Ontario Energy Board

Staff Discussion Paper

on Approaches to Mitigation for Electricity Transmitters & Distributors

EB-2010-0378

November 8, 2011

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Executive Summary

In its October 27, 2010 letter to stakeholders, the Ontario Energy Board (the "Board") described the context for a renewed framework for electricity transmitters and distributors, acknowledging that need for significant investment in the sector and concerns over bill increases are leading to a sharper focus on the total cost to consumers.

In light of these concerns, on December 17, 2010, the Board initiated a coordinated consultation process for several inter-related policy initiatives. Approaches to mitigation by electricity transmitters and distributors is the subject of this paper. This paper provides a review and summary of the Board's current approach to mitigation, identifies issues for consideration, and provides a summary and discussion of potential approaches to mitigation. While the focus of this paper is on regulated electricity transmitters and distributors, staff believes that the Board could also consider a similar framework, or aspects of it, for other regulated entities, such as Ontario Power Generation.

Staff has prepared this paper to solicit further input from all interested stakeholders on a range of approaches to help utilities and the Board mitigate the effects of rate and/or bill impacts. While examples are provided to facilitate consultations, staff does not make recommendations or express preferences.

This paper has been prepared by staff with the advice of its consultant Navigant Consulting Ltd. ("Navigant"). Navigant's report entitled *Transmission and Distribution Rate Mitigation Measures for Ontario* provides a summary of research and expert advice.

This paper identifies a number of specific issues for stakeholder comment which relate to the following general topics:

- The implications, if any, of defining mitigation as considerations that are brought to bear only after a cost has been determined by the Board to be reasonable, prudent and/or eligible for recovery.

- The Board's mitigation framework and threshold.

- The appropriate role of the conventional and alternative mechanisms for mitigation available to the Board.

It is expected that the sum of the information shared, submissions made, advice given and knowledge built during this coordinated consultation process will serve to inform the Board as it works to renew the regulatory framework for the electricity sector in Ontario.

Table of Contents

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1 Introduction

The Board's October 27, 2010 letter to stakeholders

In its October 27, 2010 letter to stakeholders (the "October 27th Letter"), the Ontario Energy Board (the "Board") described the context for a renewed framework for electricity transmitters and distributors, acknowledging that need for significant investment in the sector and concerns over bill increases are leading to a sharper focus on the total cost to consumers. This is discussed in more detail in Attachment A to the cover letter issued with this paper.

In light of these concerns, on December 17, 2010, the Board initiated a coordinated consultation process for several inter-related policy initiatives.

February 2, 2011 stakeholder meeting

A stakeholder consultation meeting was held on February 2, 2011 at which Board staff ("staff") made presentations describing the context in which policies will be developed, potential guiding concepts for the work, potential issues to be considered, and an approach to the upcoming consultations. The purpose of the meeting was to provide all interested stakeholders with an opportunity to exchange ideas with staff and each other on the scope of the inter-related policy initiatives and to provide greater detail on the planned consultation.

How information from this coordinated consultation process will be used

This coordinated consultation process will lead to the formulation of Board policies in relation to the topics of network planning, mitigation and performance in a renewed regulatory framework for electricity. Any amendments to Board documents (e.g. filing requirements) that may be required or desirable to give effect to the policies would be addressed subsequently.

The Mitigation Initiative

With respect to mitigation, this coordinated consultation process will assist the Board's determination of its policies in relation to considerations for mitigating the effects of rate and/or bill impacts that will be used to inform the setting of rates whether through a cost of service review or though a multi-year rate adjustment mechanism or as part of a specific application.

Overview of this Paper

Approaches to mitigation by electricity transmitters and distributors is the subject of this paper. Staff has prepared this paper to solicit further input from interested stakeholders on a range of approaches to help utilities[1] and the Board mitigate the effects of rate and/or bill impacts. While examples are provided to facilitate consultations, staff does not make recommendations or express preferences. Moreover, while the focus of this paper is on regulated electricity transmitters and distributors, staff is of the view that the Board could also consider a similar framework, or aspects of it, for other regulated entities, such as Ontario Power Generation ("OPG").

Consideration of affordability by low-income consumers is not within the scope of this consultation. Rather, staff believes this issue is best addressed through the Board's initiatives for low-income consumers relating to emergency financial assistance (EB-2008-0150) and customer service requirements (EB-2007-0722).

Navigant Consulting Inc. advising

This paper has been prepared by staff with the advice of its consultant Navigant Consulting Ltd. Navigant's report entitled

[1] Unless otherwise indicated, throughout this report the term "utilities" is used to refer collectively to both electricity transmitters and distributors.

Transmission and Distribution Rate Mitigation Measures for Ontario (the “Navigant Report”) advises on:

- mitigation in theory and practice;
- approaches used in other jurisdictions; and,
- consideration of rate and/or bill impact thresholds.

The Navigant Report is available on the Board’s website.

Staff invites comment from stakeholders in order to provide it and the Board with a thorough analysis of alternatives and requisite issues.

Organization of this Paper

The paper is organized as follows. Chapter 2 provides a review and summary of the Board’s current approach to mitigation. Chapter 3 outlines considerations for a mitigation framework. Chapter 4 provides a summary and discussion of potential approaches to mitigation. A number of issues for stakeholder comment are identified throughout this paper, and Appendix A provides a summary list of these issues.

2 The Board's Current Approach to Mitigation

Concern over rate and/or bill impacts by the Board, utilities and consumers has, and always will be, a regulatory constant. However, the specific causes, forces and circumstances that underlie or drive the impacts have changed over time. In 2000, the concern focused on the potential bill impacts arising from rate unbundling and the provision for market returns embodied in the corporatization and commercialization of electricity distribution utilities. In 2006, distribution rates were being adjusted following a multi-year rate freeze and there was some "catch-up" of cost recovery. Rate and/or bill impacts over the next several years are expected to be driven by significant levels of investment for the renewal of assets to maintain appropriate service levels and system reliability and to connect new generation.

The Rate-Setting Framework

The Board's framework for mitigation is implemented within the context of the Board's rate-setting processes. To help establish a common understanding in this consultation, a brief description of the Board's current approach to rate-setting is set out below.

The Board's responsibility is to set rates that are just and reasonable. The legislative framework provides the Board the discretion to select the most appropriate approach to rate-setting. The Board's guiding objectives are set out in section 1 of the *Ontario Energy Board Act, 1998* (the "Act").

Electricity distribution rate plan

The Board rate regulates 80 electricity distributors. In 2006, the Board established a multi-year rate setting plan to, amongst other matters, divide distributor rate re-basing reviews beginning in 2008 into three yearly tranches (i.e., approximately 30 distributors per year starting in 2008). As any rate-related studies and methodologies are reviewed and completed (e.g., cost allocation, cost of capital, depreciation studies, etc.), the implementation of new methodologies occur at the regularly scheduled interval for the distributors. In between re-basing rate reviews, distributors are subject to incentive regulation rate reviews.

Electricity transmission

The Board rate regulates six electricity transmitters. Uniform transmission rates for the province are set based on the combined revenue requirements that have been approved by the Board in the cost of service rate (i.e., rate re-basing) application proceedings for each individual transmission company.[2]

Rate Re-basing

Rate re-basing reviews for Ontario electricity utilities are carried out upon receipt by the Board of cost of service rate applications based on the Board's "Filing Requirements for Transmission and Distribution Applications". Applicants are expected to file for cost of service rate applications based on a forward test year.

Traditional cost of service regulation

The Board sets rates to enable a utility to recover the forecasted costs which the distributor will prudently incur to provide regulated services. This cost includes a return on capital. Rate reviews are held periodically in which estimates are made for the test year of

[2] The revenue requirement of Hydro One Networks Inc., as the largest licensed transmitter, predominantly determines the uniform transmission rates.

the cost of capital, labour, and other inputs that reflect the provision of regulated services. This becomes the utility's base rate revenue requirement.

Incentive Regulation for Electricity Distributors

Benchmarking and capital investment module

The Board's third incentive regulation plan (3rd Generation IR), which was established in 2008, makes use of benchmarking and contains an optional capital investment module[3], both of which are designed to promote efficiency, yet be flexible enough to accommodate diversity in companies' investment requirements.

Core Plan

At the core of the plan is an empirically-based "inflation minus X-factor" price-cap form of rate adjustment mechanism. The Board determined that the X-factors for individual distributors will consist of an empirically derived industry productivity trend (productivity factor[4]) and stretch factor[5].

Implications for Mitigation

As noted above, the Board's multi-year rate setting plan for electricity distributors was established in 2006. To the extent that any step-increases in rates exist at re-basing, staff suggests that this may indicate an area where consideration of mitigation may be

[3] The capital module is intended to be reserved for unusual circumstances that are not captured as a Z-factor and where the distributor has no other options for meeting its capital requirements within the context of its financial capacities underpinned by existing rates.
[4] The productivity factor is set based on estimated total-factor productivity ("TFP") for the distribution sector. Development of an Ontario-specific TFP trend was hindered by a lack of data covering a sufficient period of time; thus at present the trend is based on U.S. data.
[5] Differentiated stretch factors are also a feature of the 3rd Generation IR plan. Benchmarking provides the architecture for the annual assignment of stretch factors to distributors. This is discussed in more detail in the staff discussion paper in EB-2010-0379.

appropriate. While design considerations for the next generation IR plan are not within the scope of this consultation, the Board's approach to rate-setting may need to be taken into account in the context of considering a framework for mitigation. In addition, any policies that are developed as a result of this consultation may, as necessary, inform the development of the next generation IR framework.

2.1 The Mitigation Framework

The Board's existing policy regarding rate and/or bill impact mitigation originated in the context of rate unbundling. It was then refined in the context of the development of the 2006 electricity distribution rate ("EDR") adjustment process.

2.1.1 Rate Unbundling

Consultation on framework for electricity distribution rates

In October 1998, the Board initiated a consultation process (RP-1999-0034) to develop the regulatory framework for administering electricity distribution rates in Ontario. In January 2000, the Board issued its Decision with Reasons[6] setting out its decisions on a number of generic issues relating to the framework for rate setting, including mitigation. In that Decision, the Board indicated its expectation that distributors consider bill impacts when evaluating the appropriate split between the fixed customer charge and the volumetric charge. There was particular concern about the impact of this two-part rate structure on customers with low consumption.

[6] Ontario Energy Board. RP-1999-0034. Decision with Reasons, in the matter of a proceeding under sections 19(4), 57, 70, and 78 of the *Ontario Energy Board Act, 1998* S.O. 1998, c. 15, Sched. B to determine certain matters relating to the Proposed Electric Distribution Rate Handbook for licensed electricity distributors. January 18, 2000.

10 % threshold established

The Board also indicated that, as a guideline, "the increase in the total electricity bill resulting from rate restructuring for these customer groups should not exceed 10 per cent on an annualized basis".[7]

In the same proceeding, concern was also expressed by stakeholders about the potential bill impacts resulting from the move to market-based returns for distributors (also known as the "market adjusted revenue requirement" or "MARR"). In order to address this concern, the Board approved a deferral mechanism, and encouraged distributors to propose initial rates that would not result in undue rate impacts, using the deferral mechanism to track any deferred return for future recovery. While distributors were not required to phase-in the transition to a market-based return, the Board indicated that it would "….either seek revised proposals or fix the rates itself should it be found that rate impacts have not been adequately addressed".[8]

In March 2000 the Board issued its "Electricity Distribution Rate Handbook" which set out the rate principles, policies and procedures for establishing initial unbundled distribution rates, and was consistent with the conclusions in the Decision with Reasons noted above.[9]

[7] Ibid., page 20.
[8] Ibid., page 25.
[9] The Electricity Distribution Rate Handbook was initially issued in March 2000, but subsequently revised to reflect the decisions made in response to the Minister's Directive of June 2000.

Ministerial Directive

Subsequent to the Board's January 2000 Decision with Reasons noted above, the Government issued a Directive to the Board in June 2000 which stated, in part:[10] [11]

> *In making an order under section 78 of the Act approving or fixing just and reasonable rates for the distributing of electricity by a municipal electric utility, in being guided by the objectives set out in section 1 of the Act, the Board shall give primacy to the objective "to protect the interests of consumers with respect to prices and the reliability and quality of electricity service".*

In response, the Board initiated a proceeding (RP-1999-0069) to consider the implications of the Minister's Directive. In its Decision with Reasons in that proceeding, the Board adjusted some elements of the framework approved in its earlier proceeding in order to address the Minister's Directive. Specifically, the Board concluded that a three year phase-in of MARR was required, with no deferral of MARR forgone, in the event that a distributor chose to include in its rates for any given year an amount less than the increment permitted.[12] The three year period was chosen to be consistent with the timeframe of the first generation performance based rates ("PBR") plan.

The Board also reviewed its earlier decisions regarding the 10 per cent threshold for rate restructuring and concluded that it was not persuaded that this guideline needed to be altered.[13] [14]

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[10] Directive to the Ontario Energy Board from the Minister of Energy, Science and Technology, June 7, 2000.
[11] The Directive is no longer in effect.
[12] Ontario Energy Board. *Electricity Distribution Rate Handbook*. March 9, 2000. Section 5.5.2.
[13] Ontario Energy Board.RP-1999-0069. Decision with Reasons, in the matter of a proceeding under sections 129(7) and 78 of the *Ontario Energy Board Act, 1998* S.O. 1998, c.15, Sched. B to determine certain matters relating to the Minister's Directive dated June 7, 2000. September 29, 2000. Page 19.
[14] Section 3.3.1 of the Electricity Distribution Rate Handbook provides more detail on this requirement: *In moving to a two-part distribution rate structure, some*

2.1.2 2006 Electricity Distribution Rate Process and Beyond

Bill 210

The electricity distribution rate-setting framework established at the time of unbundling was initially intended to have a three year term. However, with the passage of Bill 210 (*Electricity Pricing, Conservation and Supply Act, 2002*) in November 2002, distribution rates were frozen at existing levels and distributors were not allowed to adjust their rates in 2003 as originally envisioned.[15] Following this rate freeze, distributors were permitted, in 2006, to file applications for rate adjustments based on a cost of service approach

2006 Electricity Distribution Rate Handbook

On May 11, 2005 the Board issued the *2006 Electricity Distribution Rate Handbook: Report of the Board* (the "2006 EDR Report") which sets out the Board's views on the 2006 Electricity Distribution Rate Handbook ("2006 EDR Handbook").[16] In the 2006 EDR Report, the Board indicates that it considers diligence respecting rate increases to be a core responsibility of distributors, but

small volume customers may see a significant rate impact. The impact increases with the size of the monthly service charge. The service charge should be set so that rate impact resulting from the change in rate structure does not exceed 10 per cent of total bill (relative to annual bill using current bundled rates), for the small volume customers group in a rate class (see Chapter 4). In mitigating the impact on total bill, the monthly service charge should be lowered and the volumetric charge raised to a point where the impact on the small volume customers group within a rate class is less than 10 per cent. Class revenue requirement neutrality must be maintained in meeting the rate impact mitigation requirement.

[15] Bill 210 also froze the commodity price for electricity payable by low-volume and designated customers at 4.3 cents per kWh. In 2003, the government announced that distributors would be allowed to recover some of the costs put on hold by Bill 210 and to also apply for their third instalment of MARR in 2005, provided the funds were used for Conservation and Demand Management initiatives.

[16] The 2006 EDR Handbook sets out the Board's policies guiding the 2006 distribution rate adjustment process.

recognizes that there are elements of the customer bill that are beyond the control of the distributor.[17]

> *The Board considers that diligence respecting rate increases is a core responsibility of the distributor. It is a fundamental element of customer relations to manage the expectations of consumers and to remedy, where possible, and to the extent reasonable, hardship occasioned by material increases in rates.*
>
> *It is important to recognize at the same time that there are limitations on the ability of a distributor to cure these situations.*
>
> *First, a distributor has to act in a manner that is non-discriminatory as between individual customers and classes of customers.*
>
> *Second, a significant portion of the customer bill derives directly from the price of the commodity itself, and other elements that are beyond the control of the distributor. The distribution charges, which are set by the Board through the Handbook process currently, represent approximately 25% of the bill received by customers.*

The 2006 EDR Report also states, in part:[18]

> *The Board sees its role in this subject area as providing direction to the a [sic] distributor in its efforts without prescribing any particular mitigation methodology or response. Mitigation proposals will need to be considered on a case-by-case basis. There is no compelling single methodology that can equitably address all of the situations that may arise.*

Consistent with this position, the 2006 EDR Handbook does not prescribe any particular methodology or approach to be used by distributors to achieve mitigation, but does indicate when distributors are required to consider mitigation.

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[17] Ontario Energy Board. RP-2004-0188. *2006 Electricity Distribution Rate Handbook: Report of the Board*. May 11, 2005. Page 89.
[18] Ibid., page 89.

10% Threshold

Specifically, as set out in Chapter 13 of the 2006 EDR Handbook, where the total bill increases for any customer class or group resulting from the change in distribution charges exceed 10 per cent, holding other charges constant, a distributor is required to file a mitigation plan. Such a plan is also required where the combined impact of distribution rate increases and rate harmonization result in total bill increases for any customer class or group that exceed 10 per cent.

In order to guide distributors' development of mitigation proposals, the Board provides some guidance in the 2006 EDR Report.[19]

> *….As a general rule, the Board does not favour mitigation plans which are dependent on imposing otherwise unwarranted increases on one customer class in order to reduce increases for another. Adjustments within a class of customers are much more acceptable, such as changes to the fixed/variable splits which may have the effect of reducing bill impact.*
>
> *The Board also considers that mitigation plans that are predicated on reductions in the revenue requirement are problematic. Revenue requirement reductions should inure to the benefit of all customers within the franchise, and should form part of the basic rate application, not a response to hardship cases. It is important that a distributor not compromise its overall ability to deliver reliable service to the service area in order to address discrete instances of hardship.*
>
> *A distributor may choose to reduce its regulated rate of return in order to address situations requiring mitigation plans. This approach may be a useful tool in dealing with hardship increases. Such a course of action should be prudently considered in light of the medium and long-term financial health of the organization and its ability to provide reliable service.*

[19] Ibid., page 90-91.

While the 2006 EDR Handbook was developed for the 2006 rate setting process, certain policies set out in that document, including that on mitigation, have continued to apply to rate setting processes beyond 2006.[20]

2.2 Implementation of the Board’s Mitigation Policy

Mitigation considered on a case-by-case basis

As noted in section 2.1.2 above, in accordance with the Board’s existing policy, the Board considers the need for, and nature of, mitigation on a case-by-base basis. The following sections (2.2.1 to 2.2.6) provide an overview of how specific aspects of the Board’s mitigation policy have been implemented, based on a review of Board proceedings where mitigation was considered.

2.2.1 Increases Requiring Mitigation

A review of previous Board decisions and policy documents indicates that the need for, and nature of, mitigation has been considered in the context of rate increases resulting from the following:

- rate harmonization;
- customer transfers (to address long-term load transfers);
- regulatory asset recovery;
- changes to revenue-to-cost ratios to be consistent with Board targets;[21]

[20] These policies are now set out in Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, dated June 22, 2011.
[21] See for example: Ontario Energy Board. EB-2010-0219. *Report of the Board: Review of Electricity Distribution Cost Allocation Policy*. March 31, 2011. Page 35: *To the extent that the application of the Board’s cost allocation policies results in a significant shift in the rate burden amongst classes relative to the status quo, distributors should be prepared to address potential mitigation measures. As in the past, and until a review of alternative options is completed*

- clearance of deferral and variance accounts;[22]
- smart meter cost recovery;
- connection of renewable generation and development of a smart grid; and
- transition to International Financial Reporting Standards.

2.2.2 Mechanisms for Mitigation

Cost recovery deferred or phased-in

A deferral or phase-in of approved costs has generally been the approach approved by the Board to address overall distribution rate increases, with the deferred revenues tracked in deferral accounts for future recovery. Generally, the recovery period has not exceeded four years in order to minimize intergenerational inequity. Utilities were permitted to earn interest on the deferred amount, at the Board's prescribed rate.[23]

Deferring rate decreases

Staff notes that the Board has also approved proposals to defer or phase-in rate *decreases* as a mitigation measure. For example, some distributors have proposed deferring or phasing in the refund resulting from disposition of deferral and variance accounts in a manner that avoids customers facing a decrease in rates, and then

as part of the Board's rate mitigation consultation, the general approach to mitigating rate impacts should be to bring the affected class into the allowed range over multiple years.

[22] See for example: Ontario Energy Board. EB-2008-0046. *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)*. July 31, 2009. Page 11: *The Board also agrees that when the impact on the total bill exceeds 10% for any given rate class, including the impact of both the disposition of Account balances and any other rate change, a distributor must also file a rate mitigation plan.*

[23] On November 28, 2006, the Board approved a methodology to prescribe interest rates for the approved regulatory accounts under the Uniform System of Accounts for natural gas utilities and electricity distributors. The prescribed interest rate for Board-approved deferral and variance accounts is equal to the Bankers' Acceptances three-month rate, as published on the Bank of Canada's website, plus a spread of 25 basis points. The applicable rates are posted on the Board's website.

a subsequent and significant increase in the following year when the end of the refund coincides with a cost of service application.[24]

Customer rebates

Customer rebates have been used as a mitigation measure in cases of rate harmonization and customer transfers (to remedy long-term load transfers). In these cases, upon transfer, the customer was charged the rates of the acquiring distributor. The acquiring distributor established a credit equivalent to one-half of one year's increase on the delivery portion of the bill based on the individual customer's previous 12 months' consumption. The credit was then applied in equal installments over the course of one year.

Funding adders

Anticipated significant capital expenditures have been addressed through the use of funding adders, which are intended to provide advance funding on an interim basis for certain investments and to mitigate or smooth the anticipated rate impact when recovery of these costs are approved by the Board. To date, the Board has

[24] See for example EB-2009-0238, an application by Norfolk Power for distribution rates effective May 1, 2010. Norfolk Power requested approval to refund the balance of Group 1 deferral and variance account balance over a period of four years instead of one, in part due to concerns about rate volatility. Norfolk stated that it intended to file a 2011 cost of service application and anticipated upward pressure on rates due to rate base increase and approval to recover stranded meter costs. In its Decision, dated April 6, 2010, the Board accepted Norfolk's rationale but concluded that a four year disposition period was too long. The Board accepted Norfolk's alternative proposal to dispose 25 per cent of the Group 1 account balances in 2010 and the remaining 75 per cent in 2011.
See also EB-2009-0200, an application by Kenora Hydro for distribution rates effective May 1, 2010. Kenora Hydro proposed to defer disposition of its Group 1 variance and deferral accounts, noting that it intended to file a cost of service application for 2011, and that any rate decrease in 2010 would cause customer confusion and not promote rate stability since customers would experience an increase in 2011. The Board, in its Decision dated April 16, 2010 accepted Kenora's proposal, but indicated that it expected Kenora to include a request for disposition of the account balances in its application for 2011 rates. In its application for 2011 rates (EB-2010-0135), Kenora requested disposition of the balances over a four year period, as a means of reducing rate shock. In its Decision and Order, dated May 25, 2011, the Board concluded that it had not been persuaded that there was sufficient reason to depart from the default one-year recovery period, and that a one-year disposition would result in significant opportunity for mitigation in the context of the current application.

made available funding adders in relation to smart meter costs, and most recently in relation to connection of renewable generation and smart grid development. All distributors have received approval for funding adders for smart meter investments. Hydro One Networks Inc. ("Hydro One") and Hydro One Brampton Networks Inc. have each received approval for a funding adder for Green Energy Act related initiatives, and other distributors currently have applications before the Board.

Inclusion of CWIP in rate base

The Navigant Report suggests that the inclusion of CWIP in rate base[25] can be used for the purposes of mitigation. In January 2010 the Board issued the *Report of the Board: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario* (the "Infrastructure Report"), a report which focused on conventional and alternative treatments for costs incurred in infrastructure development. The Infrastructure Report noted that one of the two principal benefits of including CWIP in rate base was that "…it provides a smoothing, or phased-in, effect on rates and thereby mitigates the rate impact that might otherwise take place when large new plant is placed into service".[26]

The Board has considered the use of this mechanism in two recent proceedings: in the context of the Bruce to Milton transmission line project as part of Hydro One's application for 2010 and 2011

[25] CWIP, or "construction work in progress" is a temporary holding account that captures the expended costs incurred in the design and construction of facilities that meet general capitalization rules and thresholds. During the construction period, the capitalized expenditures and the associated carrying charges are accumulated and included into CWIP. Traditionally, when the project enters into service, these expenditures and carrying charges are included in rate base and recovered in rates over the useful life of the asset.

[26] Ontario Energy Board. EB-2009-0152. *Report of the Board: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*. January 15, 2010, page 15.

transmission revenue requirement and rates (EB-2010-0002)[27]; and as part of OPG's application for payment amounts for prescribed facilities for 2011 and 2012 (EB-2010-0008)[28].

The Board rejected Hydro One's proposal in part because the Board was not convinced that the effects of any mitigation or rate smoothing would be particularly meaningful to Hydro One's customers. In its Decision the Board also noted that while mitigation or rate smoothing can be useful regulatory instruments, they ought not to be overused such that consumers fail to appreciate the direct and unavoidable consequences of utility activities, including infrastructure investment.

In the context of OPG's application, the issue of potential ratepayer benefits associated with the inclusion of CWIP in rate base was also addressed. While the Board denied the request on the basis that the project was too early in its development to warrant consideration and approval of such a mechanism, the Board indicated that it would consider the proposal again in the future, but would expect more persuasive evidence to support the argument that there is a benefit to ratepayers of paying earlier for large multi-year projects.

[27] Ontario Energy Board. EB-2010-0002. Decision with Reasons, in the matter of an application by Hydro One Networks Inc., 2011 and 2012 transmission revenue requirement and rates. December 23, 2010. In its application, Hydro One Networks Inc. sought an accelerated recovery of CWIP for the Bruce to Milton transmission line project. Hydro One argued that including costs related to construction associated with the project into rate base as they are incurred, rather than at the time they are placed in service, lowers the overall cost of the project to ratepayers, and would also serve as a rate smoothing and mitigation mechanism.

[28] In EB-2010-0008 OPG applied for accelerated recovery of CWIP on the basis that there would be benefits to ratepayers through rate smoothing and lower credit costs.

2.2.3 Target of Mitigation

Focus on "typical" customer

The Board's existing mitigation policy focuses on the "typical" customer within each rate class and whether the total bill impact experienced by that customer exceeds 10 per cent. For the residential class, a "typical" customer is defined as being one that consumes 800 kWh per month[29].

The Board has found, in most cases, that mitigation was neither required nor appropriate to address the impacts experienced by individual customers.

For example, in RP-2000-0023/EB-2001-0016, an application by Hydro One for 2002 distribution rates, Hydro One's proposal to eliminate legacy time-of-use rates would result in ten of the fifty-six customers previously served by these rates experiencing significant bill impacts.[30] As part of its reasons set out in the Decision on this matter, the Board noted that the anticipated impacts were in reference to total electricity bills and not the customers' operations, and that "[r]egulatory principles and long-standing regulatory

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[29] Prior to 2010, the consumption level used to define a "typical" residential customer was 1,000 kWh per month.

[30] Impacts ranged from a low of approximately 35 per cent to a high of approximately 110 per cent on the total bill, assuming a constant cost for the commodity. The ten customers had taken significant steps to modify their operations to take advantage of the TOU rates. The remaining customers, who had not changed their usage profiles in response to the TOU rates, were expected to experience much lower impacts, ranging from -6 per cent to 15 per cent. Hydro One proposed a transitional mitigation rate for those affected customers whose load ratio between off-peak and on-peak usage was two to one or greater, based on 1999 actual customer data. The above-noted ten customers met those qualifications. Hydro One's recommended rates for these ten customers were designed to contain bill impacts to 10 per cent or less in the first year of the two-year transitional period, and a maximum impact of 30 per cent in the second year. Hydro One also requested an accounting order which would enable it to record, for future recovery, revenue shortfalls related to the rate mitigation plan for these ten legacy TOU customers.

practices of treating customers in a class equally, cannot and should not be compromised on the basis of bill impacts, without placing such impacts in an operational perspective.”[31] The Board concluded that while it was sympathetic to the potential impact that a new rate structure can have on certain customers or customer groups, providing a few customers special treatment based on historical considerations is not in the public interest.

Similarly, in its Decision on Peterborough Distribution Inc.’s (“Peterborough Distribution”) application for 2009 distribution rates, the Board rejected a targeted mitigation plan proposed by an intervenor in the hearing on the basis that the typical residential customer would not experience impacts on the total bill in excess of 10 per cent and that the higher impacts would only be experienced by 10 residential customers with very low use.[32] Further, the Board found that the collective benefits of harmonizing rates outweighed the additional costs for a few residential customers.

However, in EB-2007-0681, an application by Hydro One for 2008 distribution rates, the Board approved Hydro One’s targeted

[31] Ontario Energy Board. RP-2000-0023/EB-2001-0016. Decision with Reasons, in the Matter of an Application by Hydro One Networks Company Inc. for an Order or Orders approving rates for the distribution of electricity. Page 25.

[32] Ontario Energy Board. EB-2008-0241. Decision, in the Matter of an application by Peterborough Distribution Inc. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2009. June 1, 2009.
As a result of rate harmonization, certain low use residential customers would experience bill impacts in excess of 10 per cent. Peterborough justified not implementing mitigation for these customers on the basis that the dollar impact was less than $4.45 per month. The Vulnerable Energy Consumers Coalition submitted that mitigation measures should be implemented to limit the impact for these customers to 15 per cent of the distribution component of the bill. Several non-residential classes would also experience total bill impacts in excess of 10 per cent due to adjustments to revenue to cost ratios. In this case, the bill impacts would be experienced by the classes as a whole, and not limited to specific group of customers within the class.

mitigation plan. As part of its mitigation plan to address the impacts resulting from rate harmonization, Hydro One initially proposed to limit the total bill impact for customers with average consumption within each customer class. However, in response to intervenor concerns about the impacts on low use customers, Hydro One also proposed additional mitigation to limit the impact on acquired low use residential and general service customers.[33] In approving the targeted mitigation plan, the Board noted that Hydro One introduced the plan in response to intervenor concerns, and that these concerns were substantially addressed as a result of Hydro One's proposal.

2.2.4 Application of the 10 Per Cent Threshold

Implementation of Board policy supersedes mitigation

Generally, mitigation has been required where the impact experienced by the typical customer exceeds 10 per cent. However, the Board has made exceptions, particularly for non-residential rate classes. For example, in the Peterborough Distribution application noted above, the Board determined that mitigation was not required for several non-residential classes since the rate increase was a result of bringing revenue-to-cost ratios more in line with the Board's target range to reduce inter-class cross-subsidization. The Board made similar conclusions in the

[33] Under Hydro One's mitigation plan, total bill impacts were limited to a maximum of 10 per cent in 2008, 8 per cent in 2009 and 7 per cent in 2010 for customers with average consumption within each customer class. Acquired Residential customers with total bill impacts higher than 15 per cent for 2008 would have the impact on their total bill limited to a maximum of $3 per month. The mitigation would be in the form of a fixed dollar rebate based on the last actual annual billing data available. For Acquired General Service customers the total bill impact will be limited to the higher of 15 per cent and $10 for Energy Billed customers and 15 per cent and $100 for Demand Billed. The cost of this mitigation (revenue foregone and incremental costs associated with implementation of the plan) would be added to the proposed mitigation variance account.

context of an application by Tillsonburg Hydro Inc. for distribution rates for the 2009 rate year[34], where the bill impacts resulted from revisions to cost allocation and rate design to reflect the Board's guidelines in relation to those matters.

2.2.5 Analysis of Total Bill

The Board has generally not required mitigation to address impacts stemming from non-delivery charges, but has expressed an awareness of the impacts of these other charges on consumers.

For example, in its Decisions on Hydro One's applications for 2009 distribution rates[35] and for 2009 and 2010 transmission rates[36], the Board noted that it was not appropriate to constrain the relief sought by regulated entities due to current economic conditions. In the latter case (EB-2008-0272), the Board went on to note[37]:

> *…Another tenet of rate making is to avoid rate shock through the smoothing of the applicant's spending programs in appropriate cases. An adverse consequence of reducing the applicant's spending to match an economic downturn would be to reduce the economic efficiency of asset optimization plans and to introduce inappropriate volatility in spending.*

[34] Ontario Energy Board. EB-2008-0246. Decision, in the matter of an application by Tillsonburg Hydro Inc. For an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2009. July 10, 2009.
[35] Ontario Energy Board. EB-2008-0187. Decision, in the matter of an application by Hydro One Networks Inc. For an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2009. May 13, 2009.
[36] Ontario Energy Board. EB-2008-0272. Decision with Reasons, in the matter of an application by Hydro One Networks Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the transmission of electricity commencing July 1, 2009. May 28, 2009.
[37] Ibid., page 4.

In its Decision on Toronto Hydro-Electric System Limited's ("Toronto Hydro") application for 2010 distribution rates[38], the Board declined an intervenor request to reduce Toronto Hydro's return on equity as a means of mitigating rates, to take into account other increases affecting ratepayers such as implementation of green energy initiatives, the global adjustment and the impact of the special purpose charge. The Board noted that such an approach would be inconsistent with the ratemaking practices of the Board and contrary to the key cost of capital principles set out in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, and is therefore not acceptable to the Board.[39]

2.2.6 Expectations for Avoiding Rate Shock

In its review of requests for rate increases, the Board has also, in some cases, expressed an expectation that utility management

[38] Ontario Energy Board. EB-2009-0139. Decision, in the matter of an application by Toronto Hydro-Electric System Limited for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2010. April 9, 2010.
[39] Ibid., page 21.
As noted by the Board in this Decision, the principles are:
- The determination of a utility's cost of capital must meet the Fair Return Standard. All three requirements – comparable investment, financial integrity and capital attraction – must be met and none ranks in priority to the others.
- The overall ROE must be determined solely on the basis of a company's cost of equity capital. The opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities.
- The opportunity cost of capital must be determined as accurately as possible to ensure that an efficient amount of investment occurs in the public interest for the purpose of setting utility rates.
- The approach adopted by the Board to determine the opportunity cost of capital should result in an environment where outcomes are predictable and consistent so that investors, utilities and consumers are better able to plan and make decisions.
- The methodology used by the Board to determine the cost of debt and equity capital should be a systematic approach that relies on economic theory and is empirically derived from objective, data-based analysis.

appropriately plan investments and other utility activity so as to avoid significant volatility in rates.

For example, in its application for 2007 distribution rates Newbury Power Inc. ("Newbury Power") sought a revenue requirement for 2007 that would result in total bill increases of approximately 30 per cent. The utility argued that no mitigation measure should be required as its customers had not had a rate adjustment since 2001, and since a significant portion of the rate increase was related to charges other than the utility's costs. However, the Board noted in its Decision that Newbury Power had had the opportunity to apply for rate changes in 2002, 2004 and 2005, but choose not to, and therefore mitigation would be required. Newbury Power subsequently proposed, and the Board approved, a mitigation plan whereby recovery of charges associated with Low Voltage and Regulatory Assets would be deferred until 2008.[40]

Utility spending should be managed so as to avoid need for "catch-up" spending

In EB-2007-0680 Toronto Hydro applied for three years of cost of service rates. The Board approved two years of the application, which included a sharp increase in spending to address material underinvestment in infrastructure over the recent past. In its Decision the Board noted concern about uneven spending and suggested that utility spending should be managed so as to avoid the need for the kind of "catch-up" spending proposed by Toronto Hydro. The Board noted that while the overall bill impact resulting from Toronto Hydro's proposal would not be large in percentage

[40] Ontario Energy Board. RP-2005-0020 / EB-2005-0392. Decision, in the matter of an application by Newbury Power Inc. for an order approving or fixing just and reasonable distribution rates other charges, effective March 1, 2007. May 1, 2007.

terms, ratepayers should nevertheless not be exposed to volatile changes in delivery rates.[41]

Such matters are appropriately considered on a case-by-case basis. The Board has indicated in a broad policy context that avoidance of volatility is not necessarily paramount. For example, rate stabilization has not been accepted as a rationale for early re-basing[42], and has also been rejected where it might result in consumers failing to appreciate the direct and unavoidable consequences of utility activities, including infrastructure investment[43].

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[41] Ontario Energy Board. EB-2007-0680. Decision in the matter of an application by Toronto Hydro-Electric System Limited for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2008, May 1, 2009, and May 1, 2010. May 15, 2008.

[42] See for example: Ontario Energy Board. EB-2010-0139. Decision and Order on the preliminary issue of early re-basing, in the matter of an application by Norfolk Power Distribution Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2011. February 11, 2011.

[43] See for example: Ontario Energy Board. EB-2010-0002. Decision with Reasons, in the matter of an application by Hydro One Networks Inc., 2011 and 2012 transmission revenue requirement and rates. December 23, 2010.

3 Issues for Consideration

As noted in Attachment A to the cover letter issued with this paper, an overarching objective for a renewed regulatory framework for electricity is to ensure that network investment is prioritized on a basis and proceeds at a pace that has regard to the total cost to consumers. However, staff recognizes that controlling costs *ex ante* through the rationalization of investment may be insufficient to lesson the impact on consumers of rising electricity rates and/or bills. As such, *ex post* mitigation to alter the timing and manner of cost recovery may also be necessary.

Rising Electricity Prices

Long Term Energy Plan projections

The Government's Long Term Energy Plan ("LTEP"), issued in November 2010, predicts that electricity prices for residential and small business consumers will rise by about 3.5 per cent annually over the next 20 years. However, the LTEP indicates that there will be a sharper increase for residential consumers in the short term, with prices rising by about 7.9 per cent annually over the next five years. The LTEP notes that this increase is intended to help pay for improvements to electricity capacity in nuclear and gas, transmission and distribution investment (accounting for about 44 per cent of the price increase) and investment in renewable energy generation (56 per cent of the increase).

Staff notes that these investments will have significant bill impacts for consumers:

- *Directly*, via higher transmission and distribution network costs and higher regulatory costs through the Renewable

Generation Connection Rate Protection Compensation Amount; and,

- *Indirectly*, from the cost of the additional renewable energy that will be connected and supplied to the power system, and recovered from consumers via the Global Adjustment.

Ontario Clean Energy Benefit

In November 2010 the Government announced, as part of its 2010 Ontario Economic Outlook and Fiscal Review, the Ontario Clean Energy Benefit (the "OCEB") which is intended to provide relief to eligible[44] consumers over the next five years in light of the forecasted increases noted above. Effective January 1, 2011, the OCEB provides a 10 per cent rebate on the total electricity bill, that is, after all other items on the bill, including taxes. While provided to eligible consumers through the electricity bill, the OCEB is funded through the tax system.

Components of the Electricity Bill

The Board is responsible for regulating only a portion of the charges that make up the total bill for electricity, and utilities only have influence, direct and indirect, over a subset these charges. This poses a challenge for the Board and the utilities with respect to mitigation options and their associated impacts.

An electricity bill for residential and small commercial customers is currently comprised of the following elements:

- **Electricity**: the charge for electricity commodity used, which reflects the Global Adjustment/Provincial Benefit;
- **Delivery:** includes regulated distribution and transmission charges;

[44] Eligible consumers are: residential, farm, small business and other small users.

- **Regulatory:** charges reflecting the costs of administering the wholesale electricity system, and includes costs associated with funding Ministry of Energy conservation programs;
- **Debt Retirement Charge:** used to pay down the residual stranded debt of the former Ontario Hydro; and
- **Taxes:** Harmonized Sales Tax (HST).

Direct control

Utilities have *direct* control over their respective component of the delivery portion of the bill. Delivery charges typically comprise about 30 per cent of the total bill.

Indirect influence

Utilities have *indirect* influence and control over two additional components of the electricity bill:

- **Electricity**: once a renewable energy generation facility connected to a distribution system operates under a contract with the Ontario Power Authority ("OPA"), the electricity portion of a customer's bill will reflect recovery of these contract payments which are recovered through the Global Adjustment mechanism; and
- **Regulatory**: a portion of network investment costs incurred for the purpose of connecting or enabling the connection of renewable energy generation facilities are recovered from all ratepayers in the province through a component of the 'Wholesale Market Service Charge'.[45] In the case of transmitters, these costs are recovered through pooled transmission rates.

Staff notes that utilities and intervenors may hold differing views regarding what components of the electricity bill should be

[45] The underlying pooling mechanism is set out in section 79.1 of the *Ontario Energy Act, 1998*.

considered in the context of assessing the overall cost to customers of a particular rate increase and whether mitigation should be required. At the February 2, 2011 stakeholder meeting it was suggested that the Board and utilities should take into account economic conditions and components of the electricity bill that may be external to the utility in the context of this evaluation. This view has also been expressed through submissions in various regulatory proceedings.

Utilities have consistently countered this view and argued that they have limited influence over many of the components that make up the total electricity bill, and that they should not be required to implement mitigation measures to address these external impacts.

Changes to RPP price setting methodology would provide little relief

While utilities do not have influence over the electricity component of the bill, with the exception of the area noted above, staff notes that the Board does have a role in setting commodity prices for small volume electricity customers that do not have a retail supply contract.[46] The Board's price setting methodology is prescribed by legislation and regulation, and requires the Board to forecast electricity supply costs and set prices to recover these forecast costs over a 12-month period. There is no contemplation in the legislation, regulations and price setting methodology to avoid these costs. As such, staff does not believe that the Board's price setting methodology would be particularly helpful in mitigating impacts on consumers.

[46] Prices under the Regulated Price Plan ("RPP") are set for a year but reviewed every six months, changing on May 1 and November 1, if required.

Staff also notes that the Board is responsible for setting payment amounts for OPG’s prescribed generation facilities, and for setting fees for the OPA and Independent Electricity System Operator.

1. Is it appropriate for the Board to consider the total bill impact even if the applicant does not control or have the ability to influence all elements of the bill?

Issue for comment

3.1 Guiding Concepts for a Mitigation Framework

Staff believes that the Board’s statutory responsibility is best fulfilled, and its statutory objectives in relation to electricity are best promoted, using an outcomes-based approach with multi-year rate-setting. In addition to the guiding concepts for the Renewed Regulatory Framework as a whole, staff believes that it may be useful to consider the following guiding concepts in the context of a framework for mitigation:

Five criteria

- **Intergenerational inequity** should be minimized.[47] The question for consideration in the context of mitigation is the extent to which policy options separate incurred costs from the period in which related services are provided. While financial accounting principles usually match costs to benefits, doing so may conflict with other regulatory objectives such as rate stability and predictability, and earnings stability. To the extent that mitigation alters the timing of cost recovery, this may be an important consideration.

[47] The Board has previously noted minimizing intergenerational inequity as one of several sound regulatory principles. See EB-2008-0408, *Report of the Board: Transition to International Financial Reporting Standards,* July 28, 2009. Page 7.

- A framework should be **sustainable** in that it can adapt to changing and varied circumstances. Different approaches to mitigation may be necessary depending on the underlying cause(s) of the rate or bill increase, the utility involved, and the point in time.

- A framework should strike a reasonable balance between **gradualism** in rates/bills and **economic efficiency**. Minimizing the magnitude of increases or volatility in the rates paid by consumers must be balanced with price signals that reflect the true cost of the services that are being provided to them. While mitigation can be a useful regulatory instrument, it ought not to be overused to the extent that consumers fail to appreciate the direct and unavoidable consequences of utility activities.

- A framework should ensure that regulated utilities continue to have the opportunity to earn **a fair return on capital**.

- A framework should promote **regulatory predictability** by allowing utilities, consumers and other stakeholders to understand how and on what basis regulatory decisions regarding rate and/or bill impacts are likely to be made.

2. Are these guiding concepts appropriate? If not, how might these concepts be changed? Are there additional concepts that should be considered?

Issue for comment

3.2 Working Definition of Mitigation

Levelization of the revenue requirement

The Navigant Report defines "rate mitigation" as "…an activity that provides for the levelization of the revenue requirement to the utility as a whole, or specific customer classes", and more broadly as "…an activity to reduce the impact of changes in tariffs, either increases or decreases, to a level that is acceptable from a social, economic and policy perspective."[48]

Navigant's definition implies a view of mitigation as a consideration not only in the context of a utility rate application, and more specifically, recovery of costs requested through that application, but throughout the entire utility planning process. This is reflected in Navigant's identification of three categories of mitigation: long-run, inter-year, and intra-year.

Staff notes that such a definition is not consistent with the Board's traditional view of mitigation, which focuses on *ex post* mitigation of the revenue requirement. Controlling costs *ex ante* through, for example, appropriate pacing and prioritization of investments is perhaps best considered in the context of utility network investment planning, which is the subject of the initiative on distribution network investment planning (EB-2010-0377).

Issue for comment

3. What are the implications, if any, of defining mitigation as considerations that are brought to bear only after a cost has been determined by the Board to be reasonable, prudent and/or eligible for recovery?

[48] Navigant Report. Pages 5-6.

3.3 Mitigation Threshold

Staff believes a key element in the design of a framework for mitigation is consideration of the circumstance(s) under which mitigation would be required.

As noted in section 2.1.2, under the Board's existing policy a distributor is required to provide a mitigation plan where total bill increases for the typical customer in any customer class or group exceeds 10 per cent. Mitigation plans are considered by the Board on a case-by-case basis. Consistent with this approach, staff notes that this 10 per cent threshold does not appear to serve as the automatic basis for approval (if below 10 per cent) or denial (if above 10 per cent) of a requested rate increase. Rather it serves as a screen for a more detailed review and consideration of requested rate increases, and whether action is needed to reduce the impact on customers.

The existing threshold is indifferent to the underlying cause of the bill impacts: changes in rate design or cost allocation versus increases in the revenue requirement. That is, the same threshold is used to evaluate the need for mitigation regardless of the underlying cause of the impact. However, as noted in section 2.2.4 in some cases the Board has determined that implementation of other Board policies superseded the need for mitigation, despite total bill impacts being above the 10 per cent threshold.

A key consideration going forward is whether the Board's framework for mitigation should continue to make use of a threshold[49], and if so, how the threshold should be derived.

[49] Navigant uses the term "rate trigger".

What constitutes rate shock or the circumstances requiring mitigation may depend on the particular utility, the circumstances of a particular customer or the overall rate environment. As such, staff suggests that a relative threshold that reflects the specific circumstances of an applicant may be appropriate. However, the absence of an absolute threshold may lead to significant uncertainty for utilities and ratepayers as to when an increase in the revenue requirement and/or rates or bills is sufficient to require mitigation or consideration of mitigation.

"Rate shock" depends on circumstances

4. Should the Board's mitigation framework continue to have a threshold? If so, why? If not, what other tool(s) might utilities and the Board use to identify the circumstances under which mitigation should be considered?

Issue for comment

3.3.1 Potential Criteria for Establishing a Threshold

For the purposes of facilitating discussion, staff believes it may be helpful to identify criteria and methodology for establishing a threshold, if the Board's framework for mitigation were to continue to incorporate use of a threshold.

Staff believes that in establishing a threshold, a key challenge is to ensure the value is meaningful for both utilities and other stakeholders and reflects the environment within which they operate, and is transparent in its derivation and implementation.

Staff suggests that the following criteria may be useful considerations to guide the setting of a threshold:

Four criteria

- A threshold should measure impacts over which a utility has **direct control or indirect influence**.

- How a threshold is derived should be **transparent** and easily understood.

- A threshold should be **meaningful** year over year, without the need for frequent updates or adjustments.

- To the extent possible, a threshold set **based on empirical data** should be considered.

5. Are the above noted criteria for establishing a threshold appropriate? Why or why not? What other criteria might be appropriate, why, and what are the implications for the setting of a threshold of these criteria?

Issue for comment

3.3.2 Potential Methodology for Deriving a Threshold

The Navigant Report identifies several methodologies that could be used to derive a threshold. Staff has also identified, through a review of stakeholder submissions in various proceedings and other jurisdictions, additional methodologies for discussion and consideration. These methodologies, outlined below, have been organized into the following categories, the first three of which would involve deriving a threshold using empirical data: market information; utility information; customer perspective; and, regulatory judgement.

Market Information

Macroeconomic-Based Threshold

Consideration of broader inflationary trends

The Navigant Report notes that broader inflationary trends can put upward pressures on utility costs and bill impacts, and may therefore be an appropriate basis to derive a threshold. As noted in the Navigant Report, the advantage of such an option is its relative simplicity, since inflation numbers are prepared and reported regularly by government agencies. However, macroeconomic inflation trends may differ from utility cost pressures. [50]

Utility Information

Industry Unit Cost-Based Threshold

Industry unit costs independent of overall inflationary pressures

The Navigant Report identifies industry unit costs as a possible basis to derive a threshold. Such an approach would require the development of a formula for measuring overall unit costs for utilities on an annual basis, and decisions on how certain costs would be estimated.

As noted in the Navigant Report, a methodology based on industry unit costs may provide a stronger link to industry unit cost pressures than macroeconomic inflation, and would be consistent across utilities. However, the value would likely still need to be updated year over year, which reduces predictability.[51]

[50] Navigant Report, pages 32-33.
[51] Navigant Report, pages 32-33.

Peer Utility Unit-Cost Based Threshold

Peer groups control for differences among utilities

The Navigant Report notes that it may be necessary for a threshold developed using utility industry data to attempt to control for differences between distributors. One method of doing so would be to compute unit cost trends for carefully constructed peer utility groups, and link the threshold value for any given network directly to the change in unit costs for its designated peers.

As identified in the Navigant Report, such a methodology would be more reflective of cost pressures experienced by similar utilities, but may be more complex to derive, and would vary among distributors and from year over year. This may reduce the transparency for stakeholders and predictability of the mitigation framework.[52]

Customer Perspective

In its submission[53] in the consultation on the development of the 2006 EDR Handbook, the Vulnerable Energy Consumers Coalition ("VECC") noted that at the time, there was no readily available empirical data regarding customer attitudes as to "acceptable" levels of bill increases, but there were several factors that may influence customer perspectives about rate or bill changes and considerations of whether increases are acceptable or tolerable. Such factors include how the proposed increase compares with the changes in the cost of other goods as measured by indexes such

[52] Navigant Report, pages 32-24.
[53] Evidence of William Harper and Joyce Poon on behalf of Vulnerable Energy Consumers Coalition, in the matter of the 2006 Electricity Distribution Rate Handbook. December 13, 2004.

as the Consumer Price Index, and customers' experience with past increases for the specific service. VECC's review found that:[54]

Factors influencing customer perspectives

- Customers are more likely to accept rate/price increases for services that have a history of volatile behaviour and where the reasons for such behaviour are understood to be driven by external/uncontrollable forces. However, until the volatility trend/pattern has been established and accepted, customers are likely to resist significant repeated increases in rates.

- When prices have exhibited a history of stability (in terms of year over year changes) customers are less likely to accept higher rate/bill increases.

- When rates have been fixed for a protracted period or there are cost pressures clearly beyond the control of the utility, customers are likely to be sympathetic to the utility's need for rate increases - even if they are in excess of inflation.

- Customers are likely to exhibit considerably less sympathy for increases that are triggered by events over which the utility and its shareholder (or government as in the case of Crown Corporations) are viewed as having some control.

In its Written Argument filed in EB-2009-0096[55], the Canadian Manufacturers & Exporters ("CME") suggested that the Board should commission, or require utilities to commission, empirical studies on the sensitivity of the Ontario economy to increases in the "all in"[56] electricity price to determine the limits of tolerance and

[54] *Ibid*., page 24-25.
[55] An application by Hydro One Networks Inc. for 2010 and 2011 Distribution Rates.
[56] CME defines the "all in" price to include (a) regulated transmission charges; (b) regulated distribution charges; (c) Global Adjustment/Provincial Benefit; (d)

affordability, and, in particular, to test the appropriateness of the existing 10 per cent threshold. These empirically-determined limits of affordability and tolerance could then serve as the limits for utility spending.

Staff notes that an advantage of a threshold based on the tolerance of customers to increases is that it focuses on the customer, who ultimately must manage the increased cost resulting from utility rate increases. However, as noted by CME, "the ability of different sectors of the economy to tolerate total bill increase [*sic*] of 10 per cent per annum likely varies".[57] As such, this suggests that it may be difficult to determine a threshold that is applicable to all customer classes. With different thresholds needed for each customer class, the regulatory burden for the Board and utilities would likely increase.

Regulatory Judgement

The Board's current threshold of 10 per cent is based on the Board's judgement as to an appropriate level of increases above which a utility is required to propose a mitigation plan.

As noted in the Concept Paper in EB-2010-0378, regulatory judgement or discretion can also be used to achieve regulatory objectives in the context of creating incentives for utilities.[58]

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regulated charge relating to province-wide recovery of shared benefits from GEA related investments; and (e) charge to recover costs of Ministry of Energy conservation programs.

[57] Written Argument of Canadian Manufacturers & Exporters in EB-2009-0096, page 7.

[58] Pacific Economics Group Research, LLC. *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper*. Report to the Ontario Energy Board. April 2011. Page 81.

While an absolute threshold based on regulatory judgement may be predictable (stakeholders would know what the threshold is), such a methodology lacks transparency unless the factors and considerations underpinning the threshold are clearly stated. Further, under certain circumstances, the threshold may not be reflective of utility cost pressures and/or the ability of consumers to accommodate rate and/or bill increases.

6. Staff invites comments from stakeholders as to the merits of, and considerations for, the approaches identified in section 3.3.2 above. Are there other approaches that the Board could consider for deriving a threshold?

Issue for comment

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4 Approaches to Mitigation

Conventional and alternative mechanisms

This chapter discusses a number of potential approaches to mitigation, and mechanisms that may be used. Staff has classified these mechanisms into two broad categories: conventional mechanisms and alternative mechanisms. Staff has defined conventional mechanisms as those that have been traditionally used by utilities in Ontario. Mechanisms that generally do not have mitigation as their primary purpose (in the case of mechanisms that are used primarily for financing) or that have not been traditionally used by utilities in Ontario in the regulatory context have been classified as alternative mechanisms.

Transition to International Financial Reporting Standards

The Board's framework for regulatory accounting, and in particular, the transition to International Financial Reporting Standards ("IFRS") may have implications for a number of the mechanisms discussed in the following sections. As such, staff believes it is useful to highlight a few of these issues.

As required by the Canadian Accounting Standards Board ("CAcSB"), Canadian Generally Accepted Accounting Principles ("CGAAP") for publicly accountable enterprises will transition to IFRS. The required effective date for rate-regulated enterprises is January 1, 2012.

IFRS treatment of deferral and variance accounts

Under IFRS, deferral and variance accounts are not recognized as legitimate assets to be included in the body of published financial statements.[59] While the Board will continue to use deferral and variance accounts for ratemaking in appropriate circumstances[60], the treatment of these accounts under IFRS may have implications for any approaches to mitigation that rely on the use of deferral and variance accounts.

Lengthening of asset service lives

The longer asset lives under IFRS should also reduce the annual depreciation expense included in rates. CGAAP requires entities with property, plant and equipment to amortize the cost of assets over the period of time that they provide useful service, and permits the use of asset service lives specified by the regulator. IFRS does not allow for the use of externally mandated depreciation rates. Based on a review of distributors' audited financial statements, staff is aware that more than half of distributors in Ontario have been using asset service lives that are less than the range applicable under IFRS.[61]

Asset lives will need to be examined more fully by the Board on a case by case basis in the context of future rate re-basing reviews.

4.1 Conventional Mechanisms

As noted above, staff has defined conventional mechanisms as those that have been traditionally used by utilities in Ontario.

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[59] To the extent that deferral and variance accounts are used, there would then be a difference between what the Board (as the regulator), and what the investor/lender would see in the audited financial statements.
[60] Ontario Energy Board. EB-2008-0408. *Report of the Board: Transition to International Financial Reporting Standards*. July 28, 2009. Page 13.
[61] This lengthening of asset lives is consistent with a recent move in the United Kingdom as part of its RPI-X@20 framework. As noted in the Office of Gas and Electricity Markets' *Handbook for Implementing the RIIO Model*, issued in October 2010, asset lives under the new framework will now reflect the average expected economic life of the asset base, in order that the interests of existing and future consumers is fairly balanced.

4.1.1 Deferred Recovery of the Revenue Requirement

Spreading a rate increase over a longer period

As noted in a report entitled *Rate Shock Mitigation* published by Edison Electric Institute in June 2007 (the "Edison Mitigation Report"), "[t]he basic intent of a deferral or phase-in of a rate increase over a multiyear period is to spread the "pain" associated with the rate increase over a longer period. A rate deferral is simply deferred recovery of a utility's prudently incurred costs".[62]

Staff notes that based on its review of regulatory precedents in Ontario, a deferred or phased-in recovery has been a common approach approved by the Board for use by utilities for the purposes of mitigation.

As noted in the Navigant Report, in order to ensure the utility is kept financially whole, a deferral or phase-in requires that the deferred amount be recognized as a credible regulatory asset and that the utility be provided the opportunity to earn a reasonable carrying charge. This is consistent with the Board's practice, as noted in section 2.2.2, whereby utilities have generally been permitted to earn interest on a deferred amount, at the Board's prescribed rate.

Deferred recovery of the revenue is by definition an *ex post* mitigation measure, which staff suggests may be appropriate where all opportunities to reduce the revenue requirement *ex ante* have been exhausted, and the requested increase still exceeds the established threshold or other trigger for consideration of mitigation.

[62] *Rate Shock Mitigation*. Prepared for Edison Electric Institute by The Brattle Group. June 2007. Page 11.

4.1.2 Funding Adders

Advance funding on an interim basis

As noted in section 2.2.2, the Board has approved funding adders to provide advance funding on an interim basis and to mitigate or smooth the anticipated rate impact when recovery of these costs is approved by the Board. To date, the Board has made available funding adders in relation to smart meter costs and connection of renewable generation and/or smart grid development investments and activities. In the Infrastructure Report, the Board noted that conventional cost recovery mechanisms such as funding adders continued to be appropriate and should remain a core component of the Board's regulatory treatment of infrastructure investment.

Staff suggests that funding adders can be particularly helpful where uncertainty exists as to the proposed expenditures, but there is nevertheless recognition that a certain level of investment is required. For example, in its Decision in EB-2009-0096, the Board stated, in part: [63]

> *The Board notes that considerable uncertainty remains regarding all the proposed green energy projects, despite Hydro One's efforts to work with all available information. The Board concludes that it is necessary to have greater detail and specificity regarding the projects to be undertaken before a finding of prudence and approval of the remaining expenditures can be made……*
>
> *Although the Board will not approve these renewable generation expenditures on the basis of the record in this application, the Board understands that Hydro One will likely need to undertake work in this area during 2010 and 2011 and should therefore have funding to undertake that work. The Board concludes that funding adders and deferral*

[63] Ontario Energy Board. EB-2009-0096. Decision with Reasons, in the matter of an application by Hydro One Networks Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges for 2010 and 2011. April 9, 2010.

accounts should be used to support Hydro One's work, while managing the risk to ratepayers and Hydro One.

4.1.3 Timing of Rate Adjustments

Taking advantage of market conditions and other factors

This approach involves the timing of rate adjustments to mitigate rate impacts.[64] More specifically, taking advantage of market conditions or other factors to lessen the impact of what might otherwise be significant rate impacts.

A survey of rate impact mitigation measures published by Edison Electric Institute in June 2010 (the "Edison Update Report")[65] indicates that this approach is becoming increasingly common in U.S. jurisdictions. In the case of the surveyed states, utilities have taken advantage of a period of lower fuel prices to partially offset base rate increases with reductions in fuel adjustment clauses.[66]

Re-basing at regularly scheduled intervals

The Board's multi-year rate setting plan for electricity distributors calls for rate re-basing reviews at regularly scheduled intervals, with incentive regulation rate reviews in the intervening years.

It is expected that distributors have their rates re-based in accordance with the schedule developed in consultation with distributors and other interested parties. The issue of early re-basing was addressed in a letter issued by the Board on April 20, 2010. The letter acknowledges that the Board's multi-year rate setting approach does contemplate that some distributors may

[64] This is in contrast to altering the timing of when costs are reflected in rates through different financing mechanisms such as CWIP.
[65] *State Regulatory Update: Rate Impact Mitigation Measures*. Prepared for Edison Electric Institute by Energy Policy Group LLC. June 2010.
[66] A fuel adjustment clause is a mechanism commonly used in the United States that permits utilities to regularly adjust the price of electricity to reflect fluctuations in the cost of fuel, or purchased power, used to supply that electricity.

legitimately need to have their rates rebased *earlier* than originally scheduled, by making provision for an "off-ramp". The conditions under which the "off-ramp" applies reflect the Board's view of the circumstances that justify a departure from the plan schedule that would otherwise be applicable.[67]

Staff notes that the "off-ramp" provisions do not appear to contemplate early re-basing for the purposes of taking advantage of conditions that may serve to lessen the impact of rate increases requested by the distributor.

The Board's multi-year rate setting approach does not prohibit a distributor from re-basing later than scheduled. A delayed re-basing could, however, trigger a review of the financial position of the distributor if there are concerns that the distributor is over- or under-recovering based on current rates.

Staff notes that some utilities have proposed deferring downward adjustments to rates so as to use the decrease to offset cost of service increases expected in a subsequent year. While this approach would not involve an adjustment to the timing of the distributors' rate re-basing review, it does highlight the manner in which the timing of rate adjustments can help to reduce the impact on consumers.

[67] As set out in the letter of April 20, 2010, a distributor that seeks to have its rates rebased in advance of its next regularly scheduled cost of service proceeding must justify why an early re-basing is required notwithstanding that the "off ramp" conditions have not been met. Specifically, the distributor must clearly demonstrate why and how it cannot adequately manage its resources and financial needs during the remainder of its IRM plan period.

Staff suggests that the granting of flexibility over the timing of an adjustment, to offset large increases, may be a powerful tool and viable opportunity for mitigation.

4.2 Alternative Mechanisms

Staff suggests that some of the mechanisms identified in the Navigant Report may be more appropriately characterized as financing tools, rather than mitigation tools. Such mechanisms "systematically change the pattern of capital recovery and the calculation of the utility's revenue requirement, and they aren't used necessarily just to mitigate rate shock".[68] [69]

Not traditionally used in Ontario or for the purposes of mitigation

In addition, these mechanisms appear more suited to mitigation of a particular investment, rather than mitigation of the revenue requirement as a whole.

The role of such alternative mechanisms in the context of a framework for mitigation is an important issue for the Board and stakeholders to consider. Staff notes that similar mechanisms are set out in the Infrastructure Report, but in a different context (i.e. providing incentives vs. mitigating costs to ratepayers).

In the Infrastructure Report, the Board noted the need for criteria to guide consideration of applications for use of the alternative mechanisms for cost recovery identified in that report. As set out in

[68] *Rate Shock Mitigation*. Prepared for Edison Electric Institute by The Brattle Group. June 2007. Page 11.
[69] The role of many of these alternative mechanisms in cost recovery is also discussed in an essay by Scott Hempling, Esq. and Scott H. Strauss, Esq., published by the National Regulatory Research Institute (NRRI) entitled *Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?*. November 2008.

the Infrastructure Report, “[t]he applicant therefore must demonstrate that there is a requisite relationship between the alternative mechanism proposed and the investment project, in the sense that the proposal is tailored to address the demonstrable risks and challenges faced by the applicant.”[70] Staff suggests that consideration of similar criteria in relation to the use of alternative mechanisms for the purposes of mitigation may be appropriate.

4.2.1 Lease of Assets

Levelized payment

The Navigant Report suggests that lease agreements can be used as a tool to finance specific large assts or classes of assets and can provide mitigation through a levelized revenue requirement over the life of the asset.

The Infrastructure Report provides the option for a company to apply for a company-specific capital structure. The extent to which a distributor uses asset leases may have implications for the distributor’s financial risk. If a distributor were to lease all of its assets, the result would be that the underlying capital structure of the distributor could effectively approach 100 per cent debt. This could adversely affect the financial risk of the distributor if its capital is not restructured, and would be exacerbated if, for some reason, the utility was required to go to market for its incremental capital needs.

Staff notes that it is possible that in a future rate case the Board could disallow a proposal to increase rates arising from an increase in the financial risk of the utility caused by leaseback

[70] Ontario Energy Board. EB-2009-0152. *Report of the Board: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*. January 15, 2010, page 20.

approaches. Conversely, if the approach lowers the distributor's cost of capital, any associated savings might be imputed into rates.

The specific accounting treatment would differ depending on whether the lease in question was structured as a financing lease or an operating lease.

4.2.2 Securitization

Issuance of a bond

Securitization is a mechanism that allows utilities to finance the recovery of certain costs through the issuance of a debt instrument, usually a bond, the interest on which, and its redemption, is recovered from the utility's customers. The Edison Mitigation Report notes that:[71]

> *…[i]n general, securitization involves the transfer of a revenue-producing asset to a legally separate special purpose entity (SPE) that will issue debt obligations secured by and payable from the revenue stream from the asset. The terms of the asset transfer as well as the various charter provisions and operating procedures of the SPE are designed to insulate the SPE and its obligations from the credit or bankruptcy risks of the transferor of the asset.*

The survey of other jurisdictions provided in the Navigant Report indicates that more recent uses of securitization have been used to finance costs relating to storm damage, and that the amounts financed by the bond issuance ranged from $89.2 million to $708 million.

Staff suggests that the *magnitude* of costs addressed through bond issuance, rather than the *type* of costs, may be the relevant factor for consideration by stakeholders and the Board.

[71] *Rate Shock Mitigation*. Prepared for Edison Electric Institute by The Brattle Group. June 2007. Page 11.

4.2.3 Trended Original Cost Ratemaking

Trended Original Cost ("TOC") ratemaking is an approach to mitigation that uses a different accounting treatment to defer recovery of a portion of a utility's return on equity.

Changes in accounting treatment

Utilities in Ontario use a net depreciated original cost ("DOC") approach to ratemaking, which allows for annual allowed returns of the cost of invested capital throughout the life of an asset, as calculated from the rate base and revenue requirement mechanism. The DOC approach utilizes a nominal rate of return, which accounts for the impact of inflation to compute recovery of the cost of equity capital.

As noted in the Navigant Report, the main difference between the DOC approach and TOC, is that under the latter approach only the "real" or "inflation-adjusted" rate of return is applied to the rate base in the current year, and the inflation component of the equity return is treated as a deferral, which is capitalized into rate base and amortized over the remaining life of the asset.

4.2.4 Inclusion of Construction Work in Progress in Rate Base

Early recovery of construction costs

Under traditional cost recovery, when a project enters service, the expenditures and carrying charges associated with design and construction costs are included in rate base and recovered in rates over the useful life of the asset. As noted in the Navigant Report, including these costs in rate base prior to the asset going into service may allow for rates to be adjusted in a more gradual manner, thus lessoning the rate shock experienced by consumers.

In the Infrastructure Report, the Board indicated that it would allow utilities to apply to include up to 100 percent of prudently incurred CWIP costs in rate base. The Board noted that one of the two principal benefits that CWIP provides is a smoothing, or phased-in, effect on rates and thereby mitigates the rate impact that might otherwise take place when large new plant is placed into service.

Staff also notes that including CWIP in rate base is a departure from traditional rate-making principles under which rate base is limited to plant that is "used and useful". However, the Board addressed this issue in the Infrastructure Report, noting that "…the existing incremental capital module already allows for the prospective collection in rates of relief associated with approved projects prior to the associated facilities being in service."[72]

4.2.5 Voluntary Customer Payment Plans

A review of the Edison Update Report and the Navigant Report indicates that several U.S. states have implemented programs that allow customers to voluntarily join payment plans designed to mitigate expected rate increases. These payment plans appear to take two general forms:

Pre-payment

- *Pre-payment* plans, whereby participating customers pre-pay a portion of expected rate increases, and then are credited with an amount to refund the prepaid balance, including accrued interest.[73]

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[72] Ontario Energy Board. EB-2009-0152. *Report of the Board: The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*. January 15, 2010, pages 15-16.

[73] For example, in March 2009 PECO Energy Co. received approval from the Pennsylvania Public Utility Commission to implement a "Phase-In Program" to smooth out potential increases that would occur when rate caps expired in

Deferred payment

- *Deferred payment* plans, whereby participating customers may defer a portion of an expected increase, and pay the deferred balance in later years, with accrued interest.[74]

Both natural gas and electricity distributors in Ontario currently offer a form of voluntary payment plan. "Equal payment plans" are intended to "smooth out" the cost to consumers of seasonal fluctuations in consumption by levelizing the amount charged to participating customers in each billing period. In months when consumption is lower, customers pre-pay for months when consumption is higher. The balance is reconciled at least on an annual basis to adjust for variations from expected consumption. No interest is accrued or charged on accumulated credits, or debits, respectively, since the reconciliation occurs within a relatively short timeframe (one year).

Such plans are therefore designed to mitigate primarily against significant bill impacts resulting from fluctuations in the pattern of

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January 2011. Under the program, participating customers would have a surcharge added to their monthly bills starting in July 2009. These customers would subsequently receive monthly credits beginning in January 2011. The amount of the monthly credit, including accrued interest at 6%, was set at a level so as to phase in the increase in customer bills from the anticipated increase in the price of generation service on a gradual basis over the refund period. The program was available to residential and small commercial customers, with accounts in good standing. A similar program was implemented by PPL Electric Utilities.
State Regulatory Update: Rate Impact Mitigation Measures. Prepared for Edison Electric Institute by Energy Policy Group LLC. June 2010. Page 7.

[74] For example, Ameren-IL's "Customer Elect Plan Rider", an optional deferred billing plan that would allow residential and small commercial customers, primary and secondary schools, and certain local governmental customers to phase in the effects of the end of a rate freeze. Under the plan, participating customers have the increase in their rates for 2007-2009 capped at 14% over the average rate charged to their group in the prior year. The deferred balances, including accrued interest at an annual rate of 3.25%, must then be re-paid through a monthly levelized charge during the 2010-2012 period.
State Regulatory Update: Rate Impact Mitigation Measures. Prepared for Edison Electric Institute by Energy Policy Group LLC. June 2010. Pages 11-12.

energy use throughout the year, and not year over year changes in utility rates.

Some electricity distributors also have experience with customer rebates as a form of mitigation as noted in section 2.2.2. While these rebates were not voluntary programs, they were nevertheless mitigation targeted to individual customers.

Summary – Conventional and Alternative Mechanisms

This chapter has identified a number of mechanisms that have been used for the purposes of mitigation in Ontario and/or other jurisdictions. Some of the alternative mechanisms staff has suggested may be more appropriate classified as project financing tools.

Issues for comment

7. In light of the cost pressures facing electricity utilities, the Board's approach to rate-setting, and the considerations noted in the Navigant Report, what is the appropriate role, if any, of the conventional and alternative mechanisms identified in this chapter for the purposes of mitigation? What criteria might utilities and the Board use to guide consideration of the use of these mechanisms?

8. What conditions need to be in place in order to ensure the appropriate and effective use of the mechanisms identified in this chapter?

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5 Appendix A: Summary of Issues for Comment

Chapter	For Comment
3. Issues for Consideration	**Components of the Electricity Bill** 1. Is it appropriate for the Board to consider the total bill impact even if the applicant does not control or have the ability to influence all elements of the bill?
	Guiding Concepts for a Mitigation Framework 2. Are these guiding concepts appropriate? If not, how might these concepts be changed? Are there additional concepts that should be considered?
	Working Definition of Mitigation 3. What are the implications, if any, of defining mitigation as considerations that are brought to bear only after a cost has been determined by the Board to be reasonable, prudent and/or eligible for recovery?
	Mitigation Threshold 4. Should the Board's mitigation framework continue to have a threshold? If so, why? If not, what other tool(s) might utilities and the Board use to identify the circumstances under which mitigation should be considered?
	Potential Criteria for Establishing a Threshold 5. Are the above noted criteria for establishing a threshold appropriate? Why or why not? What other criteria might be appropriate, why, and what are the implications for the setting of a threshold of these criteria?
	Potential Methodology for Deriving a Threshold 6. Staff invites comments from stakeholders as to the merits of, and considerations for, the approaches identified in section 3.3.2 above. Are there other approaches that the Board could consider for deriving a threshold?
4. Approaches to Mitigation	**Summary – Conventional and Alternative Mechanisms** 7. In light of the cost pressures facing electricity utilities, the Board's approach to rate-setting, and the considerations noted in the Navigant Report, what is the appropriate role, if any, of the conventional and alternative mechanisms identified in this chapter for the purposes of mitigation? What criteria might utilities and the Board use to guide consideration of the use of these mechanisms?
	8. What conditions need to be in place in order to ensure the appropriate and effective use of the mechanisms identified in this chapter?