Transmission and Distribution
Rate Mitigation Measures for Ontario

Prepared for:

The Ontario Energy Board

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Executive Summary

In December 2010, the Ontario Energy Board (OEB) initiated a consultative process to develop a renewed regulatory framework for electricity. One of the elements included in the process is an initiative to provide stakeholders with a set of tools, approaches or options to help mitigate the effects of unavoidable and significant rate impacts. As part of this objective, Navigant Consulting, Ltd. (Navigant) has been retained by the OEB to prepare this paper on transmission and distribution rate mitigation measures for electricity distributors to inform industry debate in this consultative process.

Rate mitigation can be defined as the shifting of revenues from one time period to another or the redistribution of the revenue requirement between tariff classes to avoid unacceptable rate impacts. Many of the rate mitigation approaches discussed in this paper will change the pattern of revenue collections by electricity distributors. Navigant believes that distributors should be held harmless – operationally and economically – for any rate mitigation strategy implemented by the Board.

The OEB currently employs a policy that requires rate mitigation for any rate change that would otherwise result in a change in the total bill of more than 10%. Although this approach might be considered arbitrary because the ±10% bandwidth for which rate mitigation is not required was chosen on a subjective basis, it is reasonable and easily understandable to parties. Navigant has identified some potential alternative thresholds or triggers for consideration but also notes that introducing a variable "trigger" or other refinements to the methodology used to determine when rate mitigation is required may become burdensome and may not yield benefits that exceed the additional costs to all parties.

Types of Rate Mitigation Mechanisms

Broadly speaking, rate mitigation mechanisms fall into one of the following three categories (although some rate mitigation strategies may combine mechanisms from more than one category).

Changes in an electricity distributor's rates can be triggered by a variety of actions which are associated with different time horizons. Long-run changes in the composition and assets are influenced by the financing and management of those assets. Mitigation strategies captured over the life of assets fall into the **Long-Run Rate Mitigation** category.

Abrupt rate changes sometimes occur to overall adjustments in the utility tariffs, due to regulatory action or significant changes in utility costs. In Ontario these changes may occur as part of the tariff setting cycle and rebasing of the utilities rates. Rate impacts related to the revenue requirement in total and which occur over a shorter time period are classified as **Inter-Year Rate Mitigation**.

Lastly, changes in cost allocation between customer groups (to mitigate what is determined to be an unacceptable impact on one or more customer groups) are referred to as **Intra-Period Rate Mitigation.** Intra-Period Rate Mitigation does not impact the overall revenue requirement of the utility; it simply addresses the allocation of those revenue requirements to each tariff class or customer group.

Rate Mitigation Measures

Navigant has identified a number of potential rate mitigation measures across the three categories described above. The general approaches in each category are summarized below:

- Mitigation of Long-Run Rate Impacts – Mitigation of rate increases over the lifecycle of assets should be based upon asset management and be implemented by the distributors in Ontario as part of their charter to provide these services. Mitigation measures should include strategic planning addressing the timing of constructions of the assets as well as investigating potential alternative approaches to finance these investments;

- Mitigation of Inter-Year Rate Impacts – Inter-Year Rate Mitigation during the IRM cycle should be limited to Rate Deferrals, and/or Pre-fundings, which would avoid "stair-step" behaviour triggered by a large rate increases such as could be experienced in the first year of an IRM cycle followed by relatively small increases in the second the subsequent years of the IRM cycle. Furthermore, the OEB should consider the use alternative rate mitigation triggers described in this paper;

- Mitigation of Intra-Year Rate Impacts – Intra-Year Rate Mitigation occurs when revenues and allocated costs are significantly mismatched. The OEB should adopt a policy that allows for revenues to move closer to cost of service by at a rate of change that does not trigger rate shock to customers;

While the need for rate mitigation strategies are generally not known well in advance, the expiry of the Ontario Clean Energy Benefit (OCEB) in 2016 allows the OEB ample time to set a strategy for this future rate impact. At a 10% average reduction in the customer's total bill, the expiry of the OCEB presents a challenge that needs to be carefully considered. Navigant suggests that stakeholders begin planning immediately for the expiration of the OCEB.

Rate Mitigation in Other Jurisdictions

In preparing this paper Navigant has reviewed rate mitigation practices in other jurisdictions. Our investigations have uncovered the following:

- Rate mitigation is commonly employed in several regulatory jurisdictions in North America.

- The application of rate mitigation generally occurs in an "ad hoc" manner. In other words, most jurisdictions do not have guidelines much less firm rules on when rate mitigation is applied, but rather apply it in an opportunistic manner when needed.

- Examples of large scale rate mitigation for distribution systems have occurred in the past decade. The most notable examples are related to storm damage where Securitization was used as a mitigation mechanism.

- In the past decade, a number of examples of Inter-Year Rate Mitigation occurred as a result of rate freezes ending, thus unleashing large rate increases. Ontario may face a similar situation when the Ontario Clean Energy Benefit expires in 2015.

Introduction

In December 2010, the OEB initiated a consultative process to develop a renewed regulatory framework for electricity. One of the elements included in the process is an initiative to provide stakeholders with a set of tools, approaches or options to help mitigate the effects of unavoidable and significant rate impacts. As part of this objective, Navigant has been retained by the OEB to prepare this paper, which is intended to serve as a basis for discussion among participants of the consultative process.

Recent changes of the Ontario electricity sector such as the Green Energy and Economy Act, 2009, and a trend of rising commodity costs (including the Global Adjustment), have contributed to a heightened awareness and interest in rate mitigation. While both the commodity and transmission/ distribution components of the cost of electricity are increasing, the focus of this paper includes the transmission/distribution costs only. The legislative requirement for full cost recovery of the commodity cost in the Regulated Price Plan (RPP) prohibits the OEB from applying any rate mitigation to the commodity component. As such, this paper does not consider any rate mitigation measures for the commodity component of the cost of electricity.

For the purposes of this paper, a rate impact or "rate shock" is defined as a sudden change in the revenue requirement, in total or for a specific rate class, or classes, which causes a sudden increase or decrease in the tariffs faced by customers. Changes to the revenue requirement are typically due to either a significant capital project which increases rate base, or a re-allocation of the revenue requirement between rate classes due to a change in cost allocation methodology or change in the asset mix.

Rate mitigation is defined as an activity that provides for the levelization of the revenue requirement to the utility as a whole, or specific customer classes. Rate mitigation activities can be long-run activities which shift the physical deployment of assets or their financings, or short-run measures which prefund or defer the revenue requirements. It should be clearly understood that for the purposes of this paper, rate mitigation does not include any measure which causes the utility financial harm. While the mitigation measure may alter the timing of when revenues are received, the utility shall be "held harmless" and be allowed to recover carrying charges.

The OEB's existing rate mitigation policy as set out in the 2006 Electricity Distribution System Rate Handbook, requires that a mitigation plan is required if the total bill increase for any customer class or group exceeds 10%, excluding any increase in commodity cost. The distributor has discretion over the proposed mitigation approach, which the OEB will consider on a case-by-case basis.

Rate mitigation is a commonly used tool to avoid rate impacts by vertically integrated utilities as well as distributors. Navigant's investigation of rate mitigation activities in other jurisdictions has uncovered the following similarities:

- Rate mitigation often occurs at the end of a rate design process to remedy impacts to certain tariff classes or all customers of the utility. Rarely do jurisdictions embrace a systematic approach with pre-established triggers;

- Mitigation activities often are the function of a settlement process between stakeholders which includes a number of other rate case issues in addition to rate mitigation (e.g. the revenue requirement);

- The establishment of multi-year phase-in periods typically occurs under circumstances where the utility is facing a significant transition, or addition to rate base such as movement from vertical integration to retail access or introduction of large generating system.

Types of Rate Mitigation Mechanisms

Rate mitigation can broadly be defined 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. However, the causes of the underlying shifts in the level of revenue requirement occur over different time periods and are the result of different causal factors. Based on these differences, Navigant has identified three categories of rate mitigation applicable to Ontario which is described below.

- ***Long-Run Rate Mitigation Mechanisms*** – Long-Run Rate Mitigation Mechanisms include asset planning and budgeting over of yearly capital projects and the financing of those projects in a manner that provides for their implementation in a least cost manner. A capital intensive industry such as an electric distributor generally plans investments in time frames that spans several years and even decades. Therefore, Long-Run Rate Mitigation is controlled by the management of the utility through their planning and financing processes. Investments are planned over time in manner which balances the system needs with rate impacts;

- ***Inter-Year Rate Mitigation Mechanisms*** – In contrast to Long-Run Rate Mitigation Measures which are typically tied to a specific long life asset and need to be incorporated by the utility as part of its planning and/or financing processes, Inter-Year Rate Mitigation Mechanisms apply to a much shorter time period and are implemented in response to an increase in the utility's total revenue requirement. An example of where this type of mechanism could be applied includes Ontario where the OEB has adopted an Incentive Rate Mechanism (IRM) that follows a three year cycle. The rebasing establishes the first year of the revenue requirement following by 2 years of adjustments which are a function of the rate of inflation, productivity and stretch factors. An outcome of this mechanism is that in many cases, distributors experience significant increases in the rebasing years followed by 2 years of very moderate increases, thus producing a "stair-step" pattern of rates. Using the Ontario example, Inter-Year Rate Mitigation

Mechanisms would smooth the revenue requirement within the 3 year term of the IRM cycle and eliminate the "stair-step" rate pattern;

- ***Intra-Year Rate Mitigation Mechanisms*** – The OEB uses an embedded cost of service methodology to allocate the revenue requirement to each tariff class. In cases where the revenues to cost ratio trigger significant rate increase or decreases to specific tariff classes, Intra-Year Rate Mitigation Mechanisms will be used to "smooth" these adjustments and avoid abrupt rate changes.

Contents of this Paper

The following sections of this paper elaborate on each of the three categories of rate mitigation mechanisms applicable to Ontario. For each category, examples of specific mitigation measures, experience of other jurisdictions and comments on the suitability for Ontario are provided. The paper also includes a discussion on potential "triggers" which could be used to identify when a mitigation mechanisms should be implemented. Conclusions and recommendations are provided in the last section.

As part of the jurisdictional review, Navigant reviewed mitigation activities which have occurred in other jurisdictions by electric utilities in the past decade. The examples illustrate various approaches to mitigation from a variety of factors ranging from a transition from a vertically integrated market design to a retail open-access design, financing of major reconstruction from storm damage, and, mitigation of rate impacts from the introduction of major construction programs. The results of the jurisdictional review have been inserted into the relevant sections of the paper to provide additional insights.

Long-Run Rate Mitigation Mechanisms

As previously discussed, Long-Run Rate Mitigation Mechanisms are based upon the system planning process and the financing of the distributor's investments. The implementations of these strategies are linked to the useful lives of the investments.

Navigant has identified four Long-Run Rate Mitigation Mechanisms:

- Lease of Assets;
- Securitization;
- Trended Original Cost Rate Making; and
- Construction Work in Progress (CWIP).

What follows below is a description of each mechanism, examples of where it has been deployed, and comments on the applicability of the mechanism for utilities in Ontario.

Lease of Assets

Since the 1980's utilities have utilized Leases[1] as mechanisms to finance investments and mitigate rate shocks[2]. Although the effectiveness of a Lease transaction is heavily dependent upon the tax treatment afforded the transaction in that jurisdiction, it is a mechanism that can potentially be used to mitigate rate increases.

[1] We are using the approaches of lease or sale / leaseback interchangeably in this discussion. However, in both cases a specific asset or class of equipment is dedicated for use by the utility. In the case of a Sale / Leaseback the utility possesses initial ownership of the asset. In the case of a lease the utility may not have initial ownership of the asset.

[2] http://www.osti.gov/energycitations/product.biblio.jsp?query_id=0&page=0&osti_id=5578968

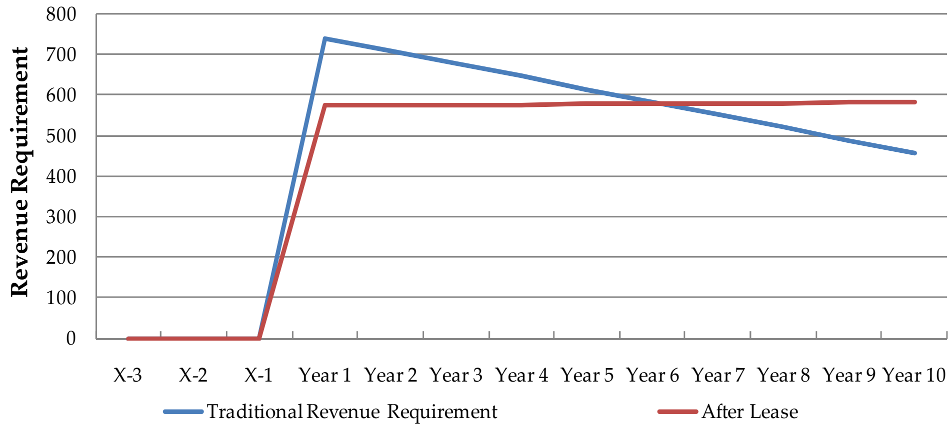

Figure 1 - Illustration of a Traditional Revenue Requirement versus the Revenue Requirement Based Upon a Lease

A utility participating in a Lease transaction establishes a lease for the use of the asset. In a Lease transaction the following economic actions occur:

- The asset is constructed;
- The lease transaction is negotiated with a third party;
- The utility provides payments to the leaseholder over the life of the transaction.

Figure 2 – Key Stages of a Lease Transaction

Example of a Lease Transaction

WE Energies

An example of the application of a lease used to mitigate rate increases was WE Energies "Power the Future Program" which created a subsidiary leasing company to finance the construction of several major electric generating stations. The assets financed through the Power the Future program include:

- The repowering of the Port Washington Station with 1000 MW of Natural Gas fired Combined-Cycle Combustion Turbine technology;

- The construction of 2 650MW Coal-fired Ultra-Supercritical Generating Units at the Elm Road Station;
- Construction of 90 wind turbines at the Glacier Hills Wind Park; and,
- A 50MW biomass fired cogeneration unit in Rothschild, WI.

WE Energies use of a lease mechanism with an unregulated subsidiary reduced the overall revenue requirement of these projects and levelized the revenue requirement of the life of these assets, thus mitigating the rate impacts to customers.

Considerations for Ontario

Lease transactions are a mechanism that can be potentially used by utilities in Ontario to levelize revenue requirements for specific large assets or classes of assets. But as stated below, leases may not yield additional benefits. The specific assets captured in the transactions will need to be clearly defined in the lease document because the utility will legally not hold title to those assets. A group of small assets would be appropriate to include in a lease as long as they can be defined.

Navigant has identified the following disadvantages to using a Lease to mitigate revenue requirements:

- The lease payments that the utility is obligated to pay are viewed as "debt like" commitments by most rating agencies and banks. As an example, Standard and Poor's[3] has for several years developed an approach for imputing debt from Purchased Power Agreements (PPA), and it can reasonably be expected that a similar imputed debt be derived from future lease payments. Therefore, the perceived benefit of these devices is reduced somewhat by the increase in risk which the utility faces through an increase in the imputed leverage;
- If implicit debt is triggered by a lease, the distributors may need to request a capital structure that differs for that which is defined in the Deemed Capital Structure in order to maintain their financial integrity;
- A lease will effectively produce no net income for a utility because the lease payment is viewed as an operating expense. Under traditional regulation the utility would earn a ROE. Therefore, the net income the utility would earn is reduced if a lease is established;
- One of the reasons leases are attractive in many jurisdictions is because they afford the participants in the transactions advantageous income tax treatment. Potential tax advantages include providing a lessee at a lower marginal tax rate entering into the lease with a leaseholder at a higher marginal tax rate the

[3] Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

ability to transfer the benefits of accelerated depreciation to the leaseholder. The lease agreement in some cases transfer the deductibility of depreciation at a higher marginal tax rate to the party holding the leaseholder. Given that the vast majority of the distributors pay PILS (Payment In Lieu of Taxes), the potential tax advantages of a lease are lost;

- Leases were used by WE Energies as a mitigation toll to levelize the revenue requirement for renewable energy investments including a wind farm and a steam plant burning biomass. Leases may be able to be utilized in a similar manner in Ontario.

Securitization

Another Long-Run Rate Mitigation Mechanism is the use of securitization mechanisms to finance reconstruction of the transmission and distribution system. Furthermore, securitization has also been used as a vehicle to finance "Stranded Investments" in some jurisdictions when a transition to competition has occurred.

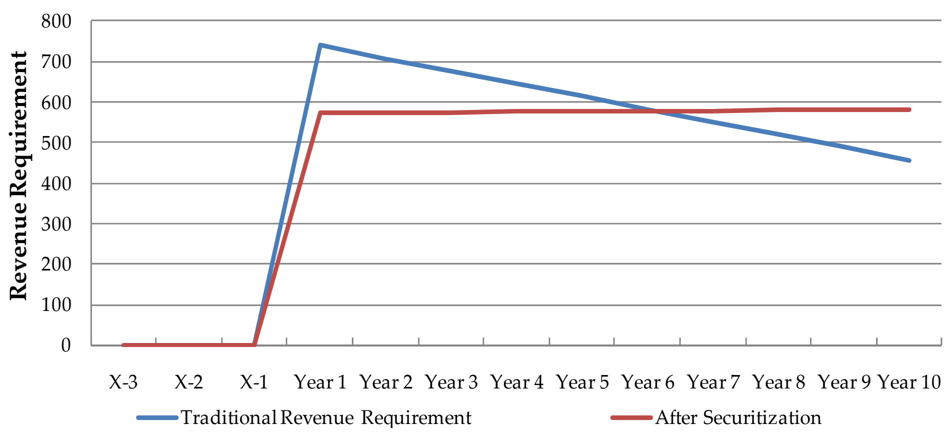

Figure 3 - Illustration of a Traditional Revenue Requirement versus the Revenue Requirement Based Upon Securitization

Securitization began in the 1970's predominantly in the housing mortgage industry and expanded over time to activities such as automobile financing, credit cards, student loans, and royalties and patents, i.e., all activities that involve periodic inflows of cash. In the energy industry, securitizations generally began in the 1980's and early 1990's predominantly to finance the above market costs associated with take-or-pay arrangements in the natural gas industry; and securitizations pursuant to an order by the Federal Energy Regulatory Commission's Order 500.[4] In the late 1990's it attained prominence as major mechanism for the

[4] There were other relatively smaller cases of securitizations in the energy industry. For example, securitization was used in 1995 by Puget Sound & Light to finance a demand-side management program (essentially cash incentives to customers to replace less energy-efficient appliances with more energy-efficient items).

recovery of electric power generation costs that might be "stranded" as a result of a transition to competition.[5] The debt instrument that was used in the recovery of such stranded costs, at least in California, was termed "rate reduction bonds"; assets underlying such bonds were the transition property or "stranded" generation assets.[6] The interest on and redemption of the debt instrument were met by using future cash inflows from utility customers via a non-bypassable charge levied on all customers.[7] Utilities in California and Pennsylvania were key players in the $40 billion securitization market over the period 1995-2000.[8]

[5] Per the Securities and Exchange Commission ("SEC"): "For ABS backed by stranded costs, the underlying asset is transition property or system restoration property. Stranded costs are the costs associated with a decline in the value of electricity generating assets due to restructuring of the industry, and the underlying property is called transition property. System restoration property is a similar underlying asset, but provides for recovery of system restoration costs incurred by electric utilities as a result of hurricanes, tropical storms, ice or snow storms, floods and other weather related events and natural disasters. These types of property are usually created by the action of a state legislature or other designated authority. The property generally includes a right and interest to impose, collect and receive charges payable by electric customers in a particular territory. Also, this right usually provides that the designated state authority may periodically adjust the charges billed to customers in order to recover the stranded costs in the event all collections are not made." (Federal Register, Vol. 75, No. 84, p. 23360)

[6] Rate reduction bonds in the sense that customers also realized rate savings from the issuance of such generation asset backed bonds compared with rates that might have resulted if the generation assets continued to remain on the books of the regulated utility and received traditional rate regulation. Also, note that since such rate reduction bonds were issued by and/or guaranteed by the state, they were federally tax-exempt. See "Alternating Currents: Electricity Markets and Public Policy", Brennan, T.J., Palmer, K.L., and Martinez, S.A., 2002, resources for the Future.

[7] Sometimes referred to in the literature as a "Competition Transition Charge" or ("CTC").

[8] Notably Pacific Gas and Electric Company (PG&E) and Philadelphia Electric Company (PECo). Securitizations were generally the result of state sponsored initiatives such as Assembly Bill 1890 in California or by regulatory authority such as in Pennsylvania.

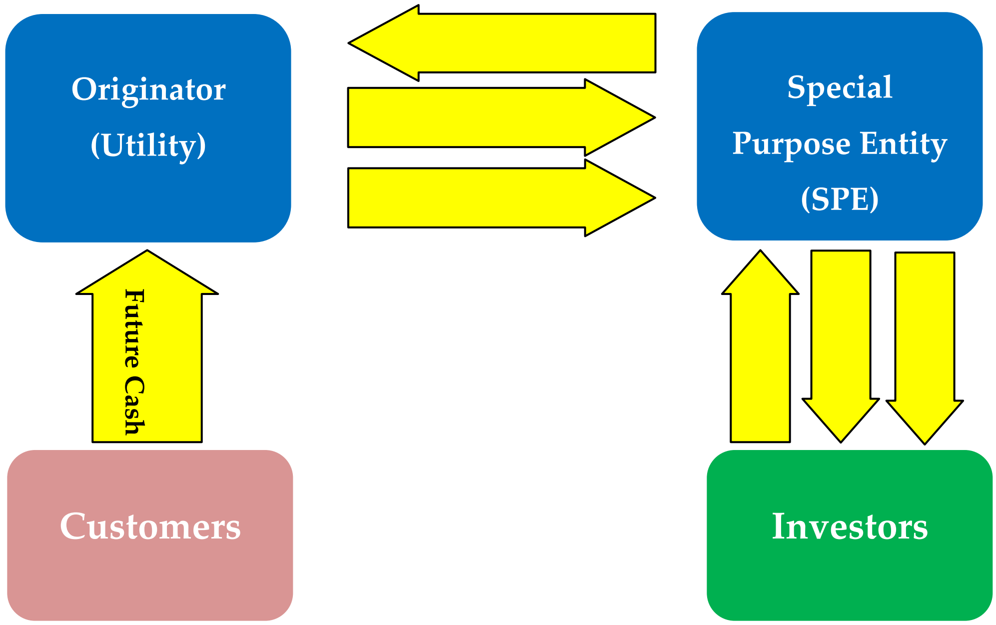

Figure 4 – Key Stages of Securitization

There have been more recent transactions that utilize securitization. Such transactions allowed utilities to finance mandated pollution control equipment and other similar environmental capital expenditures and, especially for affected coastal utilities, to recover or provide for storm recovery and reconstruction costs.[9]

The securitization strategy is attractive because:

- Utilities were able to secure funding of the investments at a significantly lower cost of capital than traditional approaches;
- Political support for securitization existed at a regional level;
- Securitization provided the utility with a levelized revenue requirement compared to a traditional utility revenue requirement;
- The jurisdictions in question were able to provide the utilities with financing which avoided Federal Income Tax, thus providing a significant discount to the normal corporate debt cost.

[9] Wisconsin Electric Power Company, 2004 and Allegheny Energy, 2007 used a variant of securitization to finance the installation of mandated pollution control equipment. Florida Power and Light and Entergy used securitization as a source of financing for reconstruction after Hurricanes Katrina, Rita, and Wilma after 2005. For more detail on these cases involving securitization, see Edison Electric Institute, "*State Regulatory Update: Rate Impact Mitigation Measures*", June 2010, Report prepared by the Energy Policy Group, Atlanta, GA.

Examples of Securitization

Entergy Mississippi and Mississippi Power Storm Recovery

In 2006 the Mississippi Public Service Commission allowed Entergy Mississippi the use of securitization as a mechanism to mitigate the impacts of costs incurred to respond to and reconstruct the system due to damage from Hurricane Katrina (Cases: 2005-UA-0555 and 2006-UA-82). The Commission granted Entergy $89.2M and Mississippi Power $302.4M.

Florida Power & Light (FPL) Storm Recovery

Florida Power and Light Company (FPL) experienced several severe storms triggering over $1.05B in storm recovery expenditures. The Florida Public Service Commission (Case 060038-EI) and the State legislature (Section 366.8260 Florida Statutes) provided FPL with the authority to recover $708M in storm recovery bonds with a life of 12 years. In approving the bond issuance, the PSC found that "the issuance of the storm-recovery bonds and the imposition of the storm-recovery charges authorized by the Order are reasonably expected to significantly mitigate rate impacts to customers as compared with alternative, more traditional methods of financing or recovering storm-recovery costs and replenishing the Reserve."

CenterPoint Energy Storm Recovery Costs

Securitization was allowed for storm damage which provided the utility with bonding authority of up to $642.8M. The Texas PUC allowed $20M in transmission costs but stated that transmission costs must be recovered through the Electric Reliability Council of Texas (ERCOT) transmission rates and not through utility's retail rates. The Texas PUC required that the final storm damage amount be reduced by: (i) any insurance proceeds, (ii) government grants, or (iii) other sources of funding which reduced CenterPoint's total costs.

Considerations for Ontario

Securitization is not always a preferred mechanism for dealing with rate mitigation as it depends on a favorable ruling supporting the bonds from both regulators and underwriters, and may in some cases require legislative action. It is imperative that regulatory authorities provide a guarantee for recovery of the Securitization Bonds or they will be classified as high risk debt and potentially require a return in excess of the distributor's cost of capital. Securitization will fail if any doubt exists that the liability will not be extinguished under the agreed upon terms. In some cases securitization has required legislative changes in order to reinforce the guarantee. Furthermore, the utility cannot earn a ROE on whatever investment results from the proceeds. For example, if a utility is using securitization to finance the reconstruction of a large part of its system, it might not be able to earn on that investment in the future, and thus could face a substantially reduced rate base.

Although severe storms are generally not as significant a concern for Ontario as they are for hurricane prone regions securitization can potentially be used as a mechanism to mitigate some capital expenditure programs driven by specific policy initiatives. For example, the use of Securitization to finance the implementation of Smart Meters in Ontario may have reduced their overall costs and levelized the rate impacts over time.

Trended Original Cost Ratemaking

The Trended Original Cost (TOC) approach to ratemaking includes minor modifications to the traditional approach to recovery of the revenue requirement formula, and allows for trending of the equity portion of the rate base through a deferral and subsequent capitalization of the inflation component of the equity return.[10] In other words, a real rather than a nominal equity return is applied to the original equity investment. The inflation portion of the return, the difference between real and nominal return, is deferred and added to the rate base, thus establishing an increasing or trended equity rate base. So far, the TOC methodology has only had limited application to the electric power industry; it is most often applied to pipeline projects in the oil industry by the US FERC.

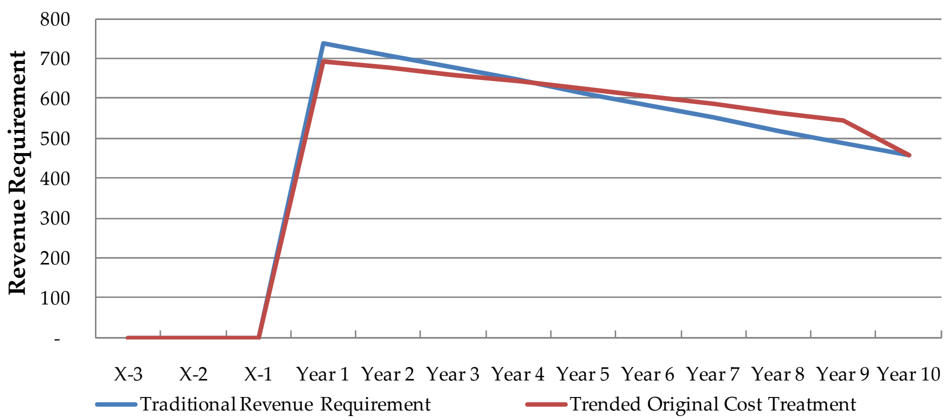

Figure 5 - Illustration of a Traditional Revenue Requirement versus the Revenue Requirement Based Upon Trended Original Cost Ratemaking

In practice, the TOC methodology applies only the "real" or "inflation-adjusted" rate of return to the rate base in the current year. It then reflects the inflation component of the equity return as a deferral, capitalizing it into rate base and then amortizing (earning) it over the remaining life of the asset. The ultimate impact is that TOC leads to a deferred recovery of a portion of the cost of equity capital as compared to traditional revenue requirement calculation, and in doing so reduces the initial revenue requirement and mitigates rate shock. While there is an obvious difference in cash flow timing, both methods yield the same discounted earnings stream for shareholders.

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[10] Kilpatrick, Jr., Henry E. 1991, Energy Law Journal V.12:323, "*The trended vs. depreciated original cost controversy*"

In order to apply TOC ratemaking, the allowed nominal (inflation-included) rate of return on equity, which normally reflects the company's risks (cost of capital), must be separated into both:

- "Inflation" component of nominal rate of return on equity; and,
- "Real" (e.g. inflation-adjusted) rate of return on equity.

Under the traditional approach, the ROE component of revenue requirement is often calculated based on the nominal rate of return on equity times the equity share of rate base. Under the TOC approach, the "Real" component is multiplied by the equity share of rate base and included in revenue requirement, which is similar to the traditional approach; however, when the "inflation" component is multiplied by the equity share of rate base, the balance is capitalized as a deferred asset and amortized over the remaining depreciation life of the asset. The main difference between the two approaches (TOC vs. traditional) is that the equity return associated with inflation is deferred and earnings are more heavily skewed toward the second half of the asset's life.

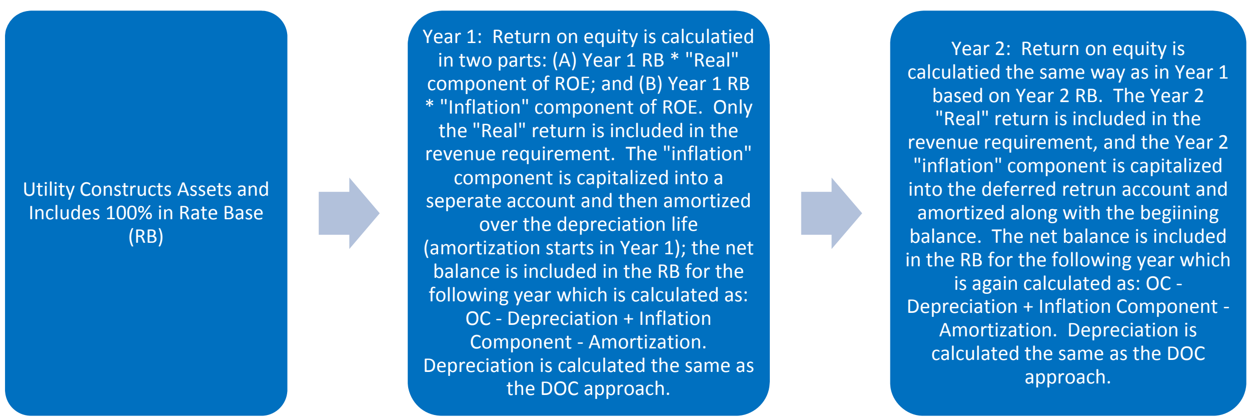

Figure 6 – Key Stages of Trended Original Cost Ratemaking

A main advantage of the TOC versus traditional revenue requirement is that it reduces front-end loaded cost recovery because it capitalizes the inflation component in the equity rate base. This deferral of income acts to mitigating rate shock.

While TOC is often only applied to the equity share of rate base, a case for trending the entire rate base can also be made, utilizing a "real" cost of debt and inflation factor. This will create an even more significant timing difference and income deferral.

Examples of Trended Original Cost Ratemaking

Williams Pipeline

The only application of TOC currently being used is the U.S. FERC decided in 1985 to regulate oil pipelines (those which transport crude oil, petroleum products, and natural gas liquids) using the TOC approach.[11]

Considerations for Ontario

Trended Original Cost Ratemaking could potentially be applied by a distributor to finance specific groups of assets. However, use of TOC would generally introduce the complexity of a bifurcated revenue requirement filing.

Construction Work in Progress

Construction Work in Progress (CWIP) is a regulatory mechanism that allows assets which have been constructed but not yet placed into service into rate base thus mitigating rate shock for a project requiring several years to construct. Effectively, the costs of the infrastructure project are included into the electric rates in a gradual and predictable manner as opposed to a single "lump sum" thus triggering rate shock.

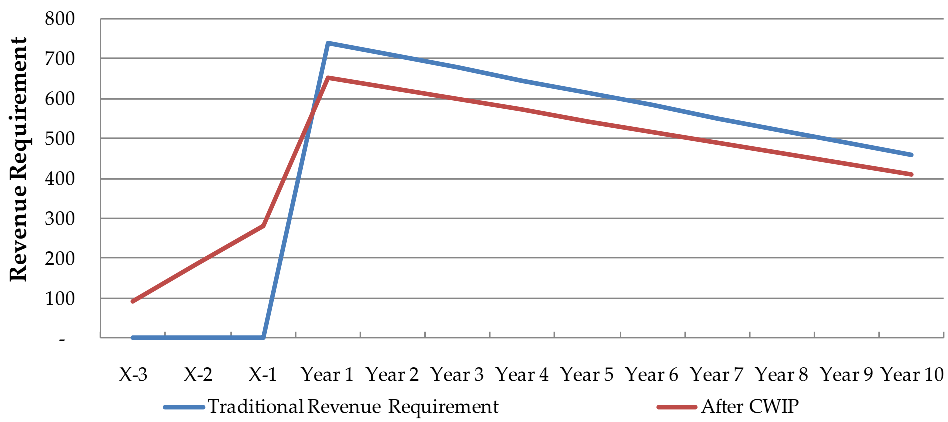

Figure 7 - Illustration of a Traditional Revenue Requirement versus the Revenue Requirement Based Upon Trended Original Cost Ratemaking

In other jurisdictions, a request for a CWIP rate treatment is submitted to the Regulator as part of a rate application or approval for a capital investment

[11] Williams Pipe Line Co., 31 F.E.R.C. 7 61.377 (1985) [Opinion No. 154-B] and Williams Pipe Line Co., 33 F.E.R.C. 7 61,327 (1985) [Opinion No. 154-C].

Figure 8 – Key Stages of CWIP

Example of CWIP

Georgia Power

An example of where the CWIP rate mitigation has been implemented is Georgia Power. In 2009, the Georgia Legislature passed a bill that allows utilities to recover the costs of building nuclear facilities through rate increases prior to a plant being placed into service. The legislation, Senate Bill 31 (SB 31), authorized Georgia utilities to earn cash return on CWIP. As described in section two (2) of the Georgia Nuclear Energy Financing Act (SB 31):[12]

> *A utility shall recover from its customers, as provided in this subsection, the costs of financing associated with the construction of a nuclear generating plant which has been certified by the commission. The financing charges shall accrue on all applicable certified costs as they are recorded in the utility's construction work in progress accounts pursuant to generally accepted accounting and regulatory principles as approved by the commission. The financing costs shall be based on the utility's actual cost of debt, as reflected in its annual surveillance report filed with the commission, and based on the authorized cost of equity capital and capital structure as determined by the commission when setting the utility's current base rates. These financing costs shall be recovered from each customer through a separate rate tariff and allocated on an equal percentage basis to standard base tariffs which are designed to collect embedded capacity costs.*

As stated in the legislation, the recovery of this cost is to be recovered from each customer through a separate rate tariff, known as nuclear construction cost recovery (NCCR). The NCCR will be added independently to a customer's base rate to determine the monthly bill. This change in historic cost recovery is described below:[13]

> *Historically, utilities are allowed to recover the cost of investments, such as power plants, after the plants begin to operate and serve customers. During the construction period, utilities incur*

[12] Source: http://www.legis.state.ga.us/legis/2009_10/fulltext/sb31.htm

[13] Source: http://www.southerncompany.com/nuclearenergy/costs.aspx

> *construction and related financing costs. Because of the tremendous cost of investments such as power plants, utilities also incur additional costs to pay the financing incurred during the construction period. Typically, recovery of financing costs is deferred during the construction period, added to the ultimate cost of the plant and recovered from customers over the anticipated life of the plant.*
>
> *As an alternative, rates can be set to allow for recovery of financing costs during the construction period — and avoid additional interest charges. Utility credit rating agencies view recovery of financing costs during construction positively, which can result in lower financing costs for all utility projects. Better credit ratings can lower the interest costs the company — and therefore customers — must incur to finance the cost of new power plants.*

While the primary driver for requesting CWIP treatment is to supplement financing (cash flow), a secondary benefit of the mechanism is rate shock mitigation. In general, the longer the construction lead-time in constructing an asset the greater the rate mitigation benefit provided by CWIP.

Considerations for Ontario

CWIP is a mechanism best suited for a single large investment which requires several years to construction. Mitigation is provided through acceleration in the recovery of the asset. However, very few distribution projects require a multi-year construction cycle and therefore the application of CWIP would probably have few applications in Ontario.

Inter-Year Rate Mitigation Measures

Inter-Year Rate Mitigation is applied when a rate adjustment triggers a significant impact in a single year followed by one or more years of moderate rate activity. The difference between Inter-Year Rate Mitigation and Long-Run Rate Mitigation is that it applies to the utility's total revenue requirement, is not necessarily related to any specific asset or investment, and no opportunity exists to influence the revenue requirement through a re-scheduling of capital investments.

Descriptions of two Inter-Year Rate Mitigation Measures are described below, including examples and discussion on the suitability for Ontario utilities.

- Deferral of the Revenue Requirement, and
- Pre-funding of the Revenue Requirement.

Also included at the end of this section is a discussion of the Ontario Clean Energy Benefits (OCEB). Mitigation of the rate impacts caused by the expiry of the OCEB would be categorized as an Inter-Year Rate Mitigation measure.

Deferral of the Revenue Requirement

The use of a deferral of the revenue requirement requires that a portion of the current year's revenue requirement be recovered in a future time period, thus reducing the current period's revenue requirement. The deferral amount becomes a regulatory asset which is assured of being fully amortized, and that deferral amount must be allowed to earn a reasonable carrying charge. Absent a guarantee from the regulator, the regulatory asset will be viewed as high risk asset by the financial community, triggering a higher return and ultimately increasing the long-run cost to customers. Even with a regulatory guarantee, the regulatory asset adds a degree of risk because it has no inherent value as a physical asset or as a commercial instrument.

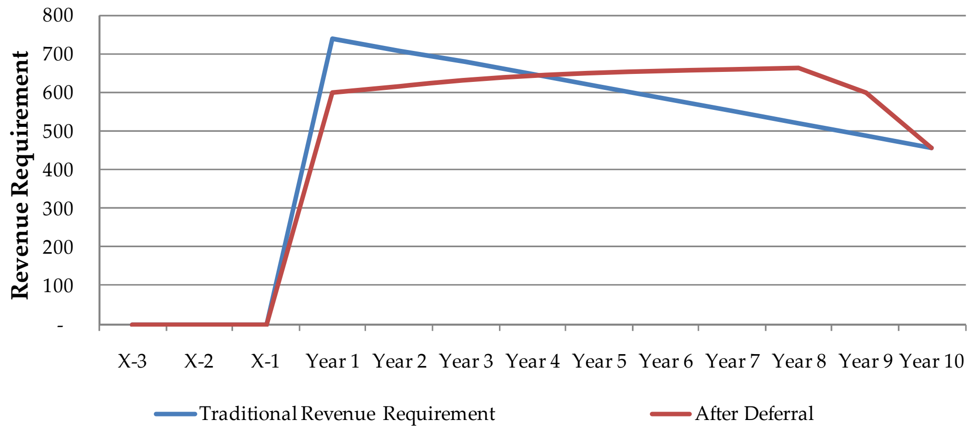

Figure 9 - Illustration of a Traditional Revenue Requirement versus the Revenue Requirement Based Upon Deferral of the Revenue Requirement

An example of the mechanics of this approach could involve setting up a revenue deferral account where reductions to the current year's revenue requirement are to be held for recovery in a future year. The deferral account becomes a regulatory asset that is included in rate base where it earns the utility's allowed rate of return.

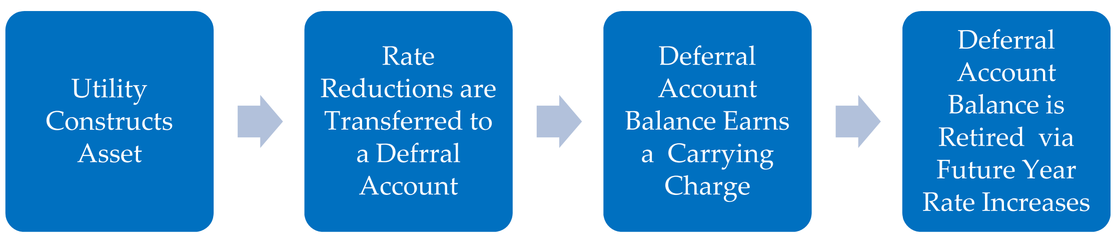

Figure 10 – Key Stages of Deferred Recovery of the Revenue Requirement

The disadvantages with the Deferral of the Recovery of Revenue Requirement approach are as follows:

- Customers will ultimately pay more in absolute terms (but not on a present value basis) because of the carrying costs associated with the deferred revenue;
- Deferral of the Revenue Requirement Reduces the Short Term Cash Flow of the Utility. However, the cash flows in more distant years will be increased;
- From the perspective of the Utility, the deferral is a delay in the timing of when revenues will be realized which may require the utility to raise additional funds than would otherwise have been necessary.

Examples of Deferral of Revenue Requirements

Illinois Jurisdictional Examples

Illinois passed Industry Restructuring Legislation in 1997 which provided under original and subsequent versions of the legislation a rate freeze for customers that would remain in effect until December 31, 2006. The legislation also provided for rate reductions for residential and small commercial customers. The transition to market-based generation rates occurred on January 1, 2007 triggering significant rate increases to many residential and small commercial customers (especially those served by the former Central Illinois Lighting Company and Central Illinois Public Service)[14] who were subjected to significant rate shock.

Ameren–Illinois[15] Rate Mitigation Riders / Customer Electric Plan

In 2006, Ameren-Illinois (Ameren) proposed a voluntary Customer Elect Plan (CEP) Rider to implement an optional deferred billing plan for residential, small commercial customers, primary and secondary schools, and certain local governmental customers. The Rider was proposed to phase in the effect of the rate changes that those customers were expected to experience beginning on January 2, 2007. Ameren reduced the interest charges on deferred amounts by 50%, from 6.5% to 3.25% with no option for future recovery of these costs. The CEP also lowered the annual rate phase-in cap to 14% for each of the three years 2007-09. In addition, a Rate Mitigation Credit (RMC) Rider was proposed and accepted which provided for special assistance to residential customers with high winter usage.

Commonwealth Edison Rate Stabilization Plan

As is discussed above in the Ameren case, the end of the transition period triggered significant rate increases for Commonwealth Edison (ComEd) customers effective January 1, 2007. However, due to legislatively mandated rate decreases implemented in 1997-99, residential and small commercial customers received decreases of approximately 20-25% below the bundled rate in effect in January 1, 1997.

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[14] In 1997 when industry restructuring legislation was passed Illinois was served by 5 electric IOUs: (1) Commonwealth Edison Company; (2) Illinois Power Company; (3) Central Illinois Lighting Company; (4) Central Illinois Public Service Company; and, (5) Union Electric Company. During the transition period (1998-2006) Union Electric was renamed Ameren Corporation and acquired through various transaction Illinois Power, Central Illinois Public Service and Central Illinois Lighting Company.

[15] At the time of the Industry Restructuring Legislation in 1997 the electric Investor-Owned Utilities (IOU) serving Illinois were Commonwealth Edison Company, Illinois Power Company, Central Illinois Public Service Company, Central Illinois Lighting Company, Union Electric-Illinois and Mount Carmel Public Utility. Union Electric changed their name to Ameren Corporation and in three separate transactions acquired the service areas of Illinois Power, Central Illinois Lighting Company and Central Illinois Public Service Company. The relevance of these transactions was that Central Illinois Public Service Company, Union Electric-Illinois and Central Illinois Lighting Company were relatively low cost utilities in 1997 which magnified the impacts of the transition to market prices when the rate cap expired on January 1, 2007.

The expiration of the legislatively mandated rate decreases coupled with market prices for generation services essentially return many of these customers to January 1, 1997 rate levels before the rate decrease was provided to customers.

In the absence of any mitigation actions customers would experience increases ranging between 20-25%. The Illinois Commerce Commission approved a mechanism which phased-in the rate increases of with a series of adjustments of 8%, 7% and 6% effective in 2007, 2008 and 2009 (Case 06-0411). The unbilled balances to customers would accrue a 3.25% return and be treated as a regulatory asset.

Nevada Power Rate Phase-in

In Nevada Power (NP) Case 08-12002, the Nevada Commission authorized a rate increase of $217 million as part of a $1.5 billion expenditure for purchasing and constructing generation assets. The Nevada Commission further ordered a phase-in of the rate increase which occurred in two steps– a 3% increase in July 1, 2009, and a 3.8% increase on January 1, 2010. NP was allowed to receive a return on the deferred balance of the second phase of the rate increase. The rationale for the phase-in was the severe economic hardship that the service area was experiencing.

Baltimore Gas and Electric Phase-in Plan, Deferred Cost Securitization, and Rate Stabilization Plan

In a manner similar to Pennsylvania, Maryland also implemented rate caps in the 1990's as utilities moved to market-based rates. In 2006, Baltimore Gas and Electric (BGE) customers faced a potential 72% increase if they opted into full market-based rates, per Standard Offer Service (SOS)[16]. In addition to the expiration of the rate caps the increases were magnified by impacts on power market prices of Hurricane Katrina. To avoid the large increase, Senate Bill 1 (SB1) was enacted such that SOS customers were given the option to participate in a rate stabilization plan which would gradually increase the generation[17] component of the rates over a two-year period. Under SB1, in the first year, all customers' rates were increased by 15%. However, in the second year, customers were given the option of receiving the remainder of the increase[18] immediately (July 1, 2007), or to pay the costs, plus interest, for the following ten years. Under the second option, monthly rate increases were capped at $2.19/month. In addition, BGE agreed to cease collecting the residential return component of its bills, resulting in an additional $387M rate reduction over ten years.

Later in 2006, the Commission filed an order (Case 9089) to allow the securitization of $630M of deferred cost stemming from the 72% rate increase. The Commission obligated residential customers served by BGE

[16] Pursuant to Commission Case No. 8909

[17] Only the generation component was increased within the bill, but all increases in this section reflect total bill impacts

[18] 57% (or, 72% - 15%)

or retail suppliers to pay the non-bypassable customer surcharge which would repay the principal, interest, and related costs of the bonds.

Pepco and Delmarva Power & Light Transition Rate Phase-in Plan

In 2006 a Settlement Agreement was filed with the Maryland PSC (Case 9058) which limited bill increases to 15% for the time period June 1, 2006 through February 28, 2007, followed by an increase of 15.7% effective March 1, 2007 through May 31, 2007 and market rates beginning in June 2007. Recovery of the deferred portion of the revenue requirement was allowed through a non-bypassable surcharge over an 18 month period beginning on June 1, 2007 with provisions for a true-up mechanism.

Pennsylvania Jurisdictional Issues

Industry restructuring legislation enacted in 1996 provided the customers of Pennsylvania's electric IOUs the ability to procure generation service from competitive service providers. To the extent that customers elected to remain with the incumbent electric distribution company, the price that such customers paid for generation was capped so as to ameliorate somewhat, potential rate shocks from wholesale market volatility.

The rate caps for all the regulated electric distribution companies have expired as of December 31, 2010.[19] In anticipation of this and after consultation with stake-holders, the Pennsylvania Public Utilities Commission put in place a policy to mitigate potential electricity price increases in 2007.[20] The following were key elements of the Commission's policy:

- Education programs conducted state-wide and by each individual electric distribution company to inform and educate customers on the expiration of rate caps;

- Consideration of energy efficiency, conservation, and demand-side response as potential mitigation options;

- Smoothing out (or "phasing-in") abrupt rate increases through voluntary pre-payment an deferral of expected rate increase;

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[19] Pennsylvania Power and Light Company's rate cap expired on 12/31/09. Caps in place for Philadelphia Electric Company, Metropolitan Edison, Penelec, and Allegheny Energy expired on 12/31/2010.

[20] *Default Service and Retail Electricity Markets*, Docket No. M-00061957, Final Policy Statement Order entered, May 17, 2007.

- Competitive and cost-effective solicitation of generation resources to meet the requirements of customers that remained with the incumbent electric distribution company;

- Reassessment of customer assistance programs particularly those targeted at low income customers;

- More active participation by the Commission at wholesale market forums and at the Federal level.

In their individual rate proceedings and consistent with the Commission's rate mitigation policy, both Pennsylvania Power and Light ("PPL") and Philadelphia Electric Company ("PECO") proposed competitive and cost effective solicitations of generation resources.[21] Both proposed the use of phase-in or smoothing out of rate increases (i.e., deferrals) as well as voluntary pre-payment to offset expected future rate increases.[22] The Commission approved the plans of both electric distribution companies.

Considerations for Ontario

The Deferral of the Recovery of the Revenue Requirement is best used by distributors in Ontario to smooth out the revenue requirements for Inter-Year Rate Impacts. This mechanism would smooth out the "stair-step" pattern of revenue requirement adjustments that sometimes occurs when the first year of the rebasing triggers a significant rate increase. However, Navigant cautions that if a deferral mechanism is used, the OEB would need to recognize the creation of the regulatory asset and provide certainty that the distributor will earn the allowed rate of return on the regulatory asset.

Another consideration is that the deferral mechanism may trigger a change in the allocation of the revenue requirement if the deferral is not allocated in the same manner as the original revenue requirement. If this mechanism is adopted, it is recommended that the cost allocation should be reviewed to ensure that no significant changes are inadvertently triggered which alter the percentage of the revenue requirement recovered from the various customer classes.

Last, many jurisdictions have designed Inter-Year Rate Mitigation mechanisms to be applied on a voluntary basis. The ability to offer voluntary mitigation is predicated upon a number of factors such as the design of the program (i.e. can the mitigated revenue requirement be separated from the balance of the revenue requirement), the distributors billing system (i.e. can the system account for balances on a customer basis)

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21 Both proposed procurement using laddered contracts to mitigate price volatility.

22 Qualifying PPL customers that voluntarily opt into this program will receive a credit on their bills to partially offset the initial financial impact of any rate increase, followed by a charge in the later years to repay the first year credits and accrued interest. The credits are designed to limit the increase of total charges, on an average for each rate class to no more than 25 percent in 2010 and an additional 25 percent in 2011 based on PPL's current estimate of the rate increase. Customers ultimately will pay the full amount of the increase plus the carrying costs on the deferred portion.

and other implementation issues. Navigant suggests that stakeholders should investigate the feasibility of implementing Inter-Year Rate Mitigation mechanisms on a voluntary basis.

Pre-Funding of the Revenue Requirement[23]

Pre-funding is in many ways a "mirror image" of the deferral mechanism discussed above. Instead of deferring a current year's revenue requirement, under this mechanism a portion of a future year's revenue requirement is recovered in the current year. The pre-funding amount becomes a regulatory liability which is used to finance future expenditures. The funds collected would earn interest and would ultimately be used as a customer contribution to reduce the utility funding needed for future capital projects. Given that only the utility portion of the funding is included in rate base, the subsequent rate increase will be reduced because both the return on rate base and depreciation expense will be lower. In addition, the pre-funding amounts paid by customers in advance provides an additional smoothing effect as the amounts paid up-front serve to reduce the magnitude of the rate increase after the rate impact event.

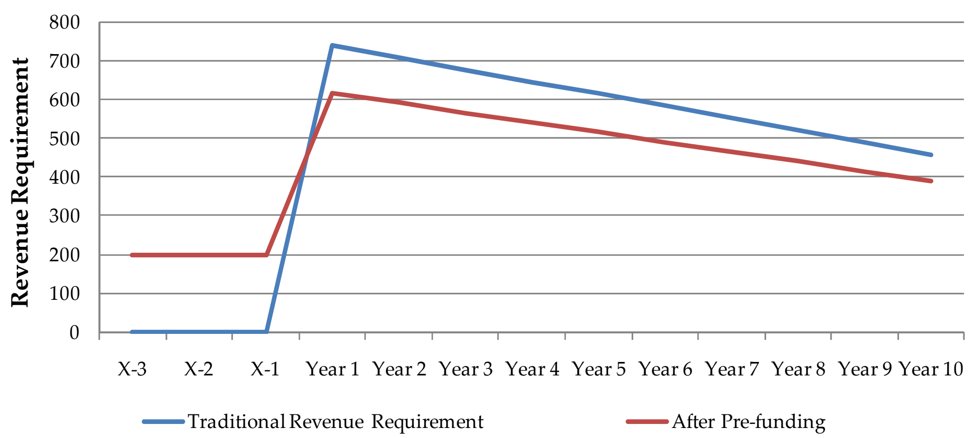

Figure 11 - Illustration of a Traditional Revenue Requirement versus the Revenue Requirement Based Upon Pre-funding of the Revenue Requirement

An advantage of this approach is that it does not impact the timing of distributor's revenue requirement[24], and increases the cash flow of the utility. Typically however, the increase in cash flow provided is set aside in a specific account where it will eventually be used for the intended purpose, and does not provide a source of additional operating cash flows to the utility. Whereas other mitigation measures tend to defer the timing of the distributor cash flows, pre-funding advances the timing of the customer payments.

[23] Although Pre-funding is classified as an Inter-Year Rate Mitigation Mechanism in the above context it is possible for long-term pre-pre-funding activities to occur which would be classified as a Long-Term Rate Mitigation Measure.

[24] The assumption that it does not impact the long-term revenue requirement assumes that the discounting is provided using the distributor's cost of capital.

Figure 12 – Key Stages of Pre-funding of the Revenue Requirement

Examples of Pre-funding of Revenue Requirements

Allegheny Power Rate Transition Plan

Allegheny Power (AP) faced potential rate shocks driven by the termination of a Maryland legislated rate cap ending on December 31, 2008. AP's proposal (Case 9091) sought to mitigate the rate shock while continuing to promote a competitive market. The company's proposal included a 15% customer rate increase on the frozen rates to start on March 31, 2007. Customer rates would then be increased again by 15% in January 2008. However, on January 1, 2009 when market-based rates become effective, any charges that exceed the market would become a credit and thus mitigate the impact to residential customers. The final order for this proceeding allowed customers to opt-out of the program, and also differentiated the credit for heating versus non-heating customers.

Considerations for Ontario

Pre-funding of the revenue requirement has previously been used for Smart Meters. In this case, pre-funding was used to reduce costs associated with the deployment of the Smart Meter program.

As described above for the deferral of the revenue requirement, pre-funding may also trigger a change in the allocation of the revenue requirement if the deferral is not allocated in the same manner as the original revenue requirement. If this strategy is adopted, the cost allocation should be reviewed to ensure that no significant changes in cost allocation are inadvertently triggered.

Last, in an analogous manner to our previous discussions of deferrals, Navigant believes that pre-funding could be applied on a voluntary basis. As noted above, a number of implementation issues would need to be overcome before the feasibility of voluntary participation is determined to be feasible.

The Ontario Clean Energy Benefit

The Ontario Clean Energy Benefit (OCEB), which was introduced on January 1, 2011, provides a 10% reduction in the total electricity bill for residential and small commercial customers over a 5 year time period. The expiration of the OCEB in December 2015 will trigger situations not unlike those experienced in Illinois, Pennsylvania and Delaware over the past decade, where the expiration of a legislatively mandated rate cap program triggered a significant increase in customer rates. Furthermore, the potential rate impacts in Ontario will be magnified for those distributors planning to rebase at the same time the OCEB expires in 2016.

Navigant recommends that the OEB work with stakeholders to prepare a menu of mitigation strategies in advance of 2016. Inasmuch as the circumstances of various distributors may differ, the strategies employed may also vary. Lessons from similar situations in the past have identified the following strategies are generally benefiting stakeholders:

- Strategies must be planned proactively and not be reactive to a negative response by stakeholders;
- Recognition that many consumers are indifferent to the rate increases, and if possible, consumers should be allowed the choice of whether or not they wish to participate in the mitigation program;
- The most widely used mitigation mechanisms include either a pre-funding or a deferral of the revenue requirement, or, a combination of the two mechanisms. The use of these mechanisms will need to be carefully considered given that the mitigation would in effect be an attempt to offset or nullify a provincial program to subsidize electricity rates. Another consideration in the implementation of a rate mitigation mechanism is that the OCEB does not apply to all customer classes.

Finally, Navigant urges the OEB and distributors to begin customer education programs well in advance of the expiration of the OCEB. Much of the negative consequences of the expiration of this program may be avoided if customer confusion over increases in electric bills is minimized.

Intra-Year Rate Mitigation

Intra-Year Rate Mitigation provides for an orderly transition from the existing tariff design to a cost of service based design while avoiding unacceptably large increases or decrease in the cost of service. Bonbright[25] included in his criteria for a sound rate design the principle of "gradualism" when designing tariffs. The mitigation strategies generally employed for Intra-Year Rate Mitigation involve shifting the revenue requirement between tariff classes in order to limit the impact to those classes which may be adversely impacted (i.e. receive larger than average tariffs) or unduly benefit (i.e. receive decreases which significantly differ from the mean).

Reallocation of the Revenue Requirement

Unlike Long-Run and Inter-Year Rate Mitigation which have a variety of mechanisms to address mitigation, Intra-Year Rate Mitigation can only be remedied by reallocating the revenue requirement among the other classes of customers.

Example of a Reallocation of the Revenue Requirement

The reallocation of the revenue requirement is accomplished by establishing a constraint of the maximum increase/decrease that is acceptable in the rate design. If the constraint is reached the revenues are reallocated to the other tariff classes. Figure 13 below illustrates the reallocation of the revenue requirement.

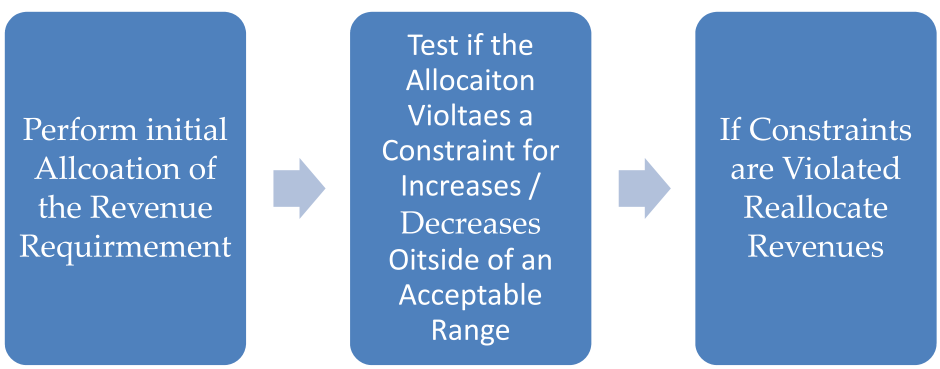

Figure 13 – Key Stages of Revenue Reallocation

[25] Bonbright, James C., Albert L. Danielson and David K. Kamerschen, *Principles of Public Utility Rates* (Arlington, VA: Public Utilities Reports, Inc., 1988)

Examples of the Application of a Revenue Reallocation

British Columbia Hydro Residential Inclining Block Rate Re-Pricing

On December 21, 2010 British Columbia Hydro (BC Hydro) prepared an application before the British Columbia Utilities Commission (BCUC) requesting authority to change a residential inclining block rate design. The changes in the rate design were driven by changes in the estimated Long-Run Marginal Cost (LRMC) as estimated by BC Hydro.

As described in the application, the tariff design consists of a customer charge and a 2 step energy charge. BC Hydro's objective is to move the second step energy charge to LRMC but has constrained these rate design changes by testing the proposed rate design for customer impacts. BC Hydro has requested that the changes to the tariff be constrained based upon a criteria of Class Average Rate Change plus 10%. Therefore, the movement to full LRMC for the second step of the energy occurs over a number of years and is finally attained.

Consolidated Edison Company of New York

Consolidated Edison of New York (ConEd) operates the electric distribution and transmission facilities in New York City and Westchester County. ConEd has received a number of significant increases in electric distribution rates that have been approved by the New York Public Service Commission (NTPSC) attributable to infrastructure upgrades. Recent increases in overall power distribution tariffs have been $425M and $721M in dockets 07-E-0523 and 08-E-0539.

The methodology used to allocate the revenue requirement to specific tariff classes is a fully allocated cost of service analysis. The results of the cost of service analysis has generally produced overall tariff increases which would be significantly in excess of the average increase for certain classes – especially the New York Power Authority (NYPA) customer classes[26].

Recent orders have included a rate mitigation adjustment that limits the class average increase in tariffs using a "dead band" mechanism. The dead band limits the class average increase for each class of service and re-distributes the residual increase to other customer classes.

It should be noted that in each of the above cases ConEd was allowed to recover the approved revenue requirement in each year. The mitigation that was provided shifted revenue responsibility from one tariff class to another within the same year.

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[26] The New York Power Authority (NYPA) is a generation and transmission services provider operating in the State of New York. NYPA has provided certain governmental customers in New York City generation services using the transmission and distribution facilities of ConEd since the 1970s.

Considerations for Ontario

Intra-Year Rate Mitigations is a controversial issue because it addresses cost allocation. The utility receives the same level of revenue, and all rate impacts occur between customers. The mitigation afforded one tariff class will be viewed as a subsidy by the tariff class(es) providing the funding for that mitigation. However, unduly large adjustments in tariffs are generally not considered good public policy. Furthermore, controversy often exists regarding the analytical approach used to allocate the revenue requirement to tariff classes or the assumptions used to perform the study, thus calling into question the results of the study.

In spite of the controversy of rate mitigation programs occurring within a single test year, it must be recognized from a practical and policy standpoint that that abrupt shifts in the allocation of the revenue requirement can be problematic. Therefore, a coherent and systematic process is required to implement these adjustments which allow the revenue requirement to eventually reach targeted levels.

Triggering Mechanisms for Rate Mitigation

Rate triggers are mechanisms that would indicate to stakeholders when bill impacts would exceed a certain threshold and thus trigger the need or potential need for rate mitigation.

The Board's current rate mitigation policy includes a bill impact "threshold." Under current policy, if the rate impact of a utility's rate filing exceeds 10% of the total bill impact, the utility must propose some type of plan to mitigate the rate impact. The quantitative threshold value of 10% is essentially arbitrary and was not derived from any explicit empirical analysis.

Provided below are several alternative triggers which could be established as mechanisms which would signal rate increases which may be unacceptable from a policy perspective. Rate triggers would be applied if any long-term rate mitigation mechanisms employed fail to provide sufficient levelization of rates.

Macroeconomic-Based Threshold

Broader inflationary trends can certainly put upward pressures on utility costs and bill impacts. It may therefore be appropriate for the mitigation threshold to be linked to broad, macroeconomic inflation in the Canadian economy. More rapid inflation would therefore tend to raise the acceptable threshold level and reduce the need for rate mitigation plans. For example, instead of a flat 10% value, the bill impact threshold could be set at three times the annual inflation in Canadian GDP-IPI, as measured at the end of the third quarter in any given year.

Industry Unit Cost-Based Threshold

Unit costs for electricity distributors and transmitters may also be driven by factors that are relatively common to the industry, but at least somewhat independent of overall inflationary pressures. It may therefore be appropriate for the mitigation threshold to be linked to unit cost trends of the respective utility industries. If a unit cost-based threshold were to be adopted, Staff would have to develop a formula for measuring overall unit costs for regulated companies on an annual basis. This is a relatively straightforward exercise, but would involve decisions on how certain costs would be estimated (*e.g.*, the cost of capital). One example of a unit cost-based threshold would be that the bill impact threshold would be set at three times the estimated inflation in unit cost for the network industry from the year before, using RRR data and an agreed formula for computing unit cost.

Peer Utility Unit-Cost Based Threshold

It may be argued that there are significant differences among distributors in Ontario, and any threshold developed using utility industry data should attempt to control for these differences. One method of doing so would be to compute unit cost trends for carefully constructed peer utilities, and link the threshold value for any given network directly to the change in unit costs for its designated peers. One of the benchmarking models that are used to set "stretch factors" for electricity distributors in Ontario is based on unit costs comparisons for 12 different peer groups of distributors. These comparisons are updated annually, and this work could easily be adapted to compute the change in unit costs for each of the 12 peer groups.[27] An example of a peer utility, unit cost-based threshold would be to set the bill impact threshold for any utility at three times the estimated inflation in unit cost for that utility's designated peer group, from the year before.

Analysis of Mitigation Trigger Options

There are advantages and disadvantages associated with the empirically-derived threshold options discussed above. The main advantage of the macroeconomic-based threshold is its simplicity. Economy-wide inflation numbers are prepared and reported regularly by government agencies. Data on macroeconomic inflation trends can therefore be obtained easily and, essentially without cost. Administering a macroeconomic-based threshold would therefore be simple and impose few regulatory costs.

On the other hand, the cost pressures for electricity networks may differ considerably from macroeconomic inflation trends. Any ongoing disparity between distributors' approved changes in revenue requirements and macroeconomic inflation would suggest that factors specific to the utility industry, rather than macroeconomic inflation, are the chief "drivers" of large rate increases and hence the need for rate mitigation. This, in turn, would reduce the value in relying on a macroeconomic-based threshold for rate mitigation.

At the other extreme, the peer unit cost-based threshold would certainly reflect cost pressures for electricity networks. Relying on peer-based unit costs is also likely to be the more accurate than the other options in reflecting the cost pressures of a given utility, since this threshold would be developed using data for networks operating under similar circumstances and, presumably, similar cost pressures. The peer-based unit cost threshold would therefore be better able to accommodate the diversity among distributors than would having a single, unit cost-based threshold derived from the entire industry's data.

However, implementing the peer-based unit cost-based threshold would be more complex and perhaps confusing. Staff would have to compute 12 separate threshold values, for twelve different sets of companies, in each year. These threshold values could differ considerably among peer groups, which could raise questions and reduce the transparency of the rate mitigation framework. The threshold values could differ considerably from year to year for any given peer group, depending on how cost pressures change from year

[27] If desired, the number of peer groups could also be modified (e.g. reduced in number, to simplify calculations and the number of peers), but developing new peer groups would require far more effort.

to year. This could in turn reduce the predictability of the threshold value and overall regulatory framework.

If there is interest in having an empirically-based threshold value, the industry unit-cost threshold could be an appealing compromise between these extremes. It clearly has a stronger link to industry unit cost pressures than macroeconomic inflation. It would also calculate a single, threshold value for rate mitigation that would apply to all utilities in the industry. This value may vary from year to year, but year to year volatility would be damped by the fact that the threshold would be calculated for the entire industry, which reduces the ability of any given company's data can have on the change in unit cost in a year. As discussed above, the change in unit cost for the entire electricity distribution industry would have to be calculated annually, but this can be done straightforwardly and at relatively little incremental cost since unit costs for each electricity distributor are already being updated annually in order to update stretch factors in Third Generation Incentive Regulation. For these reasons, if the Board is implementing an empirically-based threshold, we believe the unit cost-based threshold strikes the best balance between simplicity and accurately reflecting industry cost pressures and would be the most preferred of these three options.

Conclusions and Key Considerations

The objective of the Rate Mitigation Strategy is to the extent possible, provide guidance to stakeholders when mitigation may be required, establish mechanisms to stabilize changes in the distributor's revenue requirement and provide mechanisms that limit rate increases to a level that is acceptable to consumers. However, the goals of mitigation must also include protection for the financial health of the distributor, as well as maintaining an environment for the continued safe and efficient operation of the system. Therefore, the objective of rate mitigation should not be viewed in isolation, but as one of several objectives which the OEB desires to attain.

Although "Rate Mitigation" is often discussed generically as a single activity, it stems from a number of different activities either driven by the capital investment planning horizon of the distribution system or by the source of the rate impacts. Figure **14** below provides a summary of the rate impacts, the causes of each rate impact, and potential mitigation strategies.

Long-Run Rate Mitigation

- Long-run system planning which to the extent possible avoids "lumpy" introduction of distribution plant
- Financing mechanisms that allow when possible for the levilization of the revenue requirement for a specific asset

Inter-year rate Mitigation

- Intermediate term mechanisms which allow acceleration or deferral of the revenue requirement over a period of 2-3 years

Intra-Year Rate Mitigation

- Application of rate design techniques that provide for avoidance of rate shock for a specific tariff class or classes, while allowing for the gradual movement to full cost of service

Figure 14 – Cause of Rate Impacts and Proposed Mitigation Strategies

Experience in other Jurisdictions

Unlike Ontario, most jurisdictions do not have formal rate mitigation policies. Navigant's explanation for the lack of these policies is as follows:

- Most jurisdictions do not have an established schedule for rate case activity. Utilities file requests when needed which in some cases provides for a period of several years (or decades) between proceedings.

The lack of a an established schedule often provides for more "ad hoc" approaches to policy questions such as rate mitigation;

- Mitigation activities have been treated as a "band-aid" when the outcome of a rate proceeding or other price adjustment is unacceptable;
- Rate Mitigation should not occur at the expense of the utility as it has the potential to compromise the financial health of the enterprise and increases the long-term cost of service; and,
- In most other jurisdictions the number of utilities to be regulated is significant less than Ontario where are more than 80. In such jurisdictions the need for formal policies or prescriptive regulatory mechanisms may not be appropriate.
- In the case of utilities transitioning to retail competition, the rate increases experienced by customers were not anticipated when the enabling legislation was written. Where regulators were cognizant of the anticipated increases, they may have felt constrained by legislative mandates and did not take aggressive action.

Jurisdictions such as Pennsylvania allowed mitigation to be provided to customers on a voluntary basis. Voluntary mitigation appears to have been successful in this jurisdiction where the mitigation measure was focused on customer groups who desired that option.

Navigant's review of other jurisdictions did not uncover any systemic or formulaic approaches to rate mitigation which would apply to the specific circumstances of Ontario. In general, most jurisdictions apply mitigation in a manner which suits a specific situation. Furthermore, many examples of mitigation occur as part of a rate proceeding or negotiated settlement proceeding.

Mitigation and Clean Energy Jurisdictions

As part of Navigant's analysis, investigations were performed to ascertain if specific mitigation strategies existed in "Clean Energy" jurisdictions, and if so, could any of these policies be adopted for application in Ontario. Clean Energy has been defined as generation from Renewable Energy sources and Energy Efficiency programs.

After a review of regulatory policies in various jurisdictions in the United States and Western Europe, we have not identified any systematic mitigation policies directly related to Clean Energy. Two possible explanations for this are described below.

- ***Renewable Energy Projects Often Offer a Levelized Payment Stream*** – Much of the renewable energy in place in North America has been developed by the merchant power sector (i.e. Independent Power

Producers). The agreements which independent Power Producers typically offer are based upon a model of a levelized guaranteed payment from the off-taking utility. Therefore, the problem of adverse rate impacts is avoided because the payment structure is essentially levelized through the Power Purchase Agreement.

- ***Cost Thresholds*** – Some jurisdictions (e.g. New Mexico, Colorado and Illinois) have established limits on rate impacts to customers participating in programs which include the funding of renewable Energy or Energy Efficiency. In cases where the customer impact threshold is exceeded, the program requires that the rate impact be mitigated.

Key Considerations

Navigant has identified the following key considerations for review as part of the stakeholder process.

Proposed Rate Triggers for Mitigation of Revenue Requirement

As previously noted, the OEB's current rate mitigation policy includes a bill impact "threshold" of 10%, and if this threshold is exceeded, some type of mitigation is required. Although this approach might be considered arbitrary because the ±10% bandwidth for which rate mitigation is not required was chosen on a subjective basis, it is reasonable and easily understandable to parties.

Navigant has identified several triggers that could be used to set thresholds to signal rate increases which may be unacceptable from a policy perspective. Rate triggers would be applied in cases where long-term approaches to mitigate rate increases do not provide for the desired levelization of rates. Rate triggers to be considered include:

- Macroeconomic based threshold;
- Industry Unit-based threshold; and,
- Peer Utility-based threshold.

To a great extent the appropriate trigger will depend on the category of rate mitigation as described above (i.e., Long-run, Inter-year or Intra-year). Furthermore, review of more than one trigger may in some cases be desirable in order to identify general trends in cost structures. For example, a review of the Macroeconomic threshold may indicate that triggering mitigation is reasonable because cost have exceeded some threshold such as 3x CPI. However, a similar analysis of Peer Utilities may indicate that a specific distributor's changes in cost are in line with its peers, indicating that a general industry trend may exist.

Application of Mitigation to the IRM Cycle

The use of an IRM can trigger significant rate increases after rebasing. Navigant suggests that stakeholders investigate applying rate mitigation within the term of the IRM cycle when a significant rate increase or decrease occurs in the first year of the rebasing.

The revenue deferral is potentially a mechanism that could be used to mitigate rate impacts from IRM rebasing. Consideration of this mechanism must recognize the impacts of shifting the cash flow of the distributor from year-to-year will as well as the carrying charges on the regulatory asset. The return afforded the utility for any deferral in revenues will also need to be examined.

Voluntary versus Mandatory Rate Mitigation

Experience from other jurisdictions has demonstrated that not all customers desire rate mitigation. Rate Mitigation has a cost which ultimately will be passed on to consumers. Therefore, to the extent practical consumers should have the option to either accept or decline to participate in rate mitigation.

The ability for a distributor to offer or not offer mitigation on a voluntary basis is their Customer Information Systems (CIS). The distributor's CIS will need to have at minimum the following capabilities:

- Offer customers the ability to be billed under an alternative tariff structure;
- Account of the differences between the normal (i.e. unmitigated) tariff structure and the mitigated tariff structure; and,
- Potentially account for any accumulated interest in mitigated balances outstanding.

Appendices - Numeric Examples of Rate Mitigation Mechanisms

Appendix A– Calculation of the Traditional Revenue Requirement versus a Leased Asset

Numeric Example of a Lease

	Year	X-3	X-2	X-1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Traditional Revenue Requirement														
Rate Base		-	-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348
Incremental Capital		-	-	-	3,480									
Less Depreciation		-	-	-	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)
Sub-total		-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348	-
RoRB - Before Tax (Debt)	3.6%	-	-	-	113	100	88	75	63	50	38	25	13	-
RoRB - Before Tax (Equity)	5.7%	-	-	-	179	159	139	119	99	80	60	40	20	-
Depreciation		-	-	-	348	348	348	348	348	348	348	348	348	348
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement					**740**	**708**	**677**	**645**	**614**	**583**	**551**	**520**	**489**	**457**
% Increase						**-4.2%**	**-4.4%**	**-4.6%**	**-4.9%**	**-5.1%**	**-5.4%**	**-5.7%**	**-6.0%**	**-6.4%**
After Lease														
Rate Base		-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental Capital		-	-	-	3,480									
Less Proceeds from Sale of Asset					(3,480)									
Less Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total		-	-	-	-	-	-	-	-	-	-	-	-	-
RoRB - Before Tax (Debt)	3.6%	-	-	-	-	-	-	-	-	-	-	-	-	-
RoRB - Before Tax (Equity)	5.7%	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
Lease Payments					473	473	473	473	473	473	473	473	473	473
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement					**573**	**574**	**575**	**576**	**577**	**578**	**579**	**580**	**581**	**582**
% Increase						**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**

Appendix B– Revenue Requirement With and Without Securitization

Numeric Examples of Securitization

	Year	X-3	X-2	X-1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Traditional Revenue Requirement														
Rate Base		-	-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348
Incremental Capital		-	-	-	3,480									
Less Depreciation		-	-	-	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)
Sub-total		-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348	-
RoRB - Before Tax (Debt)	3.6%	-	-	-	113	100	88	75	63	50	38	25	13	-
RoRB - Before Tax (Equity)	5.7%	-	-	-	179	159	139	119	99	80	60	40	20	-
Depreciation		-	-	-	348	348	348	348	348	348	348	348	348	348
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement					**740**	**708**	**677**	**645**	**614**	**583**	**551**	**520**	**489**	**457**
% Increase						**-4.2%**	**-4.4%**	**-4.6%**	**-4.9%**	**-5.1%**	**-5.4%**	**-5.7%**	**-6.0%**	**-6.4%**
After Securitization														
Rate Base		-	-	-	-	-	-	-	-	-	-	-	-	-
Incremental Capital		-	-	-	3,480									
Less Proceeds from Bond Issue					(3,480)									
Less Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
Sub-total		-	-	-	-	-	-	-	-	-	-	-	-	-
RoRB - Before Tax (Debt)	3.6%	-	-	-	-	-	-	-	-	-	-	-	-	-
RoRB - Before Tax (Equity)	5.7%	-	-	-	-	-	-	-	-	-	-	-	-	-
Depreciation		-	-	-	-	-	-	-	-	-	-	-	-	-
Bond Payments		-	-	-	473	473	473	473	473	473	473	473	473	473
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement					**573**	**574**	**575**	**576**	**577**	**578**	**579**	**580**	**581**	**582**
% Increase						**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**

Appendix C – Revenue Requirement With and Without Deferral

Numeric Example of Deferral of the Revenue Requirement

	Year	X-3	X-2	X-1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Traditional Revenue Requirement														
Rate Base		-	-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348
Incremental Capital		-	-	-	3,480									
Less Depreciation		-	-	-	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)
Sub-total		-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348	-
RoRB - Before Tax (Debt)	3.6%	-	-	-	113	100	88	75	63	50	38	25	13	-
RoRB - Before Tax (Equity)	5.7%	-	-	-	179	159	139	119	99	80	60	40	20	-
Depreciation		-	-	-	348	348	348	348	348	348	348	348	348	348
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement					**740**	**708**	**677**	**645**	**614**	**583**	**551**	**520**	**489**	**457**
% Increase						**-4.2%**	**-4.4%**	**-4.6%**	**-4.9%**	**-5.1%**	**-5.4%**	**-5.7%**	**-6.0%**	**-6.4%**
After Deferral														
Rate Base		-	-	-	-	3,132	2,923	2,682	2,403	2,085	1,734	1,346	920	449
Incremental Capital		-	-	-	3,480									
Less Depreciation		-	-	-	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)
Expense Deferral						140	106	69	30	(3)	(39)	(79)	(122)	(101)
Sub-total		-	-	-	3,132	2,923	2,682	2,403	2,085	1,734	1,346	920	449	(0)
RoRB - Before Tax (Debt)	3.6%	-	-	-	113	105	97	87	75	62	48	33	16	(0)
RoRB - Before Tax (Equity)	5.7%	-	-	-	179	167	153	137	119	99	77	53	26	(0)
Depreciation					348	348	348	348	348	348	348	348	348	348
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Expense Deferral		-	-	-	(140)	(106)	(69)	(30)	3	39	79	122	101	-
Revenue Requirement - after deferral					**600**	**615**	**630**	**645**	**649**	**654**	**659**	**663**	**599**	**457**
% Increase						**2.5%**	**2.5%**	**2.3%**	**0.7%**	**0.7%**	**0.7%**	**0.7%**	**-9.6%**	**-23.7%**

Appendix D – Numeric Example of Prefunding the Revenue Requirement

Numeric Example of a Prefunded Revenue Requirement

	Year	X-3	X-2	X-1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Traditional Revenue Requirement														
Rate Base		-	-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348
Incremental Capital		-	-	-	3,480									
Less Depreciation		-	-	-	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)
Sub-total		-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348	-
RoRB - Before Tax (Debt)	3.6%	-	-	-	113	100	88	75	63	50	38	25	13	-
RoRB - Before Tax (Equity)	5.7%	-	-	-	179	159	139	119	99	80	60	40	20	-
Depreciation		-	-	-	348	348	348	348	348	348	348	348	348	348
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement					**740**	**708**	**677**	**645**	**614**	**583**	**551**	**520**	**489**	**457**
% Increase						**-4.2%**	**-4.4%**	**-4.6%**	**-4.9%**	**-5.1%**	**-5.4%**	**-5.7%**	**-6.0%**	**-6.4%**
After Pre-funding														
Rate Base		-	-	-	-	2,524	2,244	1,963	1,683	1,402	1,122	841	561	280
Incremental Capital		-	-	-	3,480									
Less Depreciation		-	-	-	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)	(280)
Less Disbursal of Pre-funding & Interest		-	-	-	(675)	-	-	-	-	-	-	-	-	-
Sub-total		-	-	-	**2,524**	2,244	1,963	1,683	1,402	1,122	841	561	280	0
RoRB - Before Tax (Debt)	3.6%	-	-	-	91	81	71	61	50	40	30	20	10	0
RoRB - Before Tax (Equity)	5.7%	-	-	-	144	128	112	96	80	64	48	32	16	0
Depreciation					280	280	280	280	280	280	280	280	280	280
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Pre-funding		200	200	200										
Revenue Requirement - after pre-funding		**200**	**200**	**200**	**616**	**590**	**565**	**540**	**515**	**490**	**465**	**440**	**415**	**390**
% Increase			**0.0%**	**0.0%**	**207.8%**	**-4.1%**	**-4.3%**	**-4.4%**	**-4.6%**	**-4.9%**	**-5.1%**	**-5.4%**	**-5.7%**	**-6.0%**

Appendix E – Revenue Requirement With and Without Trended Original Cost Ratemaking

Numeric Example of Trended Original Cost Ratemaking

	Year	X-3	X-2	X-1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Traditional Revenue Requirement														
Rate Base		-	-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348
Incremental Capital		-	-	-	3,480									
Less Depreciation		-	-	-	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)
Sub-total		-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348	-
RoRB - Before Tax (Debt)	3.6%	-	-	-	113	100	88	75	63	50	38	25	13	-
RoRB - Before Tax (Equity)	5.7%	-	-	-	179	159	139	119	99	80	60	40	20	-
Depreciation		-	-	-	348	348	348	348	348	348	348	348	348	348
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement					**740**	**708**	**677**	**645**	**614**	**583**	**551**	**520**	**489**	**457**
% Increase						**-4.2%**	**-4.4%**	**-4.6%**	**-4.9%**	**-5.1%**	**-5.4%**	**-5.7%**	**-6.0%**	**-6.4%**
After Trended Original Cost Treatment														
Rate Base		-	-	-	-	3,132	2,831	2,520	2,197	1,862	1,515	1,156	784	399
Incremental Capital		-	-	-	3,480									
Less Depreciation		-	-	-	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)
Deferred Earnings (Regulatory Asset)		-	-	-	-	48	37	25	13	1	(11)	(24)	(37)	(51)
Sub-total		-	-	-	3,132	2,831	2,520	2,197	1,862	1,515	1,156	784	399	(0)
RoRB - Before Tax (Debt)	3.6%	-	-	-	113	102	91	79	67	55	42	28	14	(0)
RoRB - Before Tax (Equity - Rea	4.0%	-	-	-	125	113	101	88	74	61	46	31	16	(0)
Depreciation		-	-	-	348	348	348	348	348	348	348	348	348	348
Amortization of Deferred Earnings		-	-	-	6	12	18	24	31	37	44	51	58	-
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement					**692**	**676**	**660**	**642**	**624**	**606**	**586**	**565**	**544**	**457**
% Increase						**-2.3%**	**-2.4%**	**-2.6%**	**-2.8%**	**-3.0%**	**-3.2%**	**-3.5%**	**-3.8%**	**-15.9%**

Appendix F – Revenue Requirement Calculation With and Without CWIP

Numeric Example of Construction Work in Progress

	Year	X-3	X-2	X-1	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Traditional Revenue Requirement														
Rate Base		-	-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348
Incremental Capital		-	-	-	3,480									
Less Depreciation		-	-	-	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)	(348)
Sub-total		-	-	-	3,132	2,784	2,436	2,088	1,740	1,392	1,044	696	348	-
RoRB - Before Tax (Debt)	3.6%	-	-	-	113	100	88	75	63	50	38	25	13	-
RoRB - Before Tax (Equity)	5.7%	-	-	-	179	159	139	119	99	80	60	40	20	-
Depreciation		-	-	-	348	348	348	348	348	348	348	348	348	348
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement					**740**	**708**	**677**	**645**	**614**	**583**	**551**	**520**	**489**	**457**
% Increase						**-4.2%**	**-4.4%**	**-4.6%**	**-4.9%**	**-5.1%**	**-5.4%**	**-5.7%**	**-6.0%**	**-6.4%**
After CWIP Rate Mitigation Measure														
Rate Base		-	1,000	2,000	3,000	2,700	2,400	2,100	1,800	1,500	1,200	900	600	300
Incremental Capital - CWIP		1,000	1,000	1,000										
Depreciation		-	-	-	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
Sub-total		1,000	2,000	3,000	2,700	2,400	2,100	1,800	1,500	1,200	900	600	300	-
RoRB - Before Tax (Debt)	3.6%	36	72	108	97	86	76	65	54	43	32	22	11	-
RoRB - Before Tax (Equity)	5.7%	57	114	171	154	137	120	103	86	69	51	34	17	-
Depreciation		-	-	-	300	300	300	300	300	300	300	300	300	300
O&M	1.0%	-	-	-	100	101	102	103	104	105	106	107	108	109
Revenue Requirement - before deferral		**93**	**186**	**279**	**651**	**625**	**598**	**571**	**544**	**517**	**490**	**463**	**436**	**409**
% Increase			**100.0%**	**50.0%**	**133.1%**	**-4.1%**	**-4.3%**	**-4.5%**	**-4.7%**	**-4.9%**	**-5.2%**	**-5.5%**	**-5.8%**	**-6.2%**