Projections

Hydro believes it is reasonable that projections of revenues realized from the sale of electricity to a customer not be used to reduce the funding contribution from the customer under the beneficiary pays approach. There can also be material risk incurred by Hydro and ratepayers if the projected revenues do not materialize. Hydro considers this an appropriate approach, as any additional load-based revenues will be utilized to minimize ratepayer impacts of the additional cost of common transmission assets net of the contributions provided under the beneficiary pays approach.

3.4 Labrador Interconnected System Approach

The LIS is close to capacity and there is potential for significant new load to be added that would be served by new transmission assets normally classified as common rather than specifically assigned. The current network additions approach has the potential to inhibit both the fair allocation of costs to customers and timely cost recovery.

Hydro does not have the ability to serve new load requests on the LIS without transmission system reinforcement. Even relatively modest new service requests can be significant compared to available capacity. This condition suggests that regional considerations in project evaluation will be particularly important.

Hydro has reviewed its current approach to the assignment of cost responsibilities for network additions and determined an enhancement to its current policy is warranted. Hydro plans to integrate the principles supporting the beneficiary pays approach in dealing with the assignment of cost responsibility for new network additions for the LIS.

3.5 Distribution-Level Pricing

Hydro will also consider the implications of applying a beneficiary pays approach to distribution customers. In reviewing the Ontario Energy Board's ("OEB") proposal, it was noted that the OEB recommended that distribution customers that request large load additions also be required to pay a contribution to support upstream network additions through an Upstream Capacity Charge, effectively applying the concept of the beneficiary pays approach to its distribution customers as well as at the transmission level.

To deal with the recent influx of requests for service on the LIS, Hydro will consider the merits of charging an Upstream Capacity Charge to new and existing distribution customers requesting large load additions to support the recovery of upstream network addition costs. The Upstream Capacity Charge ensures that the customer requiring the large amount of additional capacity will contribute equitably towards the cost of network capacity additions.[8]

Capital contributions received through the application of an Upstream Capacity Charge can be applied to reduce the transmission investment cost to be recovered through customer rates on the LIS.

Hydro believes it is reasonable to undertake a true-up provision to ensure that the load projections provided by customers for use in calculating the Upstream Capacity Payment are reasonable. A similar two-year review provision currently applies in the distribution CIAC Policy for General Service customers. If no true-up provision is established, customers requesting new services may be incented to understate their capacity requirements.

4 Conclusion

The integration of the beneficiary pays methodology to Hydro's current network additions policy approach for the LIS is sound as it will assist in addressing the current transmission

[8] Hydro does not believe it is practical to require a capital contribution for all load addition requests (i.e., residential, small business). Based on input from consumer group representatives, the OEB determined that 3 MW was an appropriate definition for a large load.

capacity issues being experienced. Subsequent to the submission of the LIS expansion study, Hydro will file with the Board a proposal to deal with the assignment of cost responsibility for new network additions for the LIS by December 14, 2018. At this time, there are no changes to Hydro’s current network additions policy proposed for the IIS, however, Hydro will inform the Board and stakeholders if fairness concerns arise with respect to the requirement for new network additions.

Appendix A

Proposal by Christensen Associates Energy Consulting, LLC for Transmission Cost Allocation Methods to Account for Network Additions

DISCUSSION PAPER

TRANSMISSION COST ALLOCATION METHODS TO ACCOUNT FOR NETWORK ADDITIONS

for

NEWFOUNDLAND AND LABRADOR HYDRO

prepared by

CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

July 18, 2018

1. INTRODUCTION

Newfoundland and Labrador Hydro (Hydro) wishes to explore how North American utilities allocate the costs of transmission network additions, in particular those undertaken in response to requests for service by large customers, either at new sites or as additions of load at existing sites. Substantial load additions often require upgrades and reinforcements to the common network to ensure the continuation of reliable service to all customers, including the load addition, and the provision of service at least total cost. Approaches to customer requests are typically nested in rules meant to apply to general requests for new service since the transmission planner's perspective treats all requests as problems for analysis according to a similar set of analytic procedures.

This discussion paper reviews the cost allocation practices associated with network additions in several Canadian electric jurisdictions, as well as the practices of the largest independent system operators (ISOs) and regional transmission organizations (RTOs) in the United States. Such information is intended to assist Hydro to develop its own network additions policy.

Section 2 provides background information on the development of the current challenges of transmission cost allocation. Section 3 reviews practices applied in Canadian jurisdictions, both those that are still vertically integrated and those in which deregulation of generation services has occurred. Section 4 examines current practices and rules in the United States jurisdictions where transmission is managed by regional organizations, subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). The U.S. experience is instructive because of the parallels in industry structure to the case of Hydro, and because of the strong influence of U.S. practice on Canadian wholesale trade, due to the high volume of cross-border transactions. Section 5 closes the discussion paper by drawing on the preceding text for summary lessons applicable to the case of Hydro.

2. BACKGROUND

Traditionally, allocation of transmission costs has not been the subject of great controversy. In the era of vertically integrated utilities, prior to deregulation of generation and retail services and the emergence of wholesale markets for generation and reserves services, transmission investment was undertaken predominantly to meet the needs of a jurisdiction's customers (native loads). As loads grew, utilities planned and undertook new investment, and allocated the cost of this investment to customer classes under stable rules approved by state or provincial regulators.

Utilities recovered the cost of their incremental transmission investment, and the subsequent additional operating expenses, through the standard process of functionalizing, classifying, and allocating common costs to rate class. There were two major exceptions to the process. First, some costs that might have been functionalized as transmission were instead functionalized as generation, since the assets were dedicated to a specific generation source. In Canada, this has often occurred due to the remote siting of generation assets, especially hydraulic generation.

Second, some large customers require connection via dedicated transmission assets that must be specially constructed for the customer's use. While such lines may subsequently come to serve other customers, the initial investment is intended to serve the single customer. In this case, it can occur that the utility requires the customer to pay the incremental costs of the dedicated line.[1]

Costs functionalized as transmission were usually classified as being driven by peak demand exclusively (as opposed to total usage or number of customers) and then allocated by means of a demand rule that was deemed to best reflect the utility's circumstances. Typically, utilities selected a coincident peak (CP) allocator, relying on anywhere from one to twelve months of data. Canadian utilities, characterized by winter peaks, would often use a function of the three or four winter peaks as the benchmark of class cost responsibility. Less seasonal utilities might rely on more months.[2] In such circumstances, the cost implications of any customer-initiated request for new or additional service was manageable under relatively simple rules: assign costs of dedicated facilities to the customer(s) requesting new service and allocate all remaining costs under the utility's standard rules for allocation of common transmission costs.

The advent of deregulation has driven up total transmission cost and has complicated the transmission costing problem. The development of wholesale markets for energy and reserves has highlighted locational differences in marginal cost. These differences have precipitated investment in transmission that have provided market participants with net benefits and have lessened locational price differentials. However, these cross-jurisdictional investments have involved multiple participants, complicating the challenge of cost allocation. In the U.S., the FERC has used Orders 888/889, 890, and 1000 to articulate over several years rules to ensure open access for all parties to the transmission grid and to encourage cost allocation for multi-jurisdiction products that meets the traditional standards of *just and reasonable* rates.

[1] Previous analysis by Christensen Associates Energy Consulting indicated that such practices are not infrequent in cases where customer are distant from the grid. Additionally, in some few cases, utilities follow Hydro's practice of charging customers for operating & maintenance and other costs related to the dedicated lines.

[2] The National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual*, January 1992, Chapter 5, documents traditional transmission cost allocation methods.

Under FERC Order 2000, ISOs and RTOs were created to facilitate the development of wholesale markets.[3] Under FERC authority, these newly formed organizations also were charged with ensuring equal access to the transmission system. Open Access Transmission Tariffs (OATTs) issued by transmission service providers specify transmission access charges that all participants in energy delivery must pay.

Transmission access charges cover fixed costs, including capital-related charges[4] and fixed operations and maintenance expenses (FOM). Access fees are charged to all wholesale transactions and are paid monthly, or on shorter timeframes (weekly, daily, hourly) depending on the schedules of short-term transactions. Access fees as set forth in the OATTs of service providers are generally, although not exclusively, based on a *load ratio share* methodology. This approach is drawn from longstanding cost allocation methods applied in retail markets and is sometimes referred to as *peak load responsibility* since sharing is based, as before in retail cost allocation, upon a measure of peak demand.[5] Under this method, transmission costs for upgrades are simply rolled into region-wide access charges which are not usually differentiated by sub-regional zone.[6]

It is common for incumbent transmission service providers to prefer system-wide postage stamp rates (cost socialization) despite substantial differences in costs among various areas that comprise a regional footprint. For the access charges of both regions and zones within regions, the *load ratio share* methodology is used, with virtually no exception, as the basis to determine transmission charges, either postage stamp rates covering regional transactions across large regions, or the individual service territories of incumbent retail utilities within a region.

The need for an improvement on the conventional approach to cost allocation became increasingly clear with the introduction of open access.[7] The rise in transmission volumes, and the increase in multi-

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[3] The central directives for competitive U.S. wholesale markets are Title VII of the Energy Act of 1992 and, subsequently, FERC Order 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*.

[4] *All-in* capital-related charges including return on capital (return to equity, interest costs of outstanding debt, insurance, working capital, materials and supplies, administrative and general overheads, capital charges on general plant, property taxes, and capital depletion allowance (depreciation).

[5] For transmission services, the FERC has established criteria for determining the facilities and costs for inclusion in OATT access charges, and definitions of peak loads, respectively referred to as the 7- and 3-factor tests.

[6] The most significant rebuke of rolled-in pricing resulting in a common level of transmission charges is the U.S. 7th Circuit Court of Appeals decision in *Illinois Commerce Commission, et al., v Federal Energy Regulatory Commission*, dated June 25, 2014. The 7th Circuit Court rejected the FERC's Order approving the assignment of costs of new high voltage facilities located in the Eastern region of the PJM Interconnection to PJM utilities located in PJM West. In its decision, the 7th Circuit states: "The Commission acknowledged that this was a crude method of cost allocation—which is to put it mildly, because without quantifying benefits of the eastern projects to the western utilities it is impossible to determine what those utilities should be charged: charging costs greater than the benefits would overcharge the utilities, and charging costs less than the benefits would undercharge them….FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs to be shifted to its members."

[7] J.S. Dennis, *Transmission Cost Allocation and "Beneficiary Pays"*, presentation by FERC staff, Jan. 14, 2015.

jurisdictional investments exposed what was commonly known but not relevant previously: network externalities in transmission investment abound. Changes in load levels and transactions specific to areas can have large price and reliability impacts across entire regions. Similarly, expansion of network facilities in specific areas can relieve congestion and provide reliability benefits across fairly large regions. Thus, the benefits from an upgrade are potentially distributed widely, over several regions and service territories, while the allocation of costs via peak demand share may bear little relationship to the distribution of benefits. Additionally, there is a free rider problem: it may be that several participants in the market would benefit from a transmission upgrade, but each will be reluctant to step forward, since it is the initiator of a transmission service request who bears the risk of being burdened with a disproportionate share of the costs, while the benefits will be shared among many.

Under these complicating circumstances, the impacts of a customer-initiated service request can be unexpectedly widespread. From the perspective of an RTO tasked with allocating costs not assignable directly to the customer, many more possible recipients of the benefits of new transmission investment needed to be considered. While the *load ratio share* method is currently broadly applied in transmission cost allocation, the incidence, size, and complexity of new transmission projects have raised concerns about how best to differentiate access fees, such that transmission charges better conform to benefit flows. At present, regulatory changes governing wholesale markets in the U.S. have not displaced the *load ratio share* approach to allocating existing transmission costs but have induced the introduction of access charges for new transmission additions that are differentiated across regions and tariff zones. The revised standards for transmission cost allocation have been articulated by the FERC, and are often referred to as *beneficiary pays* criteria.

The *beneficiary pays* approach is predicated upon the understanding that transmission cost allocation and the determination of access charges are inseparable from transmission expansion planning: decisions regarding the scale and location of transmission investment determine the distribution of benefits across regions. This broader consideration of cost allocation is fully consistent with *just and reasonable rates* criteria, codified in section 205 of the U.S. Federal Power Act. Indeed, just and reasonable criteria would seem to require that cost allocation processes take account of the locational nature of benefits in the determination of who pays.

FERC Order 1000 goes to some length toward the realization of just and reasonable rates through the *beneficiary pays* approach to cost allocation, requiring transmission service providers to apply net benefits criteria for the determination of plans and cost allocation. Major changes are twofold. First, planners must apply much more complete analytics in order to capture the full dimensionality of benefits, both in terms of total amount (or level) of benefits, as well as the spatial distribution. The distribution of benefits, and thus cost allocation, can be predominantly or exclusively local, or can reach broadly across multiple regions. Second, the distribution of benefits—which can cover very large regions—must be understood or otherwise estimated over future years under conditions of considerable uncertainty. Planning includes settling in advance upon transmission expansion plans and the categorization of selected network upgrades according to predefined criteria. Predefined cost allocation protocols are applied to the annual carrying charges and fixed O&M expenses, where methodology is specific to the category of the facility.

Cost allocations are subject to regulatory scrutiny[8] with cost allocation methods satisfying explicit criteria set forth by the FERC. The net benefits admissible for consideration include not just energy and reserve market impacts but reliability, public policy requirements, and interconnection of generation resources.[9]

Transmission providers are now grappling with this methodology question, as well as with the issues of measurement of future benefits under conditions of uncertainty that the *beneficiary pays* approach raises. The next two sections report on how Canadian and U.S. jurisdictions are dealing with the problem of allocating transmission investment costs—*i.e.*, the carrying charges on investment in transmission facilities—precipitated by increased demand for network capability, including customer requests for new or increased service.

3. CANADIAN PRACTICES

Canadian jurisdictions can be thought of as being of two types. One is the familiar vertically integrated utility that dominates its province's electric grid. The other features deregulated generation services and some form of ISO/RTO similar to those in the U.S. This review examines the transmission investment cost allocation approach for three Crown corporations – BC Hydro, Manitoba Hydro, Hydro-Quebec, and NB Power – one investor-owned utility, Nova Scotia Power, and two deregulated jurisdictions, Ontario and Alberta. These jurisdictions share with Hydro, once it has been fully interconnected with eastern North American, circumstances of potentially substantial electricity exchange with other jurisdictions ("in" and "out" traffic) but relatively little "through" traffic.[10]

A unifying feature of these jurisdictions, though, is the presence of OATTs, driven in part by *reciprocity standards*. These tariffs indicate the manner in which costs of certain transactions are to be shared. For example, all vertically integrated Crown corporations treat network integrated transmission service (NITS) charges in a fairly similar manner, utilizing *load ratio share* cost allocation procedures to allocate the annual revenue requirement of a transmission provider to its network customers. However, this approach does not fully describe how the costs of a large new investment are to be allocated.

Perhaps the simplest case is that of Manitoba Hydro. That company treats all network additions as additions to common property, with one exception. Customers who require a dedicated radial addition

[8] Approval of changes in cost allocation are not necessarily forthcoming without conforming modifications. In its Order in Docket ER17-387-001, dated September 20, 2017, the FERC rejected the cost allocation methodology proposed by the Midcontinent Independent System Operator (MISO) regarding interregional cost allocation. In its September 20 Order, the FERC states "…we find that MISO has not shown that its proposed cost allocation methods for MISO's share of the costs of interregional reliability, economic, and public policy transmission projects that terminate wholly outside MISO are just and reasonable."

[9] J.S. Dennis, *Opcit*, p. 8.

[10] Other jurisdictions, specifically those in the Maritime provinces of New Brunswick and Nova Scotia, have the potential for significant through traffic. They are not included in this review. Hydro-Quebec also has significant through traffic, which will increase, presumably, with the completion of the various projects related to Muskrat Falls.

must pay those costs, but any impact on the system other than the specific radial line is treated as being in common, and allocated across all customers.

NB Power and Nova Scotia Power are also practitioners of common allocation with limited use of direct assignment, at least in terms of their COS studies. Their OATTs make provision for direct assignment and recovery of network upgrade costs that are demonstrably triggered by a transmission service applicant. The full costs are then recovered in pre-construction payments from the applicant. This approach does not appear to be consonant with the *beneficiary pays* methodology in that the benefits to other parties are not assessed and costs are not distributed among other customers.[11]

Newfoundland and Labrador Hydro is akin to Manitoba Hydro in its general approach. However, perhaps due to the significance in total sales of the Island's industrial customers and their relative remoteness, dedicated transmission assets receive a somewhat more detailed review. In particular, a customer with dedicated transmission assets also receives an assignment of O&M and general administrative expenses based on these assets.

BC Hydro adopts a somewhat different approach from that of Manitoba Hydro, recognizing a cost obligation not simply for new radial transmission line, but for upstream connections denoted "system reinforcements". The utility responds to a request for new service by a transmission customer (served at 60 kV or higher) by preparing a "detailed estimate of cost" study that includes the full cost of system reinforcement. From this cost the utility deducts a "BC Hydro Offset", that is the lesser of the full cost of the project and a maximum offset consisting of net expected annual revenues divided by 0.135 (to recognize multiple years of net revenues) plus a contribution to depreciation expense and other benefits to the BC Hydro system, as estimated by the utility. The customer is responsible for any excess over the Offset.[12] The remainder is treated as an addition to common assets and allocated according to the transmission cost demand allocation process. This involves sharing costs through the OATT based on shares of point-to-point and NITS forecasted energy, and then using the cost-of-service process to allocate the share that internal retail customers must bear. Note that this approach is "marginal" in nature in that the computation attempts to estimate forecasted increases in revenues and costs arising from the system reinforcement and then assigns to the customer the share calculated by the offset.

This approach goes beyond the simple recording of dedicated expenses to encompass system impacts. It also recognizes the possibility of future developments, as a customer is eligible for a rebate via an adjustment to the Offset if, within five years, another customer arrives to make use of the new transmission facilities.

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[11] Also, the OATT structure appears to suffer from the free rider problem mentioned above: the initiator of a transmission service request is likely to bear disproportionately the burden of cost. Similar customers who expect to benefit from the investment need only await a customer willing to submit an application. Only if all customers jointly apply is this avoided.

[12] BC Hydro, *Electric Tariff Supplements 5 and 6*; see especially TS 6, Section 5.

Hydro-Quebec adopts a similar approach to that of BC Hydro, although the vertical segmentation of Hydro-Quebec by function into separate operating companies alters the process somewhat. For example, transmission service requests by customers are routed through the Distribution subsidiary, even if service is requested at the transmission level only. A customer of greater than 5 MVA pays for expanded/new transmission service based on a "detailed cost of work" calculation. As at BC Hydro, the customer pays that estimated cost less the utility's computed allowance. In this case allowance is per kW, multiplied by the contracted kW expansion. Hydro-Quebec includes a provision to ensure that, for five years, the customer utilizes at least their contract demand, and pays a charge that recoups one-fifth of the above allowance for each kW of shortfall.[13]

These three utilities appear to make uniform use of traditional cost allocation techniques in that they apply the *load ratio share* approach to network asset revenue recovery while using, to varying degrees, methods that extend dedicated asset recovery principles to overall network cost increments that result from individual market participant load increases. They are not yet fully applying notions of net benefits though, in the spirit of the *beneficiary pays* principle, since there doesn't yet seem to be an explicit enumeration of benefits but only of cost impacts. Costs that cannot be attributed to the customer inducing the transmission system reinforcement are merely allocated in common.

Nova Scotia Power is somewhat different from the Crown Corporations in that it tends not to engage in direct assignment. This perspective then influences treatment of customer-initiated transmission project costing, since all such costs are treated as common and handled under standard cost allocation rules.

In Alberta and Ontario, the emergence of the Alberta Electric System Operator (AESO) and Independent Electric System Operator (IESO), respectively, as part of the deregulation of generation services, has formalized costing and pricing of transmission to a greater degree than elsewhere in Canada. Alberta classifies any prospective upgrade as either "system" or "customer" and treats system costs as recoverable from all market participants via OATT charges. The costs of customer upgrades are recovered directly from customers initiating a service request.

As with some Crown corporations, Alberta makes provision for a capital contribution rebate. In cases in which a new customer appears on a recently completed transmission project to which a customer contributed funds, the customer originating new transmission investment can receive a rebate reducing the amount of the original contribution.

One recent complication in Alberta, apparently, is a trend to classifying an increasing proportion of costs as customer-related. However, this does not cause Alberta's general approach to depart significantly from practice elsewhere in Canada. Alberta last reviewed its costing methodology in 2012 and there is some indication in current proceedings of a need for a revision in costing procedure to explore issues related to the *beneficiary pays* concept.

[13] Hydro-Quebec, *Conditions of Service,* April 1, 2018 Edition, pp. 74-75.

Ontario currently applies a similar approach to that of Alberta and, thus, other jurisdictions. An application for new service triggers a study of the net revenue implications of the transmission project. Any shortfall in net revenue is charged to the customer. (There can be multiple customers in the application process, with costs shared based on non-coincident peak demand.) If a new customer emerges in the subsequent 15 years, a capital contribution rebate is provided.

Like Alberta, Ontario is exploring the *beneficiary pays* concept. The Ontario Energy Board (OEB) recently issued a notice to this effect, the first public declaration of formal intent to review this issue.[14] The proposed changes, hereafter referred to as *Proposal to Amend T&D Codes*, were precipitated by Hydro One Network's 2014 application before the OEB for Leave to Construct. The application proposed a proportional benefit approach of cost apportionment. In addition, Hydro One Network also proposed the assignment of upstream costs to selected downstream distributors. Both cost allocation proposals departed significantly from the cost allocation methods embedded in the OEB's *Transmission System Code* and *Distribution System Code* at the time. The fundamental concern is common to Canadian and U.S. markets: that the benefit flows from a transmission facility may not match the costs allocated to various parties under current rules, which are based on conventional *load ratio share* methods. Namely, locational distribution of benefits may significantly depart from load shares.

The OEB's Proposal to Amend T&D Codes identifies three principles:

- *Optimal Infrastructure Solution:* Optimal solutions are infrastructure investments that meet regional needs at the lowest cost. 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.[15]
- *Open, Transparent and Inclusive:* The process used to determine the costs of infrastructure investment and the appropriate allocation of those costs to the beneficiaries should be transparent and include all affected parties.

In brief, the OEB proposes to adopt a "proportional benefits" methodology.

[14] Ontario Energy Board, *Notice of Proposal to Amend a Code: Proposed Amendments to The Transmission System Code and the Distribution System Code to Facilitate Regional Planning*, Board File No.: EB-2016-0003, Sept. 17, 2017. T

[15] Notably, the OEB makes reference to the Board report entitled *Renewed Regulatory Framework for Electricity*, July 2012, where the OEB states "The Board believes that a shift in emphasis away from the 'trigger' pays principles to the 'beneficiary' pays principles is appropriate…" (page 43).

Under these principles, the OEB advances four changes to the Transmission System Code (TSC) and Distribution System Code (DSC) codes of Ontario. Each is discussed below:

1) <u>Approaches to Apportion Transmission Connection Investment Costs to the Network Pool</u>

   As experienced in both Canada and the U.S., facilities that are planned, installed, and paid for by local loads under *load ratio share* can often be superseded by regional plans/solutions that satisfy immediate local needs—say, voltage constraints—as well as more broadly defined requirements including reliability, voltage, congestion and line loss issues. These larger regional facilities/solutions may solve multiple local and regional issues at a lesser total cost. On this point, the OEB's Proposal to Amend T&D Code incorporates an illustrative example, demonstrating how a larger regional facility resolves both system and customer requirements. The OEB proposes to allocate the costs of the regional facility between the network customers and the local customer(s) according to the relative costs of the two separate facilities/solutions.[16]

2) <u>Approaches to Apportion Upstream Transmission Connection Investment Costs</u>

   Under TSC and DSC rules, the transmission service provider (Hydro One Networks) charges distributors and large industrial loads according to common rules, where the source of the apportionment of costs is an economic analysis, and capital contribution by loads (distributors, industrial customers). Distributors include both host and embedded entities and, under Ontario's DSC, embedded distributors can be subsidized by other loads of the host. As proposed by OEB, upstream transmission charges would be assigned specifically to embedded distributors according to *beneficiary pays*. As stated by the OEB in its Proposal to Amend T&D Codes:

   > "The OEB is of the view 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."

3) <u>Approaches to Apportion Costs for End-of-Life Connection Replacements and Multi-Distributor Regional Solutions</u>

   The TSC includes provisions for replacement of facilities approaching end-of-life status. Under the current TSC rules, distributors and customers are not charged for replacement facilities, as they have previously paid for the facilities in full.[17] Should they request an upgraded facility, the customer pays the full cost of replaced facility. The OEB suggests that the customer should be charged only the incremental costs for the upgraded facilities, compared to the replacement costs of a facility of

[16] See section 1 of the OEB document. This methodology is, referred to as separable costs-remaining benefits, is present in cost allocation theory.

[17] Presumably, long-standing customers have covered return on and of capital, paid over decades.

equivalent capability, referred to as *like-for-like facilities*. Stated by the OEB in the Proposal to Amend T&D Codes:

> "…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 [replacement] cost whether it is the same capacity (*fully* offset) or an upgraded connection (*partially* offset)."

The OEB goes on to clarify that should a customer request the replacement of a connection facility prior to end-of-life status, "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."[18]

4) Facilitating Regional Plan Implementation and Mitigating Electricity Bill Impacts

The OEB recognizes the differences in realized capacity compared to immediate capacity needs of distributors and loads, caused by the indivisible lumpy nature of capacity additions. The result can be sizable bill impacts, caused in part by the front loading of rates inherent in original cost accounting principles. Second, the result may be that comparatively small sub-optimal facilities are installed. The OEB has proposed changes to the TSC protocols to address this issue. These include an "annual installment" approach. As stated by the OEB: "In addition to mitigating bill impacts by spreading the cost over time, the OEB believes this approach would also result in better alignment between incremental revenues received by distributors due to customer load growth and paying the cost of the connection investment." The OEB's Proposed Amendment to T&D Codes also discussed two other rate mitigation methods, including *Upstream Capacity Payments*, and an *Upstream Stream Connection Adder*, where the latter is a rate rider applied to energy bills of the customers of distributors.

In summary, the major Canadian jurisdictions, both vertically integrated and deregulated, use similar methods to allocate the costs of new transmission. At present, these methods generally make use of a customer pays methodology and load ratio sharing for costs not attributed to the specific loads, including distributors and customers—essentially, rolled-in pricing. The new cost allocation approach proposed by the Province of Ontario, however, closely follows that developing in the U.S., where the *beneficiary pays* principle is being applied to determine the cost assignment of new facilities. Along this line, utility regulators in the other Canadian provinces are expressing interest in the use of benefit distribution as the basis for cost allocation methodology. Specifically, the *beneficiary pays* concept is on the agenda for consideration.

[18] The language is insufficiently precise. That is, does the OEB mean that the customer would pay the costs of the new facility, net of the remaining life of the replaced facility, or the costs of the remaining life of the replaced facility including return on and of capital. The former interpretation would appear to be correct. That is, if the limit is the latter, the customer obtains a new facility and, likely, the increased reliability associated with it, for no more than the costs of the facility it replaces.

4. U.S. APPROACHES TO TRANSMISSION COST ALLOCATION

The U.S. review covers contemporary transmission allocation approaches, focusing primarily on methods implemented in regional wholesale markets organized under ISO/RTOs. The organized markets covered in the review are shown below:

PROFILES OF SELECTED ISO/RTOs

Organizing Entity	*Circuit Miles*	*Installed Capacity (MW)*	*Peak Demand (MW)*	*Within Footprint Energy Sales (GWh)*
ISO New England	9,000	31,000	28,130	124,258
Midcontinent ISO	65,800	174,724	127,125	670,000
New York ISO	11,131	39,064	33,956	156,370
PJM Interconnection	82,546	165,569	165,492	792,314

From the earliest days of deregulation, charges for transmission services—and the availability of transmission services—have been a front row issue in the development of wholesale markets. The institutional and technical means by which transmission is expanded, and charged for, have changed dramatically in the U.S., as *beneficiary pays* criteria applicable to new transmission facilities enter the cost allocation methods, a result that is most prominent in ISO New England, Midcontinent Independent System Operator (MISO), New York ISO, and the PJM Interconnection.

ISO NEW ENGLAND

The ISO New England (ISO-NE) manages the wholesale markets that comprise the six New England states, covering approximately 9,000 miles of transmission lines (>68 kV facilities) and 31,000 MW of installed capacity. Consistent with other ISO/RTOs, the transmission plans of ISO-NE recognize several types of transmission facilities including generator interconnection, request for delivery service (elective), participant funded projects/merchant transmission, reliability, economic efficiency,[19] and public policy-driven projects. The starting point is the transmission needs assessment process, which is based on expectations of loads and the location of new generators.[20] ISO-NE collaborates with the incumbent utilities in its region, who are primarily responsible for determining upgrades of local facilities. Thus, the region-wide system plan incorporates the effects of near-term local facilities.

Along with regional requirements including reliability- and public policy-driven requirements, economic efficiency solutions may also be identified. These regional needs for system expansion are satisfied by proposed projects of qualified transmission developers. Proposed regional solutions are referred to as additions to Pool Transmission Facilities (PTF), and identified as regional benefit upgrades (RBUs), public

[19] Economic efficiency-driven projects are new transmission facilities that obtain future net benefits, including relief of congestion and reduced line losses, which are greater than facility costs, including carrying charges on invested capital and fixed operations and maintenance expenses.

[20] Transmission planning can involve the development of a long-term market outlook, including alternative futures. Often, transmission planners will have only limited knowledge of new generators, or likely new generators by location or area.

policy transmission upgrades, and reconstruction/replacements.[21] The proposed projections are assessed by ISO-NE according to defined planning criteria. If approved, such projects—*i.e.*, additions—are subject to regional cost allocation, as pool-support PTFs. Other non-elective and non-participant fund projects are local, and underwritten by loads served by the incumbent transmission service providers of the several states/service areas.

Fixed costs of facilities categorized as region-wide—*i.e.*, PTF—prior to January 1, 2004, as well as upgrades to those facilities are allocated to the service regions according to peak loads—*load ratio share*. New transmission facilities that satisfy the criteria for PTF categorization can include Northeast Massachusetts Upgrades (NEMA) and RBU projects including market efficiency projects but for those that do not satisfy regional criteria. Notably, shares of public policy transmission upgrade costs are also incorporated into the regional pool. As stated in Schedule 12 of ISO-NE's OATT:

> "(a) seventy percent of each Public Policy Transmission Upgrade shall be allocated to Transmission Customers taking service under this OATT in the same manner as Regional Benefit Upgrades…(b) The remaining thirty percent of the costs of each Public Policy Transmission Upgrade shall be allocated to the Regional Network load of each state in direct proportion to the state's share of the public policy planning need that gives rise to the … ("Planning Need")".

It is worth noting key provisions of ISO New England's OATT with respect to generator interconnection, Schedule 11. The cost allocation methodology for generator-related transmission projects is specific to project categorization, including categories A, B, and C, where cost associated with categories A and B refer to *direct interconnection transmission costs*, and *generator interconnection related upgrades*, respectively. In the case of categories A and B, "the generator owner shall be obligated to pay, in addition to the direct interconnection transmission costs or interconnection related upgrades, … half of the shared amount of the capital costs of the pool transmission facility upgrade and all of the capital costs in excess of the shared amount, and any applicable tax gross-up amount … ".[22] Under interconnect cost category C, the generator owner pays all direct interconnection costs to the extent that such costs would not have been incurred but for the interconnection. The remaining costs are assigned as pooled transmission facility costs, and subject to region-wide cost allocation. Category C interconnection costs came about as a consequence of a highly contested complaint before the FERC by a market participant within the ISO-NE region.

In summary, IS0-NE appears to be in the process of evaluating and adopting *beneficiary pays* methods. Note that apparent use of rules of thumb, such as the 70-30 split in public policy upgrade project funding between OATT customers and regional participants should be considered under the umbrella of

[21] Reference ISO New England Planning Procedure No.4, *Procedure for Pool-Supported PTF Cost Review*, July 7, 2017.

[22] Reference ISO New England Planning Procedure No. 4-1, *Cost Responsibility for Transmission Upgrades with Multiple Needs, Section 3*. February 1, 2005.

beneficiary pays methods, since the share is intended to represent weighting of the benefits of the various parties.

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR

The Midcontinent Independent System Operator (MISO) operates the wholesale markets of the upper Midwest and mid-south regions of the U.S. The territory comprises many retail service providers which, together, constitute about 175,000 MW of peak demand and 66,000 transmission circuit miles. What sets the MISO region apart is the degree of interface of its footprint and transmission network with neighboring regions, including those of PJM and the Southwest Power Pool and, for transmission planning purposes, the Southeastern Regional Transmission Plan. This feature of MISO, coupled with the regional and interregional cost allocation requirements of Order 1000, suggests the potential for a considerable share of the total expenditure for transmission expansion to carry regional and interregional designation.

For over a decade, MISO's transmission expansion plan has been developed under the auspices of the Midcontinent Transmission Expansion Plan (MTEP), a collaborative process involving many market participants including state regulators. The MTEP process is unusually complicated in view of numerous participating stakeholders, and has undergone significant evolution in response to FERC Orders 890 and 1000, and underlying market forces also. Following these guidelines, the MTEP process for 2017 resulted in 354 transmission projects, with a combined investment expenditure of $2.7 billion for projects with in-service dates through 2024. MTEP 2017 accommodates the planned interconnection of some 5,000 MW of new generation to the MISO network, much of which constitutes renewable resources. Five transmission projects are designated as market efficiency projects and are, by definition, interregional and subject to the MTEP interregional cost allocation methodology.

Consistent with the requirements of Order 1000, the MISO cost allocation scheme assigns costs to entities including private generators and incumbent electric utilities, and the native loads that they serve, according to the category of independent projects, as follows:

> <u>Participant Funding Projects (Merchant Transmission)</u>: project costs are recovered through expected revenue flows arising from capacity subscriptions, as contracted for by either generators or loads.[23]
>
> <u>Delivery Service Projects</u>: a result of a request for transmission service, project costs are underwritten by individual customers. However, transmission service providers can elect to roll in a portion of facilities costs within zonal rates, local to the area served.
>
> <u>Generation Interconnection Projects</u>: a result of a generator interconnection request (large, small), where project costs are underwritten exclusively by the generator, at low and moderate voltage levels. For interconnection to high voltage levels (>345 kV), 10% of the facility costs are assigned to loads, allocated under the *load ratio share* methodology.

[23] It would seem possible that other transmission companies could contract to use a merchant transmission facility in lieu of their own. Many merchant transmission projects are HVDC facilities.

Market Efficiency Projects (MEP):[24] Investment and operating costs of market efficiency projects are assigned to the loads in the MISO resource zone in which the project is sited.

Multi-Value Projects (MVP): MVP projects are commissioned for two reasons: 1) to satisfy the requirements of energy policy laws and regulations such as Renewable Portfolio Standard (RPS) requirements, or 2) to provide broadly distributed regional and interregional benefits. The costs of MVP projects are socialized regionally to loads according to regional postage stamp transmission access fees, and regional exports, either through or out transactions.

All categories of transmission plans use the *load ratio share* methodology, but differentially applied to loads in service territories of incumbent electric utilities, regions, or on an interregional basis. MISO and the PJM Interconnection manage interregional cost allocation under the longstanding Joint Operating Agreement (JOA), first established in 2005/06,[25] conducted on a case by case basis.

In summary, it appears that MISO has already engaged in exploring and implementing alternatives to the traditional *load ratio share* method. Specifically, for all types of transactions they appear to have identified participants and benefits and developed methods for measuring benefits.

NEW YORK ISO

The New York ISO (NYISO) operates the wholesale market that comprises the State of New York, Including the five boroughs of New York City plus Long Island. In total, the NYISO market involves 11,000 circuit miles of transmission lines and 39,000 MW of installed generating capacity serving 34,000 MW of peak demand and 156,000 GWh of retail sales. As with other regions, the main mechanism to recover transmission costs is access fees, determined on the basis of *load ratio share*.

In view of the provisions of FERC Order 1000, NYISO's transmission cost allocation process begins with the transmission expansion plan. The NYISO's plans include reliability, economic (congestion, line losses), public policy, and interregional categories of projects, and are carried out on a two-year cycle. NYISO's expansion planning process begins with local transmission studies prepared by the Incumbent Transmission Developers (ITDs). These studies cover the service territories of the incumbent electric utilities, and are sponsored. These local plans identify specific facilities, which are incorporated into the NYISO's transmission study, referred to as a *reliability needs assessment*, which results in a *Comprehensive Reliability Plan* (CRP) covering the entire New York regional market.

Focused on reliability, NYISO's CRP is supplemented by a *congestion assessment and resource integration study* (CARIS), which identifies transmission needs for congestion relief over forward years. General solutions—*e.g.*, a high voltage transmission line from zone G running south though zones H and I,

[24] Such projects are commissioned where the expected benefits, in the form of reduced network congestion and line losses, are greater than costs by 25%—*i.e.*, the project has a benefit/cost ratio > 1.25.

[25] The reliability and market effects of interregional power flow dynamics became serious issues with the appearance of significant West to East power transmissions and MISO's implementation of locational pricing. The JOA was implemented in order to manage these seams and related issues. This is not surprising: the spatial configuration of the MISO and PJM regions is an institutional artifact that has little relationship to the physical characteristics and power flows of the underlying transmission network.

terminating in zone J—are identified, on the basis of benefit-cost analysis. Specific projects are solicited from both incumbent and private transmission developers. Selected projects are subject to regional cost allocation. Regulated solutions sponsored by incumbent utilities may be accelerated.

Transmission cost allocation is carried out under highly specific allocation rules. NYISO begins with a succinct statement of principles[26] set forth in Order 1000. To the general list of principles set forth by the FERC, the NYISO identifies the separate but similar cost allocation rules applicable to reliability and to economic projects. The main (but not all) rules of cost allocation governing reliability-related projects in the NYISO region are as follows:

- Primary beneficiaries shall initially be those in load zones identified as contributing to the reliability violations;
- Cost allocation among primary beneficiaries shall be based upon their relative contribution to the need for the solution;
- NYISO will examine the development of cost allocation rules based on the nature of the reliability violation (thermal overload, voltage, stability, resource adequacy, short circuit);
- Cost allocation shall recognize the terms of prior agreements among transmission owners;
- Consideration will be given to the use of materiality threshold, for cost allocation;
- Cost allocation methodology will provide for ease of implementation and administration;
- Consideration will be given to the "free rider" issue, as appropriate;
- Cost allocation methodology shall be fair and equitable; and,
- Cost allocation shall provide cost recovery certainty to investors, to the extent possible.

The NYISO's cost allocation methods are specific to type of facility, categorized according to solution. Cost allocation methods are drawn from the projections of system impacts, analytical results estimated with complex generation and transmission planning tools. Costs are allocated to pricing zones and subzones, with the explicit recognition that planned facilities, once in place, often provide solutions to multiple issues.

Described according to type of facility and solution, NYISO methods of allocation with respect to Reliability Issues are as follows:

[26] As listed by the NYISO in its OATT, these principles (in paraphrase) are: 1) Costs shall be allocated to those parties within the planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits; 2) costs shall not be involuntarily allocated to those that receive no benefit from the facilities; 3) benefit-cost thresholds—threshold levels greater than unity—must be set sufficiently low in order that facilities with significant net benefits are not excluded from the pool of facilities subject to selection; 4) costs subject to interregional allocation must be to the regions in which the facility is, in part located. Costs cannot be assigned involuntarily to another region, nor shall the ISO bear the costs of required upgrades in a neighboring region; 5) data, information, and analysis regarding the costs of a facility must be sufficiently transparent for stakeholders to understand how proposed cost allocation results are obtained; and, 6) the cost allocation methodology can be differentiated for different types of projects. However, the NYISO allocates all interregional projects using a common cost allocation approach, regardless of the type of project (reliability, congestion relief, or public policy).

RELIABILITY PROJECTS

- Resource Adequacy: The costs of transmission facilities that address resource adequacy concerns for a target year are assigned a *pro rata* share of facility costs to the loads[27] in pricing zones where resource adequacy is less than the NYISO planning criteria (annual LOLE <0.10). Two observations are as follows:
  - Transmission facilities can substitute for generation capacity (resource adequacy) requirements.
  - Loads in pricing zones are charged only for the share of the facility costs necessary to arrest the resource adequacy issue, referred to as the *LCR deficiency*. As an example, a new regional-wide facility may provide 800 MW additional transfer capability during a target year, but only 40 MW of capability is needed to resolve the LCR deficiency. The loads in the pricing zone would be charged the annual carrying charges for 5% of total financial costs of the facility during the target year.[28]
- Thermal Constraints of *Bulk Power Transmission Facilities* (BPTF): BPTF cost allocation is applicable to the portion of new facilities attributable to resolving thermal constraints—*i.e.*, network congestion. As stated in NYISO's OATT:[29]

  > "If, after consideration of…the resource adequacy reliability solution cost allocation in accordance with Section 321.5.3.2.1, there remains a BPTF thermal transmission security issue, the ISO will allocate the costs of the portion of the solution [the new physical facility] attributable to resolving the…issue(s) to the Subzones that contribute to the issue(s) in the following manner."

  Allocation of the costs of BPTF-related solutions is based on PTDF. This involves system planning transmission tools, which determine the contributing loads and contributed flows along congestion transmission paths. Subject to materiality constraints, loads in subzones are assigned costs according to PTDF analysis results. Where new BPTF facilities resolve multiple constraints, the costs of the new facilities are allocated according to zones based on weighting factors. As stated in the NYISO OATT: "…weighting factors based on the ratio of the present value of the estimated costs of individual solutions to each BPTF thermal transmission security issue."[30]

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[27] Including projections of native loads and firm transactions.

[28] The full cost allocation procedure for resource adequacy takes account of other conditions, including region-wide resource adequacy deficiency under a so-called free-flow test, and binding interface tests.

[29] Section 31.5.3.2.2 of Attachment Y, *BPTF Thermal Transmission Security Cost Allocation Formula*.

[30] For example, the present value of the costs over forward years to solution A attributable thermal constraints to subzone X is A_{PV}; the present value of costs to solution B attributable to thermal constraints to subzone Y is B_{PV}. A_{PV} is 25% of the sum of A_{PV} and B_{PV}. Solution C resolves the thermal constraints in both subzone X and Y. Then, 25% of the costs of solution C would be assigned to the loads in subzone X.

- <u>BPTF Voltage Security</u>: The share of facility costs that resolve voltage security issues are assigned "to the subzones that contribute to the BPTF voltage security issue(s)… …will be allocated on a load-ratio share to each subzone to which each bus with a voltage issue is connected…"
- <u>Dynamic Stability</u>: The share of facility costs that resolve dynamic stability (*i.e.*, transient stability) are allocated to subzones: "…the ISO will allocate the costs of the portion of the solution attributable to resolving the dynamic stability issue(s) to all subzones in the NYCA [New York Control Area] on a load-ratio share basis…"
- <u>Short-Circuit Issues</u>: The costs of facilities which address short-circuit concerns are considered local, and assigned accordingly.

<u>ECONOMIC PROJECTS (EFFICIENCY)</u>

The cost allocation methodology governing *regulated economic transmission projects* (RETP) are delineated in a separate section of the NYISO OATT (section 31.5.4 of Attachment Y). What sets RETP cost allocation apart is the provision for *beneficiary pays* in response to Order 1000. As stated in the NYISO OATT: "The ISO shall implement the specific cost allocation methodology…in accordance with the Order No. 1000 Regional Cost Allocation Principles…". Most remarkable is section 31.5.4.2.4: "cost allocation shall be based upon a *beneficiaries pay* approach. Cost allocation under the ISO tariff for a RETP shall be applicable only when a *super majority of the beneficiaries* of the project, as defined in Section 31.5.4. of this Attachment Y, *vote to support the project*." In other words, this is highly collaborative, with respect to the applicability of *beneficiary pays* cost allocation to pre-defined RTEP projects. Key cost allocation provisions for economic projects are as follows:

- Proposed RTEP projects may proceed on a market basis with willing buyers and sellers.
- Cost allocation among beneficiaries shall be based upon their relative economic benefit.
- Benefits determination shall consider non-quantifiable benefits as appropriate (e.g., system operation, environmental effects, renewable integration).
- Benefits determination shall consider various perspectives, based upon the agreed-upon metrics for analyzing congestion.
- Benefits determination shall account for future uncertainties as appropriate (e.g., load forecasts, fuel prices, environmental regulations).

Eligible economic/efficiency projects are determined according to classic benefit-cost analytics, where the benefit metric is clearly delineated:[31]

> "expressed as the present value of the annual NYCA-wide production cost savings that result from the implementation of the proposed project, measured for the first ten years from the proposed commercial operation date for the project"; and,
>
> "the cost for the ISO's benefit/cost analysis will be supplied by the Developer of the project, and cost metric…will be expressed as the present value of the first ten years of

[31] As specified in Attachment Y, sections 31.5.4.3.2 through 3.5.4.3.2.7, respectively.

> annual total revenue requirements for the project, *reasonably allocated over the first ten years* from the proposed commercial operation date for the project"; and,
>
> "For informational purposes only, the ISO will also calculate the present value of the annual total revenue requirement for the project over a 30-year period…".
>
> "the ISO will calculate additional metrics to estimate the potential benefits…for information purposes only. These additional metrics shall include reductions in LBMP load costs, changes in generator payments, ICAP costs, ancillary service costs, emissions costs, and losses."
>
> "the ISO will work with the ESPWG to consider the development and implementation of scenario analyses, for information only, that shed additional light on the benefit/cost analysis of a proposed project."

Allocation of the first ten years of costs of all MTEP projects selected proceeds directly from benefits, as estimated in accordance with the above methodological provisions. Namely, the ten-year present value of estimated reduction in LBMP-based energy charges incurred by loads—*i.e.*, so-called *load costs* in the parlance of NYISO's OATT—for all load zones that have load cost savings.[32] The zonal cost allocation results are submitted to the ESPWG as "information to inform the beneficiary voting process."[33]. In essence, the beneficiary entities that proceed to authorize the RTEP projects, are left to their own devices about how best to allocate the costs of projects, with the NYISO providing supporting analysis of estimated benefits and costs. This is a most remarkable provision within public utility regulation.

PJM INTERCONNECTION

The wholesale market operated by the PJM Interconnection covers six states of the mid-Atlantic region[34], Ohio much of Kentucky, and smaller areas in another four states. The physical facilities of PJM comprise about 83,000 circuit miles and 166,000 MW of installed capacity.[35] As required by FERC Order 1000, transmission cost allocation within the PJM region—at least for new additions—begins with transmission expansion planning. The plans determine what is local and what is regional, with the regional share being subject to regional cost allocation. Where charges are applied, either locally or regionally/interregionally, the charging mechanism is based on *load ratio share*, where loads are often subjected to the three-factor test.[36]

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[32] The load cost savings used in the present value-based cost allocation are determined *net of transmission congestion cost-based revenues and bilateral contracts* (based on official information available to the NYISO).

[33] Section 31.5.4.4.2.2 of Attachment Y of the NYISO OATT.

[34] Delaware, Maryland, New Jersey, Pennsylvania, Virginia, and West Virginia.

[35] Of note, peak demand of the PJM market is 165,492 MW. PJM requires an estimated Installed Reserve Margin (IRM) of 16.1%, as revealed in PJM's 2017 Reserve Margin Study for years 2020-2028. This level of IRM constitutes nearly 27,000 MW which, in view of installed reserves of 166,000 MW, implies major supply contributions by within-region demand response within PJM's capacity auctions and outside-region power supply.

[36] The three-factor test provides guidance with respect to the use of peak demands for the determination of cost allocation using load ratio share methods.

The regional plan, referred to as the *Regional Transmission Expansion Plan* (RTEP) begins with a baseline projection of loads and firm transmission service, generation interconnection, and merchant transmission. Baseline projections account for supplemental projects/plans of incumbent service providers, which are driven by reliability criteria—given NERC standards—and market efficiency, predominantly congestion. This baseline, *footprint-wide* analysis provides the basis for *proposal windows*, in which participants, including incumbents and non-incumbent transmission developers, propose alternative facilities or plans to solve a defined problem or need. Proposed projects by sponsors are assessed by PJM.

Much like MISO's MTEP process, the PJM RTEP process seeks to identify projects that satisfy multi-dimensional gains in value—*i.e.*, voltage support, congestion relief, improved reliability through contingency response and observability, sectionalized networks, response to transients, etc. These projects are referred to as Multi-Driver Projects (MDP), akin to MISO's Multi-Value Projects (MPV). Often, though not always, MDP transmission network upgrades are classified as regional and interregional, where costs are widely distributed across the PJM footprint, and within adjacent ISO/RTOs. In the case of interregional cost allocation, the costs of facilities entail special tariff provisions.[37]

Interregional cost allocation involves two-way interregional flows among ISO/RTOs. This is most evident in the just-released OATT of the PJM Interconnection, dated June 18, 2018.[38] Schedule 12, *Transmission Enhancement Charges*, section (a)(ii) *Establishment of Transmission Enhancement Charges with Respect to Required Transmission Enhancements Constructed by Entities in Another Region*, states:

> "The revenue requirement with respect to a required transmission enhancement constructed pursuant to an Appendix B Agreement in another region by an entity designated by such other region shall be governed by the tariffs or agreements in effect in such region. Transmission enhancement charges to recover the costs of such required transmission enhancement for which PJM is responsible shall be determined in accordance with this Schedule 12. Other than with respect to a required transmission enhancement constructed pursuant to an Appendix B Agreement, no PJM network or transmission customer will bear cost responsibility for any required transmission upgrades in another region as a consequence of a required transmission enhancement included in the Regional Transmission Expansion Plan."

This excerpt from Schedule 12 of PJM's OATT says two things. First, neighboring ISO/RTOs must have regulatorily approved Appendix B agreements (within the PJM OATT) with PJM, in order to impose on the transmission entities and customers of PJM cost sharing responsibility for transmission upgrades incurred by the neighboring ISO/RTOs. Second, charge-backs are prohibited: the costs of transmission facility upgrades implemented within an adjacent ISO/RTO as a consequence of PJM's RTEP, cannot be charged

[37] In its November 17, 2017 Order on *Tariff Revisions and Cost Allocation Report* for the PJM Interconnection (Docket ER17-2362-000) the FERC approved PJM's OATT tariff revisions.

[38] The length of the PJM OATT is over 3,500 pages.

to transmission service providers and customers of the host ISO/RTO (PJM), absent prior estimates of interregional benefit flows accounted for in an interregional Appendix B agreement.

In PJM, the costs of transmission facilities subject to regional cost allocation are referred to as *Regional Projects* and include facilities with 765 kV, 500 kV, and dual circuit 345 kV voltage ratings, system-support facilities[39] installed in conjunction with these high voltage facilities, and new (or enhancements to existing) lower voltage facilities that are necessary for the integration of facilities that qualify for regional allocation. The allocation methodology is as follows:

- <u>In the case of high-voltage regional facilities that also involve changes to lower voltage facilities</u> ("necessary" lower voltage facilities) including both *reliability* and *economic* projects:
    - 50% of the costs are assigned annually on a *load ratio share* basis to the transmission tariff zone where the facilities are located. (Reference section (b)(i)(A)(1) of Schedule 12 of the PJM OATT.)
    - In the case of *reliability-driven projects*, the remaining 50% of the costs are distributed to all loads within the region according to *power transfer distribution factors* (PTDF, DFAX).[40] The PTDF/DFAX transfer distribution factors are determined in accordance with NERC's Interchange Distribution Calculator (IDC) methodology and accompanying procedures.[41]
    - In the case of *economic benefits-based projects*—relief of transmission constraints and reduced line losses—50% of the costs are distributed according to either PTDF and LMP benefits methodology (reference section (b)(v)(A) of Schedule 12 of the PJM OATT).

The costs of lower voltage facility upgrades—mainly local facilities—which are not necessary for implementation of regional facilities are allocated as follows:

- <u>In the case of *lower voltage reliability projects*</u>, facility costs are allocated within the PJM region according to PJM's PTDF/DFAX methodology.
- <u>In the case of *lower voltage economic projects*</u>—*i.e.*, reduced congestion and lower line losses—facility costs are allocated according to:

[39] As specified in the PJM OATT, system support facilities include "shunt reactive resources (such as capacitors, static var compensators, static synchronous condensers), synchronous condensers, inductors, and other shunt devices, or their equivalent", as connected to the facilities that qualify for regional cost allocation.

[40] As described in Schedule 12, section (b)(iii) of the PJM OATT.

[41] The power transfer distribution factors, or *outage power transfer distribution factors* (OPTDF) are calculated and made available by the North American Electric Reliability Corporation to operationalize the *Transmission Load Relief* (TLR) procedures for managing power transfers in support of system-wide reliability across the Eastern Interconnection.

  - Either the PTDF/DFAX methodology or PJM's LMP Benefits methodology.[42] These two methods provide different estimates of benefit flows across regions, both as a matter of level and spatial distribution. Both analyses are conducted and compared. If the difference in allocation of benefits is less than 10%, the PTDF/DFAX methodology is used to allocate benefits to zones. Otherwise, costs are assigned to zones according to the LMP benefit methodology.

- <u>In the case of *lower voltage economic projects that are modifications to reliability projects*</u> facility costs are assigned in accordance with the cost allocation methodology of reliability projects, either for regional or lower voltage reliability projects.
- <u>In the case of *lower voltage economic projects that are enhancements or expansions that relieve transmission constraints*</u>, facility costs are assigned to the zones of the PJM region that experience decreases in energy costs.[43] The assignment of all-in facility costs to these zones—*i.e.*, zones that are estimated to experience energy cost reductions—in accordance with the 15-year net present value of the changes in energy payments, occurs on a *pro rata* basis. Once total project costs are assigned to zones—*i.e.*, service territories of the incumbent utilities of PJM—such costs are incorporated into transmission access fees ($/MWh) and paid by loads and transactions according to *load ratio share*.

In summary, in response to the cost allocation mandates specified in FERC Order 1000, PJM'S member utilities and participating stakeholders, including private transmission developers, have implemented a highly detailed cost allocation methodology. Facilities identified in PJM's transmission expansion plan (MTEP) are assigned to the native loads and firm transactions of the zones that comprise the PJM footprint in a manner that arguably conforms to the *beneficiary pays* approach: where benefits are predominantly local, costs are assigned locally; where benefits are distributed broadly across the region, costs are distributed accordingly—including, selectively, via interregional cost assignment.

5. Lessons in Cost Allocation for Hydro

For decades, the cost allocation of transmission services was of only secondary concern. This was due in part to the comparatively low share in total cost occupied by transmission.[44] Second, transmission investment provided benefits predominantly to the customers of the service territory that paid for the investment. *Load ratio share* (peak demand share) cost allocation provided a satisfactory sharing of costs among customers of the service territory and may have been an adequate proxy for *beneficiary pays*

[42] The LMP benefits methodology estimates expected benefit flows as the change in locational energy prices within zones of the PJM region. Facility costs are then shared across zones according to the change in LMPs, as estimated, over the period that facilities are accelerated, say from 2026 to 2022.

[43] Load-weighted locational marginal prices which, implicitly, are differentiated by network effects, including congestion and line losses.

[44] All-in transmission costs in the 1990s were a comparatively small share of bundled retail prices for the U.S.: approximately $3.70/MWh within a bundled average price of $67.50/MWh.

methods in many cases. In addition, there were limits on technical methods for understanding and estimating the distribution of benefits. The fact that some transmission costs could be directly assigned to generators or customers did not diminish the applicability of the predominant cost allocation method to common costs.

Deregulation and open access have both increased the relative importance of transmission costs and complicated cost allocation, since some transmission projects provide benefits to customers in more than one region and to customers in multiple jurisdictions. Indeed, within-service territory—and within-region—cost allocation has been revealed to contain spatial bias when parties outside the jurisdiction may participate significantly in the benefits arising from the implementation of transmission projects. As a consequence, major developments in the form of beneficiary methods are being evaluated and implemented. Yet, despite this evolution of methodology, the *load ratio share* methodology is still widely used, once the spatial distribution of benefits, and thus costs, is determined.

As detailed above, contemporary transmission cost methodology for U.S. wholesale markets have advanced in significant ways by including the distribution of benefits explicitly in cost allocation. However, there is no common methodology, at least at this point, for the determination of benefits or cost allocation. Rather, methods of ISOs and RTOs appear to be specific to each organization. Under Order 1000, entities have latitude in determining what benefits to include and how to measure them. They are, however, required to be fairly comprehensive rather than restricting computations simply to, say, production cost savings only. Similar trends are observed in Canada where, in particular, the Ontario Energy Board is in the process of explicitly incorporating *beneficiary pays* principles into the protocols of Ontario's Transmission System Code and Distribution System Code.

Generally speaking, it appears that transmission cost allocation is evolving in two ways:

- *Two-Tiered Cost Allocation*: Under an implicit provision of grandfathering, the costs of existing, embedded facilities are assigned locally based on *load ratio share*, applied system- or utility-wide. Driven by much higher costs, allocation methods for new facilities will likely involve increasingly complex cost allocation procedures, where the objective is to better align transmission charges and benefits across service territories and regions.
- *Beneficiary Pays*: Advances in computational capability facilitate the use of modern analytical tools and provide the basis to estimate net benefits of transmission networks, measured in terms of level—*i.e.*, total cost savings and reliability gains, system-wide—and spatial distribution. The distribution of benefits can be estimated across large regional footprints, including incumbent electric utilities and local retail customers.[45] If we know who benefits, is it not right to charge beneficiaries for the costs associated with benefit realization? Thus, the *beneficiary pays* rule of cost allocation.

[45] Benefits assume several dimensions including reduced production costs in the form of lower energy, congestion, and line losses, improved reliability manifested as improved voltage, control, and transient stability. Benefit flows accrue far into the future. Estimated benefits are conditional on projections of future load levels, the location of future generation, and forecasts of fuel costs, and are thus highly uncertain.

The application of the *beneficiary pays* approach provides an improved form of cost socialization. The starting point is transmission expansion plans, and the estimation of total benefits and benefit distribution of network projects. Projects are then categorized, and pre-defined allocation rules are applied according to facility type. Where benefits are broadly distributed, facility costs are allocated broadly. The OATTs of ISO/RTOs indicate that estimation of benefit distribution can be explicitly analytical—*e.g.*, PJM Interconnection—the results of which are codified in rules for cost allocation to transmission participants. Once determined, the well-known *load ratio share* approach—*i.e.*, contribution to peak loads—is used to determine transmission access charges.

Driven by FERC policy and recent developments in Ontario, much of the contemporary action appears to be in unbundled ISO/RTO markets including Ontario's IESO market. Broadly speaking, Canadian utilities are aware of the ongoing policy dialogue regarding cost allocation, and we anticipate that Canadian jurisdictions will be reviewing and perhaps soon employing variants of the *beneficiary pays* methodology.

In its deliberation of network additions policy, we recommend that Hydro take under advisement recent developments in cost allocation across North America. It seems to us that, for transmission, these emerging developments are potentially applicable, for both new and existing loads. Depending on analytics, it may be that, depending on location, alternative methodologies applied to transmission network additions would result in sizable differences the allocation of costs to transmission customers.

Operationally, the *beneficiary pays* approach is challenging in terms of benefit definition, participant definition, and benefit measurement. Obtaining agreement among participants regarding cost allocation methodology is a necessary precursor to transmission project initiation.[46] If Hydro follows the broadly defined steps of U.S. transmission entities, *beneficiary pays* would appear to entail a process that roughly adheres to the following steps:

- Take account of the types of benefits considered elsewhere in North American, and determine what might be included in benefits criteria, for categorization of transmission facilities;
- Explore the analytical methods and models used to estimate the various types of benefits, including the distribution of benefits.
- Define cost allocation rules for Hydro's defined categories of facilities, where cost allocation methods broadly adhere to *beneficiary pays* principles;
- Categorize transmission facilities in Hydro's transmission plans in terms of net benefits;
- Determine Hydro's transmission plans, and categorize specific facilities of the plan according to predefined criteria; and,

[46] State regulators have collaborated to enable multi-state regulatory oversight, in order to both contribute to and monitor the formulation of the market rules of ISO/RTOs. As an example, the Organization of MISO States, which is comprised of the regulatory authorities of the several states of the MISO footprint, directly participates withinthe committee structure of MISO and its members.

- Assign costs to participating parties—i.e., transmission customers—according to the predefined cost allocation rules.

Based on developments in both Canada and the U.S., it appears that Hydro would benefit from investigating *beneficiary pays* methods for allocating the costs of investment in new transmission facilities. The beneficiaries of such investment are unlikely to be exclusively Hydro customers, suggesting that traditional methods will be inadequate. Since other Canadian utilities will likely be pursuing research in this area in the near future, Hydro can likely share the burden of research with other Crown corporations and it may be appropriate to collaborate with other utilities toward a common end. Similarly, further review of Ontario and U.S. methods, especially those of nearby U.S. ISO/RTOs, may prove of value, contributing to the formulation of Hydro's New Additions Policy.

Appendix B

Ontario Board of Energy:
Proposed Amendments to the Transmission System Code and the Distribution System Code to Facilitate Regional Planning

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BY EMAIL AND WEB POSTING

September 21, 2017

NOTICE OF PROPOSAL TO AMEND A CODE

PROPOSED AMENDMENTS TO THE TRANSMISSION SYSTEM CODE AND THE DISTRIBUTION SYSTEM CODE TO FACILITATE REGIONAL PLANNING

BOARD FILE NO.: EB-2016-0003

To: All Licensed Electricity Distributors
All Licensed Electricity Transmitters
All Participants in Consultation Process EB-2013-0421
All Other Interested Parties

The Ontario Energy Board (OEB) is giving 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).

A. Background

On January 7, 2016, the OEB issued a letter (January 7th 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.

Proportional Benefit and Upstream Transmission Investment Issues

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 proposed methodology is not currently contemplated in the TSC.[1] It also differed in some respects from the proportional benefit approach that had been previously proposed in an OEB Supplementary Proposed TSC Amendment that was issued for comment in August 2013 but was not concluded by the OEB.[2] Those two proportional benefit approaches are discussed below.

Hydro One's SECTR application also 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.

The OEB determined that those cost allocation issues should be reviewed from a *policy* perspective. A policy process allows for a consideration of the issues from a broader perspective (i.e., not based on one specific project). It also 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.[3]

Other Issues – Regional Distribution Solutions, Code Gaps & Inconsistencies

The following additional issues were identified in the January 7th letter for this policy initiative:

- Consider whether changes to the DSC are needed to facilitate regional planning and the implementation of regional infrastructure plans
- Identify potential inconsistencies between the TSC and the DSC and, to the extent any exist, determine whether those inconsistencies should be aligned or whether they remain appropriate
- Identify potential gaps in the TSC and the DSC related to cost responsibility and regional planning that should be addressed

Working Group Process

In June 2016, the OEB issued a letter announcing the formation of a Working Group comprised of various stakeholders – representing consumer groups, distributors, a

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[1] Under the current TSC rules, the costs associated with investments in connection assets are recovered from only the customer(s) that caused the need for the investment.
[2] The consultation process involving the Proposed Supplementary TSC Amendment was placed *on hold* when the SECTR application was submitted by Hydro One.
[3] On August 28, 2015, the OEB issued a letter to all parties in the SECTR case explaining the OEB would not continue to proceed with Phase 2 – cost allocation phase.

transmitter and the IESO – to provide input to OEB staff on issues and potential solutions that would help inform which revisions to the TSC and DSC may be desirable.

The OEB held three Working Group meetings during which a number of issues were identified.[4] Materials related to the Working Group are available on the OEB's website. The OEB notes that not all of the issues raised by the Working Group can be addressed through a code amendment. However, the OEB has identified in this Notice where that is the case.

B. Proposed Amendments to the TSC and the DSC

Attachments A and B to this Notice contain the proposed amendments to the TSC and the DSC, respectively. The following is a high level summary of the proposed Code amendments. Preceding the high level summary are guiding principles that provided the basis for the proposed Code amendments.

Guiding Principles

The OEB is of the view that the following guiding principles should be used to determine the appropriate approach to allocating the costs associated with distribution and transmission connection investments:

- *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[5]

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[4] Materials from the Working Group meetings can be found on the following OEB web page: www.oeb.ca/industry/policy-initiatives-and-consultations/regional-planning-and-cost-allocation-review
[5] In the RRFE Report (p. 43), the OEB identified that "a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate".

- *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

Organization of Notice

The proposed TSC and DSC amendments are described below in the following five sections:

- The first section discusses a proposed proportional benefit approach to apportion costs associated with transmission connection investments between the transmission network pool and customers directly connected to the transmission system that caused the need for the connection investment

- The second section includes proposed changes that relate to the apportionment of costs to customers of distributors (including *embedded* distributors and other 'large' load customers), where they benefit from investments in upstream transmission connection facilities. A new proposed *threshold* for determining what size of load constitutes a 'large' customer for this and other purposes is also proposed in that section of the Notice

- The third section proposes an approach to cost apportionment between a load customer(s) and all ratepayers,[6] where a connection asset requires replacement at its end-of-life. Also included in this section is a proposed approach to facilitate a regional distribution solution, where more than one distributor is involved, and it would avoid a more costly upstream transmission connection investment. The proposed cost apportionment between the distributors is discussed

- The fourth section proposes an approach that is intended to facilitate the implementation of regional infrastructure plans relative to the status quo. The proposed approach would achieve that goal by mitigating consumer bill impacts through smoothing mechanisms and/or provide advanced funding to distributors to reduce their borrowing requirements. Those bill impacts result from the large lump sum capital contribution amounts that may be required under the current rules

- The final section is comprised of proposed amendments to address inconsistencies between, and gaps within, the TSC and DSC

[6] At the transmission level, the reference to all ratepayers is province-wide through the connection pool. At the distribution level, the reference to all ratepayers is limited to customers in the distributor's service area.

1. 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, which is discussed in the OEB's January 7th letter, is whether it is appropriate to allow for a *portion* of the costs associated with a transmission *connection* investment that is triggered by a specific customer(s) to be recovered from all ratepayers (like a *network* investment).

Currently, under the TSC, the costs associated with transmission *connection* (line and transformation) investments are recovered only from a load customer or group of load customers that caused the need for the investment. On the other hand, except in exceptional circumstances, the costs associated with transmission *network* investments are recovered from all ratepayers since all Ontario consumers benefit.[7] There was a provision in the TSC (section 6.3.6) that allowed for apportionment of *connection* asset costs to the network rate pool. However, that provision was eliminated in a previous OEB proceeding (EB-2011-0043) for a number of reasons. First, it allowed for the apportionment of 100% of the cost to all ratepayers (i.e., non-beneficiaries), even if the primary reason for the investment was to serve a customer's needs. It was therefore inconsistent with the beneficiary pays principle. It was also incompatible with the OEB's approach to regional infrastructure planning, as it was premised on the transmitter planning investments to connect transmission customers (including distributors) without obtaining input from those customers.

The OEB generally believes a specific customer should not be required to pay all of the 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).

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[7] There may be exceptional circumstances where a capital contribution is required for network investment.

Two approaches were identified for addressing the apportionment of costs where both system and connection benefits will be realized, both of which are described below. Based on a consideration of both methods, the OEB is of the view that the proportional benefit approach is more appropriate, for reasons that are discussed below. That approach is similar to the methodology that Hydro One and the IESO had proposed in the SECTR proceeding.

In that SECTR case, the proposed investment met the needs of certain customers (i.e., three distributors connected to Hydro One) and also addressed a broader network need – meeting load restoration criteria set out in the IESO's ORTAC requirements, which are related to restoring power to consumers after an outage within a reasonable period of time.[8] This proposed methodology was used to determine the proportional benefit between the customer(s) and the broader system. The proposed allocation of costs between the customers and all ratepayers was based on the lowest cost solutions to address the customer and broader system needs *separately*. See sidebar for an illustrative numerical example reflecting this proportional benefit methodology.

The other approach to addressing the apportionment of connection costs to the network pool was identified in the OEB's January 7th letter. This approach is premised on a transmitter making incremental transmission *connection* investments that exceed the capacity needs of those customer(s) because they would *avoid* a more expensive upstream transmission *network* asset upgrade (i.e., avoided cost methodology). Under this approach, it was proposed that the incremental connection investment costs would be apportioned to

Proposed Proportional Benefit Approach: An Illustrative Example

The cost of each *separate* solution to meet the two regional needs is first determined. In this example, the cost is $30M to address the *system* need and $90M to meet the *customer(s)* need. The aggregate cost of the two solutions is therefore $120M ($30M + $90M). The relative proportion (i.e., percentage allocation of aggregate cost) attributed to each solution is as follows: *system* need ($30M / $120M = 25%) and *customer(s)* need ($90M / $120M = 75%).

Those relative proportions are then applied to the cost of the *single integrated optimal* solution that addresses both needs at a lower cost (e.g., $100M or $20M lower): *system* need is 25% * $100M = $25M and *customer* need is 75% * $100M = $75M. As a result, applying the proportional benefit to the cost of the optimal solution would result in *$25M* being recovered from *all ratepayers* (rather than $30M under the sub-optimal solution) via the network pool and *$75M* would be recovered from the *benefiting customer(s)* – rather than $90M.

[8] Ontario Resource and Transmission Assessment Criteria (ORTAC), IESO.

the network pool (like the avoided network investment costs would have been). In such instances, this would reduce the amount apportioned to the applicable network pool (i.e., all ratepayers) relative to the cost of the network solution. It was consistent with the OEB's goal for regional planning – the lowest cost wires solution that addresses the need. However, the OEB has determined that the 'proportional benefit' methodology could also be used for apportionment scenarios that are limited to addressing 'capacity' needs. That would include cases where incremental connection investments would avoid a higher cost network solution, as described above. In other words, the proportional benefit methodology would solve for all scenarios where proposed connection facilities could also provide network benefits.

The OEB is of the view that the *proportional benefit* approach achieves the objective of ensuring that the cost of a proposed connection facility that addresses a network requirement or provides network benefits is properly shared according to the beneficiary pays principle. Unlike the provision discussed above that was removed from the TSC (section 6.3.6), the proportional benefit approach is compatible with the OEB's approach to regional infrastructure planning by encouraging the optimal investment in transmission assets. In fact, the OEB would expect such an integrated solution to be reflected in a regional plan.

The OEB is therefore proposing 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.

The OEB believes there would be a 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).

A case by case application approach would also be necessary as the apportionment would be expected to change based on the specific circumstances. The methodology relies on a proxy to estimate the cost to address each need individually, which provides the basis to determine the apportionment. The OEB expects the proxy and/or associated values to differ in each case. The proxy is therefore critical to this methodology. Whether the proxy used was the most appropriate (and the associated estimated cost) would therefore need to be tested.[9] 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 that is similar in nature to the assessment that was provided in support of Hydro One's SECTR application.

[9] For example, the proxy used in the SECTR proceeding as the most cost effective 'separate' solution to address the broader load restoration need was a natural gas generation facility.

2. PROPOSED TSC AND DSC AMENDMENTS: APPROACHES TO 'APPORTION' UPSTREAM TRANSMISSION CONNECTION INVESTMENT COSTS

Upstream Transmission Connection Investments – Treatment of Embedded Distributors

There is an inconsistency between the TSC and the DSC where an investment involves an upstream transmission connection asset and both the host and embedded distributor(s) have contributed to the need for that investment. One code requires a capital contribution from a distributor, while the other does not. That results in an inconsistent treatment among distributors. This was the second major issue raised in the SECTR LTC proceeding that related to cost responsibility.

In the TSC, a 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. As a consequence, the customers of the host distributor subsidize the customers of the embedded distributor under the status quo.

The OEB is of the view 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.

The OEB is therefore proposing to amend section 3.2.4 of the DSC so that embedded distributors are no longer exempt from providing a capital contribution.[10] Section 3.2.4 would be further amended to change "may" to "shall" to further ensure consistent treatment of customers across distributors. The OEB does not believe it should be left to each distributor to decide whether to apply the beneficiary pays principle.

[10] Where a capital contribution is required based on an economic evaluation.

Upstream Transmission Connection Investments – Treatment of Large Load Customers

The same concept described above applies to all large load customers (e.g., industrial). That is, the OEB also believes all large load customers should be treated the same in terms of cost responsibility whether they are connected to the system of a transmitter, host distributor or embedded distributor.

At the same time, the OEB does not believe it is practical for distributors to require a capital contribution from all load customers (e.g., residential, small business) related to upstream transmission connection investments. The OEB believes there is a need to strike a balance between precision and administrative burden. The OEB is therefore of the view that a materiality threshold for 'large' load customers of distributors is needed for this purpose.

Various potential materiality thresholds were discussed during the Working Group process. 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.

The proposed threshold for 'large' load customers (that are not distributors) is based on non-coincident peak demand that meets or exceeds 3 MW. Under this proposed approach, a capital contribution would not be required from customers that are below that threshold, including those considered low volume consumers (i.e., residential, small business). The OEB believes this threshold would strike that appropriate balance between precision in terms of allocating costs and administrative burden for distributors.

The OEB is therefore proposing to add new section 3.2.4A to the DSC reflecting the above.

The OEB notes that the proposed 3 MW threshold is also being proposed for other purposes, which are discussed below. Those include: *bypass compensation, capital contribution true-ups and capital contribution (and expansion deposit) refunds*.

3. PROPOSED TSC AND DSC AMENDMENTS: APPROACHES TO 'APPORTION' 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 customer since the cost of 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.

The OEB is of the view 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).

On the other hand, if the customer *requests* the replacement of a connection asset that has *not* reached its EOL, the OEB is of the view that the customer should pay. However, the OEB is also of the view that 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.

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 (i.e., small scale) generation has encouraged customers to install load displacement generation in order 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.

The OEB believes the Codes should reflect that evolution and is proposing to address a third scenario. The OEB expects there will be cases 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. Currently, the standard industry practice is for the transmitter to replace it with a like-for-like connection asset (i.e., same capacity). 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 an over-investment.

As a result, in such cases where a customer's load has materially declined over time, the OEB expects that 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-size'). 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. The OEB is not proposing to include a code requirement to 'right-size' to a lower capacity. The OEB acknowledges that there will be a need for some transmitter judgment. However, the TSC will be amended to make it clear that a lower capacity replacement connection asset is a potential outcome.

The OEB is therefore proposing 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.*

The OEB is also proposing 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. This proposed requirement is similar to those set out in section 6.2.14 of the TSC, which address the situation where a transmission facility is reaching 75% of its rated capacity. In that case, a transmitter is required to give affected customers notice and seek input from them on their future needs (e.g., forecast demand). The OEB is of the view that similar notice is necessary to ensure the transmitter has engaged in a consultation with its affected customers to be able to identify the future demand on the facility, for the purpose of right-sizing.

The OEB intends 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.

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.

The OEB is therefore proposing 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. The requirement for distributors to consult with customers, at the time of replacement of an asset, will be limited to those considered to be large customers (3 MW and above), as described in the section above.

The proposed TSC and DSC amendments related to the replacement of EOL assets would achieve the following outcomes:

- 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, as a way 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 – 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 future growth* is expected. This approach would be taken to avoid a more costly upstream transmission connection investment. The OEB will refer to LDC (A) as the 'connecting' distributor and LDC (B) as the 'facilitating' distributor below.

The OEB sees merit in this proposal. It would result in achieving the OEB's goal associated with regional planning of implementing the least cost wires investment that addresses a regional need. This proposed change would also result in less excess capacity on the system, i.e., improved utilization of existing assets since the 'facilitating' distributor's unused capacity would be used by the 'connecting' distributor.

The OEB is therefore proposing to amend 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.

For example, to the extent the ‘facilitating’ distributor had paid the transmitter for capacity (through a capital contribution) in relation to a transmission connection facility that will be used by the ‘connecting’ distributor, the OEB expects the ‘facilitating’ distributor would receive a capital contribution refund from the ‘connecting’ distributor, where applicable. The ‘facilitating’ distributor would also need to be compensated for any incremental charges (e.g., transmission, regulatory charges, etc.) it is required to pay to the IESO due to incremental electricity withdrawn from the grid by the ‘connecting’ distributor. The ‘connecting’ distributor would essentially be treated as an embedded distributor, with the ‘facilitating’ distributor functioning like a host distributor.

From a process perspective, if this proposed amendment is adopted, the OEB believes 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 are in agreement and all investments proposed by the distributors have been taken into consideration.

The OEB also expects such a solution would flow from a regional infrastructure plan, since it would require close coordination and agreement among the transmitter and the distributors involved. A regional infrastructure plan would therefore need to be submitted in support of the joint application to demonstrate the distribution solution is more cost effective than a transmission connection upgrade. Distributors would also be required to obtain an assessment from the IESO confirming that the distribution solution is more cost effective than an upgrade to the transmission connection facility that connects the ‘connecting’ distributor to the grid; i.e., confirm the distribution investment is the optimal wires solution from a regional planning perspective.

The OEB would also 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 does not want to see an outcome whereby the distribution investment is made to avoid a transmission connection investment, while triggering a different transmission connection investment during the forecast period. Under such a scenario, the end result would be an unnecessary distribution investment (i.e., sub-optimal solution). The OEB would look to the IESO to take that potential outcome into account as part of its assessment.

4. 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 within the distribution system tends to be *gradual*. Load growth (i.e., *demand*) and the assets to *supply* it 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.[11]

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.[13] As a

[11] The total system demand of some distributors in Ontario is less than 400 MW including distributors as large as Oakville Hydro and Kitchener-Wilmot Hydro (OEB 2016 Electricity Distributor Yearbook).
[12] There is more flexibility to size *transformation* connection assets to better meet the transmission customer(s) need. However, this issue can also arise in relation to some transformation stations.
[13] Stakeholders often refer to this as an "affordability" issue for the distributor. In the OEB's view, it is a bill impact issue for customers of the distributor, since all of the cost is typically passed on to end use consumers by the distributor under the current regulatory construct.

consequence, 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

Three approaches are discussed below which are intended to address the issue discussed above. The OEB is proposing the implementation of all three approaches through code amendments and/or changes to other regulatory instruments. A summary of the implementation details associated with the three approaches is set out at the conclusion of the section.

Providing for alternative approaches to fund capital contributions related to connection assets will, in the OEB's view, increase the effectiveness of regional planning by avoiding the unintended consequences noted above.

1. Annual Installment Option (for distributors)

One of the approaches discussed during the Working Group process is referred to as the Annual Installment approach.[14] It would involve a capital contribution being provided via *multiple annual installment payments* over a certain number of years instead of the status quo which is a *single lump sum payment* to the transmitter.

In addition to mitigating bill impacts by spreading the cost over time, the OEB believes this approach would also result in better alignment between incremental revenues received by distributors due to customer load growth and paying the cost of the connection investment to the transmitter. Both would occur over a period of time. It also remains fully aligned with the beneficiary pays principle. It would only be a *timing matter* as to when the beneficiary pays the full cost to the transmitter (including any additional financing costs).

The TSC includes a true-up process related to capital contributions due to the difference between actual load growth and the load forecast. Under this proposed amendment,

[14] During the Working Group process, this approach was referred to as the "Smoothing Option". However, the OEB felt a change in terminology was needed to better describe it and recognize that it is not the only approach that would smooth the costs to reduce bill impacts.

that true-up process would remain in place. The difference between actual and forecast load would be captured by adjusting the final installment payment.

This approach would be limited to regulated distributors since there is virtually no risk that they will not pay the transmitter the full cost of the investment. On the other hand, an industrial customer (e.g., mining company) could cease operations at any time before the investment in the connection asset is paid off. The remaining cost would need to be recovered from all Ontario consumers in all instances where that occurred. As discussed below, there are also a number of other differences between regulated distributors and commercial customers.

The transmitter already finances connection investments under the status quo. The cost is currently recovered through a combination of a capital contribution and through rates over time (as determined by an economic evaluation).As a consequence, under this installment approach, *all* (instead of *part*) of the cost would be recovered over time. The capital contribution portion would just be recovered over a much shorter period of time; e.g., five vs. 25 years.

To strike a balance between minimizing the bill impacts and also minimizing the carrying costs, the OEB is proposing that the period of time over which the full capital contribution would be provided would not be permitted to exceed five (5) years.

Under the current approach, a distributor that makes a lump sum capital contribution will seek to include it in its rate base and thus earn a return on rate base to finance that investment. This proposed installment approach means that a distributor would be recording less upfront and adding to its rate base over time as it makes each installment payment toward the required capital contribution.

The OEB notes this approach represents a relatively minor deviation from the current approach set out in the TSC in relation to recovery of capital contributions. It is only a matter of extending the period over which the full capital contribution is paid. The approach is also consistent with the OEB approved approach used by the natural gas utilities for expansion projects, where cost recovery is spread over a period of time to mitigate bill impacts for the customers of the utility.[15]

[15] In RP-1999-0034, section 6.2, it states *"In many cases this up-front one-time payment was seen as a financial barrier to customers who could not afford such initial outlays. This allowed for the introduction of the periodic contribution charge (PCC) which presented customers with the option of paying a contribution over time. Essentially, the utilities would finance the contribution amounts."* The PCC remains in effect and is typically charged over a 5 year term as a separate line item on the bill.

This approach to addressing the customer bill impact concern discussed above received the most support among Working Group members, particularly the members representing consumer groups.

Advanced Funding Option

The OEB has also considered two approaches that would both provide distributors with a pool of funds before the new or upgraded connection investment goes into service – Upstream Capacity Payment and Upstream Connection Adder.

2. Upstream Capacity Payment Approach

The first approach involves a distributor including in its economic evaluation a payment reflecting future upstream system costs. The payment for capacity ensures the new customer that is connecting to the system and therefore benefitting from existing available capacity (or a new transmission connection asset) pays towards the cost of its future capacity requirements.

Under this approach, distributors would apply a per kW payment reflecting the forecast costs to be paid by customers (e.g., developers) before an upstream transmission investment is made and before a capital contribution is provided to the transmitter. The OEB expects that the forecast cost of the upstream transmission investment would be based on the most recent regional infrastructure plan.

Distributors would hold the funds collected through such charges (including any interest that accrued) in a separate account until the capital contribution related to the new upstream connection asset is provided to the transmitter. The capacity payments collected by the distributor would be included in the capital contribution provided to the transmitter.

The primary benefit associated with this approach is that it ensures those customers who are connecting to transmission connection facilities, where there is existing capacity, would contribute to the next upgrade. In essence, these customers would pay for the use of capacity that would otherwise have been available for other customers, or for general load growth. Since funds would be collected before the capital contribution is due, this would reduce the amount distributors need to borrow to fund the capital contribution. In doing so, it would also reduce the distributor’s incremental financing costs (relative to the status quo). This outcome should therefore facilitate the implementation of regional plans. This approach also aligns with the beneficiary pays principle.

The OEB acknowledges, however, that this approach would not fully eliminate the 'lump sum' issue or mitigate the impacts on all customers of the distributor. To some extent, the cost is being shifted to new customers of the distributor since they would be paying 'in advance' of the date the capital contribution must be provided to the transmitter (i.e., when customers begin to pay under the status quo). In addition, there could be cases where a connection investment was required where there is no new development(s) and, therefore, little or no load growth. A scenario where this may be the case is where an upstream transmission investment has been deferred for a number of years and the connection asset slowly becomes overloaded due to gradual existing customer load growth. If this approach was adopted, there would be a need for cost responsibility rules that support it, as *existing* customers would then be responsible for the full cost.

Any amount collected through the Upstream Capacity Payment would need to be tracked by the distributor and reflected as a future capital contribution offset related to new transmission connection assets.

The capacity payment would also be based on an *estimated* cost rather than an *actual* cost. To eliminate some of the risk, distributors will be expected to calculate the amount of the capacity payment based on the cost estimates included in the most recent regional infrastructure plan. The OEB expects that estimated cost would be developed, in consultation with the lead transmitter and the IESO, during the regional infrastructure planning process.

3. Upstream Connection Adder

The final approach that the OEB is proposing to implement is a funding adder, referred to in this Notice as the Upstream Connection Adder.

It would be similar to the Upstream Capacity Payment approach in that it would provide advance funding to the distributor before the upstream connection asset goes into service and before a capital contribution needs to be provided to the transmitter.[16] Where it differs is it would collect the funds by adding a rate rider to the bills of all the

[16] It typically takes about two years for a line connection and three years for a transformation station from confirmation of the 'need' for the new asset to the date construction is completed and it goes 'into service'. Various factors can affect the amount of time (e.g., environmental approvals, whether land needs to be acquired, whether leave to construct approval is required, etc.).

distributor's customers, rather than applying a per kW charge to new and expansion customers. Other differences are discussed below.

Similar to the Upstream Capacity Payment approach, the funds collected through the Upstream Connection Adder would be kept in a separate deferral account. Any interest that accrues in relation to the funds collected would remain in that deferral account. The pool of funds in the account would be used to reduce the amount of the capital contribution paid to the transmitter for the upgrade to upstream transmission connection assets. As a result, it would reduce the amount the distributor would need to borrow to finance the capital investment. In doing so, it would also reduce the associated financing costs. However, like the Upstream Capacity Payment, this outcome is possible because some of the cost is being shifted to customers of the distributor, since they would be paying 'in advance' of the date the capital contribution is due to the transmitter.

The OEB is proposing both this approach and the Capacity Payment approach as they will provide distributors with options to address different circumstances. As noted above, there are some differences between the two approaches.

- Both would be set or be expected to recover a portion of the capital contribution before it is due to the transmitter to use as an offset. The amount recovered through the adder would depend on how it is designed (e.g., portion targeted), while the amount for the capacity payment would depend on the how much capacity is required before the in-service date

- The Upstream Connection Adder would be applied solely to the electricity bill, rather than being reflected in both the cost of new developments and the electricity bill like the Upstream Capacity Payment[17]

- The Upstream Connection Adder would be applied to 'all' *existing* customers before the facility goes into service, since it is a rate rider that would be in place before the *new* customers moved into the new development and began to consume electricity. The Upstream Capacity Payment would apply to 'all' *new* customers that benefit, with remainder of the cost recovered from 'all' *existing* customers until all of the capacity on the connection asset is utilized

[17] For the Upstream Capacity Payment, recovery through the electricity bill would be related to any 'excess' capacity.

Since the funds collected through the Upstream Connection Adder would only cover a *portion* of the capital contribution before the upstream asset goes into service, the capital contribution would ultimately be based on *actual* costs. The 'net' capital contribution would cover the outstanding actual cost.

The reason for proposing recovery of only a *portion* of the capital contribution in advance is to limit the extent that there may be a deviation from the beneficiary pays principle, as it would be applied to the bills of existing customers. When the connection asset goes into service, the Upstream Connection Adder would no longer be applied. The economic evaluation would then take into account the actual amount recovered through the Upstream Connection Adder to determine the 'net' remaining capital contribution. There may not be a material deviation from the beneficiary pays principle for the following reasons:

- Background studies prepared for determining municipal development charges that were reviewed by the OEB show a relatively material allocation to *existing* dwellings, where it involves 'hard' services like electricity infrastructure (e.g., water and sewage)
- From an electricity perspective, there may be a reliability-related benefit to existing consumers

The OEB notes both the OEB and distributors have experience with a similar approach, from a process perspective. An example is the funding adder for *Renewable Generation Connection and Smart Grid Development* expenditures which is described in the following guideline: "Deemed Conditions of Licence: Distribution System Planning"(G-2009-0087).[18] The OEB also approved funding adders in the past in relation to smart meters.

In the OEB guideline referred to above, it notes the following:

> Distributors who anticipate substantial expenses related to the qualifying renewable connection or smart grid development investments … may apply for a "Renewable Connection/Smart Grid Funding Adder"… a **tool to provide advance funding** [to the distributor] for these qualifying investments and activities and thus also **to mitigate the anticipated rate impact of the associated costs**. [emphasis added]

[18] www.oeb.ca/oeb/_Documents/EB-2009-0087/Dx_System_Planning_Guidelines_20090616.pdf

This approach also builds on the primary positive attributes associated with the other two approaches discussed above – Upstream Capacity Payment approach (i.e., advanced funding to reduce distributor borrowing requirements) and Annual Installment approach (i.e., smoothing cost recovery over time to mitigate bill impacts). Since this approach would reduce the amount of the capital contribution and associated distributor borrowing requirements, the OEB expects that it would also facilitate the implementation of regional infrastructure plans.

If this approach were to be adopted, the OEB would consider an application for an Upstream Connection Adder through a hearing. This type of application would need to be supported by a Distribution System Plan (DSP) and/or a RIP. The development of filing guidelines would also be necessary that are similar to those referenced above. The OEB expects that would be achieved through changes to the DSP filing guidelines.

Of the approaches discussed above, including the status quo, the OEB expects the advanced funding options would result in the lowest overall cost to consumers, since they would reduce financing costs. It would depend on the distributor's circumstances and the design of those options in terms of which would result in the lowest overall cost. For example, where a distributor is experiencing high load growth in its service area, it should be the Upstream Capacity Payment approach that achieves that outcome. On the other hand, where there is little load growth (e.g., connection asset has become gradually overloaded over time), the Upstream Connection Adder approach should result in the lowest overall cost. The reason for those different outcomes is the revenues raised through the former are dependent on load growth, while the revenues associated with the latter approach are largely independent of load growth. The OEB expects most new connection investments will be necessary under scenarios involving material load growth. If that is the case, the Upstream Capacity Payment approach would result in the lowest cost option in most instances.

OEB's Proposed Approach

The OEB has considered the pros and cons associated with all three approaches discussed above and is proposing to implement all of them to provide for flexibility and adaptability to different scenarios of development within distributor territories.

The OEB notes that the status quo (i.e., single lump sum payment) would remain an option for distributors and expects a number of distributors would continue to opt for that approach; particularly, the larger distributors.

Under the OEB's proposed approach, distributors would therefore have a suite of options to choose from that would best address their circumstances (e.g., high vs. low load growth).

The OEB is therefore proposing to amend the TSC by adding new section 6.3.19 which would require transmitters to accept the provision of the capital contribution by distributors in annual installments over a period of time of up to five years. As noted, where a distributor opted to provide installments, the distributor would be responsible for any associated financing costs. This is necessary to ensure the transmitter is not worse off (nor better off). The OEB is therefore also proposing to include in this new section a requirement for the transmitter to include financing costs (from the date the asset goes into service) in each installment payment. In doing so, the transmitter would be compensated in a timely manner for any financing costs that have accrued over the year. The OEB is proposing to use the prescribed construction work in progress (CWIP) rate, which reflects the Mid-Term Bond Index All Corporate yield, for this purpose.[19]

The OEB is also proposing amendments to the appendix in both the TSC and the DSC that addresses the "Methodology and Assumptions for an Economic Evaluation". That is, Appendix B in the DSC and Appendix 5 in the TSC. The proposed amendments would revise the Economic Evaluation methodology to take into account any revenues realized through the Advanced Funding approaches before the 'gross' capital contribution is due to be paid to the transmitter to determine the 'net' remaining capital contribution that needs to be financed. The purpose of these proposed Code amendments is therefore to *accommodate* these Advanced Funding approaches. A Code is not the appropriate regulatory instrument for *implementation* purposes, as a funding adder and a capacity charge involve a *rate.*

To that end, following the completion of this Code amendment process, the OEB will develop Filing Guidelines related to the Upstream Connection Adder and the Upstream Capacity Payment that are similar to those that have been issued in the past for funding adders (e.g., smart meters), if the proposed approach discussed above is adopted by the OEB. Once that process is completed, distributors would be able to apply for an Upstream Connection Adder or the Upstream Capacity Payment. The OEB would also update reporting and accounting guidance with respect to tracking the Upstream Capacity Payment amounts collected through expansions.

[19] www.oeb.ca/industry/rules-codes-and-requirements/prescribed-interest-rates

The OEB acknowledges that this issue – requirement to provide a relatively large capital contribution in a single lump sum payment – can also impact large commercial (e.g., industrial) customers. However, the OEB is proposing that the financing mechanisms discussed above would only be made available to regulated distributors. The only approach that would seem to be viable for commercial customers is the Annual Installment approach. The OEB's primary concern is the non-payment risk associated with such customers paying the capital contribution over time. That risk would be shifted to all other customers of the distributor. The OEB also believes commercial customers differ from regulated distributors in a number of ways. For example, their additional capacity needs tend to be 'lumpier' in nature (e.g., due to a planned plant expansion). In contrast, distribution systems grow in an 'organic' fashion (e.g., new residential customers in new subdivisions connected).

To summarize, the OEB is proposing amendments to the TSC to *implement* the Annual Installments related to capital contributions. Further amendments are proposed to the Economic Evaluation appendices of the TSC and DSC to *accommodate* the *advanced funding options* – Upstream Connection Adder, Upstream Capacity Payment – as a capital contribution offset.

5. PROPOSED TSC AND DSC AMENDMENTS: ADDRESSING INCONSISTENCIES AND GAPS

This section discusses the proposed code amendments that are intended to address inconsistencies between and gaps within the TSC and DSC.

A key consideration in assessing the need for alignment between the Codes in relation to the inconsistencies discussed below is the evolution of the distribution system, as the functions it performs are becoming more similar to those of the transmission system.

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 of its customers). There are a number of sections where that is the case.[20]

As discussed earlier, the evolution of the distribution system is resulting in it operating in a similar way to the 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 the 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.[21]

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[20] Examples of that contrast between the Codes are set out below.

- Section 6.3.1 of **TSC**, it states *"… transmitter shall require a capital contribution from the load customer to cover the cost of a connection facility"*.
- Section 6.3.2 states "… transmitter shall require the load customer to make a capital contribution to cover the cost of the modification… "
- Section 3.2.4 of **DSC** states: "The capital contribution … a distributor may charge a customer …."
- Section 3.2.5 states "The capital contribution that a distributor may charge a generator …."

[21] The DSC includes a provision (s. 3.3.3) – Enhancements – that addresses where the OEB has determined cost recovery from all the distributor's customers is appropriate (i.e., capital contribution cannot be required). It relates to investments where the benefits accrue to all customers of the distributor.

The OEB is therefore proposing to amend 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.

The OEB is not contemplating a broader review of the DSC at this time given the breadth of this consultation and potential unintended consequences of a wholesale change of sections throughout the DSC from "may" to "shall".

Capital Contribution Refund / Rebate to Initial Customer(s)

Under the TSC, the initial load customer that requires a new or upgraded transmitter-owned connection asset must provide a capital contribution to the transmitter to fund it. Where there is excess capacity and it is assigned to a subsequent load customer that connects, they must also pay their share in the form of paying a capital contribution refund to the initial customer(s). The same approach is taken in the DSC except where the load customer is an embedded distributor. As noted earlier in this Notice, the host distributor currently cannot require a capital contribution from an embedded distributor and the OEB is proposing to change that.

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 in order to provide the refund to the initial customer. That change was made due to 'gaming' concerns, as five years is a relatively short timeframe.[22]

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.

[22] A distributor could make lower cost '*sub-optimal*' investments until the five year threshold is met, to avoid providing a capital contribution for available capacity (AC) on a transmission connection facility. Once that five year timeline is met, they are assigned that AC at no cost (i.e., free) and the initial customer(s) is not compensated for that capacity. That outcome is incompatible with the OEB objectives for regional planning and two of the *Guiding Principles – Beneficiary Pays and Optimal Investment*.

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 3.2.23 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.

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 *rate revenues* for the distributor. If the load forecast is too low, the outcome is the opposite.

As a consequence, 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 in order 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.[23] 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

[23] There would be no capital contribution required because the customer is committing to a load forecast and an associated amount of revenue that is more than enough to cover all of the costs.

commercial and industrial developments) 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.

Mix of load and generator customers on a connection asset

The TSC and the DSC are currently 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 (via the transmitter). 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 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 end result would be the same wording in both Codes.

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 of 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 considered to be 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, similar to 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.

During the Working Group process, some members expressed the view that a separate consultation process was necessary, in the future, to address this inconsistency. It was suggested this issue was too significant to include in this consultation.

The OEB is of the view that a separate consultation process is not required. Bypass compensation at the transmission level was addressed in the TSC, as part of broader consultation than this consultation process, and there were no bypass provisions in the OEB’s codes that could be leveraged to inform the added bypass provisions at that time. The bypass provisions in the TSC can now be leveraged to inform any DSC amendments.

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.

The OEB is also proposing that the 3 MW materiality threshold would apply in relation to bypass compensation, for the same reason reasons discussed above.

Similar to 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 take action 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.

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.

In order 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.

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. In particular, 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.

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.

As a consequence, 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 only *aesthetic* reasons. Currently, neither code (TSC or DSC) addresses how costs should be allocated in relation to such ‘premium’ wires solutions. Some members of the Working Group expressed the view that this represents a gap in the Codes that should be addressed.

The OEB believes that, where such an unnecessary premium wires solutions is 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 similar to 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 cost 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.

The LAC preference may be DG and/or CDM, in some cases. Those alternative solutions are discussed in the next section of this Notice under “None-Wires Solutions”.

<u>Out of Scope</u>

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.[24]

[24] 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.[25] 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 'type' of 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).[26]

C. Anticipated Costs and Benefits

The OEB believes the Code amendments set out in this Notice will result in benefits that exceed any additional costs.

The OEB expects that aligning the cost responsibility provisions in the Codes and addressing the gaps that have been identified will achieve the following beneficial outcomes:

- Ensure that transmitters and distributors have clear and common requirements for allocating costs
- Better align with the beneficiary pays principle which would ensure that all beneficiaries pay their fair share of connection investments
- More consistent treatment of consumers and distributors across the province
- Reduce the potential for cross-subsidization by non-beneficiaries
- Facilitate new technological developments by recognizing that distribution systems are evolving and becoming more dynamic (i.e., no longer limited to delivering electricity to consumers)

[25] Guidelines for Electricity Distributor CDM (EB-2014-0278), section 4.1 (Applications for Rate-Funded Activities to Defer Distribution Infrastructure), p.4 – 6.
[26] This future initiative is discussed in the OEB's Business Plan (2017-2020).

- Ensure that embedded distributors and large consumers connected to the distribution system are accountable for the costs related to upstream transmission connection investments they contribute to and benefit from
- Enhance cost discipline among distributors and transmitters
- Enhance regulatory predictability, which is particularly important within the context of large capital investments

The OEB also believes the proposed Code amendments associated with addressing the 'lumpy' connection investment and related 'affordability' issue will result in the following benefits:

- Facilitate the implementation of regional infrastructure plans and therefore the most cost effective wires investments
- Recovery of large capital contributions would be smoothed over time to reduce consumer bill impacts, to the extent distributors adopted the smoothing mechanisms
- The above would result in lower electricity bills for consumers

The OEB expects that some of the proposed amendments to the TSC and the DSC, particularly those related to capital contribution true-ups and extending the capital contribution refund period (for some customers) in the DSC, will result in distributors incurring additional administrative costs. The OEB expects the magnitude of such costs will differ across distributors. It will depend on how many customers they have that exceed the 3 MW materiality threshold.

The proportional benefit approach to apportioning some costs to the network pool would also impose new costs on all Ontario ratepayers. For example, Hydro One proposed apportioning $22.5 million in costs to all Ontario ratepayers in its SECTR application. As discussed above, under the status quo, all costs associated with transmission connection investments can only be recovered from the specific customers that caused the need for the connection investment; i.e., no allocation to all ratepayers.[27]

[27] The total estimated SECTR project cost was $77.4 million. It did not exceed the needs of the customers that caused the need for the project. It is also uncertain if that load restoration need would have been addressed in isolation at a total cost of $22.5 million. The triggering customers would be responsible for the full cost ($77.4 million) under the existing cost responsibility rules. All of the cost estimates can be found in IESO's (then OPA) supporting evidence – *Recommended Cost Allocation Treatment for the [SECTR] project (page 9)* – included in Hydro One's SECTR application.

D. <u>Coming into Force</u>

The OEB proposes that the proposed amendments to the TSC and the DSC, as set out in Attachments A and B, come into force on the date that the final Code amendments are published on the OEB's website after having been made by the OEB.

E. <u>Cost Awards</u>

Cost awards will be available under section 30 of the Act to those that are eligible to receive them in relation to written comments provided on the proposed TSC and DSC amendments in this Notice. Cost awards will be available to a **maximum of 20 hours** per eligible participant.

The OEB's January 7, 2016 letter noted that the OEB would determine later how costs will be apportioned. The OEB has now determined that costs will be recovered from all rate-regulated licensed electricity distributors (65% of the costs awarded) and all rate-regulated licensed transmitters (35% of the costs awarded). Within the distributor class, costs awarded will be apportioned based on respective customer numbers. Within the transmitter class, apportionment will be based on respective revenues (using the most recent three year average from their audited financial statements or similar documentation).

Attachment C contains important information regarding cost awards for this Notice and comment process, including in relation to eligibility requests and objections. The deadlines for filing cost eligibility requests and objections will be strictly enforced to facilitate a timely decision on cost eligibility.

F. <u>Invitation to Comment</u>

Anyone interested in providing written comments on the proposed TSC and DSC amendments in Attachments A and B are invited to submit them by **October 23, 2017**.

Your written comments must be received by the Board Secretary by **4:45 p.m.** on the required date. They must quote file number **EB-2016-0003** and include: *your name, address, telephone number and, where available, your e-mail address and fax number.*

One paper copy of your written comments must be provided, and should be sent to:

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

The OEB requests that you make every effort to provide electronic copies of your written comments in a searchable/unrestricted Adobe Acrobat (PDF) format, and to submit them through the OEB's web portal at https://www.pes.oeb.ca/eservice/. A user ID is required to submit documents through the OEB's web portal. If you do not have a user ID, please visit the "e-filings services" webpage on the OEB's website at www.oeb.ca, and fill out a user ID password request. Participants are also requested to follow the document *naming conventions* and document *submission standards* outlined in the document entitled "RESS Document Preparation – A Quick Guide", which is also found on the e-filing services webpage. If the OEB's web portal is not available, electronic copies of your written comments may be provided by e-mail at boardsec@oeb.ca**.**

Those that do not have internet access should provide a CD containing their written comments in PDF format.

If the written comment is from a private citizen (i.e., not a lawyer representing a client, not a consultant representing a client or organization, not an individual in an organization that represents the interests of consumers or other groups, and not an individual from a regulated entity), the OEB will remove any personal (i.e., not business) contact information from those written comments (i.e., address, fax number, phone number, and e-mail address) before making the written comment available for viewing at the OEB's offices or posting it on the OEB's website. However, the private citizen's name and the content of the written comment will be available for viewing at the OEB's offices and will be placed on the OEB's website.

This Notice, including the proposed TSC and DSC amendments in Attachments A and B, and all related written comments received by the OEB will be available for public viewing on the OEB's web site at www.oeb.ca and at the OEB's office during normal business hours.

If you have any questions regarding the proposed amendments to the Codes described in this Notice, please contact Chris Cincar at Chris.Cincar@oeb.ca or at 416-440-7696. The OEB's toll free number is 1-888-632-6273.

DATED at Toronto, **September 21, 2017**

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Attachments:

Attachment A — Proposed Amendments to the Transmission System Code
Attachment B — Proposed Amendments to the Distribution System Code
Attachment C — Cost Awards

Attachment A
to
Notice of Proposed Amendments to the
Transmission System Code and the Distribution System Code

September 21, 2017

EB-2016-0003

<u>Proposed Amendments to the Transmission System Code</u>

Note: Underlined text indicates proposed additions to the Transmission System Code and strikethrough text indicates proposed deletions from the Transmission System Code. Numbered titles are included for convenience of reference only.

[see separate document attached]

Attachment B
to
Notice of Proposed Amendments to the
Transmission System Code and the Distribution System Code

September 21, 2017

EB-2016-0003

Proposed Amendments to the Distribution System Code

Note: Underlined text indicates proposed additions to the Distribution System Code and strikethrough text indicates proposed deletions from the Distribution System Code. Numbered titles are included for convenience of reference only.

[see separate document attached]

Attachment C
to
Notice of Proposed Amendments to the
Transmission System Code and the Distribution System Code

September 21, 2017

EB-2016-0003

Cost Awards

Cost Award Eligibility

The OEB will determine eligibility for cost awards in accordance with its *Practice Direction on Cost Awards*. Any participant in this process intending to request cost awards (and has not already been determined eligible for cost awards in the OEB's Decision issued on June 13, 2016) must file a written submission with the OEB by **October 2, 2017,** identifying the nature of their interest in this process and the grounds on which they are eligible for cost awards (addressing the OEB's cost eligibility criteria in section 3 of the OEB's *Practice Direction on Cost Awards*). An explanation of any other funding to which the participant has access must also be provided, as should the name and credentials of any lawyer, analyst or consultant that the person intends to retain, if known. All requests for cost eligibility will be posted on the OEB website.

Licensed electricity distributors and licensed electricity transmitters will be provided with an opportunity to object to any of the requests for cost award eligibility. If an electricity distributor or transmitter has any objections to any of the cost eligibility requests, those objections must be filed with the OEB by **October 12, 2017**. Any objections will be posted on the OEB website. The OEB will then make a final determination on the cost eligibility of the requesting participants.

Eligible Activities

Cost awards will be available in relation to providing comments on the proposed TSC and DSC amendments in Attachments A and B, to a **maximum of 20 hours.**

Cost Awards

The OEB will apply the principles in section 5 of its *Practice Direction on Cost Awards,* when determining the amount of the cost awards. The maximum hourly rates in the OEB's Cost Awards Tariff will also be applied. The OEB expects that groups representing the same interests or same type of participant will make every effort to communicate and co-ordinate their participation in this process. Cost awards are made available on a per eligible participant basis, regardless of the number of professional advisors that an eligible participant may wish to retain.

The OEB will use the process in section 12 of its *Practice Direction on Cost Awards* to implement the payment of the cost awards; i.e., the OEB will act as a clearing house for all cost award payments in this process. For more information on this process, please see the OEB's *Practice Direction on Cost Awards* and the October 27, 2005 letter regarding the rationale for the OEB acting as a clearing house for the cost award payments. These documents can be found on the OEB website at www.oeb.ca on the "Rules, Codes, Guidelines & Forms" webpage.

Attachment A
to
Notice of Proposed Amendments to the
Transmission System Code and the Distribution System Code

September 21, 2017

EB-2016-0003

Proposed Amendments to the Transmission System Code

Note: Underlined text indicates proposed additions to the Transmission System Code and strikethrough text indicates proposed deletions from the Transmission System Code. Numbered titles are included for convenience of reference only.

Section 6.3 of the Transmission System Code is amended as follows:

6.3 COST RESPONSIBILITY FOR NEW AND MODIFIED CONNECTIONS

6.3.14 Where more than one generator customer triggers the need for a modification to a transmitter-owned connection facility, a transmitter shall attribute the cost of the modification to those generator customers:

(a) in accordance with such methodology as may be agreed between the transmitter and all such generator customers; or

(b) failing such agreement, in proportion to the rated peak output of their respective generation facilities and, in the case of line connection facilities, taking into account the ~~relative~~ length of line used by each generator customer in proportion to the length of line being shared by the customers.

6.3.15 Where more than one load customer triggers the need for a new or modified transmitter-owned connection facility, a transmitter shall attribute the cost to those load customers:

(a) in accordance with such methodology as may be agreed between the transmitter and all such load customers; or

(b) failing such agreement, in proportion to their respective non-coincident incremental peak load requirements, as reasonably projected by the load forecasts provided by each such load customer or by such modified load forecast as may be agreed by such load customer and the transmitter and, in the case of line connection facilities, taking into account the ~~relative~~ length of line used by each load customer in proportion to the length of line being shared by the customers.

6.3.16 For a new or modified transmitter-owned connection facility that will serve a mix of load customers and generator customers, a transmitter shall attribute the cost of the new connection facility or modification to ~~the~~ those customers based on their proportional benefit, which the transmitter shall determine by considering such factors as the rated peak output of each generation facility, the non-coincident incremental peak load requirements of each load customer, and the length of line used by each customer in proportion to the length of line being shared by the customers. ~~that cause the net incremental coincident peak flow on the connection facility that triggered the need for the new or modified connection facility. If and to the extent that the net incremental coincident peak flow is triggered by one or more load customers, the transmitter shall attribute the cost to each of those triggering load customers in the manner set out in section 6.3.15. If and to the extent that the net incremental coincident peak flow was triggered by one or more generator customers, the transmitter shall attribute the cost to each of those triggering generator customers in the manner set out in section 6.3.14.~~

6.3.18A Where one or more load customers triggers the need for a new or modified transmitter-owned connection facility and the IESO undertakes an assessment at the request of a transmitter that confirms the new or modified connection facility will also address a broader network system need, the transmitter shall determine the proportional benefit between the triggering customer(s) and the network pool. In doing so, the transmitter shall attribute the costs accordingly. The transmitter shall determine the capital contribution to be made by the triggering load customer(s) based on that proportional benefit and each load customer's non-coincident incremental peak load requirements, as reasonably projected by the load forecasts provided by each load customer.

6.3.18B Where section 6.3.18A applies, the transmitter shall apply to the Board for approval of the attribution of costs between the triggering load customer(s) and the network pool. Where the Board approves a different attribution of costs, the transmitter shall recalculate the capital contribution to be made by the triggering load customer(s).

6.3.19 Where a distributor is required under this Code to provide a capital contribution to a transmitter, the transmitter shall permit the capital contribution to be provided in equal installments over a period of time not to exceed five years. Where a distributor provides the capital contribution in installments, the transmitter shall charge interest on the unpaid balance at the OEB's prescribed construction work in progress (CWIP) rate which is updated quarterly and published on the OEB website. The interest charges shall accrue monthly commencing on the date the connection asset goes into service and be paid annually, as part of each installment payment.

Section 6.7 of the Transmission System Code is amended as follows:

6.7 REPLACEMENT AND~~,~~ RELOCATION ~~AND BYPASS~~ OF EXISTING CONNECTION FACILITIES

6.7.2 Where a transmitter-owned connection facility has reached its end-of-life and is retired and replaced with a new connection facility, the transmitter shall undertake an assessment, in consultation with any affected customers, to determine the appropriate capacity of the replacement connection facility. The transmitter shall either:

(a) not recover a capital contribution from a customer to replace that connection facility, where the new facility is the same capacity or lower capacity; or

(b) recover a capital contribution from a customer to replace the connection facility, where the customer requires additional capacity. The capital contribution shall be limited to the incremental cost relative to the cost of a like-for-like replacement facility.

~~transmitter's connection facility is retired, the transmitter shall not recover a capital contribution from a customer to replace that connection facility.~~

~~6.7.5 When a load customer provides its own connection facility to serve new load or transfers new load to the connection facility of another person, the transmitter shall not require bypass compensation from that customer~~

~~6.7.6 Subject to sections 6.7.2, 6.7.7 and 6.7.8, for all or a portion of existing load a load customer may bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person, provided that the load customer compensates the transmitter.~~

~~6.7.7 For the purposes of sections 6.7.6 and 11.2.1, but subject to section 6.7.8, the transmitter shall calculate bypass compensation by first multiplying the net book value of the bypassed connection facility, including a salvage credit and reasonable removal and environmental remediation costs, if applicable, by the bypassed capacity on the relevant connection facility. The transmitter shall then divide the resulting figure by the total normal supply capacity of the bypassed connection facility. For purposes of this calculation:~~

~~(a)the bypassed capacity on the relevant connection facility shall be equal to the difference between the customer's existing load on that connection facility at the time of bypass and the customer's average monthly peak load in the three-month period following the date on which bypass occurred; and~~

~~(b)the normal supply capacity of the bypassed connection facility shall be determined by the transmitter in accordance with the Board-approved procedure referred to in section 6.2.7.~~

~~6.7.8 Where an economic evaluation, including an economic evaluation referred to in section 6.3.9 or 6.3.17A, was conducted by a transmitter for a load customer in relation to a connection facility on the basis of a load forecast, a transmitter shall not, during the economic evaluation period to which the economic evaluation relates, require bypass compensation from a customer under section 6.7.6 in relation to any load that represents that customer's contracted capacity.~~

~~6.7.9 A transmitter should avoid overloading a connection facility above its total normal supply capacity. Where a connection facility has been overloaded, and a customer transfers the overload to its own connection facility or to the connection facility of another person, the transmitter shall not require bypass~~

~~compensation from that customer.~~

~~6.7.10 A transmitter shall promptly notify the Board upon becoming aware that a load customer that is a distributor intends to bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person.~~

~~6.7.11 Where a transmitter becomes aware that a load customer intends to bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person, the transmitter shall promptly notify all other load customers served by the connection facility that is intended to be bypassed.~~

Section 11.2 of the Transmission System Code is amended as follows:

11. EMBEDDED GENERATION AND BYPASS COMPENSATION

11.2 BYPASS COMPENSATION

11.2.4 When a load customer provides its own connection facility to serve new load or transfers new load to the connection facility of another person, the transmitter shall not require bypass compensation from that customer.

11.2.5 Subject to sections 6.7.2, 11.2.6 and 11.2.7, for all or a portion of existing load a load customer may bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person, provided that the load customer compensates the transmitter.

11.2.6 For the purposes of sections 11.2.1 and 11.2.5, but subject to section 11.2.7, the transmitter shall calculate bypass compensation by first multiplying the net book value of the bypassed connection facility, including a salvage credit and reasonable removal and environmental remediation costs, if applicable, by the bypassed capacity on the relevant connection facility. The transmitter shall then divide the resulting figure by the total normal supply capacity of the bypassed connection facility. For purposes of this calculation:

(a) the bypassed capacity on the relevant connection facility shall be equal to the difference between the customer's existing load on that connection facility at the time of bypass and the customer's average monthly peak load in the three-month period following the date on which bypass occurred; and

(b) the normal supply capacity of the bypassed connection facility shall be determined by the transmitter in accordance with the Board-approved procedure referred to in section 6.2.7.

11.2.7 Where an economic evaluation, including an economic evaluation referred to in section 6.3.9 or 6.3.17A, was conducted by a transmitter for a load customer in relation to a connection facility on the basis of a load forecast, a transmitter shall not require bypass compensation from a customer under section 11.2.5 in relation to any load that represents that customer's contracted capacity, during the related economic evaluation period.

11.2.8 A transmitter should avoid overloading a connection facility above its total normal supply capacity. Where a connection facility has been overloaded, and a customer transfers the overload to its own connection facility or to the connection facility of another person, the transmitter shall not require bypass compensation from that customer.

11.2.9 A transmitter shall promptly notify the Board upon becoming aware that a load customer that is a distributor intends to bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person.

11.2.10 Where a transmitter becomes aware that a load customer intends to bypass a transmitter-owned connection facility with its own connection facility or the connection facility of another person, the transmitter shall promptly notify all other load customers served by the connection facility that is intended to be bypassed.

Appendix 5 (Methodology and Assumptions for an Economic Evaluation) of the Transmission System Code is amended by adding "Advanced Funding Revenues" to the formula for the Net Present Value (NPV) calculation as follows:

> Advanced Funding Revenues + Present Value ("PV") of Operating Cash Flow + PV of Capital Cost Allowance (ACCA@) Tax Shield - PV of Capital, calculated over the economic evaluation period.

In the "Notes" section of Appendix 5, the following is added:

> "Advanced Funding Revenues" are revenues collected by a distributor, through a mechanism that is approved by the Board, before the payment of a capital contribution to a transmitter is required.

Attachment B

to

Notice of Proposed Amendments to the Transmission System Code and the Distribution System Code

September 21, 2017

EB-2016-0003

Proposed Amendments to the Distribution System Code

Note: Underlined text indicates proposed additions to the Distribution System Code and strikethrough text indicates proposed deletions from the Distribution System Code. Numbered titles are included for convenience of reference only.

The definition of "customer" in the Distribution System Code is amended as follows:

1 GENERAL AND ADMINISTRATIVE PROVISIONS

1.2 Definitions

"customer" means a ~~person that has contracted for or intends to contract for connection of a building or an embedded generation facility~~ generator, consumer or embedded distributor whose facilities are connected to or are intended to be connected to a distributor's distribution system. This includes developers of residential or commercial sub-divisions;

Section 3 of the Distribution System Code is amended as follows:

3 CONNECTIONS AND EXPANSIONS

3.1 Connections

…..

3.1.5 For non-residential customers other than micro-embedded generation facility customers, a distributor shall ~~may~~ define a basic connection by rate class and recover the cost of connection either as part of its revenue requirement, or through a basic connection charge to the customer.

3.1.17 Where a distributor-owned asset has reached its end-of-life and is retired, the distributor shall undertake an assessment, in consultation with the applicable customer(s), to determine the appropriate capacity of the replacement asset. The distributor shall either:

(a) not recover a capital contribution from a customer to replace that asset, where the new asset is the same capacity or lower capacity; or

(b) recover a capital contribution from a customer to replace the asset, where the customer requires additional capacity. The capital contribution shall be limited to the incremental cost relative to the cost of a like-for-like replacement asset.

3.1.18 A distributor shall not connect to the distribution system of another distributor for the purpose of obtaining additional transmission connection capacity without the approval of the Board. The two distributors shall file a joint application for approval of the distribution asset, and the compensation to be provided by the connecting distributor to the other distributor ("the facilitating distributor"), with the Board and include as part of the application:

(a) confirmation by the IESO that the proposed distribution investment would avoid a higher cost investment in a transmission connection facility and would be the optimal infrastructure solution from a regional planning perspective;

(b) a copy of the agreement between the connecting distributor and the facilitating distributor; and

(c) evidence that there is sufficient capacity on the transmission connection facility that connects the facilitating distributor to the transmission network to meet the forecast needs of both distributors (i.e., a transmission connection investment will not be required during the forecast period), by providing the amount of excess capacity on the transmission connection facility and a load forecast from each distributor.

The agreement between the connecting distributor and the facilitating distributor shall ensure the customers of the facilitating distributor will not be negatively affected in any way due to the connection to the facilitating distributor's distribution system. In that regard, the agreement shall specify:

(a) the capital contribution that the connecting distributor will provide to the facilitating distributor to compensate it for all the costs incurred to facilitate the distribution investment that connects it, taking into account any capital contribution refund that may be required under section 6.3.17 of the Transmission System Code;

(b) any additional charges incurred by the facilitating distributor, due to the incremental load withdrawn from the transmission system by the connecting distributor, shall be recovered from the connecting distributor;

(c) any other costs that may be identified by the two distributors, for the purpose of cost recovery from the connecting distributor;

(d) the frequency by which the connecting distributor will provide an updated load forecast to the facilitating distributor.

For the purpose of this section, the connecting distributor shall be considered a customer of facilitating distributor under section 3.1.

3.1.19 For a new or modified distributor-owned asset that will serve a mix of load customers and generator customers, a distributor shall attribute the cost to the customers on a pro-rata basis, based on the apportioned benefit, taking into account factors including the respective rated peak output of each generation facility and the respective non-coincident incremental peak load requirements of each load customer, and the relative line length in proportion to the line length being shared by the customers.

3.1.20 Where a customer requests the relocation of a distributor-owned asset, the distributor shall recover from that customer the cost of relocating that connection facility.

3.1.21 Where a distributor-owned asset is relocated in the absence of a customer request, the distributor shall bear the cost of relocating that asset.

Expansions

3.2.4 The capital contribution that a distributor ~~may~~ shall charge an embedded distributor or a customer other than a generator ~~or distributor~~ to construct an expansion shall ~~not exceed~~ be equal to that customer's share of the difference between the present value of the projected capital costs and on-going maintenance costs for the facilities and the present value of the projected revenue for distribution services provided by those facilities. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B.

3.2.4A Where a distributor has been required to provide a capital contribution to a transmitter under the Transmission System Code for the purpose of modifying a transmitter-owned connection facility, and the modification also meets the needs of an embedded distributor and/or a load customer with a non-coincident peak demand that is equal to or greater than 3 MW, the distributor shall require a capital contribution from all beneficiaries that contributed to the need for the modification based on their respective incremental capacity requirements.

3.2.5 The capital contribution that a distributor shall~~may~~ charge a generator to construct an expansion to connect a generation facility to the distributor's distribution system shall ~~not exceed~~ be equal to the generator's share of the present value of the projected capital costs and on-going maintenance costs for the facilities. Projected revenue and avoided costs from the generation facility shall be assumed to be zero, unless otherwise determined by rates approved by the Board. The methodology and inputs that a distributor shall use to calculate this amount are described in Appendix B.

3.2.20 For expansions that require a capital contribution, a distributor ~~may~~ shall require the customer to provide an expansion deposit for up to 100% of the present value of the forecasted revenues as described in Appendix B. For expansions that do not require a capital contribution, a distributor ~~may~~ shall require the customer to provide an expansion deposit for up to 100% of the present value of the projected capital costs and on-going maintenance costs of the expansion project.

3.2.21 ~~If an~~ The expansion deposit ~~is~~ collected under section 3.2.20~~, the expansion deposit~~ shall cover both the forecast risk (the risk associated with whether the projected revenue for the expansion will materialize as forecasted) and the asset risk (the risk associated with ensuring that the expansion is constructed, that it is completed to the proper design and technical standards and specifications, and that the facilities operate properly when energized) related to the expansion.

3.2.23 Once the facilities are energized and subject to sections 3.2.22 and 3.2.24, the distributor shall annually return the percentage of the expansion deposit in proportion to the actual connections (for residential developments) or actual demand (for commercial and industrial developments) that materialized in that year (i.e., if twenty percent of the forecasted connections or demand materialized in that year, then the distributor shall return to the customer twenty percent of the expansion deposit). This annual calculation shall only be done for the duration of the customer connection horizon – 15 years (if the customer's non-coincident peak demand meets or exceeds 3 MW) or five years (if the customer's demand is lower than 3 MW)~~as defined in Appendix B~~. If at the end of the applicable customer connection horizon the forecasted connections (for residential developments) or forecasted demand (for commercial and industrial developments) have not materialized, the distributor shall be allowed to retain the remaining portion of the expansion deposit.

3.2.24 If the alternative bid option was chosen, the distributor shall~~may~~ retain at least ~~up to~~ ten percent of the expansion deposit for a warranty period for at least two years. This portion of the expansion deposit can be applied to any work required to repair the expansion facilities within the two year warranty period. The two year warranty period begins:

(a) when the last forecasted connection in the expansion project materializes (for residential developments) or the last forecasted demand materializes (for commercial and industrial developments); or

(b) at the end of the customer connection horizon – 15 years (if the customer's non-coincident peak demand meets or exceeds 3 MW) or five years (if the customer's demand is lower than 3 MW)~~as defined in Appendix B~~, whichever is first. The distributor shall return any remaining portion of this part of the expansion deposit at the end of the two year warranty period.

3.2.27 Unforecasted customers that connect to the distribution system during the customer connection horizon~~-~~ – 15 years (if the customer's non-coincident peak demand meets or exceeds 3 MW) or five years (if the customer's demand is lower than 3 MW) – ~~as defined in Appendix B~~ will benefit from the earlier expansion and should contribute their share. In such an event, the initial contributors shall be entitled to a rebate from the distributor. A distributor shall collect from the unforecasted customers an amount equal to the rebate the distributor shall pay to the initial contributors. The amount of the rebate shall be determined as follows:

(a) for a period of up to 15 years for a large load customer (i.e., a customer whose non-coincident peak demand meets or exceeds 3 MW) and five years for a customer whose non-coincident peak demand is below 3 MW ~~the customer connection horizon as defined in Appendix B~~, the initial contributor shall be entitled to a rebate without interest, based on apportioned benefit for the remaining period; and

(b) the apportioned benefit shall be determined by considering such factors as the relative name-plate rated capacity of the generator customers~~parties~~, the relative non-coincident peak demand~~load level~~ of the load customers~~parties~~ and the relative line length in proportion to the line length being shared by both customers~~parties~~, as applicable.

3.5 Bypass Compensation

3.5.1 A distributor shall require bypass compensation from a customer, with a non-coincident peak demand that meets or exceeds 3 MW, if:

(a) the customer disconnects its facility from the distributor's distribution system and subsequently connects that facility to a generation facility or to the facilities of any customer such that both the load facility and a generation facility are connected to the distributor's distribution system on that customer's side of the connection point; and

(b) the distributor will no longer receive rate revenues in relation to that distribution asset.

The distributor shall calculate bypass compensation using the methodology set out in section 3.5.3.

3.5.2 A distributor shall not require bypass compensation from any customer:

(a) when a load customer provides its own facility to serve new load or transfers new load to the facility of another person;

(b) for any reduction in a customer's existing load served by the distributor's distribution system that the customer has demonstrated to the reasonable satisfaction of the distributor (such as by means of an energy study or audit) has resulted from embedded renewable generation, energy conservation, energy efficiency or load management activities; or

(c) where a distributor-owned asset has been overloaded, and a customer transfers the overload to its own facility or to the facility of another person.

3.5.3 For the purposes of section 3.5.1, the distributor shall calculate bypass compensation by first multiplying the net book value of the bypassed distributor-owned asset (including a salvage credit and reasonable removal and environmental remediation costs, if applicable) by the bypassed capacity on the relevant distributor-owned asset. The distributor shall then divide the resulting figure by the maximum amount of load that can be supplied by the bypassed distributor-owned asset. For the purposes of this calculation, the bypassed capacity on the relevant distributor-owned asset shall be equal to the difference between the customer's existing load on that distributor-owned asset at the time of bypass and the customer's average monthly peak load in the three-month period following the date on which bypass occurred.

Appendix B (Methodology and Assumptions for an Economic Evaluation) of the Distribution System Code is amended by adding new bullet (a), under "Revenue Forecasting", and making other consequential changes set out below:

(a) Advanced Funding Revenues collected by a distributor and recorded in a deferral account;

~~(a)~~ (b) Total forecasted customer additions over the Customer Connection Horizon, by class as specified below;

…

The following explanation of "Advanced Funding Revenues" is also proposed to be added to Appendix B.

"Advanced Funding Revenues" are revenues collected by a distributor, through a mechanism that is approved by the Board, before the payment of a capital contribution to a transmitter is required.