Ontario Energy Board

In the matter of the

2006 Electric Distribution Rate Handbook

Evidence of PA Consulting Group

Derek HasBrouck and James Heidell

On behalf of Hydro One Networks, Inc.

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FOREWORD

Hydro One Networks, Inc. (Hydro One) is pleased to sponsor evidence to the Ontario Energy Board (OEB) regarding the issue of rate mitigation and the completion of the OEB *2006 Electricity Distribution Rate Handbook* (the Handbook). We recognize that implementation of restructuring and unbundling in electric markets must be carefully undertaken so as to deliver the anticipated long-term benefits to consumers and the Province without creating unnecessary rate shocks to small groups of customers or adversely impacting the short-term economy. Hydro One offers this evidence in the spirit of advancing electric restructuring, including price transparency and economically appropriate price signals, maintaining healthy distribution utilities in Ontario so that customers can continue to receive reliable and efficient electric delivery services, and protecting customers from undue economic harm. The intent of this submission is to assist the OEB in the completion of Mitigation chapter, Chapter 13, of the Handbook.

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

PA Consulting Group (PA), at the request of Hydro One Networks, Inc. (Hydro One), has prepared evidence to assist the Ontario Energy Board (OEB) in completing the Mitigation chapter of the *2006 Electricity Distribution Rate Handbook* (the Handbook). The foundation for our comments is based on the principles of utility regulation, experience of other jurisdictions with restructured electric markets, and our extensive experience in this realm.

Our review of other jurisdictions found that while the customer impacts associated with rate increases are always a concern, we found no examples of systematic, routine rate impact mitigation in restructured gas or electric markets. As a policy matter, energy bill assistance for low-income customers is most commonly handled through means tested customer assistance programs, not tariff design.

Our assessment of economic principles and financial considerations, points to the need to balance the customer benefits of a financially healthy distribution company, with a desire for rate stability. Foremost is the need for each utility to have its revenue requirement set to include all prudently incurred costs and a fair return on capital. Cost shifting of portions of this revenue requirement between customer classes or segments of society should be done in accordance with appropriate cost allocation studies.

Our assessment of the Ontario specific issues suggest that the OEB's experience with gas ratemaking provides a model for how to approach customer impact analysis and the potential need for rate impact mitigation. We also note that, at least for Hydro One Networks, a majority of low volume electricity users are seasonal customers and therefore presumably not low-income customers. Thus, any assumption that low usage customers are low-income customers should be seriously questioned.

Therefore, in consideration of the above facts we conclude that the OEB should take into consideration the following recommendations and observations.

1.1 RECOMMENDATIONS BASED ON OTHER JURISDICTIONAL EXPERIENCE

It is reasonable to consider mitigating distribution cost increases through rate design. However, mitigation typically starts from a principled view of a utility's cost based revenue requirement in conjunction with current rate structures. Distribution rate pressures have been created as a result of the rate freezes that accompanied the movement toward restructured markets. Experience in other jurisdictions does not support a reduction of cost based revenue requirements to achieve rate mitigation.

Mitigation measures designed to redistribute responsibility for revenue recovery should consider targeting specific customers within the residential population instead of the entire customer class. Class rate design including block rates and changes in the proportion of fixed and variable cost recovery can be used to mitigate rate impacts.

Assistance for low-income customers should be done through explicit, means tested programs, not through untargeted and opaque cross subsidies embedded in utility rates. If this is an area that concerns the OEB, the Board should take this matter up as a question of policy, separate and distinct from setting the Handbook.

1.2 RECOMMENDATIONS BASED ON REGULATORY PRINCIPLES

Mitigation of distribution rates, to the extent required, should be based on distribution costs only. Pass-through costs associated with energy, transmission, and government mandates are outside the control of the distribution utility. The review and basis for pass-through costs are not addressed in the 2006 distribution rate proceedings.

The standards for evaluating the appropriateness of the revenue requirement should be independent of the amount of rate adjustment requested. Uniform standards should be applied in the determination of what costs were prudently incurred and the determination that they are just, fair, and reasonable.

1.3 RECOMMENDATIONS BASED ON FINANCIAL PRINCIPLES

Requirements for mitigation must be clearly defined and should not adversely impact the distribution utility's access to the capital markets. Mitigation that reduces the opportunity for a fair return on capital negatively impacts both debt and equity holders. As a result, customers can be negatively impacted through higher future utility borrowing costs and deferral of capital projects needed for safety, reliability, and regional economic growth.

Rate mitigation that creates regulatory deferrals must be carefully evaluated. Regulatory deferrals may be appropriate for spreading out transition costs associated with restructuring that creates long-term benefits for customers. However, deferrals of current costs, such as fuel expense, can create inter-generational inequities for customers. Further, deferral accounts by definition create cost recovery risks that the capital markets factor into risk assessment, and can potentially raise the distribution utility's cost of capital and thereby place upward pressure on distribution rates.

1.4 ONTARIO SPECIFIC ISSUES

The Handbook should continue to emphasize standardized processes for processing distribution rate cases, but should not be prescriptive with regards to policy. Policy issues, especially in areas related to rate harmonization, rate caps, or delaying the transition to market based rates should be explicitly addressed in separate proceedings to allow a full review of the relevant issues. It is important to maintain sufficient flexibility in the Handbook to fairly address the diverse issues and characteristics of the Ontario distribution utilities when setting distribution rates, while also enabling efficient processing of numerous LDC rate applications.

A threshold for standardized review of rate requests is desirable given the large number of distribution cases that must be processed in a limited period of time. A standardized review should emphasize that the utility's rate filing conforms to the procedures and documentation established in the Handbook. For proposed rate increases in excess of this threshold, greater information should be provided to aid the OEB in applying a uniform standard for evaluating the appropriateness of proposed revenue requirements.

A threshold for the standardized review of LDC rates should exclude pass-through charges, governmental mandates such as smart metering, tax changes, and compliance costs associated with new governmental regulations. A threshold of the annualized inflation rate is a reasonable starting point.

Formulaic benchmarks for determining the need for any mitigation should be rejected. The rationale for rate adjustments will differ from utility-to-utility and from year-to-year and the OEB should retain sufficient flexibility for individual LDCs to address these issues. To the extent benchmarks are adopted by the OEB, they should be formulated based on experience in restructured utility distribution services, as opposed to the traditionally vertically integrated electric utilities.

Distribution rate harmonization is utility and situation specific and hence should not be addressed as a standard procedure in the Handbook. The need for harmonization is based on unique historical circumstances and thus it is more appropriate to address in utility specific plans. Therefore, the Handbook should make allowance for LDCs to harmonize rates but should not be prescriptive in terms of setting rate mitigation thresholds.

2. INTRODUCTION

The purpose of this evidence is to assist Ontario Energy Board (OEB) in completing the chapter on rate mitigation contained in the draft *2006 Electricity Distribution Rate Handbook*. In order to provide a basis for our recommendations we have laid out a foundation based on:

- The experience of other gas and electric utilities operating in restructured gas and/or electricity markets in North America, and
- The appropriate economic principles to consider.

This foundation is laid out in Chapters 3 and 4 and in Appendix A. Chapter 5 addresses issues specific to Ontario and the Handbook. Here we also supplement the submission sponsored by the Vulnerable Energy Consumers Coalition (VECC). The purpose of the supplemental information is to provide a broader perspective for the OEB to consider. The supplemental information relates to both experiences from restructured markets and expands upon the utility/investor perspective. Chapter 6 concludes with our recommendations for practical options that the OEB should consider in respect of rate mitigation with the intention of advancing the development of a durable rate mitigation policy that is relevant for both the 2006 proceeding and for future proceedings.

Our recommendations consider the needs of the diverse constituents who are impacted by rate decisions. Distribution utilities have the challenge of meeting the potentially competing needs of the different customer segments, the owners (shareholder/municipality), the financial markets needed to access capital, and the policy makers. The unbundling and restructuring policy goals include the critical end-result of shifting from subsidized electric service to rates based on costs to serve and to create transparent and competitive markets where applicable.

2.1 OVERVIEW

The restructuring of the Ontario electricity market, as well as other electricity markets around the world, is intended to: create price transparency, replace the traditional vertically integrated investor owned utilities and government monopolies with a more economically efficient business oriented distribution companies, create more choices for customers, and lead to more cost effective service. Significant challenges to managing this transition have arisen as a result of rising generation fuel prices and, in some cases, the need to refine market rules for energy prices in order to eliminate the abuse of market power. A critical metric of measuring success is the impact on the consumer’s electricity bill. Unfortunately, it is difficult to measure the success of market restructuring based solely upon bill impacts since one has to speculate on what would have happened absent market restructuring. While this is a critical issue, our report is intended to focus on a much narrower issue; how to address the need for distribution rate increases in a restructured market.

The issue we address is whether it is appropriate to consider distribution rate adjustments and bill impacts independently of the other components of the customer’s electricity bill. In conjunction with this issue, we provide perspectives on the related issue of whether to mitigate rate increases and how mitigation should be done. In the absence of utility specific rate filings and cost studies, we have not made any prior assumptions that it is appropriate to initiate rate mitigation in the 2006 distribution rate cases.

In the recent history of Ontario's electricity market restructuring the decision whether to adjust distribution rates has been made in the context of the customer's total electric bill. The schedule for transitioning to market based electric delivery services was delayed by the introduction of government policies that dealt with the volatility in electricity prices, resulting in the deferral of distribution rate increases planned for 2003 and 2004. For example, Hydro One Networks and other LDCs in Ontario did not institute two of the originally planned rate adjustments designed to phase in market-based returns due to a Government directive (Bill 210, November 2002) that was put in place to deal with electricity price volatility. Going forward, we present the case for isolating the need for distribution rate adjustments from changes in commodity costs.

2.2 THE BASIS FOR DISTRIBUTION RATE MITIGATION

One of the defining issues raised in regard to rate impact mitigation is determining the basis for the evaluation. Specifically, should the analysis be based on changes in the distribution rates/bill or changes based on the customer's total energy bill? Consumers are naturally concerned with their total energy bills.[1] However, as a result of restructuring, the total energy cost to the consumer is made up of a number of identifiable and different components, the majority of which are outside the control of the electric distribution companies.[2] While we understand that the consumer is concerned about all components of the electric bill, the rate proceeding is related to the distribution companies and does not address the portion of the bill that represents pass-through costs for the distribution company. Just as the electric distribution company is not responsible for mitigating costs associated with non-electric items in the consumer's budget, they should not be responsible for mitigating costs of electric components that are pass-through costs since those items are also beyond the distribution company's control. Further, attempts to mitigate on a total bill basis can severely harm the financial health and stability of the LDCs.[3] Maintaining the financial stability of the LDC is critical to advancing restructured electricity markets.

The issue of rate mitigation in the 2006 EDR proceeding is complex since it goes beyond the issue of mitigating distribution cost increases. There are a number of legacy issues that must be addressed as well as advancing the market transition plan. In order to arrive at a reasonable conclusion, we recommend that four dimensions to distribution rate mitigation be given due consideration:

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[1] This report is limited in scope to the discussion of the total electric bill impacts versus impacts due to the distribution rates. However, from the customer perspective the focus on affordability should potentially consider total energy costs including natural gas.

[2] For example, urban residential customers using 1,000 kWh/month served by Hydro One will have less than 33% of their bills dedicated to distribution costs.

[3] The California experience illustrates what can happen to the financial health of LDCs when rate mitigation measures, freezes in this case, are imposed on total bills collected by LDCs, while the actual level of pass-through costs are unaffected. One major LDC filed for bankruptcy and the other major LDC teetered on the brink of bankruptcy for many months. While customers were insulated from this turmoil in the short run, the financial stress the LDCs suffered may affect customer bills and service levels for many years to come.

- Bill impacts due to rate adjustments associated with day-to-day issues of utility operations including inflationary pressures and system maintenance,
- Bill impacts due to distribution rate adjustments necessary as a result of government mandates including Smart metering, conservation/demand side management, environmental regulations, and tax rate changes,
- Bill impacts associated with phasing in a market based rate of return (MBRR) that include needed adjustments to complete the transition to market based distribution rates, and
- Bill impacts due to rate harmonization (an issue that does not apply to most of the LDCs) associated with creating uniform rates associated with combining small distribution companies to obtain economies of scope and scale.

We recognize that all four issues need to be collectively considered since they all come together on the customer's electric distribution bill. To that end we have provided comments on issues of rate spread and rate design, including:

- Customer impacts associated with transitioning to cost-based rates and properly setting the fixed and volumetric components of the residential distribution bill[4], and
- Use of targeted mechanisms to address the needs of vulnerable (low income) customer segments.

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[4] Earlier restriction that the fixed charge be set to a level that would result in the total customer bill increase being less than 10% for a low volume customer's bill (250 kWh or less per month).

3. JURISDICTIONAL REVIEW

The current situation in Ontario is similar to experiences in a number of other jurisdictions that are in the process of restructuring their electricity and gas industries. Common elements of the restructuring plans included transition periods to deal with one-time costs, transition costs, and interim rate freezes. The end of a rate freeze period inevitably results in the need to address the issue of delivery rate increases in addition to, or in combination with rising electricity costs. Increases in natural gas and oil prices are not a result of electric market restructuring, but policy makers are naturally concerned about the cumulative impact on customers. The first section of this chapter highlights key observations about the experience of other jurisdictions dealing with similar issues, as is the OEB. Details related to our jurisdictional review are provided in Appendix A and summarized in the following table.[5] The second section summarizes our observations and insights arising from the jurisdictional review.

Rate Mitigation in Restructured US Jurisdictions

State	Relevant Issues
New York	Power costs addressed through monthly adjustment clause, earnings sharing plan, targeted programs for low income customers, harmonization of delivery rates developed independent of commodity costs
Connecticut	Distribution rate increase partially mitigated with over-recoveries from a true-up mechanism, policy not to create deferrals that mask current period service costs
Ohio	Settlement for adjusting distribution rates following the end of a distribution rate freeze allows for adjustments to distribution costs beyond the normal control of the utility, ie homeland security, taxes, and environmental compliance
Illinois	Distribution rate increase request to be addressed separately from commodity costs, budget billing and extended payment plans used to address rising natural gas commodity costs
Maine	Targeted power cost mitigation funded by gains from divestiture of generation assets
New Jersey	Long term deferral of power costs incurred by distribution utilities above levels allowed in current retail rates has negatively impacted utility financial stability.

[5] The number of decisions associated with rate adjustments for restructured electric and gas utilities is voluminous. We have provided selected examples in Appendix A to demonstrate how other Commissions and Regulatory Boards have addressed the issue. We are not making any representations that this is a complete record of all decisions related to rate mitigation and restructuring.

We provide reference to the experience with rate setting in Alberta in the context of discussion of the Ontario Issues in Chapter 5. A summary of the experience in Alberta rate setting is also provided in Appendix A.

3.1 KEY OBSERVATIONS FROM OTHER JURISDICTIONS

3.1.1 Significant rate increases are being requested or required

Rate increases have been requested by a number of utilities to address cost recovery for both default energy service and rising distribution costs. These rate adjustments often involve a “catch-up” component due to rate freezes that were implemented in conjunction with the electric market restructuring. In the United States the evaluation of these increases does not explicitly consider mitigation of the revenue requirement. The standard is that utilities should have a fair opportunity to recover their prudently incurred costs, including returns and taxes. Hence determination of the appropriate revenue requirement is based on cost of capital and appropriate cost recovery. While regulators are concerned about the overall energy bill of the customer, our research shows that in restructured jurisdictions the delivery rates and rate design are addressed separately from the supply costs rather than collectively.

Mitigation of bill impacts associated with rising costs has been addressed in a number of ways. In some cases, the utilities have had net positive deferral balances in favor of the customer as a result of generation asset divestiture. Those deferral balances have been used to offset increased electricity costs. In other instances, deferral balances have been used to even out bill increases. Another approach is targeted assistance programs to economically vulnerable customer segments.

Pass-through production and generation costs for default service have been addressed separately from distribution rate increases. There have been a number of proceedings related to how to address generation cost increases and how to deal with price provider of last resort (POLR) load requirements. However, we have not identified any proceedings in restructured electric or gas markets where cost mitigation for supply costs have been addressed in the context of the setting of delivery rates.

With respect to those proceedings where electric or gas service has been unbundled, there were instances where the overall level of the rate increase (both supply and delivery) created concern about the impact on customers was discussed. However, the basis for mitigating distribution rates as a result of costs associated with non-delivery services was not established or adopted.

3.1.2 Implementation of restructured markets is moving forward

In the United States, with the exception of California, the general response to increasing rate pressures is not to retreat from market restructuring since the cost pressures are generally not attributed to the failure of the restructuring model. However, ongoing refinements are typically being investigated and implemented.

3.1.3 Adoption of rate mitigation

Our review of proceedings of unbundled electric and gas service rates did not reveal any examples of formulaic standards for adoption of rate mitigation. However, it is not unusual for mitigation to be addressed in rate spread, the assignment of a portion of the revenue requirement to individual customer classes, and rate design, the formulation of the charges within a customer class to yield the targeted revenue requirement. The general approach to rate mitigation is to follow either or both of the methods identified below:

- Rate mitigation, where used, is addressed with a combination of inter rate class subsidies to fund assistance programs for low income customers, and
- Customer balances in deferral accounts are used to target selective customer classes.

3.1.4 Low income assistance programs

Our review of jurisdictions with restructured electric and/or gas markets also identified targeted, income qualified assistance programs as the preferred method for assisting those customers whose income is at or near the poverty line. These programs do not result in creating a separate rate class, but rather entail assistance programs that help with paying energy bills, weatherproofing residential structures, improving the energy efficiency of appliances and lighting, etc. The affected customers remain on the applicable tariff for the customer group for which they otherwise would be part of. The funding for such programs may come from the government, other aid agencies, or from funds specifically included in the utility's revenue requirement.

3.1.5 Rate mitigation associated with rate harmonization

Rate harmonization has not been a significant issue in the restructuring of U.S. electric markets due to a slow down in distribution utility acquisitions and the typical practice of separating out financial and regulatory accounting and rates by the original jurisdictions. Distribution rate harmonization following acquisition of municipal entities typically is based on predefined plans, commitments or agreements.

3.2 USE OF MITIGATION IN OTHER RESTRUCTURED JURISDICTIONS

Our review of rate mitigation policies identified significant references to rate mitigation for both restructured and traditional vertically integrated utilities. However, we did not uncover examples of formulaic thresholds and application of mitigation as potentially contemplated for the Handbook. The range of references to rate mitigation included:

- Use of sharing mechanisms between the customers and the Company to both mitigate rate adjustments and provide utilities with the incentives to manage costs,
- Rate adjustments accompanied by negotiated rate freezes,
- Use of customer credit balances in other utility accounts to offset bill increases,
- Mitigation in other proceedings was directed toward addressing rising power costs and the difference between market-based costs and the historical embedded costs,
- Mitigation of energy costs for low-income customers through directed low income assistance programs, and
- Recognition that cost increases associated with fuel used for generation would have been passed through to customers regardless of whether restructuring had occurred.

Since the different jurisdictions we reviewed had unique circumstances we cannot definitively identify a preferred approach. However, we note that use of customer credit balances in deferral accounts appears to be frequently used, especially where the credit balances resulted from restructuring benefits. Targeted low-income assistance is also frequently used as a measure to achieve a specific social policy, funded through government assistance programs or through societal benefits charges associated with all customers' electric bills. Finally, we note that these mitigation approaches are not unique to restructured markets.

In summary we observed that distribution rate setting in restructured markets continues to be a balancing act to incorporate:

- Setting policy goals of creating competitive commodity markets,
- Implementing social policy including objectives related to low-income assistance and promotion of renewable resources,
- Ensuring that financially stable distribution utilities are able to make the investments necessary to maintain or enhance reliability,
- Ensuring that distribution rates are just, fair and reasonable,
- Addressing cross subsidies between customer classes, and
- Mitigating rate changes within a customer class.

4. ECONOMIC PRINCIPLES AND FINANCIAL CONSIDERATIONS

This section considers rate and bill mitigation from the principled and capital markets perspective. This view includes the customer, utility, financial and social policy perspective. Incorporation of all these perspectives involves a balancing act; one must trade-off often competing principles to achieve an optimum result, a win-win solution. In the first section we review mitigation in the context of revenue recovery, the second section examines the role of rate spread and rate design with regards to mitigation. The third section examines the financing implications. In the final section we provide an integrated summary of our findings.

4.1 REVENUE REQUIREMENTS AND RATE MITIGATION

The widely recognized principles of ratemaking process clearly delineate between the different phases of determining the revenue requirement, rate spread and rate design. In the first phase, development of the revenue requirement, the determination of what is appropriate is isolated from the decision of how it should be recovered. Clearly there is a linkage that includes the level of service customers desire, the level of service for which customers are willing to pay and other public policy considerations.

The basic principle in determining the revenue requirement is to: (1) identify utility costs for a twelve-month period, (2) make appropriate pro forma adjustments to costs and (3) determine what is a fair return on investment.[6] The option of not providing an opportunity to recover legitimate expenses and earn a fair return is not a principled, or sustainable, approach to addressing the affordability of electric distribution service. In fact, the assumed starting point for revenue recovery is a sufficient revenue requirement.

> "A utility, in order to remain viable, must be given the opportunity to recover its prudently incurred total cost of providing electric service to its various classes of customers."[7]

> "Public utility commissions spend the major part of their time, by far, directly or indirectly regulating price. This task has two major aspects and the commissions have tended typically to treat them quite distinctly. The first has to do with the level of rates, taken as a group. The second has to do with the structure of rates. The commissions decide what total revenues the companies are entitled to take in, then adjust permitted 'rate levels,' either selectively or across the board, to yield these totals."[8]

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[6] The treatment of cost of capital and return of capital is different for investor-owned and publicly-owned utilities.

[7] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, 1992. p 24.

[8] *The Economics of Regulation Principles & Institutions*, Alfred E. Kahn, 1989, pp 25-26.

A sufficient revenue requirement is critical for:

- Attracting the capital necessary to maintain the current delivery system and service quality,
- Financing expansion to deliver electricity to new customers,
- Having the necessary operating funds to maintain the distribution system and provide customer service, and
- Having the working capital necessary to fund day-to-day operations, including sufficient credit worthiness to purchase wholesale power on behalf of customers.

Extensive work has already been completed by the OEB regarding the preparation of the process details for dealing with 2006 distribution revenue requirement. The purpose of this report is not to repeat or even address appropriate measures for determining the revenue requirement. Instead, this report assumes that the procedures outlined in the Handbook will determine the necessary revenue requirement. Our recommendation is that this determination should be separated from the determination of how the revenue requirement will be recovered. Furthermore, any mitigation through reducing the properly determined revenue requirement is counter-productive to the objective of providing reliable service to customers, unless the mitigation itself enables a reduction in the properly determined revenue requirement.

4.2 REVENUE RECOVERY

Revenue recovery addresses both rate spread (allocation of responsibility for the revenue requirement among the customer classes) and rate design. These phases include incorporation of often-competing policy goals of stabilizing rates, stabilizing revenue recovery, equity among customers and providing economically efficient price signals.

4.2.1 Rate design standards

Regulatory principles regarding recovery of the revenue requirement emphasize a cost based approach as opposed to an arbitrary approach. Standards for rate making that are widely recognized include[9]:

- ***Effectiveness:*** providing the utility a reasonable opportunity to recover its revenue requirement including a return and a return-of capital,
- ***Fairness:*** having customers pay their fair share of cost,
- ***Efficiency:*** promoting efficient use of the delivery system resources,

[9] These standards are often attributed to Bonbright and are reflected in the U.S. rate making manuals used by the American Public Power Association, and the National Association or Regulatory Utility Commissioners.

- ***Avoiding undue discrimination:*** requiring customers to pay the same rates for the same level of service, and

- ***Minimizing rate impacts:*** avoiding “rate shock” and potentially protecting particularly sensitive segments of the customer base (this can include low-income customers as well as promoting jobs).

The economic literature related to the theory of ratemaking is extensive and rate design typically includes a blend of rates designed on embedded costs and rates designed on marginal costs. Embedded cost rate making often includes supporting arguments related to equity and matching revenue recovery with cost causation. Alternatively, marginal cost rate making is typically justified on the basis of economic efficiency. In addition to the economic principles of rate making, there are also social principles of ratemaking. Social principles include ability to pay including special dispensation for low income consumers and monetizing externalities.

While rate shock is often discussed in the context of rate increases, we have not identified any theoretical basis, or widely accepted standards for what constitutes rate shock. While there does not appear to be any standard for rate shock, it is frequently discussed in the context of specific rate requests and the specific circumstances.

There are diverse perspectives related to the social aspects of ratemaking. Public policy intervention is often justified regarding:

- Redistribution of wealth (special assistance programs for low-income customers)[10],

- Incorporation of externalities (arguments that rates based on utility costs do not reflect the true cost of the services being provided),

- Promotion of economic development (discounted rates to retain or encourage business within the utility’s service area), and

- Use as a taxing authority (funding local government though municipal revenue taxes and other taxing mechanisms).

The purpose of this report is not to review all the arguments for the different approaches, but rather to note that both marginal and embedded cost practices are widely in use as well as the incorporation of ability to pay. In regard to process, the typical approach is to conduct cost studies first to determine the cost basis for rate spread and rate design and then adjust that basis, accounting for other considerations including customer impacts.

[10] There is often an assumption that low-income customers are low users of electricity. While low-income customers may use less electricity on average as opposed to non low-income customers, it should be recognized that not all low-income customers are low users of electricity and not all low-users of electricity are low-income customers.

4.2.2 Mitigation of rate shock

At this stage in the proceedings, it is difficult to make recommendations about how the OEB should specifically implement rate mitigation since the starting point of knowing where cost-based rate levels are is yet to be determined.

The objective of mitigating rate shock is often referenced in the context of mitigating impacts associated with proposed changes to rate spread and rate design. Rate shock does not have a hard quantitative definition based on the economic literature. As pointed out by the Econalysis Consulting Services evidence, there are instances where there have been attempts to define it for the purposes of regulatory proceedings.[11] It is a consumer perception issue. The same percentage rate increase might be viewed differently depending on the circumstances and point of view. In some circumstances the consumers might be adversely impacted, but not necessarily have "rate shock." For example, if consumers hear in the news everyday about increases in oil prices, then a 15% increase in gasoline prices at the pump might not be seen as rate shock even though it may have undesirable consequences.

It is important to recognize that there are numerous tools for addressing rate shock while still providing the regulated utility an opportunity to cover its costs and maintain its capitalization.

4.2.3 Tools for mitigating rate shock

Methods for mitigation of rate increases fall into two broad categories:

- Modifications to rate spread and rate design to equalize bill impacts or to shift increases to customers who will be less impacted, and
- Modifications to the immediate revenue requirement through deferral accounting or application of reserve funds from other sources to offset a rate increase.

A. MODIFICATIONS TO RATE SPREAD AND RATE DESIGN

A common tool for mitigating the impact of rate redesign and correcting rate class parity as defined by cost allocation studies is to limit class increases as a percentage of the overall system average increase. Guidelines such as limiting a class adjustment to 1.5 or 2 times the average system increase are common under the principle of gradualism to phase in cost based rates.

Once the class revenue requirement is set, a number of other tools can be used to either mitigate the impact of rate increases, or target the rate increases to certain segments of the customer class. Changes in rate design that are driven by cost studies or policy changes tend to result in unequal impacts that may warrant mitigation through phasing in rate redesign.[12] Another approach to rate design that helps stabilize recovery of fixed costs is to apply inverse

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[11] For example it was proposed that the BCUC used a definition of 10% increase per annum but the Board did not endorse a hard measure noting that it depends on the circumstances. [Evidence of Joyce Poon and William Harper, p 18]

[12] Deferring rate adjustments is not a panacea, as exemplified by the current situation in Ontario where rate increases have been deferred resulting in the need for catch up adjustments.

elasticity where the rate increase is applied to those customers with the least elastic demand. Note, that this may adversely impact low-income residential customers. Alternatively, special rates or assistance programs for low-income or economic development are typically used to avoid undue hardship.

In addition to mitigating rate shock through changes in rate spread and rate design, there are also tools available for use to help customers manage their energy costs and manage the impact of rate increases. These tools include: budget billing, credit guarantees, prepayment meters, and discounts for debit payment. Certain of these tools can, under certain circumstances, also result in a reduction in the overall LDC revenue requirement.

B. DEFERRAL AND BALANCING ACCOUNT MECHANISMS

One-time costs or transition costs are often addressed with deferral accounting mechanisms and gas and power cost trackers are used to true-up fuel and power costs. Tracking accounts used to true-up power and fuel costs generally are associated with correcting estimated costs and typically target annual or more frequent adjustments to attempt to create a zero balance deferral account. Deferral mechanisms are often used for longer-term adjustments. The justification of deferral accounts is often linked to matching costs and benefits. However, they are also used to phase in large rate adjustments. Risks associated with deferring cost recovery include risk to the utility, and to the holders of its debt and equity securities, that future rules will change and that the costs will not be recovered, and risks to the customer that such deferrals put off an even larger rate increase in the event of unanticipated future utility cost increases.

4.3 FINANCIAL CONSIDERATIONS

Rate mitigation resulting in denying the opportunity to earn a fair return to the distribution utility has repercussions for the customers and the utility owners. Utilities need the opportunity to obtain a fair return in order to cost-effectively attract the capital needed to maintain and expand the distribution system, as well as to provide the financial foundation of the wholesale energy market. Our review of financial considerations starts with the principles of providing a fair return then proceeds to review the issue from the perspective of the financial community, and concludes with the implications for customers.

The need to provide a fair return to investors goes beyond the needs of the investors in that it influences both the utility’s access to capital markets and the cost of access. Insufficient cash to service debt and an inadequate debt cushion leads to a higher cost of debt that ultimately translates into higher costs to the utility’s distribution customers as well as impacting the capacity to borrow which in turn can impact quality of service and ability to serve customers. Difficulties in accessing the capital market can be translated into deferral of needed capital improvements, which in turn can impact the safety and reliability of electric distribution service.

4.3.1 Principles for providing a fair return on investment

The principles for developing a regulated utility's revenue requirement provide for the opportunity to earn a fair return on investment.[13] The five major criteria outlined by Bonbright are: attraction of capital, rate stability and predictability, consumer rationing, fairness to investors and management efficiency.[14] These principles are briefly reviewed in the context of how rate mitigation accomplished through mitigation of the revenue requirement can violate these principles.

Probably the most important of the five criteria is the attraction of capital to the distribution utility. The electric distribution business is a capital-intensive business that requires construction of an infrastructure that has high fixed costs. In order to provide the capital necessary to build and maintain the infrastructure to the desired reliability standard, the utility needs to be able to attract the necessary capital from the financial markets. As noted in the next section, the financial markets are relatively disciplined with regards to providing guidance on what level of returns are required to attract capital. The level of risk as assessed by the capital markets directly impacts the cost of capital for the utility and ratepayers. An inability to attract capital likely will result in lower service quality. Alternatively, a "risky" investment translates into higher financing costs and higher rates. The purpose here is neither to review the literature on determining the appropriate cost of capital, nor review the theory on capital markets. Rather, the brief discussion is simply intended to remind the OEB that rate mitigation that impairs the ability to attract capital is not advantageous or appropriate.

The second criteria for a fair return on investment, is that it is required for rate stability and predictability. The relationship to rate mitigation is that deferral of revenue collection or capital projects can result in shifting costs to a later period, creating inter-generational inequities for customers by under-charging current customers and over-charging future customers.

The third criteria, consumer rationing, is related to the efficient use of resources. This argument relates to marginal cost pricing and the desire to have customers receive a price signal related to the marginal cost of the distribution services that they are using. The marginal cost signal is a precept for efficient use of societal resources and for consumers making trade-offs between alternative goods and services.

4.3.2 Impact of rate mitigation on the investment community

Utilities rely on the capital markets to finance investments in the electric distribution system that typically have a service life of thirty years or longer.[15] The cost of this capital is related to a number of factors including: the type of capital (debt versus equity), exogenous economic factors such as the cost of risk-free debt, and utility specific factors. A number of the utility

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[13] A fair return of investment is equally important. Fair return is typically addressed in including test year depreciation expense in the build-up to the utility's revenue requirement.

[14] *Principles of Public Utility Rates*, James Bonbright, p 203.

[15] For example, Hydro One reported that it spend $64 million on distribution capital expenditures for the first quarter of 2004.

specific factors are impacted by the actions of the regulator. These factors include the determination of the allowed return, willingness of the regulator to allow recovery of prudently incurred costs on a timely basis, and the overall structure of the regulatory regime. Note, this is not meant to imply that utility management and its actions do not influence the cost of capital.

Clearly there are many factors that influence the cost of debt for an electric utility. The recourse of the debt holder for repayment is also a key criterion. While utilities such as Hydro One currently have had an improvement in their bond rating, it is important to note that the general trend has been for more downgrades than upgrades for investor-owned utilities.[16] For example, at the end of 2003 less than 32% of U.S. investor-owned utilities had A bond ratings or better.[17]

The bond rating agencies look at a number of factors in developing their ratings. These factors include the availability of cash to fund debt service, the regulatory regime, the legal structure of the utility, and management controls. Since the distribution utility is a regulated entity, the rating agencies naturally examine and give significant weight to the regulatory climate. Factors considered include the willingness of the regulator to support the credit rating through its actions with respect to rates including allowing the utility to recover rising costs related to pensions, the treatment of recovery of deferred costs, and the policies in-place to allow the utility the opportunity to earn a fair return. The availability of cash to fund debt-service is clearly a complex issue, but timely recovery of costs enter into the equation and the build-up of large regulatory assets has an impact on cash flow.

4.3.3 How a fair return impacts customers

A lower cost of capital translates into a lower revenue requirement and lower short-term rates for customers. However, it is not necessarily true that not providing a fair rate of return is in the customers' long-term interest. The ability to earn a fair rate of return impacts the cost of capital for the utility and hence the long-term financing costs for distribution system replacements and expansion. From the customer perspective it is a balancing act between providing a sufficient rate of return to optimize the cost of capital and the rate impact. For example the spread between an A rated utility bond and a BBB rated bond is close to 50 basis points while the spread between an A and BB rating is closer to 200 basis points.[18]

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[16] For example, EEI reports that for the period of 2001 through 2003 there were more bond downgrades than upgrades reported by S&P and Moody's. [*EEI 2003 Annual Review*, p. 69]

[17] *EEI 2003 Annual Review*, p 70.

[18] Spreads based on utility bond spreads on 30 December 2004. Note that the credit spreads change over time based on a number of macro economic factors.

4.4 SUMMARY

The options for rate mitigation are virtually unlimited until constrained by generally accepted rate design principles including that rates should be reflective of cost and incorporate principles of equity, efficiency, and transparency. Based on our review, we recommend that the OEB consider the following principles for guiding implementation of any mitigation strategy.

- Distribution revenue requirement and revenue recovery should be separated and rate mitigation should not be at the detriment of the determination of the revenue requirement based on recovery of prudently incurred costs and providing an appropriate return on and of investment.

- The starting point for any distribution rate mitigation should be a cost-based allocation of the total distribution and customer service revenue requirement to the individual rate classes, and cost-based rate design.

- Distribution rate stability should be incorporated as a guiding principle of rate design. However, rate stability should not be translated into either fixed metrics for the determination of what is a “reasonable” rate adjustment, or fixed percentages that trigger thresholds for rate mitigation.

- Regulatory deferral accounts should be used cautiously since efficient use of resources requires transparency of costs and deferrals can distort the process by creating inter-generational inequities. As a practical matter, deferrals can create more burdensome rate adjustments in the future and compound “rate shock.”

- Postponing, or worse going against, movement toward cost reflective rates is defeating the purpose and goals of restructuring and cost unbundling.

- Economic and financial considerations point to the fact that rate mitigation should avoid reductions in revenue requirements, and should not detract from the fundamental principle of allowing the LDCs to recover prudently incurred costs since that ensures the LDCs’ ability to maintain reliable delivery of electric services to customers whilst maintaining sound business practices.

As a practical matter, the treatment of rate mitigation in the 2006 rate proceedings may need to be addressed differently than future proceedings where cost-based rate design can be factored into the assessment of where rate mitigation may be most appropriate.

5. ONTARIO SPECIFIC ISSUES

This section examines rate mitigation based on the specific circumstances regarding electric market restructuring for Ontario. Just as one solution does not fit all electric distribution utilities, one approach to market restructuring is not necessarily appropriate for all electric markets. Our recommendations supplement the evidence presented by Econalysis Consulting Services (ECS) in its 13 December 2004 Expert Report on behalf of VECC.[19] Our intent is not to rebut the ECS report, rather our purpose is to provide additional information for the OEB to consider. Specifically, we want to ensure that the customer perspective is balanced with the utility perspective as well as the perspective of the financial community that provides needed capital for the distribution utilities. Our comments are targeted to the following six areas:

- Review of Ontario electric restructuring,
- Comments on consumer expectations regarding rate adjustments,
- Review of the categories and standards for approval of distribution rate adjustments for the 2006 rate cases and future proceedings,
- Relevant experience from Ontario natural gas market restructuring,
- Analysis of rate impacts including the basis for calculations and the implications on assessing the need and basis for mitigation of distribution rates, and
- Review of rate harmonization and related mitigation issues.

5.1 REVIEW OF ONTARIO RESTRUCTURING

The ECS (VECC) report does a reasonable and fair assessment of summarizing the recent history of restructuring and setting of electric distribution rates in Ontario. In addition, it provides a summary of recent rate changes in selected Canadian provinces. However, there are some aspects of the report that we feel it is important to comment on in order to ensure that the OEB has the full range of information available to it prior to making policy decisions regarding the 2006 distribution rate submissions. Specifically, we recommend that the OEB take into consideration the recent experience of deregulated utilities including the restructured Alberta market. (Please see Appendix A for more detailed reference to rate setting experience in Alberta.)

The Alberta Energy and Utilities Board (AEUB) has had to address the requirements of its natural gas and electric LDCs in conjunction with rising natural gas and energy prices. The AEUB reviewed the 2004 EPCOR Distribution interim rate adjustment in the context of the traditional approach of seeking evidence whether the distribution cost increases had been justified. Justification of the costs, including the appropriate rate of return, was based on

[19] *Evidence of Econalysis Consulting Services*, Harper & Poon, 13 December 2004. Docket No. RP-2004-0188

evidence of the costs rather than using a metric of whether the distribution service was affordable.

The Board approved the Company's proposal to maintain a deferral account for transmission access charges separate from distribution charges. The Company argued that the charges should be separated so that the costs are transparent and consumers receive the appropriate price signal based on the approved transmission rates. The Company further argued that the true-up of these costs should be separated since these costs are largely out of the Company's control. The AEUB concurred with the Company's proposal.[20]

In a 2002 decision the AEUB ruled on an interim rate increase request by ATCO Gas.[21] In addressing the request for interim rate adjustment the Board acknowledged the difficulties associated with the impact of increases on customers, but expressed a concern for delaying interim increases and creating inter-generational equity issues and causing rate shock by differing rate adjustments.[22]

5.2 CUSTOMER EXPECTATIONS

It is our experience that rate shock does not have an absolute metric and what constitutes rate shock depends on the circumstances and the customers' expectations. ECS notes that there is no empirical data for customer expectations regarding electric rate increases in Ontario.[23] Absent empirical data, it is difficult to conclude what level of distribution rate adjustments would be viewed as rate shock. Since the revenue requirement is determined based on a principled review of costs, addressing gaps between customer expectations and fairly determined and adjudicated costs is critical. However, to the extent that there is a gap between expectations and reality, the answer is not necessarily to manage costs to existing expectations. Instead, customer education should be seen as a critical component to establishing reasonable expectations. Customers need to understand how recovery of the reasonable costs associated with electric distribution services needs to occur whether it is done directly through the utility bill or indirectly through general or targeted taxes. Furthermore, subsidies should be clearly identified.

Experience in other jurisdictions implementing electric restructuring shows that extensive consumer education needs to be part of the equation.[24] Customers need to understand what part of their bill is for distribution service and why rate adjustments are needed.

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[20] EPCOR Distribution Co. 2004 Distribution Tariff Application, Part A: 2004 Interim Distribution Rates, Decision 2003-085, p 13.

[21] 2003/2004 General Rate Application – Interim Rate Application, 24 December 2002. Decision 2002, p 15.

[22] IBID p 19.

[23] Evidence of Econalysis Consulting Services, p 24.

[24] Residential electric market deregulation or restructuring in the United States involves extensive education efforts initiated by the state utility commissions. For example, the New Hampshire Utility Commission noted: "With a policy change that has as fundamental a citizen impact as changing how consumers buy their electricity, the state has a responsibility to prepare consumers to such change."

5.2.1 What are reasonable expectations?

The ECS study identifies that one benchmark for reasonable expectation is inflation in the economy. ECS notes that since the introduction of restructuring, the accumulated inflation for the period has been 12.3%.[25] Using the average annual inflation rate calculated by ECS of 2.35%, this rate is likely to produce an accumulated inflation rate of over 15% for the period of 1999 through 2006. ECS compares historical adjustments based on the total residential electric bill with the inflation rate. While consumer's first reaction may well be to look at their total bill, the issue of education is relevant in that consumers need to understand that the distribution utility is subject to cost increases as a result of rising labor costs, material costs, and pensions. Given the noted lack of empirical data and no documentation about consumer education efforts, we take exception to ECS's conclusion that "[this] analysis demonstrates that the impact of distribution rate changes can not be considered in total isolation."[26]

Prior to any decisions about what distribution rate increase is within consumer expectations, we recommend that customer education about the sources of rate adjustments be considered. Distribution and transmission service rates have increased slightly more than inflation as exemplified by Hydro One Network's rate increases. However, the increases are attributable to policy changes rather than increases associated with operating the distribution system Over the five year period of 1999 through 2004 residential customers consuming less than 750 kWh/month had rate increases on the order of 4.2% per annum including increase for the market rate of return adjustment and recovery of costs associated with market transition.[27] The fact is that the real cost of distribution service for customers has not increased. The calculation is not intended to serve as a benchmark, only to note that the changes in distribution rates should be inline with consumer expectations absent dealing with restructuring issues such as moving rates to a level where they provide a market based return on investment.

Customers should also be educated about the distribution cost pressures and the associated need for rate adjustments. At the same time, customers can also learn about cost increases associated with energy costs and other pass-through items as well as any increases associated with taxes and government mandates. This process of transparency is critical for customers to understand rate adjustments and to separate out the impacts of restructuring from other factors that are reflected in changes in the total electric bill.

Another example is a 15 February 2002 report by the Connecticut DPUC emphasizing the importance of education to promote understanding of customer choice.

[25] Evidence of Econalysis Consulting Services, p 25.

[26] IBID, p 29.

[27] A cut off of 750 kWh was chosen to remove the impact of the increase in the energy rate applied to consumption over 750 kWh per month. Distribution rates for 1999 were estimated assuming the proportion of the rate that was power costs.

5.3 STANDARDS FOR APPROVAL OF RATE ADJUSTMENTS

ECS has taken the initiative to propose four different standards for rate filing requirements based on the overall proposed level of the distribution increase.[28] Given that the OEB needs to process over ninety distribution utility rate requests in a short period of time, we concur that a simplified process to address "small" increases in distribution rates makes sense. However, we are concerned that the proposed increasingly complex filing requirements tied to the level of the proposed increase can be interpreted as multiple standards of prudence. Therefore, to the extent that the OEB adopts a standard, our recommendation is that there is a single threshold value based on the requested distribution rate increase. Distribution rate increases below the threshold value would qualify for simplified filing requirements as defined by the data requirements and spreadsheets outlined in the Handbook. Simplified filing presumably would lessen the administrative burden and costs for both the filing utility and the OEB.

5.3.1 Determination of the threshold

ECS has recommended a threshold of up to an 8% increase in distribution rates, a "Category 1 Application," as the point where a rate filing complying with the Handbook worksheets is sufficient documentation. We are concerned about the selection of the threshold value and are not clear about how ECS concluded, "distribution rate increase expectations are likely to be – at best – in the order of 8%."[29] As previously noted, information on customer expectations has not been documented and it is not clear that customers have an understanding about what are the factors associated with the rate adjustments since 1999. Furthermore, customer expectations may differ by utility and on whether utilities have already made distribution rate adjustments since 1999 for movement toward the market based rate of return. A final issue is that there needs to be a clear definition of what costs are incorporated in the calculation of the distribution rate increase and whether the calculation is based on residential customer rates or the overall requested increase. If the calculation is based on only residential customers there needs to be an understanding about how the revenue requirement responsibility is spread to the residential class versus the other customer classes.

Based on the evidence available, we are not convinced that there is either a cost basis for selecting a specific threshold, or a rationale for having a single threshold value applied to all distribution utilities. We also recommend that should a threshold be established, the basis for the calculation needs to be clearly defined. Never the less, we see merit with simplifying the administrative burdens associated with filing and processing requests for distribution rate increases.

Our recommendation for the threshold value is that it be set at the cumulative inflation since the last rate adjustment. In 2006, the base for the adjustment would be 1999 when restructuring started. The calculation should be prior to inclusion of any proposed increases associated with implementation of the MBRR, government tax increases, government or OEB policy changes such as Bill 210, Bill 100 and Bill 4, Smart Metering and Conservation and Demand Management programs, or other distribution pass-through costs. (Exclusion of the

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[28] IBID, p 37.

[29] IBID, p 33.

MBRR adjustment removes the "penalty" for utilities that previously deferred the adjustment for mitigation reasons.) For customer communication purposes, the individual components would be explained to customers, but rate impacts would be shown for the total distribution increase.

If a threshold value is adopted, its purpose should be as a screen for simplified filing requirements and not necessarily as a basis for automatic approval. It is assumed that the OEB will still need to decide whether to grant the increase and consider policy issues such as revenue requirement adjustments for the MBRR. As the MBRR is an OEB policy issue, it should not require a utility to submit more accounting and cost evidence.

Similarly, increases in excess of the threshold value should not be viewed prejudicially or requiring a higher standard of proof. Rate increases in excess of the threshold should be subject to the normal review to ensure that the request is just, fair and reasonable.

5.3.2 Treatment of requests for rate adjustments above the “threshold”

ECS proposes four different filing requirements based on the requested percentage of the distribution rate increase. Categories 2 through 4 require progressively more detailed filing requirements based on the increasing level of the requested rate increase. We find the distinctions between Categories 2 and 4 problematic in that they imply a different burden of proof based on the level of rate adjustment. From a theoretical perspective the revenue requirement and rate adjustment should all conform to same level of rigor with regards to justification of costs. As such, we do not recommend different levels of filing requirements. Instead, there should simply be the expectation that increases above the threshold level will be subject to data interrogatories as appropriate based on the specifics of the rate filing.

5.4 EXPERIENCE WITH NATURAL GAS IN ONTARIO

In this section we review the treatment of commodity costs and distribution costs under Ontario’s natural gas market restructuring. Our recommendation is that the OEB’s experience and precedents established with regard to rate increases for natural gas distribution companies be considered when addressing rate mitigation for the electric distribution companies.

5.4.1 Commodity costs

ECS’s summary of Ontario’s experience of Ontario with natural gas deregulation identifies that residential customers of both Union Gas and Enbridge have experienced commodity charge increases of over 53% over the 4.5 year period of October 1999 through April 2004.[30] The increase in residential commodity costs represent a pass through of fuel costs that the distribution utility neither earns on, nor has any control over. The gas local distribution companies pass through commodity costs through a quarterly adjustment process referred to as the Quarterly Rate Adjustment Mechanism (QRAM). The use of frequent adjustments “help reduce the risk of large, one-time adjustments to the consumer.”[31] Both Union Gas and

[30] Evidence of Joyce Poon and William Harper, RP-2004-0188, pp 12-13.

[31] OEB press release dated 22 December 2004

Enbridge recently received approval to pass through additional gas cost increases under QRAM. According to the OEB's decision, a typical residential Enbridge customer will have their annual gas costs increase an additional 4.9% in 2005.[32]

As a point of reference, we note the similarities between the gas LDCs and electric distribution business and customers. The cost of natural gas commodity is outside the control of the natural gas LDCs. While the natural gas LDCs are responsible for delivering and billing for the natural gas, they do not earn a profit on those costs. Their role is to procure the gas for customers who do not directly purchase gas, bill for the gas, and track deviations in a Purchase Gas Variance Account (PGVA). The electric distribution companies are in a similar position; the electric LDCs do not have control over wholesale electricity costs, bill the electric costs for residential customers, and track deviations in a balancing account. One difference between gas and electricity is that the deviations between electric commodity revenues collected and power costs are currently being absorbed by the provincial government rather than being charged to customers through a quarterly rate adjustment process.

The natural gas LDCs have not been expected to mitigate natural gas commodity costs. Under current policy, the electric LDCs have not been expected to mitigate escalating power costs. Instead, residential electric customers have been shielded from the part of the commodity price increase through government subsides of wholesale power costs. Going forward, in the context of the Handbook, we recommend continuing the current OEB policy of not mitigating wholesale power costs through distribution rates.

5.4.2 Distribution delivery costs

Enbridge Gas and Union Gas have had distribution rate adjustments. ECS notes that the Enbridge residential distribution rates have increased approximately 3.6% per annum while Union Gas residential rates have not changed significantly.[33] The stability of the Union Gas residential distribution rates is a result of both cost allocation decisions and the PBR mechanism. The OEB has recently approved distribution rate adjustments effective 1 January 2005 for both utilities.[34]

As in the case of the commodity costs, we note that there are similarities between the natural gas and electric LDCs and that the OEB experience with natural gas should be considered when dealing with the electric distribution companies. These experiences include PBR mechanisms that are limited to costs under the control of the distribution company, cost based distribution rates, and use of market based returns in establishing Return on Equity Guidelines.

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[32] Decision and Interim Rate Order, Docket RP-2003-0203 (notation 15).

[33] Evidence of Joyce Poon and William Harper, RP-2004-0188, p 11.

[34] Rate adjustments to Enbridge Gas Distribution Inc rate application dated 1 December 2003 were approved on 22 December 2004 in Docket No. RP-2003-0203. Residential customers received a rate decrease in their delivery charge.

5.5 COST ALLOCATION, RATE DESIGN AND RATE MITIGATION

While rate impacts are relatively straightforward to calculate, the basis for mitigation is not as easy to measure. Prior to developing a formulaic approach to rate mitigation, such as maximum allowable rate increases, it is important to understand the cost basis for the current rates. Absent utility specific unbundled cost studies, it is difficult to understand what is the current status of intra-class and inter-class rate subsidies. While limiting the distribution rate increase to a subset of customers may appear reasonable in order to avoid rate shock, it potentially can be unfair if that same customer group is benefiting from subsidies from other customers. In some cases, the customers who are providing the subsidy may have competitive issues; for example C&I customers subsidizing residential customers. Alternatively, large residential energy users subsidizing small energy using residential customers may suffer hardship; for example customers in rental units using electric heat might end up subsidizing part-time residential customers who have a summer cottage.

5.5.1 Fixed and variable split for revenue recovery and rate design

The current proposal is to leave the split between fixed and variable charges unchanged in 2006 rates. At this stage we have no specific recommendations regarding changes to the fixed/variable split in revenue recovery beside our recommendation that the split be updated based on cost studies of fixed and variable cost components related to distribution, meter reading, billing, and customer service.

Changes in the allocation of cost recovery between fixed and variable rate (volumetric) components can have significant percentage bill impacts for customers who use a small amount of energy. ECS recommends fixed limits to the change in rates resulting from changes in cost allocation and rate design. The recommendations are based on the level of the average increase in the rate class. In the instance where the average class increase is under 9% or $5/month, ECS recommends a maximum increase of 9.5%. If the average class increase is over 9% then ECS recommends a maximum increase of 0.5% over the average increase.[35]

We have two concerns with the ECS recommendation. First, changes in cost allocations that are not associated with the determination of cost-based rates are problematic. We are concerned about making changes to non-cost based rates for reasons other than policy issues. While we recommend that rates be cost-based we understand that the Board has the need and obligation to consider policy issues in all rate changes. To the extent that a policy adjustment is not done on a cost basis, we do not think there is a basis for developing a prescriptive standard in the absence of consideration of the policy that is motivating the change.

The second concern we have is that to the extent that rate changes are proposed in the 2006 or future proceedings that are based on Board approved cost studies, the limits on the adjustments may be too small to effectuate real movement toward cost based rates.

[35] *Evidence of Econalysis Consulting Services*, Harper & Poon, page 40, 13 December 2004. Docket No. RP-2004-0188.

5.5.2 Low consumption vs. low income

It is assumed that future cost studies and proceedings will identify the cost basis for fixed charges. However, it is noted that the issue of rate mitigation often arises in the context of the percentage increase in bills that results from increasing fixed charges for low volume residential users. The dollar amount of the increase and the characteristics of the impacted customers should be considered prior to any determination to mitigate rates as a result of fixed charge increases. For example, with regards to the characteristics of the residential customers who are low volume electric users we note that these are not necessarily low-income customers. On average 14% of Hydro One's residential customers use less than 250 kWh/month, however, 75% of those customers are seasonal users of electricity. Data from the United States shows that while low-income customers on average use less electricity than the rest of the residential population, these customers are not necessarily low electricity users.[36]

5.6 RATE HARMONIZATION AND RATE MITIGATION

Distribution rate harmonization is an important issue to distribution utilities that have recently combined with number of other distribution utilities. One of the benefits of combining distribution companies is to create economies of scope and scale and create long-term benefits to all the distribution customers. One element to achieving these economies is to reduce administrative, accounting, and information systems costs. A consequence of achieving administrative cost savings is that the property records used to justify the area rates may no longer be available and the operating costs may not be tracked at a level of detail sufficient to support the former area rates.[37] There are also multiple facets to the customer equity issue. Customers who had a lower rate might feel entitled to retain that lower rate. However, there might not be a basis for the lower rate or that basis might have disappeared as a result of eliminating subsides provided by the former utility. In addition, there is a going forward equity issue if similarly situated customers who are separated by a municipal boundary pay different rates for the same level of service. Finally, there is an ongoing administrative burden associated with maintaining multiple rates for the same type of service.

The purpose of this testimony is not to resolve the complex issues associated with rate harmonization. Instead, the purpose is simply to highlight the complexities and issues and recommend that the Board consider the associated mitigation issues on a utility-specific basis rather than through a formulaic approach in the Handbook. Therefore, we do not concur with the ECS proposals regarding mitigation of rate harmonization impacts.

ECS proposes that any adjustments associated with rate harmonization be limited to twice the average "all customer" increase."[38] Again we are concerned about prescriptive standards

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[36] *A Look at Residential Energy Consumption in 1977*, U.S. Energy Information Administration, November 1999. DOE/EIA-0632 (97)

[37] In addition, developing costs based on former distribution utility boundaries can be problematic due to the need to allocated significant amounts of joint costs.

[38] Evidence of Econalysis Consulting Services, p 39.

without consideration of the utility specific circumstances. In the case of an average increase of 9% absent extenuating circumstances we would anticipate that increasing a customer class more than 18% in one year is probably not appropriate. However, if the average rate increase were only 2%, then adjustments over 4% might well be appropriate if they are cost based. Instead of prescriptive standards, we recommend that OEB either remove this issue from the Mitigation chapter, or use guidelines. Guidelines for review of rate harmonization adjustments could include:

- ***Perception of fairness:*** customers in adjacent communities served by the same Company should not be charged different amounts for the same level of service,

- ***Cost management:*** the cost of maintaining multiple rate classes for comparable levels of service should be factored into the evaluation; increases in administrative costs could hamper the utility's ability to reduce costs and mitigate rate increases for non-controllable costs, and

- ***Cost justification:*** the cost basis for separate rates may be missing because the historical records necessary to justify separate rates may not be available.

5.7 SUMMARY

Our recommendation is that OEB not adopt hard standards for rate mitigation at this time as there is insufficient evidence to support such a determination. We are concerned that the consumer expectation basis for establishing mitigation points is not well documented nor necessarily appropriate. The standards for determining the revenue requirement should not be based on the requested level of the rate increase. Once the revenue requirement is established the rates to recover the revenue requirement should be guided by a cost allocation study and tempered by other policy considerations. Absent the cost allocation study or definition of the specific policy considerations (which may be utility specific) there is not a basis for creating specific mitigation standards. There also needs to be recognition that for every customer "helped" by a cap, someone else is hurt, either another customer, the financial health of the utility or taxpayers who provide the subsidy.

We endorse ECS's proposal to create a threshold value under which the filing requirements will be limited to the information required in the Handbook. This endorsement is based on assumed benefits to both the filing utilities and the OEB to minimize administrative requirements. We have concern about the selection of the 8% threshold and recommend the use of the cumulative inflation since the last filing and recommend that the calculation exclude both pass-through costs and the cost of capital adjustments associated with transitioning to a market based return.

6. PRACTICAL OPTIONS FOR THE OEB TO CONSIDER

In this section we put forth our recommendations regarding the issue of rate mitigation. These recommendations are based on the results of our jurisdictional investigation, the assessment of economic principles and financial considerations, and our experience. While the ECS evidence is thorough, there are certain aspects of their recommendations that we find problematic. Consequentially, we propose some alternative guidance to the OEB for completion of the Mitigation chapter in the Handbook.

6.1 BASIS FOR EVALUATING RATE IMPACTS

The restructuring of the electric markets and the associated unbundling of energy services and delivery services has created a debate about the degree of separation of the services with regard to assessment of rate impacts and any potential need for impact mitigation. Energy costs have risen as a result of a number of factors including the cost of the input fuel, transmission, and the generation supply demand balance. The increase in energy costs has led to a freeze of energy prices in Ontario and in some cases the deferral of distribution rate adjustments. The OEB needs to determine how distribution rate adjustments should be evaluated in the Handbook. For the purpose of managing the distribution rate adjustment, we recommend that any impact test be performed only on the distribution bill. The test should be based on the distribution bill because it is not equitable to hold the distribution companies responsible for cost increases that are pass-through costs set by other entities or in other proceedings. This recommendation is not intended to suggest that the OEB should not be concerned about the impact associated with changes to the total energy bill on the customer. However, under the principles of rate making, it is not appropriate to hold the distribution utility accountable for bill impacts associated with changes in energy costs, taxes, changes in government or OEB policy directions and other regulations. This still leaves unresolved the key issues of what is the threshold when mitigation may be appropriate and what degree or type of mitigation could be used.

6.1.1 Percentage vs. dollar increases in customer bills

The evaluation of distribution bill impacts and the potential need for rate mitigation inevitably will lead to the question of how impacts should be measured; is it the percent bill increase, the dollar bill increase, or both metrics that need to be evaluated. We refer to this as an “and” test or an “or” test. The “and” test is important since residential customers who use a small amount of electricity may have a relatively large percentage increase but a relatively small dollar increase. For example a seasonal customer, typically a low-use customer, may have a relatively large percent increase as a result of a rate design that increases the fixed charge, but they may have a relatively small dollar increase in their bill. In that case we believe that looking only at percentage increases in bills is misleading. Likewise, a large user of electricity might have a big dollar increase in their monthly bill, but on a percentage basis may be less than average annual inflation. Therefore, examination of rate increases and the potential need for rate mitigation needs to consider both the dollar increase and the percentage increase in the bill.

6.1.2 Recommendations for a single threshold for simplified filing requirements

As noted in Chapter 5, our review of the ECS report, we concur with the ECS proposal of having a threshold that determines where filing requirements for a distribution rate increase are simplified. The ECS proposal is that distribution rate increases below 8% have filing requirements limited to conforming to the structure, format, and models defined by the Handbook. We do agree that a threshold guideline is an appropriate administrative simplification for the OEB, given the large number of expected LDC rate filings. However, we again stress that this guideline should not formally establish different standards of proof, based on the magnitude of the rate increase requested, for documenting and evaluating costs.

Should the OEB adapt the concept of a single threshold, we do not concur with ECS's selection of 8% as the threshold value. We propose that the threshold exclude certain costs in the calculation in order to create a level playing field among the distribution companies. Specifically, we propose that the calculation exclude adjustments for the costs associated with implementing the electric market restructuring including adjustment to a market based return. These adjustments should be excluded for two reasons. First, not all utilities have already implemented the phased-in adjustments. Thus utilities that deferred increases as a result of other non-distribution cost pressures are penalized for prior efforts to mitigate rate adjustments. The second argument for eliminating the phase-in return from the adjustment is that the movement to market based rates is a policy implementation decision and does not reflect on the distribution utility's ability to control costs.

Another group of costs that should be eliminated from the calculation are costs associated with governmental mandates and increased taxes, and any policy changes from OEB. While these are real pass-through costs that the distribution customer must pay, the fundamental issue in establishing the revenue requirement is whether the costs are just, fair, and reasonable. Disallowance of recovery of costs associated with government mandates does not make sense. These charges reflect government implementation of social policy and revenue collection mechanisms. If it were not the desire of the government to recover these costs through the distribution rate, an alternative revenue collection method would have been chosen. In any event, responsibility for paying for these mandates should rest on the consumer for both reasons of fairness and efficiency. It is the consumers who are the beneficiaries of public policy and the consumers should understand the cost of the services they are requesting or voting for.

6.1.3 Purpose of the threshold

The purpose of the threshold, should the Board find that such a threshold is necessary, should be limited to a test of what will qualify for a simplified filing requirement. The test should not be a litmus test for either what is an appropriate level of rate increase for the distribution utility, or whether rate mitigation is required.

The threshold should not be a test for acceptable rate increases since the determination of an acceptable increase to the revenue requirement should be based on a determination of whether the test year costs are reasonable and prudently incurred. It is not appropriate to reduce the utility's recovery of its reasonable costs in order to mitigate customer bill increases. It is inappropriate since not allowing cost recovery to maintain the distribution system reliability and customer service harms the customers as much as it harms the utility.

The effect of under funding distribution programs, based on our experience, can be a negative impact on reliability and customer service. We have also seen how inappropriate deferral of maintenance costs can lead to higher costs in the long run.

6.1.4 Cost associated with electric market restructuring

The treatment of costs incurred by distribution utilities in preparation for market implementation should be addressed outside of the Handbook. These costs are associated with the implementation of a regulatory policy. To the extent that the policy is deemed to "not be affordable" then that policy needs to be reviewed with regards to scope and timing. Should it be necessary to review the policy again, as a result of rate impacts, that review should be done in the context of a separate proceeding and not part of a prescriptive standard in the Handbook.

6.2 RECOMMENDATIONS FOR TYPES OF MITIGATION TO CONSIDER

Our recommendation is that the OEB not implement a formulaic threshold and approach for addressing rate mitigation. There are a variety of tools that can be used for rate mitigation including deferring revenue recovery, relying on prior regulatory balances held in favor of the customer, inter-class allocation of the revenue requirement, intra-class assignment of the revenue recovery achieved through changes in rate design, and special credits and surcharges to target a minority of the rate class. Each of these tools has advantages and disadvantages the best approach depends on the circumstances.

Considerations in selecting any rate mitigation mechanism that redistributes the revenue requirement among rate classes or customers within a rate class parallel the standards for rate design. The procedure should have a cost basis, be equitable, avoid masking important price signals, and be consistent with larger policy goals. Alternatively, rate mitigation that defers collection of revenue should consider whether inter-generational inequities are being created. An additional concern that we have with formulaic rate mitigation is there appears to be an assumption that users of small amounts of electricity are less able to absorb rate increases that may be a relatively high percentage amount but a relatively low dollar amount. The assumption appears to equate low energy users with low-income customers. This concern is amplified by the fact that small energy users represent a small amount of the revenue requirement and thus should not drive how the bulk of the revenue requirement is recovered.

Our experience is that while low-income customers on average use less electricity on a per household basis than the population of residential customers, there is a wide dispersion of energy use per customer among low-income customers.[39] Thus targeting mitigation to low energy user customers at the expense of larger energy use customer can be disadvantageous to low income customers.

While we have not reviewed any statistics on electricity use by low income customers in Ontario, we note that Hydro One Network customers that use less than 250 kWh/month account for less than 2% of the residential sales and represent less than 15% of the customers. Furthermore of those 15% of Hydro One Network customers that use less than

[39] The U.S. Energy Information Administration reported average electricity usage by U.S. household income for 1997. The average household used 851 kWh/month while customers eligible for Federal Assistance used 706 kWh/month. Proprietary information from a U.S. utility indicates that the dispersion around the average use per month is similar for both low-income and other customers. Based on these factors we note that low users of electricity are not necessarily low-income customers.

250/kWh per month, 75% of those customers (11% of the total residential customers) are seasonal users of electricity.

6.3 RECOMMENDATION TO PROCEED WITH PHASING IN COST-BASED RATES

In order to have equitable and transparent rates, we encourage the OEB to adopt a well-defined transition to cost reflective rates. Again, we are not proposing a formulaic approach to rate spread and rate design, but having a cost basis for the rates provides the best starting point for addressing policy considerations such as mitigation. (It is worth remembering that mitigation to one customer group represents an added cost responsibility to another group.) Cost studies will also assist in defining the proper relationship between fixed and variable distribution charges.

In general, the electric distribution system can be characterized as having a high amount of fixed costs and the marginal cost of incremental consumption is relatively low. (Higher marginal costs occur when increased load necessitates increasing substation capacity or reconductoring distribution lines.) Therefore, from both an equity and efficiency perspective, we recommend review of the current practice of constraining the basic monthly charge from recovering basic monthly costs. A Cost Allocation study that addresses functionalization and classification of distribution costs is the appropriate forum for identifying what the target is for the basic charge.

6.4 TARIFF HARMONIZATION

Tariff harmonization is an issue that does not pertain to all the distribution utilities. Consequentially, we recommend that the Handbook avoid a prescriptive approach. The draft manual's guidelines that the rate harmonization plan "include a detailed explanation, justification, implementation plan, and a sufficient analysis" are consistent with general rate making practices.[40]

Since the recommendations are broad, further definition of the terms may be appropriate. For example, "justification" of the harmonization plan can mean justifying the schedule for harmonization and the end tariff, or it could refer to justification why any harmonization is required. The rationale for undertaking harmonization is based on notions of equity and efficiency. It is proposed that the rationale for harmonization be accepted and that implementation proceedings focus on the schedule and approach for achieving the objective.

[40] Draft 2006 Electric Distribution Rate Manual, Chapter 13, p 98.

APPENDIX A: DETAILS OF JURISDICTIONAL REVIEW

A.1 CANADIAN EXPERIENCE WITH RESTRUCTURING

A.1.1 Alberta

a. ATCO

In a 2002 decision the Alberta Energy and Utilities Board (AEUB) ruled on an interim rate increase request by ATCO Gas.[41] In addressing the request for interim rate adjustment the Board acknowledged the difficulties associated with the impact of increases on customers, but expressed a concern for delaying interim increases and creating inter-generational equity issues and causing rate shock by differing rate adjustments.[42]

b. EPCOR DISTRIBUTION

The requested 2004 interim rate adjustment was reviewed by the AEUB in the context of the traditional approach of seeking evidence whether the distribution cost increases had been justified. Justification of the costs, including the appropriate rate of return, was based on evidence of the costs rather than using a metric of whether it was affordable.

The Board approved the Company's proposal to maintain a separate deferral account for transmission access charges. The Company argued that the charges should be separated so that the costs are transparent and consumers receive the appropriate price signal based on the approved transmission rates. The Company further argued that the true-up of these costs should be separated since these costs are largely out of the Company's control. The AEUB concurred with the Company's proposal.[43]

c. DIRECT ENERGY REGULATED SERVICES

The issue of separation of distribution and supply costs figured prominently in AEUB's Decision 2003-106.[44] The issue framed as "Separation of Costs" related to whether under the restructuring of the Alberta markets the determination of costs and recovery of those costs for supply and distribution should be distinct activities. In the AEUB's decision, it was determined that the costs and recovery for the two components are separate and distinct activities.[45]

[41] 2003/2004 General Rate Application – Interim Rate Application, 24 December 2002. Decision 2002-15.

[42] IBID, p 19.

[43] EPCOR Distribution Co. 2004 Distribution Tariff Application Part A: 2004 Interim Distribution Rates, Decision 2003-085, p 13.

[44] Direct Energy Regulated Services, Electric Regulated Rate Tariff and Gas Default Rate Tariff, 18 December 2003, Decision 2003-106.

[45] IBID, p 30.

d. ENMAX POWER CORPORATION

AEUB's Decision 2004-098[46] approved a negotiated settlement between Enmax Power Corporation (EPC) and interested parties. The settlement provided for a process whereby EPC will procure the energy and capacity required to serve its load on a quarterly basis, with the procurement prices to be reviewed by an Independent Advisor (IA). The rates customers will be charged will include a pass through of external distribution costs borne by EPC, with these costs subject to review by the IA as well. Once the prices are agreed to for each quarter, EPC will be allowed to hedge within that quarter to earn any profits available.

A.2 U.S. EXPERIENCE WITH RESTRUCTURING

A.2.1 New York State

a. CONSOLIDATED EDISON

New York State has restructured its electric markets and has had to address significant, and unanticipated, cost increases as a result of rising generation fuel prices. The response to these increases has not been to retreat from restructuring, rather there have been proceedings on how to mitigate power cost volatility. Under the restructured markets power price adjustments are passed through to consumers under the Monthly Adjustment Clause (MAC).[47] Under the MAC, 90% of the difference between actual and forecasted power costs (and savings) is passed through to consumers. From an economic perspective, the monthly adjustments provide the customers with timely price signals. However, due to instability in the power markets, a cap of a maximum price of US$0.22/kWh in any month was proposed. If the cap is reached, amounts in excess of the cap are carried over to a month with lower power prices.

In 2004 Consolidated Edison (Con Ed) filed for, and obtained approval to equalize the MAC charges between New York City and Westchester County since both areas are in the same New York state zone for wholesale market power costs.

Con Ed has been operating under a multi-year rate plan that expires 31 March 2005. In April 2004, Con Ed filed for new tariffs and began negotiations with interested parties, and on 2 December 2004 filed a Joint Proposal for a settlement.[48] In the proposed settlement, Con Ed will provide for a discount to low-income customers. The funding for the cost of this discount – estimated to be $37.5 million annually – will come from $9 million already built into the revenue requirement, and the remainder will be allocated from other customers' revenue.

The proposed settlement sets a target return on common equity of 11.4%. Earnings above this target will be shared between Con Ed shareholders and ratepayers on a sliding scale. In addition the settlement sets target levels of capital expenditures on transmission, distribution,

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[46] Energy Price Setting Plan Negotiated Settlement, 26 October 2004, Decision 2004-098.

[47] See New York State Public Service Commission, Docket No. 96-E-0897.

[48] Joint Proposal, 2 December 2004, Case 04-E-0572.

and production plants. Variances in these expenditures from the target levels will be either recovered from or credited to ratepayers.

b. NEW YORK STATE ELECTRIC & GAS

In 2003, the New York State Public Service Commission (the Commission) approved a transition plan to unbundled natural gas distribution for New York State Electric & Gas (NYSEG) residential customers.[49] Key elements of the plan included:

- 15% rate increase in 2002,
- A distribution rate freeze,
- Matural gas commodity increases passed through to customers – some commodity cost increases were mitigated using a deferred credit balance account,
- Weather normalization adjustment to reduce seasonal fluctuations in residential bills associated with weather much warmer or colder than normal, and
- Continuation of a component of the customer charge that is used for low-income bill assistance, the Heating Energy Assistance Program (HEAP).

On 23 September 2004, the Commission issued another order in this case.[50] The order addressed several issues not covered in the first two orders in this case.

The September 2004 order directed that rates be changed to eliminate long-standing disparities among the rates of return generated for NYSEG by comparable customer classes in each area. The geographic rate differentials had developed not because the cost of service varies among localities, but for reasons unrelated to cost (such as the various areas' prior status as service territories of independent utilities acquired by NYSEG). Consequently, the rates effectively compelled some NYSEG gas customers to pay more than the actual cost of their delivery service while others were paying less. Such rates were not only unfair but also inefficient, as they masked the real cost of delivery service and added to the administrative costs ultimately borne by customers of NYSEG. New delivery rates to correct the geographic disparities by 1 October 2008 were phased in through equal annual percentage increases or decreases starting 1 October 2004.

In addition to correcting geographic delivery rate differentials, the proposed rate design changes decreased the monthly customer charge for non-heating residential transportation customers (ie those to whom NYSEG provides only delivery service, and not the gas commodity itself), and increased the monthly customer charge for all other residential customers, by a total of $2.00 over the four years starting 1 October 2004. These changes did not directly affect the customer's total bill or NYSEG's revenues, as they would merely shift costs between the customer charge and other components of the bill. But, like the

[49] See New York State Public Service Commission, January 2003, Docket No. 01-G-1668.

[50] Order Concerning Rate Design, Economic Development, and Affordable Energy Program, 23 September 2004, Case 01-G-1668.

geographic rate consolidation discussed above, the rate design changes would correct geographic and historic anomalies that obscure the cost of service.

In discussing the various intervener arguments against the normalizing of these rates, the Commission stated " … As for the significance of comparatively low commodity rates in some areas, we do not regard them as a justification for increasing delivery rates. Rather, delivery rates in certain areas should be increased because those areas' present rates fail to recover the cost of delivery service and therefore necessitate higher rates for similar service in other areas. To the extent that commodity rates are low, it becomes easier to mitigate adverse bill impacts when raising delivery rates for other reasons. But, in adopting the rate increases proposed here, our objective is not to pursue a policy that delivery rates should be high if commodity prices are low; rather, we seek to align delivery rates with the cost of delivery service."

These statements by the Commission reflect its philosophy that distribution rates should be based on cost of service, and not be used to equalize other customer classes' overall bills.

A.2.2 Connecticut

a. CONNECTICUT LIGHT & POWER

Connecticut Light & Power (CL&P) recently had a contentious hearing with respect to an application to raise its distribution rates by 16.7%.[51] The company proposed an average electric rate of 12.58 cents/kWh. The proposal represented an increase of 1.802 cents/kWh over current 2004 rates. This application received negative publicity generated by the State Attorney General and others due to the size of the increase.

In the Draft Decision released 17 December 2004 the Department of Public Utility Control (CPUC) approved an increase to the rates of the Company that will become effective on 1 January 2005. Approved rates reflect several modifications to CL&P's original proposal. CL&P's rates will increase by approximately 11.4% above the average rates that were in effect in January 2004. This percentage increase reflects a current bill credit that will continue into 2005 and is explained in the Decision.

The decrease in the approved rate increase (from 16.7% down to 11.4%) was not a matter of mitigating the rate increase. Rather, the DPUC found that certain over-recoveries associated with 2004 true-up mechanisms, which the Company did not dispute, should be applied to the 2005 rate increase beginning 1 January, instead of waiting until later in the year in 2005 to begin to return those over recoveries to ratepayers.

The Draft Decision also dealt with deferrals, and ruled that deferrals would be inappropriate: " … The Department believes the customers should pay ongoing costs on a current basis while maintaining rate stability where possible … The Department believes that it would be dangerous and deceitful to hide the current rate increase by deferring a portion of it for future recovery. The Department therefore will not require any additional deferrals …"

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[51] Docket No. 03 07 02RE05, Application of The Connecticut Light and Power Company To Amend Its Rate Schedules – 2005 Distribution Rates.

A.2.3 Ohio

The Ohio General Assembly passed legislation restructuring the state's electric industry in June 1999.[52] Pursuant to this legislation, in August 2000 the Ohio Public Utilities Commission adopted market transition plans for the major electric utilities in the state, including a rate freeze until the end of 2005. In 2003, the PUC requested the utilities to file rate stabilization plans to be implemented on expiration of the rate freeze. In January 2004, Cincinnati Gas & Electric (CG&E) filed its rate stabilization plan and began negotiations with interested parties to resolve the issues involved. Following negotiations, CG&E and many of the parties agreed to a stipulation.

On 29 September 2004, the PUC issued an order[53] approving the negotiated stipulation with some modifications. The order allowed for the market transition period to end for nonresidential customers at the end of 2004 and on the last day of 2005 for residential customers. In addition, the order allowed CG&E to charge two non-bypassable fees: a rate stabilization charge (RSC), and an annually adjusted component charge (AAC). These fees are intended to maintain adequate capacity reserves and recover CG&E's costs associated with homeland security, taxes, environmental compliance, and emission allowances. The RSC would be effective for nonresidential customers on 1 January 2005, and for residential customers on 1 January 2006. The AAC would be effective 1 January 2005 for all customers, although CG&E would waive collection of the AAC from residential customers during 2005.

In addition to the above charges, CG&E would establish an accounting deferral for increases in its distribution business expenses over and above the revenue requirement approved by the PUC in the original market transition plans. These deferrals would account for the period from 1 July 2004 to 31 December 2005, and beginning in 2006, CG&E would recover these deferrals through an additional rate rider.

The effect of the negotiated stipulation was to increase distribution rates for CG&E. The PUC considered arguments from several interested parties in approving the stipulation – these arguments stated, among other issues, that the RSC and AAC were creating subsidies from one customer class to another. After considering the arguments from both sides, the PUC decided that these subsidies were not being created, and the rates being charged to each customer class were based on cost of service.

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[52] Amended Substitute Senate Bill No. 3 of the 123rd General Assembly.

[53] Case No. 03-93-EL-ATA, 29 September 2004.

A.2.4 Illinois

a. ILLINOIS POWER

In the Summer 2004, Illinois Power proposed increasing base distribution rates by 9% – the first such increase since 1994. Increase would cover transmission and distribution lines, new gas storage facilities, and increases in daily operations costs. The proposed increase would not affect commodity charges, but basic distribution costs only. The Illinois Commerce Commission is reviewing the request.

b. AMEREN UE, CONSUMERS GAS COMPANY, ILLINOIS GAS COMPANY, AND ILLINOIS POWER COMPANY

In 2001, the Illinois Commerce Commission addressed rate mitigation in response to dramatically rising natural gas prices (Docket No. 00-0789). The docket addressed rising natural gas prices for a number of local distribution companies Ameren UE, Consumers Gas Company, Illinois Gas Company, and Illinois Power Company. Solutions included:

- Levelized monthly billings (budget billing), and
- Extended payment plans.

A.2.5 New Jersey

a. PSE&G

PSE&G has had large rate increases for natural gas (15% as a result of three increases in one year). PSE&G uses securitized taxable transition bonds.

A.2.6 Maine

a. CENTRAL MAINE POWER

Central Maine Power addressed rate mitigation through rate credits. The credits are funded by gains from the sale of generation assets realized from the required divesture of generation. The gain was held in a regulatory account, the Asset Sale Gain Account (ASGA). In 2003 the Maine Commission reviewed and rejected a stipulation that would selectively target continued rate mitigation for a subset of customers.[54] The Commission acknowledged that rate mitigation is a tool for addressing rate stability.

> "This rationale for rate mitigation, then, is based on the traditional ratemaking concepts of maintenance of rate stability and avoidance of rate shock. [As pointed out in the IECG petition, the Commission previously ordered rate mitigation to be funded from the ASGA on two occasions. On both occasions the rate mitigation was ordered on rate stability/rate shock grounds. Investigation of Central Maine Power Company's Stranded Cost Revenue Requirement, Order Approving Stipulation, Docket No. 2001-232 at 9-10

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[54] Docket No. 2003-275.

(Feb 15, 2002); Investigation Into Central Maine Power Company's Stranded Cost, Transmission and Distribution Revenue Requirements, And Rate Design, Order, Docket No. 97-580 at 3-4 (Mar. 28, 2001)]"[55]

The Maine Commission was concerned about the proposal regarding distribution of ASGA funds through a narrowly targeted credit. The Commission approved an alternative distribution scheme that provided benefits to a large group of commercial and industrial customers. The approved method excluded residential and small commercial and industrial customers on the grounds that these groups had received benefits from standard offer service that were not available to the larger C&I customers.

[55] IBID.

APPENDIX B: QUALIFICATIONS

Hydro One Networks (Hydro One) engaged PA Consulting Group (PA) to provide an independent review of the rate mitigation issue and to comment on the expert report submitted by the VECC. PA has extensive experience in utility rate making and electric market redesign. Mr. Heidell and Mr. HasBrouck have had extensive experience in the field of financial and economic analysis and utility rate making. A brief summary of the qualifications of the review team follows in the first section with detailed resumes provided in the second section.

B.1 QUALIFICATIONS SUMMARY

Derek HasBrouck advises senior distribution company executives on topics ranging from corporate strategy to operations improvement. He is a recognized expert in electric and gas delivery regulation, network reliability, and customer service. In addition, he has led a number of energy market redesign/transformation assignments around the world, including PA's comprehensive redesign of the Singapore Electricity Market. He has testified on distribution regulation issues before a number of State regulatory commissions, and has created PA's annual ReliabilityOne™ and ServiceOne™ awards programs.

James Heidell has over 22 years experience in the energy and utility business. Mr. Heidell was previously the Director of Financial Planning at Puget Sound Energy (PSE), a combined electric and natural gas utility in Washington State. Prior to his position in utility finance he was the Director of Federal and State Regulation at PSE. Mr. Heidell has extensive experience in financial analysis of major utility investments including the purchase and sale of generation assets. His expertise includes both financial modeling at the corporate level and analysis of major investments. His regulatory experience includes all phases of cost modeling, rate design, and preparation of expert testimony. Mr. Heidell directed the load forecasting activities while at PSE and in his work at PA has worked on multiple engagements involving the review of load forecasts. Mr. Heidell's educational background includes: MBA Finance – University of Washington, MS Engineering Economics – Stanford University, and BSE Civil Engineering Tufts University. Mr. Heidell is a CFA.

B.2 RESUMES

Personal Profile

Name	Derek W. HasBrouck
Present Position	Member of PA's Management Group and Leader of PA's ReliabilityOne™ and ServiceOne™ award programs.
PA Experience	Derek joined PA in October 2000, when PA Consulting Group acquired Hagler Bailly. *2004 Partner in Charge* for the development and implementation of a new strategic business plan and capital construction program management system for an independent transmission company. *2004 Expert Witness* for reliability issues in a dispute between a major petrochemical company and the local transmission service provider. *2004/5 Expert Witness* on distribution rate impact mitigation approaches on behalf of Hydro One Networks before the Ontario Energy Board. *2004 Partner in Charge* for research on historical network reliability performance for a major piece of reliability litigation. *2004 Expert Witness* on transmission business management issues, including resource allocation, capital spending, maintenance spending, and asset performance on behalf of First Energy in two class action lawsuits. *2004 Expert Witness* on distribution capital and O&M spending, distribution reliability measurement and service level standard setting issues on behalf of Public Service of Colorado before the Colorado Public Utilities Commission. *2004 Partner in Charge* of real time, hands on assistance in managing electric restoration efforts in the aftermath of two hurricanes in Florida. *2002 Partner in Charge* for the due diligence reviews of several proposed sales of electric transmission assets. The due diligence reviews focused on the actual transmission assets to be transferred, their condition, levels of O&M and capital anticipated to be required to run the assets on an ongoing basis, and the related service contracts for the provision of some of these engineering, construction, operations, and maintenance services.

2002/3. Senior Energy Partner responsible for the design and implementation of the new competitive wholesale electricity market for the Republic of Singapore. This advanced market co-optimizes energy, reserves, and ancillary services using locational marginal pricing for all generation resources. PA delivered a complete market solution, from the initial market rules through to development and implementation of the wholesale market software.

2003. Partner in Charge for the development of a Midwestern electric utility's operational excellence strategy. This business strategy used benchmarking techniques to establish top decile performance objectives for its coal generation, electric delivery, and customer service business units. Generation capital expenditures for emission controls were a significant driver in projecting top decile performance standards.

2002/3 Partner in Charge for the performance benchmark analysis of a fleet of utility and non-utility generating units. Analysis included both traditional operating metrics, as well as capital costs and emissions costs related to continued operation of specific generating units.

2003/4 Partner in Charge for the development and implementation of OPTIMIZER, a PA software tool for optimizing capital and O&M spending, given defined corporate objectives. The software has been installed at a vertically integrated utility, to enable informed trade-offs between generation efficiency projects, emission control projects, T&D projects, and customer service projects.

2001. Partner in Charge for the review and critique of prospective asset separation agreements and long-term O&M service contracts for transmission assets being sold. Work included developing a negotiation strategy framework, analyzing and quantifying the business, technical, and performance risks, and recommending alternative contracting approaches to mitigate the risks and maximize the value of the O&M service contracts.

2001. Partner in Charge for the pre-audit preparation and audit management of a regulator sponsored distribution network reliability audit of an East Coast utility. The preparation included a business risk assessment, development of desired audit outcomes, an audit management strategy and plan, interview preparation, data request management, and draft report review.

2001. Partner in Charge and testifying witness for the Service Guarantee Program developed and proposed as a key feature of the Pepco acquisition of Conectiv. Our team analyzed historical company performance, the regulatory climate in each of five jurisdictions, utility service guarantee programs worldwide, and developed an optimized program for Pepco and Conectiv. We authored and sponsored testimony describing the plan and its benefits and defended the plan in the 5 parallel local regulatory proceedings.

Pre PA Experience

PHB Hagler Bailly, Inc., 1988–2000

2000. Engagement Director for the regulatory and public affairs intervention following a major distribution system failure at a major East Coast utility. We researched, analyzed, and prepared internal and external reports covering the technical issues, the regulatory issues, and the related financial issues. We project managed the development of an Independent Review Board, the retention of an international engineering firm, and targeted research by an industry research consortia.

2000. Engagement Director for the development of a strategic business plan for a newly formed electric and gas delivery company. Plans addressed tactical issues of improving reliability and service while under a rate freeze and longer term strategic issues of business structure, profitability of system expansion, and contestability of core work.

2000. Lead Consultant for the development of cost projections and associated revenue requirements for the proposed municipal utility resulting from a major municipalization case.

1999–2000. Engagement Director for the telecommunications strategy development, partner solicitation, proposal screening, and contract negotiation for a 10,000 unit greenfield development in Las Vegas.

1999–2000. Engagement Director for the diagnostic review, regulatory intervention, and major storm restoration process redesign for a major East Coast electric and gas utility following an extended storm outage. We reviewed the existing restoration processes, systems and procedures and benchmarked these against industry leaders. We prepared regulatory updates and information filings for several overlapping regulatory and legislative proceedings investigating these issues. We also provided data, coaching, and support for a 7 team, 25 person effort to redesign the restoration procedures for severe storm damage, with a goal of assuring restoration within 4 days.

1999–2000. Engagement Director for the pre-audit preparation and ongoing management of a regulatory mandated audit for a major electric utility. We conducted a pre-audit risk assessment, prepared position papers on key issues expected to be investigated during the audit, provided interview preparation and coaching, managed the discovery process, and guided the

Company's response to the audit findings, conclusions, and recommendations.

1999. Engagement Director for the comprehensive, proactive review of the reliability of the T&D system for a major Midwestern utility. The analysis included primary customer research, employee focus groups, a comprehensive inspection of the physical system using a sampling protocol, a review of design, operating, maintenance, and restoration policies, procedures, and performance, and a benchmark analysis of system performance.

1999. Engagement Director for the post mortem analysis of emergency preparedness and restoration efforts following a major ice storm for a major electric utility. We benchmarked the state of the system, guided client team's through route cause analysis, developed recommended improvements in emergency planning and developed reports on these topics for several interested regulatory and governmental bodies. Topics analyzed included emergency planning, resource mobilization, customer communications, pre-event maintenance, and the supporting information systems.

1998. Engagement Director and expert witness on behalf of Commonwealth Edison Company in the Illinois Commerce Commission's Reliability Rulemaking proceeding. We conducted a benchmark analysis of the reliability of Illinois utilities, statistically analyzed their reliability performance, and recommended rules and procedures that fairly balanced the legislative intent of the restructuring act and the realistically achievable levels of reliability.

1997–1998. Engagement Director and expert witness on behalf of Entergy Gulf States for electric distribution system operations performance, including performance during a major storm, as part of a rate case. Our analysis included a benchmark comparison of performance in reliability, system maintenance, tree trimming, call center operations, and storm/restoration management. The proceeding led to the adoption of reliability reporting requirements, reliability performance standards, storm management procedures, and customer contact standards.

1999. Engagement Director for the regulatory support for a major New Jersey utility's strategy, regulatory case management, and operational planning the unbundling of metering, billing, and customer account services.

1999. Engagement Director for the project management oversight of the introduction of supplier consolidated billing and competitive metering for Pennsylvania Power & Light (PP&L) and West Penn Power.

1999–2000. Engagement Director for the development of a retail energy delivery infrastructure for an energy supplier planning to enter the Nevada and Arizona markets.

1999. Engagement Director and Lead Consultant for the pricing analysis of several alternative retail energy offerings. Clients included a major semiconductor manufacturer, a large aquarium, and a paper manufacturer. Suppliers evaluated included Exelon, Enron and NEV.

1995–1999. Engagement Director for the gas purchasing review of Chattanooga Gas on behalf of the Tennessee Regulatory Authority.

1999. Lead Consultant for the development of a comprehensive retail and distribution strategy for a major Midwestern investor-owned utility.

1996–1998. Engagement Director for the concept development, business plan development and rapid launch of an outsourced distribution facility management subsidiary for a major utility holding company. We developed the business case, financial modeling tools for prospective transactions, marketing and sales collateral, information systems architecture plans, and we provided direct sales and transaction execution support for the first few customers. The first year value creation of the subsidiary exceeded $100 million.

1997–1998. Engagement Director for the project management of all the Direct Access implementation projects for a major California electric utility. This $400 million dollar, 5-year project, required extensive development and/or modification to information systems including usage measurement, billing, and market participant interface systems. Our project management team established financial, chronological, and managerial controls to minimize project costs and maximize regulatory cost recovery opportunities, while meeting all of the electric market restructuring milestones.

1998. Engagement Director for an audit of Pennsylvania Power & Light's capacity to offer supplier consolidated billing and competitive metering for the Pennsylvania Public Utility Commission. The audit identified the constraints in PP&L's soon to be implemented Customer Information System that delayed the introduction of competitive billing offerings. We recommended a firm implementation timetable and mitigation strategies to allow the marketplace to evolve while PP&L developed the necessary systems capabilities.

1996–1998. Engagement Director for the acquisition screening and preliminary analysis of electric distribution companies in Poland for a major U.S. utility. We analyzed the evolving industry structure, the industry and company specific privatization plans, and the customer base of specific companies. High level contacts were made at attractive investment targets on behalf of the client and strategic investor discussions are underway.

1996–1997. Engagement Director for the development of a strategic plan for a major Western utility distribution company. Market analysis, customer needs analysis, cash flow modeling, and shareholder value impacts were all analyzed under alternative market scenarios. A loyalty, customer retention, and new revenue streams strategy was selected and implemented, based on these analytic results.

1996–1998. Engagement Director for a market assessment of opportunities to provide operations and maintenance services to municipal utilities. Key results included quantification of cost savings and service level improvements which could be offered.

1996. Engagement Director for a benchmark evaluation of distribution O&M costs and reliability for an East Coast electric utility. Results demonstrated a high level of reliability and identified over $10 million in feasible operating cost reductions.

1995. Lead Consultant in the restructuring of a major Midwestern utility's retail operations. Competitive business units and businesses were established with the objective to minimize the degree and extent of future regulation while increasing near-term profits.

1995. Engagement Director for the benchmark evaluation of T&D material management for a major Midwestern utility. The study identified, focused management attention on, and set forth a plan to achieve savings of over $8 million annually.

1994. Engagement Director for a process reengineering project for a Northeastern combination utility's electric and gas metering operations. Client team achieved annual operating cost savings of over $2 million, inventory investment reduction of $3 million, and customer satisfaction improvements of 20%.

1995–1996. Engagement Director for the process reengineering and specification of an integrated Work Management System and Geographic Information System for the retail section of a Fortune 500 utility.

1994. Engagement Director for a market and competitor assessment for a broadband utility communications provider. Key results included prioritized sales targets, key product discriminators, and targeted sales messages.

1994. Engagement Director for the concept evaluation and business plan preparation for a proposed wholesale power market service. Based on this plan, the holding company board approved a new subsidiary with projected revenues of up to $100 million.

1994. Engagement Director for a benchmarking evaluation of retail energy marketing practices for a combination utility. Customer loyalty programs and specialized services for key accounts are now in place, based on study recommendations.

1994. Engagement Director for a benchmark evaluation of LNG plant operations in the United States. World class plant design, operations, and maintenance practices were identified and internalized for use within our client's business.

1993–1994. Engagement Director for a process reengineering assignment focusing on the customer inquiry process. Redesigns not requiring a new CIS resulted in 30% reductions in costs with measured, significant improvements in customer perception and satisfaction.

1993. Engagement Director for the determination of optimal and minimal regional staffing for a major electric and gas utility. Linear programming techniques were used to analyze workloads, service levels, and resource requirements by work headquarters. Recommendations led to the consolidation of eight work headquarters and an 18% reduction in full-time staff. Cost savings of over $10 million per year were achieved.

1993. Engagement Director for a market potential assessment for a distribution automation product. The electric utility and water distribution markets were analyzed and no attractive niche was identified. Product development resources were shifted to alternative product concepts.

1993–1994. Engagement Director for a multi-functional benchmarking and process improvement program for a major electric and gas utility. Targeted areas benchmarked by a joint client-consultant team resulted in annual savings of over $5 million, and service level improvements of 15% to 30%.

1992–1994. Engagement Director for a multi-client benchmarking study of the United Kingdom Regional Electric Companies. This annual study assesses the performance and practices of the RECs and compares their performance with similar utilities in the United States.

1992–1993. Engagement Director for the development and implementation of a product management approach and organization for a major electric utility. This leading edge management approach is designed to leverage proven consumer goods marketing techniques to help shape deregulation and drive performance improvement.

1992. *Engagement Director* for the design and implementation of a strategic planning, goal setting, and incentive compensation system for a major Southeastern electric utility. The program replaced a fragmented, unstructured planning process that led to poor and sometimes conflicting departmental goals. The Board of Directors and front-line employees and all levels of management in between now clearly understand what is expected and are motivated to achieve.

1992–1994. Engagement Director for the development of a corporate benchmarking program for an Eastern gas and electric utility. The program established a cohesive set of corporate-wide benchmark measures and designed a process to stimulate functional benchmarking as part of the ongoing management process.

1991–1993. Engagement Director for the development of a new, market-driven approach to the outdoor lighting business for a major Western utility. Product options were dramatically increased to meet the needs of specific customer segments, resulting in substantially increased market share, improved profitability, and improved relations with local municipalities.

1991. Engagement Director for the review, benchmarking and process improvement of the inventory accuracy measurement system for a major Midwestern utility. Revised reporting system clearly highlighted operational problems, while requiring significantly less manual entry, review, and auditing.

1991–1993. Engagement Director for the business process analysis and reengineering across the retail operations of a major electric utility. The project team identified, analyzed, and reengineered the fundamental business processes of the utility, helping to achieve a product/market orientation throughout the organization, while reducing capital and operating costs substantially.

1990–1991. Engagement Director for the effectiveness review of the corporate engineering and corporate T&D departments of a major Southwestern utility. The study identified critical gaps in responsibility for costs, schedules, and the introduction of new technologies and approaches. Recommendations included a revised organization, new cost controls, improvements to internal and external customer service, and a structured approach to evaluate and implement new technologies.

1991. Engagement Director for the evaluation of an Eastern natural gas distribution company's Automated Meter Reading (AMR) demonstration project. Customer satisfaction, operational savings, and related operational benefits were quantified and modeled relative to the system's cost. This model was subsequently used to evaluate alternative implementation scenarios and develop the company's AMR strategy.

1990–1991. Engagement Director for a distribution construction improvement program at a large Southern municipal utility. Facilitated the development by client analysts of an improvement plan with significant customer service improvements and construction savings of 15% annually.

1990. Project Manager for a review of electric operations at a major Southern utility to develop a long-range labor relation's strategy. Reviewed fossil and hydro generation, T&D construction and maintenance, dispatch, engineering, metering, meter reading, and related support activities. Developed a three bargaining cycle plan to fundamentally alter the employer-employee relationship.

1990. Lead Consultant for a diagnostic review and productivity improvement program at a major Northwestern municipal utility. Responsible for the hydro generation, engineering, substation, materials management, and T&D functional areas. The project resulted in a reorganization, redefinition of job responsibilities, revised maintenance programs, and improved training activities which dramatically improved the work environment, customer service performance, and cost competitiveness of the utility.

1989. Project Manager for market potential assessments of utility provided electric service monitoring and solar cell generation services. Identified high potential customer segments, key product attributes, and the competitive advantages of the product and the supplier. Recommended essential product and service modifications to achieve marketplace success.

1989. Lead Consultant for a diagnostic review of line crew, labor crew, and tree crew operations for a large West Coast municipal utility. Identified opportunities to achieve a 20% reduction in field forces.

1990–1991. Project Manager for a generating station operations study for a leading Southwestern investor-owned electric utility. Project assessed the strategic direction for plant operations through a benchmarking approach, restructured the station organization, and identified methods for improved cost performance by 40% and production reliability by 10% in a competitive bulk power market.

1989. Project Manager for the development of a power supply planning process and 20 year supply plan for the City of Glendale Public Service Department. The planning process evaluated all supply options given the new emission regulations, established the least cost compliant supply strategy and identified key external trigger events to be monitored.

1991. Engagement Director for the diagnostic review of engineering and construction functions at a large Southern water utility. Identified design process, contract administration, and workforce management improvement opportunities worth in excess of $5 million.

1989. Project Manager of two concurrent improvement projects for the City of Glendale Public Service Department. These projects identified and implemented significant effectiveness and efficiency improvements in engineering and construction, and defined material management improvements that eliminated the need for additional warehouse space and reduced inventory investment by 15%.

1987. Lead Consultant on a joint consultant/client team at a major electric utility, studying crew staffing and supervision. Identified, recommended, and implemented a 30% reduction.

1989. Lead Consultant for the development of a workload-based expense budgeting process for gas and electric operations at a major West Coast utility. Implemented management process changes to improve cost-performance evaluations by line management of ongoing and proposed maintenance activities.

1988–1989. Project Manager for the development and implementation of a workload-based expense budgeting process for the bulk power transmission and substation maintenance organization of a major utility. Designed the management processes used to evaluate and prioritize work volumes and funding levels for the O&M budget.

1988–1989. Lead Consultant for a review of the capital and O&M budgeting process at a large East Coast utility. Identified improvement opportunities in the process and staffing reductions within the function.

1988–1989. Project Manager for a study of senior management information needs at a large Eastern holding company. Inventoried and evaluated approximately 1,000 existing reports. Defined 100 key indicators for senior management. Guided changes in information reporting philosophy and systems to increase the quality and decrease the quantity of executive information.

Florida Power & Light Co., 1983–1986

Transmission and Distribution Supervisor. Supervised distribution construction and maintenance crews performing hot line tool and gloving work, URD work, hot metal work, and submarine cable work. Supervised barehand and hot line tool transmission maintenance activities. Facilitated five quality improvement program teams.

Field Engineer. Designed OH & UG distribution facilities. Planned, designed, and coordinated construction of new customer extensions and service. Administered the local electronic distribution database.

Jones & Laughlin Steel Company, 1982

Project Engineer. Wrote project design specifications. Reviewed construction bids and supervised construction. Provided training and technical support to operating personnel.

Education

J. L. Kellogg Graduate School of Management, Northwestern University, MM, 1988

Rensselaer Polytechnic Institute, BSEE, 1982

Societies

Member, Institute of Electrical and Electronics Engineers (IEEE)

Qualifications

Management of retail operations in the electric, gas, and water utility industries; director of PA Consulting Group's ongoing research in utility customer service and distribution management; management of retail energy marketing and operations; utility industry restructuring and the commercialization of energy supply. Mr. HasBrouck is experienced in retail choice implementation in many states including California, New Jersey, Pennsylvania, Massachusetts, Illinois, Nevada, and Arizona.

Personal Profile

Name	James A. Heidell
Present Position	Managing Consultant – Wholesales Energy Markets Practice
	Mr. Heidell has over 20 years experience in the energy and utility business. His responsibilities at PA include the analysis of wholesale energy markets in the United States to support the strategic development and financing and restructuring of generation assets and asset portfolios. Mr. Heidell has extensive experience in financial analysis of major investments including his purchase and sale of generation assets. His expertise includes both financial modeling at the corporate level and analysis of major investments. He also has extensive experience in regulatory policy including electric and gas cost-of-service, pricing, performance based regulatory mechanisms, and service quality.
PA Experience	James Heidell joined PA in October 2000, when Hagler Bailly joined PA Consulting Group.

Analysis of Wholesale Energy Markets

Mr. Heidell has worked on modeling energy prices using PROSYM and PA proprietary volatility models to support the financing of generation assets and identification of new generation markets for a number of clients including Edison Mission Energy. He has also developed SAS models to analyze the market value of power contracts for Exelon. The work for Exelon was used to support a bond financing. In a separate transaction involving bond reinsurance, Mr. Heidell modeled distributions of prices to identify 95% and 97.5% probabilities of repayment.

Mr. Heidell has provided power market expertise to a large bank group in support of the restructuring of the NRG portfolio. The project involves identifying strategies for disposition of distressed assets, independent asset valuations to support the asset disposition process, and cash flow analyses to validate restructuring plans.

Mr. Heidell has worked with two retail electric utilities to develop least cost generation resource acquisition strategies. In one case the work involved analysis of wholesale markets and identifying the least cost alternative between build versus buy decisions. In the second instance Mr. Heidell developed probabilistic distributions of future market electric prices to identify how resource acquisition strategies are impacted by uncertainty.

Mr. Heidell has developed valuations of generation assets to support development of bids for the acquisition of major generation portfolios. In two separate transactions the valuation of assets involved developing distributions of asset values as well as valuing POLR load and merchant generation contracts.

Risk Modeling

Mr. Heidell developed a model to analyze quarterly earnings risk associated with weather variation for a U.S. retail utility. The model incorporated correlations between weather, load, and wholesale energy prices to identify changes in retail revenue and associated changes in cost based on historic temperature distributions.

Mr. Heidell developed a value at risk model for a U.S. retail utility to guide risk management decisions about the level of surplus power sales to target for long-term versus short-term positions. The model develops target long-term positions based on risk preferences, earnings targets, and a combination of historical and simulated distributions of wholesale gas and electric prices.

Litigation Support

Mr. Heidell prepared cost-of-service and rate design testimony for PSE's electric rate case. Mr. Heidell was actively involved in the negotiation process that led to the settlement of the 2001 rate case.

Mr. Heidell developed a gas and electric cost of service model for PSE that is used to support regulatory filings.

Mr. Heidell provided complex financial modeling support in a tax case to identify levels of losses associated with contracts that were not fungible.

Mr. Heidell has supported NRG in litigation pertaining to breach of contract claims. The analysis involves examining the value of certain merchant power opportunities in New York state through the development of market assessments and development of a financial analysis.

Mr. Heidell supported Firestone in the preparation of insurance claims for recovery of losses related to major injury claims associated with recalled tires. The work involved development of databases and analysis of claim rates.

Presentations

Western Power Markets: Short-Term Supply and Demand Fundamentals, 1 May 2001

Pre PA Experience

Mr. Heidell has worked in the energy business for eighteen years. For the past ten years he worked at Puget Sound Energy, an investor-owned electric and natural gas utility in Washington state. He held multiple positions including Director of Financial Planning and Director of Federal & State Regulation. Prior to working at Puget Sound Energy, he was an energy consultant providing services to government agencies, investor owned utilities, and public utilities. Mr. Heidell has conducted numerous financial studies related to the purchase and sale of power plants, NUG contracts, and natural gas generation supply contracts. He has also worked on the valuation of utility distribution companies and determined the profitability associated with adding and disposing of electric and natural gas distribution service areas. Mr. Heidell has performed numerous embedded and marginal cost of service studies and developed pricing for regulated and market-based electric services. Mr. Heidell has presented expert testimony on cost-of-service and pricing.

Sample Projects

- Valuation of the buy-out of NUG contracts by an investor owned utility.
- Valuation of the buy-out of long-term fixed price natural gas contracts for an investor owned utility.
- Financial analysis of fractional sales in coal plants.
- Long and short term corporate financial modeling under alternative scenarios of generation ownership and power costs.
- Analysis of stranded generation costs of an investor owned utility.
- Preparation of bond rating agency reports for an investor owned utility and modeling of bond repayment for bondable conservation assets.
- Valuation of utility property in instance of threatened condemnation.
- Valuation of municipal natural gas distribution systems for potential purchase by an investor owned utility.
- Preparation of electric and natural gas unbundled cost-of-service studies for an investor owned utility.

	• Preparation of rate studies for federal and state regulatory agencies including the preparation of cost-of-service studies, rate design, and expert testimony. • Preparation of testimony and support of state application to merge an electric and natural gas utility with over lapping service territories. • Development of an open-access pilot for electric utility customers. • Development and implementation of program to transition large electric power users from core utility service with bundled rates to market rates.
Education	CFA – Chartered Financial Analyst, 1997 University of Washington, MBA, Finance and Accounting, 1989 Stanford University, MS, Engineering Economic Systems, 1982. Tufts University, BSE, Civil Engineering, 1979
Societies	Association of Investment Management Research
Qualifications	Short and long range financial analysis of electric and natural gas distribution and generation plant. Analysis of major utility investments, corporate financial analysis, due diligence, utility restructuring, unbundling, pricing strategy, rate design, cost of service analysis, and regulatory relations management.
Languages	English