REPORT OF THE

ONTARIO ENERGY BOARD

PERFORMANCE BASED REGULATION

IMPLEMENTATION TASK FORCE

MAY 18, 1999

Prologue

The Ontario Energy Board (OEB) is proposing performance-based regulation (PBR) for the electricity distributors in Ontario. The OEB's approach in developing a PBR framework for electricity distribution is to involve the stakeholders through task force efforts. As such, the OEB set up four PBR task forces consisting of volunteer stakeholders to examine the following: cap mechanisms, yardstick grouping, implementation issues, and distribution rates. The task forces had a total of 83 members representing various electricity distributors, gas utilities, customer groups, and special interest groups.

The Task forces were formed in mid-January and worked on the assigned tasks for approximately 3 months. The task force meetings were co-managed by OEB consultants Michael King and Frank Cronin of PHB Hagler Bailly, who also provided the task forces with technical expertise on PBR and restructuring issues in general.

To address the diversity of scope and the large number of emerging issues, working groups were formed within the task forces. Each working group produced reports which Board staff has collated into the task force reports.

All four task forces ran into concerns that led to the common proposal that the OEB should allow for a regulatory transition period. The regulatory transition period would allow utilities the opportunity to meet restructuring requirements without rigorous regulatory impositions, and allows for the collection of consistent and robust baseline data for PBR. The task forces agreed that a three-year first generation PBR plan should apply for the transition period to avoid gaming opportunities, in anticipation of PBR, during the transition period.

The first generation plan will have sophisticated incentive parameters (i.e. industry specific price indexes and productivity factors) developed from data collected from the electricity distributors and will also have risk mitigation terms (i.e. earnings-sharing). However, inconsistencies in data and utility practices precluded the implementation of yardstick groupings and a complete set of comprehensive performance standards applied to all distributors for the first generation plan.

The OEB would like to express its sincere appreciation for the conscientiousness of the task forces members and the time expended on the task force efforts, as well as its admiration for the collaborative attitude demonstrated by each of the task forces. Board staff and their consultants are confident that the outcomes of the discussions by the task forces will facilitate the production of a draft Board PBR Rate Handbook and result in a fair and practical PBR framework for the electricity distributors in Ontario.

OUTLINE

PARTICIPANTS

Name	Title	Association
Judy Allan	Director, Regulatory Policy Development	Enbridge Consumers Gas
George Armstrong	Director, Energy Services	Pickering Hydro
Joe Bailey	VP Infrastructure Management	Toronto Hydro
Gunars Ceksters	Executive Director Operations	Hydro Mississauga
Lisa DeMarco	Lawyer	Donahue & Partners
Paul Elliott	CS Manager	Whitby Hydro
Thomas Eyre	General Manager	Brantford Hydro
Jack Gibbons	Senior Economic Advisor	Canadian Institute for Environmental Law
Ron Lapier	Manager of Engineering	Sarnia Hydro
Bob Menard	Staff Officer	Power Workers' Union
Larry Murphy	Consultant	AMPCO
Cosmo Picassi	System Planning and Performance	Toronto Hydro
Patricia Planting	Co-ordinator, Rate case Administration	Union Gas
Adrian Pye	Senior Research Analyst	Enbridge Consumers Gas
Doug Reeves	Manager Operations	Sudbury Hydro
Marcel Reghelini	Manager, Distribution Regulation	Ontario Hydro Services Co.
Mary Ellen Richardson	Consultant	Econalysis Consulting Services
John Savage	Advisor, Electricity Operations	Ministry of Energy, Science and Technology
Claudio Stefano	Supervisor, Systems Engineering	Great Lakes Power Ltd.
Rick Stevenson	Staff Officer	Power Workers' Union
Brenda Todman	Officer	Municipal Electric Association
Ken Walsh	Senior Manager Engineering Solution	London Hydro
Philip Walsh	VP, Gas Supply, Storage and Marketing	CanEnerco

TASK FORCE MANAGEMENT TEAM

Co-Manager	Michael King	Vice-President, PHB Hagler Bailly Consulting, Inc.
Co-Manager	Frank Cronin	Senior Advisor, PHB, Hagler Bailly Consulting, Inc.
Coordinator	Judy Kwik	OEB, Research & Policy Analyst
Co-coordinator	Edward Sweet	OEB, Regulatory Officer

1. INTRODUCTION

The objective of the Implementation Task Force was to identify and assess features, procedures and requirements regarding the implementation of PBR.

The task force identified, prioritized, and evaluated the non-economic aspects and some economic aspects of PBR. As such, the task force covered the following topics:

- PBR implementation time-line;
- Requirement for processes/procedures associated with PBR;
- Sharing mechanisms;
- Compliance and enforcement mechanisms;
- Plan term;
- Exit ramps;
- ‘Z’ factors;
- Demand-supply management;
- Customer service performance indicators; and
- Service reliability performance indicators

Three work groups were formed within the task force as follows:

Work Group 1 - Customer Service

Chair:	George Armstrong	Pickering Hydro
	Gunars Ceksters/Mike Angemeer	Mississauga Hydro
	Thomas Eyre	Brantford Hydro
	Adrian Pye/Judy Allan	Enbridge Consumers Gas
	Marcel Reghelini	Ontario Hydro Services Company
	Brenda Todman	Municipal Electricity Association
	Philip Walsh	CanEnerco

Work Group 2 - Service Reliability

Chair:	Ken Walsh	London Hydro
	Bob Menard/Richard Stevenson	Power Workers' Union
	Ron Lapier	Sarnia Hydro
	Cosmo Picassi	Toronto Hydro
	Doug Reeves	Sudbury Hydro
	Claudio Stefano	Great Lakes Power Ltd.

Work Group 3 – Plan Term, Exit Ramps, 'Z' Factor, Earnings-Sharing, Process, Timeline

Chair:	Joe Bailey	Toronto Hydro
	Lisa DeMarco	Donahue & Partners
	Mary Ellen Richardson	Econalysis Consulting Services
	Paul Elliott	Whitby Hydro

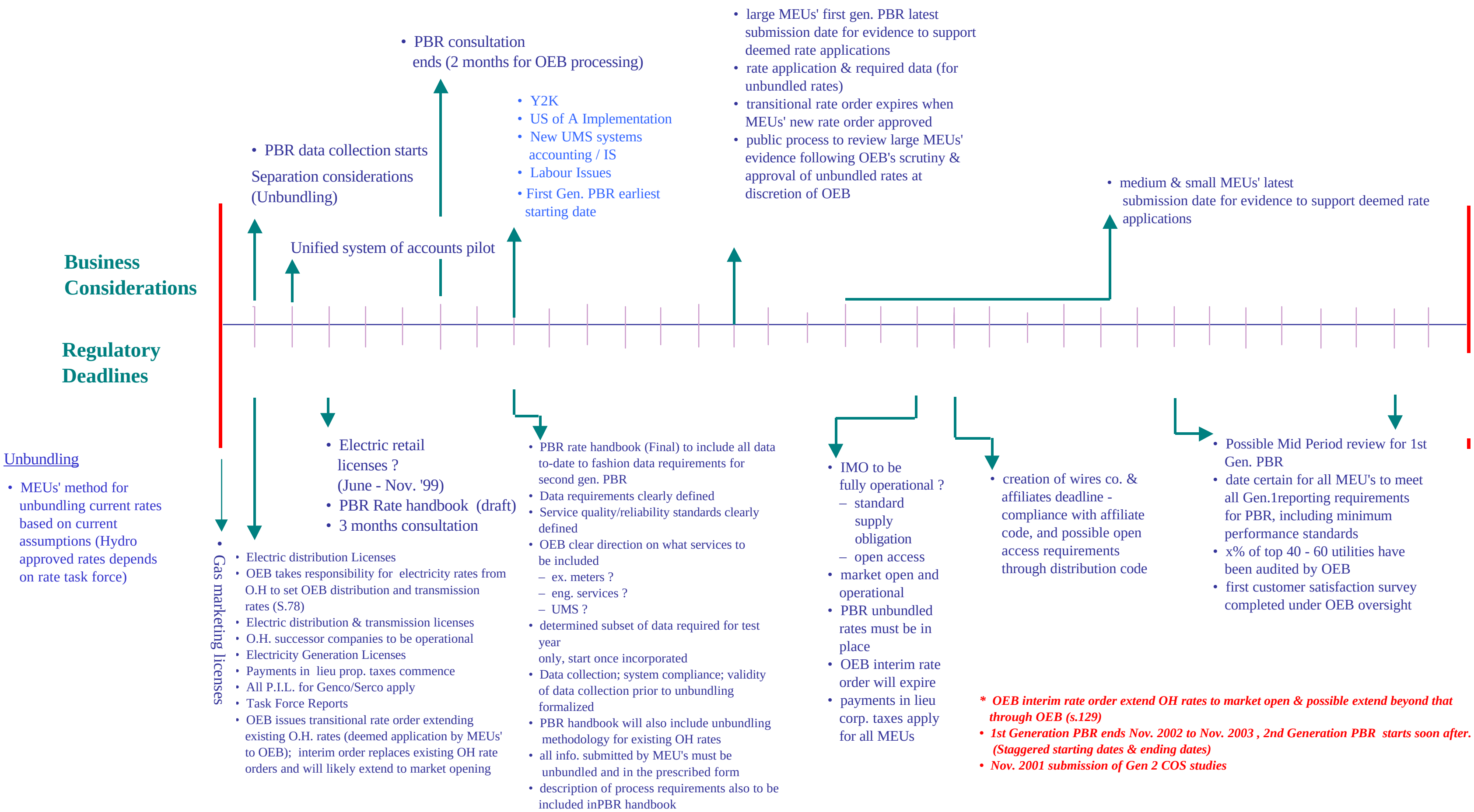
The intent is for Board Staff to draw on the task force's discussions and recommendations in preparing an Ontario Energy Board draft PBR rate handbook for the electricity distributors. The Board will hold a public consultation on the draft rate handbook in the summer of 1999, with issue of the rate handbook expected in the fall of 1999. The distributors will then be in a position to file evidence according to the guidelines contained in the rate handbook for a rate order establishing unbundled PBR rates prior to the introduction of open access expected in the fall of 2000.

2. IMPLEMENTATION ISSUES

The work group began this task by projecting, over the next three to four year horizon, some of the most significant business and regulatory challenges which the Ontario electric participants are going to face. Amongst these were deadlines with respect to the >opening up= of the electricity market, and those deadlines which are specified by legislation (e.g. corporatization, the length of time by which current rates can be extended). The sub-committee also consulted with both OEB and Ministry of Energy Science and Technology counsel so as to clarify any legislative requirements (e.g. Bill 35, OEB Act). The requirements of the Statutory Powers and Procedures Act were also considered with respect to the need for public hearing, due process, and the form of hearing required. The group was specifically asked not to consider how the processes would be financed. The sub-committee then focussed on two processes: the public review of the PBR handbook (to take place during the summer of 1999), and the public review of the municipal utility rate evidence submitted to support the first generation PBR applications (to take place between November 1999 and August 2000).

Readers should reference Figure 2.1: ASuggested PBR Implementation Timeline@ Schematic, Section 2.1.1 entitled AFirst Generation PBR Process Requirements@, the overview presented in Section 2.1.2 entitled “Goals of Draft PBR Rate Handbook”; and the four charts presented in Section 2.1.3 detailing the process options.

Figure 2.1
Suggested PBR Implementation Timelines



2.1 Work Group Recommendation

The participants of the task force sub-committee understood that one of the objectives was to minimize regulatory burden, oversight and cost. Processes were to be streamlined, as much as possible, but needed to provide for some public scrutiny and feedback. The forum for the latter would be at the discretion of the OEB.

The public review process for the draft PBR Rate Handbook in the summer of 1999 should be relatively rigorous so as to provide education to all stakeholders; increase stakeholder buy-in to the new regime, and; improve the framework, and, most importantly, attempt to minimize the need for protracted public scrutiny and debate at the point when municipal utilities submit rate evidence. To this end, it was recommended that a training seminar should be initiated prior to the public review process, followed by both written and oral submissions of evidence by interested stakeholders. In the oral portion of the review, stakeholders would be permitted to present experts but cross-examination would only be allowed between OEB Board members and the witness for the purpose of clarification. This limitation was intended to limit the time allowed for this portion of the public review process.

It was assumed that municipal utilities would be provided with formulae to assist in the calculation of unbundled rates. It was also understood that any municipal utility submission would be subject to a rigorous review by OEB staff to ensure compliance with the PBR Rate Handbook guidelines.

The public review process for the decisions regarding rate orders was contemplated to be fairly minimal. This was designed for the Generation I PBR rate orders only. For small and medium municipal utilities, limited hearing / review was contemplated. For large municipal utilities, a written review was contemplated.

It should be noted that interested stakeholders might make their wish for more rigorous reviews known to the OEB at the time of submission.

With respect to time-line (Figure 2.1), it was acknowledged that municipal utilities could conceivably submit rate evidence in accordance with the PBR Rate Handbook immediately following issuance of the final PBR Rate Handbook contemplated for November 1999. However, the sub-committee recommended that two ultimate deadlines be specified for submission of evidence: May 2000 for large municipal utilities and August 2000 for small and medium municipal utilities. Municipal utilities would be required to issue notice of rate submissions in accordance with the notice requirements to be specified by the OEB.

2.1.1 First Generation PBR Process Requirements

The following nine preliminary process requirements have been identified in conjunction with the proposed PBR implementation timeline. In determining the processes to fulfill the identified process requirements, the Board should attempt to develop processes which are consistent with the nine objectives for PBR which are outlined in the OEB Draft Policy on PBR.

A discussion of participant funding and cost awards, and the associated processes for determining all aspects of the same, has not been included at the direction of Board Staff. It is trite to say that the development of a funding process is necessary to ensure the adequate and effective participation of integral stakeholders.

The following nine points along the suggested PBR implementation timeline will require an associated process:

1. **April, 1999**: The Board must determine a consistent process for the review of the April 1st, 1999 rate orders if their "just and reasonableness" is challenged.

2. **May, 1999:** The Board must have a process in place to deal with name changes in licenses and rate orders following the incorporatization of Municipal Electric Utilities (MEU’s).

3. **June, 1999:** The Board must have a defined process in place and outlined in the draft PBR rate handbook to allow for the contemplated three months of public scrutiny and feedback on the same.

4. **November, 1999:** When the MEU's file the evidence to support their deemed rate applications, the OEB must have a process in place to notify affected stakeholders, deal with potential interventions and make final orders on the deemed applications.

5. **November, 1999:** The OEB must have a policy and consistent process in place for determining individual applications for rate adjustments which are filed outside of the planned review period(s).

6. **November, 1999:** The annual rate review process must be clearly defined and outlined in the PBR Rate Handbook.

7. **November, 1999:** The PBR Rate Handbook should also include a clearly defined process to deal with an MEU's failure to comply with the defined performance standards. The process should be cognizant of overlap with licensing and distribution code requirements and be harmonized with the same.

8. **November, 1999:** The process associated with the planned mid-period review for first generation PBR should also be fleshed out and included in the PBR Rate Handbook.

9. **May, 2000:** Long before the mid-period review of first generation PBR, the Board should define and outline the process associated with rebasing and moving from first generation PBR to second generation PBR.

2.1.2 Goals of Draft PBR Handbook Review Process (Summer 1999)

A. Educate Stakeholders

- Particularly those who could not participate in task force

B. Increase Buy In

- PBR is not optional
- Clarify process and define how to operationalize
- Emphasize reasons for generation I & II
- Offer help

C. Decrease potential for intervention when Evidence submitted

- Desire least cost/least time option at implementation
- Justify limited scope/written hearing
- Decrease regulatory burden/cost
- Meet deadlines
- Leads one to choose greater time/cost option for review of handbook

Considerations

- SPPA requires due process/opportunity to be heard
- Bill 35 provides for hearings for all rate applications, though at OEB discretion
  - Need rationale for granting/refusing
  - Need some due process
  - Limited scope desirable to meet severe time constraints

Prerequisite

- Rate handbook provides sufficient detail regarding:
  - Rate design
  - Plan parameters
  - Time lines
  - Data submission requirements (year 0, subsequent)
  - Non compliance process (year 0, subsequent)

- OEB staff review thoroughly for conformance with PBR handbook.
- Minimum requirement for granting hearing may be deficiency in written submission.

2.1.3 Process Options

CHART 1

OPTIONS FOR PARTICIPATION IN DRAFT PBR HANDBOOK REVIEW PROCESS (Summer 1999)

	Options	Pros	Cons
Least Inclusive/ Least Buy-in Least Cost,Least Time	1) No hearing/Review Process	No cost or time	
	2)Regional Educational Seminar (Overview, Question & Answer) by OEB Staff/Consultants	-relatively low cost -least time alternative	-not as beneficial - lack of effective participation/buy-in -politically untenable -no Board participation - no direct – ‘face to face’
	3) Technical Conference	- cost / time efficient	-limited to clarifying specific elements -lack of opportunity for comprehensive discussion -lack effective participation/buy-in -politically untenable -lack of widespread provincial understanding/participation
	4) Written Submissions Only	-least cost alternative -relatively better participation -available to all provincial stakeholders	-no Board participation - no direct – ‘face to face’ -lack of opportunity for comprehensive discussion -lack effective participation/buy-in -politically untenable
	5) Written Submission & Oral	-Board participation – ‘face to face’ -Addresses written submissions of other intervenors	-no pre-hearing education -relatively more money -relatively more time-consuming
	6) Seminar, Written Submission & Oral, establish specific parameters so as to limit hearing length and breadth of topics covered	-Board participation ‘face to face’ -Addresses written submissions of other intervenors -Education -Most inclusive/participation	-Could be costly
Most Inclusive/ Most Buy-in Most Cost Most Time	7) Full Generic Hearing (Includes technical panel, I/Rs, ADR, Cross Examination, and witnesses and seminar	-most thorough -more rigorous -potentially less rigorous later when utilities submit evidence, as mandated by the OEB	-cost and time intensive -lack of control over process -greater redundancies in issues submitted -more adversarial

CHART 2

RECOMMENDED OPTION FOR PARTICIPATION IN DRAFT PBR HANDBOOK REVIEW PROCESS (Summer 1999)

Option 6: Seminar, Written & Oral

Process	Description	Timeline
Seminar	-HB Consultants & OEB Staff Road Trip (5 locations, 1 day each). -Overview of Handbook re: Rate design, Regulatory process overview for PBR consultation i.e. Consultation of Rate Handbook, filing of evidence (Process/timeline), hearing process for PBR, Board review process, Q&A Session	Commence: Distribution of Handbook + 1 week Elapsed Time: two weeks
Written	Invitation to participants to submit written information to support/refute positions presented in Handbook -Position papers	Deadline: Distribution + 5 weeks
Compilation	OEB staff issues "Issue List/Groupings" based on written submissions to be addressed in the oral proceeding. Encourages coalitions of stakeholders to put forward a position of similar interests.	Deadline: Distribution + 7 weeks
Oral	At discretion of participants, to provide further support or evidence for written positions or to comment on other party's submissions/positions in front of panel of Board members, supported by Board staff/consultants. -constrained interventions -limit length -limit scope -could present experts	Deadline: Distribution + 12 weeks

CHART 3

OPTIONS FOR PARTICIPATION IN DECISIONS REGARDING RATE ORDER

(Nov 1999-Aug 2000)

	OPTIONS	Generation 1 PBR Recommendation	Generation 2 PBR Recommendation
Least Inclusive/Least Buy-In Least Cost Least Time	1. No Hearing/Review Process a) OEB staff makes recommendations on rate order to OEB members b) OEB reviews, may make modifications, and rules	Small / Medium	
	2. Written Hearing a) OEB staff makes recommendations on rate order to OEB members b) Intervenors make written submissions c) OEB reviews, may make modifications, and rules	Large	Small / Medium
	3. Written Hearing +IR response a) OEB staff makes recommendations on rate order to OEB members b) Intervenors ask interrogatories; MEUs respond c) Intervenors make written submissions OEB reviews, may make modifications, and rules		Large
	4. Written + ADR a) OEB staff makes recommendations on rate order to OEB members b) Intervenors make written submissions c) ADR involving intervenors, MEUs and moderator; negotiate items within PBR handbook issue list parameters; modification of evidence to incorporate resolved issues d) OEB reviews, may make modifications, and rules		

	5. Written + Tech. Conference a) OEB staff makes recommendations on rate order to OEB members b) Technical Conference; Interrogatories from intervenors; MEUs responses c) ADR involving intervenors, MEUs and moderator; negotiate items within PBR handbook issue list parameters d) Intervenors make written submissions e) OEB reviews, may make modifications, and rules		
Most Inclusive/Least Buy-In Most Cost Most Time	6. Tech.Conf., ADR, + Oral a) OEB staff makes recommendations on rate order to OEB members a) Technical Conference; Interrogatories from intervenors; MEU's responses b) ADR involving intervenors, MEUs and moderator; negotiate items within PBR handbook issue list parameters c) Intervenors make written submissions d) Oral hearing on unresolved issues e) Final argument by MEU, responding argument by intervenors; reply argument by MEU; f) OEB reviews, may make modifications, and rules		

NOTE:

1) Process will get significantly more rigorous for second generation as increasing familiarity with processes for all parties, and submitting companies prepare cost of service studies to support rate cases.

2) During first Generation, significant time constraints limit intervention.

3) First generation ADR seen as non-productive given lack of data available for meaningful negotiation.

4) *Funding remains unresolved. Specifically not considered as a factor in this analysis at the behest of the OEB staff.*

Chart 4

Process for Rate Applications for First Generation PBR
(November 1999 through August 2000)

Item	Description	Timeline
Evidence Notice	-MEU to give notice of filing of rate evidence in accordance with notice requirements and including a 30 day deadline for intervenor expression of interest and desire to participate	In accordance with OEB requirements.
Submission of Evidence in support of deemed application	Evidence to support PBR rates, prepared in accordance with specifications of PBR Handbook. Rates to be unbundled, and inclusive of CTC and market based ROR.	Earliest submission possible: Immediately following distribution of Final PBR Rate handbook (November 1999) Deadline: Large: May 2000 Small/Medium: Aug 2000
Implementation Deadline	Implementation of PBR rates	Deadline: Oct 2000 (Market Open)
Review Process	OEB staff reviews evidence to ensure compliance with Handbook. This may involve 3rd party assistance. Intervenor participation and process varies depending on process chosen. OEB rules. Timing of implementation, funding and process dependent at OEB discretion.	Deadline: Oct 2000 (Market Open)

2.2 Plan Term

There was a general consensus among the members of the subcommittee that a PBR plan term in the range of 3 years was appropriate. Some smaller MEUs may tend to favour longer terms given the additional administrative burden that may be associated with plan renewal and the initial lag time that will be required to conform with additional data collection requirements. Similarly, they may wish additional time to implement the requisite SCADA or other monitoring systems to facilitate collection of the data that is likely to be required. Many of the concerns of the smaller MEUs may be addressed by:

i. Staggering implementation dates; and

ii. Providing for some form of automatic PBR rollover or renewal associated with the rate payer protection mechanism which could take the form of a Board review trigger by the existence of:

    a) Any complaints, a certain level of complaints, or a complaint by a consumer organization;

    b) A MEU, Board or other third party administered customer survey indicating customer satisfaction below a predetermined level; Some form of automatic PBR rollover mechanism may also function to decrease the administrative burden of the Ontario Energy Board, provided neither of the above events occurs.

The members of the working group generally agreed on the following:

1. Short term (2 or 3 years) is appropriate for the initial introduction of PBR;
2. Ultimate objective for term should be 5 years;
3. Same term should apply for all utilities with possibility of staggering terms for logistics;
4. Incentives should be comparable irrespective of utility size;

5. Mechanism should not encourage utilities to stay small;
6. Streamlined process should be developed for smaller utilities; and
7. All utilities should be on a scheme by some ‘drop-dead’ date.

The discussions on plan term were initiated based on the initial suggestions presented here.

Initial Suggestions: Joe Bailey, Toronto Hydro

For a pricing plan with a limited PBR to start – recommend a relatively short term – 2 years with liberal exit ramps and earnings-sharing so as to minimize the risk and opportunity for extraordinary gain.

For a pricing plan that starts with a cost of service study and then goes into PBR – recommend a limited term to start. A limited term provides better security for both the OEB and the utility, particularly those utilities having the uncertainties of amalgamation costs and allocations.

The ultimate objective for term should be more length, 3-5 years with 5 being the preference so as to institutionalize regulatory lag time between “rate cases” and to ensure a time frame that is adequate to optimize the incentives (e.g., go through a life cycle of planning, achieve efficiency improvements).

The OEB should consider different terms for different utilities – e.g., those with existing cost of service studies may be able to go into a more comprehensive long term PBR than those without.

The other issue of term is whether or not all utilities should start PBR on the same day (and finish on the same day). For price caps, this is less important than for benchmarking/yardsticks. There is real appeal to staggering the start dates and terms for caps so as to not overwhelm the regulatory process. The downside is that the OEB might focus too much attention and try to accomplish too much with the first cap. The first utility to go forward with a cap should be treated as a case study with a discrete term, liberal exit ramps and earnings-sharing to obviate the need to address all issues.

Initial Suggestions: Mary Ellen Richardson, Ecoanalysis Consulting Services

Assuming that the review period is the period until a revised PBR regime is implemented, it appears that the maximum initial period that would be reasonable would be 4 years. In order to implement a new regime, it will be necessary to initiate a review 1 to 2 years before the planned date of the introduction of a revised scheme. It would be appropriate to gain at least 2-3 years experience with the initial PBR regime before evaluating it. A shorter period would not provide a fair test of the level of productivity improvement that is realistically achievable on an on-going basis. Also a shorter review period would provide little opportunity to realize the benefit of reduced regulatory burden.

As noted above, however, the review period that is appropriate is interrelated with the earnings-sharing mechanism that is adopted for two reasons. First, the smaller the company share of earnings, the longer the review period in order to provide adequate opportunity to earn a payback on productivity initiatives that have a high up-front cost. Second, the larger the ratepayer share of excess productivity gains, the less is the need to quickly correct the mechanism if the productivity offset has not been set at the right level (i.e., less need to correct if it was too low, because harm to ratepayers is lessened; less need to correct if rate was set too high, because harm to ratepayers is lessened; and less need to correct if rate was set too high, because harm to shareholders is lessened).

It is clear that over a four-year period the cumulative excess profits, or losses, that could accrue if the productivity offset is set incorrectly are very large. Adoption of an earnings sharing mechanism would significantly reduce the potential impact and may therefore be an important protection against the risk that very high or very low earnings could discredit a PBR regime in the eyes of Ontarions.

Initial Suggestions: Elisabeth (Lisa) DeMarco, (Donahue & Partners)

The Board should seek to mandate an initial plan term which is long enough to allow for equilibration and adjustment to a new regulatory mechanism without causing undue financial risk to the rate-payer[1]. It is suggested that the data collection and homogenization phase will likely require at least one year, and that it will take greater than one year to allow for adjustment and achieve some early indication of equilibrium. Consequently, an initial plan term of approximately 3 years may be warranted.

Some initial timing consideration (PBR staggered phase-in) to allow the least organized MEUs to better assess their business options may be warranted and viewed as an equitable attempt to achieve fairness in implementation. In no way, however, should this allowance act to deter MEUs from making necessary strategic decisions. It is therefore suggested that any timing allowance must be coupled with a fixed “date certain” by which all MEUs must have implemented their appropriate PBR plan.

It is very unlikely that the Board’s administrative burden will be lessened during the early stages of the transition to a new mode of regulation, particularly given the expected number of mergers, acquisitions, and divestitures. The assessment of the initial plan term should, therefore, be made with the understanding that no suggested plan term may achieve the Board’s administrative efficiency objective in the first iterations.

2.3 General Implementation Issues

The consideration of the implementation timelines for all of the affected MEUs necessitates a more detailed consideration of many sub-issues including:

1. The MEU’s initial state of readiness;
2. Possible issues regarding proposed business separation;
3. The determination of billing rates in the interim between full PBR implementation and the December 31, 1999 expiry of the last Ontario Hydro imposed rates;
4. The final determination of MEU PBR groupings and the criteria for those groupings (load-based determinations versus customer number determinations);

[1] Plan term is merely one factor that may affect the ultimate risk to the rate-payer. Consequently, forwarding rate-payer objectives through plan term must be balanced and assessed in the context of the many econometrics which may be adjusted to achieve the same goal (i.e. productivity offset, stretch factors, sharing mechanisms, inflationary measures, and off-ramps).

5. Qualification of the many uncertainties which remain associated with PBR; and
6. Government directions and deadlines in the context of an election year.

All of these issues will have to be considered and balanced in the determination of the initial "dates certain" (drop dead dates) for PBR implementation. The Board will essentially be called upon to make an initial policy decision weighing its stated PBR objectives related to consistency and fairness and the likelihood of political acceptability. It is generally suggested that the initial policy factors should be weighted in a fashion that allows the PBR implementation state to be as close to the proposed PBR end state as is politically feasible.

In the end it was generally suggested that the PBR groupings allow for one date certain for the price cap grouping and approximately three dates certain for the small, medium and large MEUs included in the yardstick groupings.

Discussion on the above summation was based on the initial suggestions presented below:

Initial Suggestions: Mary Ellen Richardson, Econalysis Consulting Services

Need for Consistency

Wherever possible, we believe that the same plan term should be used for all utilities. Otherwise, the 'playing field' for Ontario utilities will not be level, and differences in the regulatory treatment may impact investment and other business decisions. The selection of a regulatory system will probably affect the future structure of the industry. If different mechanisms are introduced to account for size variation, it is important that these mechanisms do not provide the incentive for utilities to bias corporate size in order to fall into a particular regulatory system. In particular, we are concerned that a more flexible mechanism for smaller utilities might provide incentive to remain small. Due to the nature of the Ontario utility industry, an incentive to maintain an inefficient structure is clearly not in the interests of consumers. Instead, incentives should be built into the system to encourage conformity with industry levels.

Having said this, we recognize that there exists an important variation in size among Ontario's utilities. We understand that the concern was expressed that it may be prudent to provide different PBR terms for smaller sized utilities due to the cost inherent in shorter plans and more frequent PBR reviews. Thus, although, we are not in favour of a racially different term being approved for smaller utilities, we believe the review process and the initialization of the plan could accommodate differences to reduce the cost for smaller utilities. These are discussed below:

Variations in PBR Mechanisms by Utility Size

A streamlined regulatory review approach, which offers more flexibility, may be suitable for smaller utilities. For the annual public reviews of the PBR plans, the Board could assemble all the submissions from the smaller utilities into a single filing and consumer organizations and individual customers could review it. Smaller utilities could be reviewed on an exception or complaint-driven basis, as opposed to the company-specific approach in which larger utilities are subject to regular public scrutiny. For the larger utilities, individual review of each submission would probably be necessary. These annual reviews would not constitute a full hearing, but would allow all the parties to monitor the industry, to voice complaints, and to participate in ongoing dialogue.

Secondly, the OEB may wish to consider 'phasing-in' the PBR plans by utility size. Obviously, the individual plans for the larger MEU's should be initialized early. The yardstick plans, however, could be phased-in in order of the size "groupings" (e.g. large, medium, and small could be phased in sequentially). This would allow the time for the smaller utilities to be better prepared for the new regulatory regime (this preparation might include some amalgamations). It would also seem to relieve some of the practical challenges that we envision from starting all the utilities at the same time. We would support this 'phasing-in' approach provided that a "date certain" was provided to all participants stating the final date by which PBR material must be filed.

2.4 Z-Factor

There was a general consensus that Z-factors should be limited to an initial threshold imposed by definition. Specifically, Z-fators should truly be extraordinary costs that are clearly beyond management control. In addition, they should be unique to a utility, not something that applies to all utilities. Examples of resulting costs falling within this definition would include tax changes or accounting standard changes that uniquely affect the electricity industry. In addition to this threshold imposed by definition, the Board may also wish to considered imposing an impact threshold based on the rate of return, i.e., the effect of the accounting or tax change must be greater that x% of the return on equity in order to be passed through as a Z-factor.

The sub-committee also contemplated an additional category of Z-factors which we termed “Ex-adds”, extraordinary adders. The Board may also wish to contemplate this additional category in order to pass through costs which affect many utilities by greater than a pre-determined (we assumed large) percentage of the return on equity. The inclusion of storm damages in this category was discussed. There was a general consensus that extraordinary storms such as last year'' ice storm may, in fact, be included as an Ex-add but care must be taken to avoid incenting little or no investment in capital infrastructure.

Process

There was general agreement that Z-factors could, in theory, be both positive and negative. The annual data monitoring and reporting requirements should be thorough enough to allow for consumer scrutiny of Z-factors which are passed through to rate-payers and any proposed Ex-adds should be provided to the Board in sufficient detail to allow for consumer review. There should be a limited mechanism whereby consumer groups may apply to the Board to get a written determination of the validity of Z-factors and Ex-adds proposed by the MEU (this does not have to take the form of a full oral hearing).

The discussion on Z-factors is based on the initial suggestions presented below:

Initial Suggestions: Joe Bailey, Toronto Hydro

PBR mechanisms, specifically price caps, revenue caps and benchmarking, typically provide for the recovery of certain exogenous costs or ‘Z’ factors. Exogenous costs are positive or negative costs that are beyond the control of the utility management and are not reflected in the inflation factor. These factors are generally subject to some threshold amount (individual or cumulative) and require documentation supporting the level and nature of the associated cost. Exogenous costs may be included in prices at the time of annual compliance filing and may require affirmative demonstration that costs qualify under the ‘Z’ factor definition.
Two general methods have been used for establishing exogenous costs: 1) a general definition vs. 2) specifically identified items. The general definition would typically use criteria to define the exogenous costs as costs that are not included in the PBR, that are not a part of doing normal business, that are necessary, and that have a major impact on the utility. The specific definition would typically include: changes in tax laws or accounting standards uniquely affecting the industry natural disasters or force majeure events, and regulatory, legislative or governmental mandates uniquely affecting the industry. Other costs that could be included are: environmental compliance costs, DSM costs, and societal program costs. The costs for capital additions may also require special consideration.

The preference is to use a dual definition specifically identifying certain cost categories and generally including all others that satisfy some objective criteria. Thresholds should be developed that are triggered before the financial performance of the utility is significantly impacted. Initially the thresholds should have a low base. The exogenous cost thresholds could also be tied to rate of return bandwidths (higher rate of recovery/lower threshold being triggered by a lower ROE).

Initial Suggestions: Mary Ellen Richardson, Ecoanalysis Consulting Services

Exogenous factors may be defined as occurrences beyond the control of the regulated company that result in changes to the company's revenues and expenses and that are not reflected in the other elements of the PBR plan, and which do not provide for any future benefit to the company. In general, exogenous factors may be defined to be changes that are triggered by legislative, judicial or administrative actions that are beyond the control of the company, and have a significant impact on the company such that, barring an adjustment to the regulation plan, unreasonably high or low rates may result.

The primary danger with taking exogenous factors into account explicitly is that there will be double counting if the factor is also partially or wholly reflected in other elements of the PBR plan. The difficulty is that every cost factor that is directly or indirectly reflected in the PBR mechanism is not explicitly enumerated. Not only are many cost factors explicitly measured in deriving inflation measures (i.e., are included in the basket of goods used to derive the inflation measures), but cost drivers – such as input prices that affect both the cost of electric utility services and the cost of other goods and services – will also be implicitly reflected in the inflation measure. As a consequence, each cost factor that the company wishes to recognize as an exogenous factor will have to be examined with care to determine whether it is recognized either explicitly or implicitly by any other element of the price cap plan. It is not adequate to rely on a conceptual or general definition, as stated above. Instead, it is necessary to explicitly, precisely and unambiguously identify costs factors that will be treated as exogenous. General or conceptual definitions are open to interpretation and dispute. Furthermore, the <u>less</u> precise the definition, the <u>more</u> necessary it will be to permit a public process to assess any proposed exogenous cost factor. Conversely, with a very precise list, the more expeditious the public reviews process.

A further concern is that there will be a bias in the exogenous factors that will be introduced into the price caps because the companies have an incentive to only bring forward those exogenous factors that increase costs and can therefore be used to increase the cap. Representatives of consumers, who would be the beneficiaries of adjustments for exogenous factors that decrease costs, may have limited opportunity to identify and initiate adjustments that reflect exogenous factors that will reduce the companies' allowed costs.

For this reason, it seems appropriate to include exogenous factors only if they are explicitly identified and, ideally, are automatically incorporated into the annual "price cap determination" process. In this case, any changes will flow through to the cap automatically and with minimal regulatory cost.

This narrow definition leads to a very restrictive view of what should be included as 'z' factors in the PBR plan. The following implications, for example, are important to consider.

1. First, legislative, judicial or administrative actions that will be reflected in other elements of the price cap plan should not be treated as exogenous factors. For example, an increase in tax rates would be reflected in other elements in two ways. A general tax increase (e.g., an increase in the rate of tax on corporate income) will affect the rate of inflation for all goods and services, hence, may be reflected in the inflation measure that is used in the price cap plan. In addition, to the extent that the productivity offset is based on past experience, that experience may reflect a trend toward increasing tax rates; hence, the impact of future tax increases may already be implicit in the productivity offset.

2. Second, there should be some threshold below which the dollar impact of a change is deemed to be too small to result in unreasonably high or low rates. Thus, an appropriate threshold should be included in the plan specifications.

3. Third, legislative, judicial or administrative actions that will result in the company making certain business decisions and incurring costs based on the expectation of future resulting benefit would not be included as an exogenous factor. For example, the costs associated with a corporate restructuring to create a regulated or unregulated affiliate to handle the sale of default supply would not be deemed as a 'z' factor. The company would only undertake this restructuring investment if they expected that they would reap some future benefit from this investment that would compensate and justify the current expenditure. From the evidence of Dr. J.M. Bauer in the EBO 179-14 EBO 179-15 Consumers' Gas hearing, it appears that in other jurisdictions, "regulators treatment of transition costs has depended on the causes of the costs as well as the likely ratepayer

> impacts of a measure of reorganization. Transition costs are typically only flown through to ratepayers in case of an unanticipated external change. In other cases, they are either fully attributed to shareholders or shared between all stakeholders, especially if clear benefits of the measure causing the transition costs can be demonstrated."

Initial Suggestions: Elisabeth (Lisa) DeMarco , Donahue & Partners

Again, the necessity of the inclusion of Z-factors must be assessed in light of decisions regarding plan term. If a very short plan term is adopted, it is suggested that it may be possible to proceed without the inclusion of Z-factors. Conversely, if plan term is longer, the PBR plan should provide for their inclusion.

It is strongly suggested that the Board establish a defined threshold to ensure that Z-factors are "one time extraordinary costs that are entirely beyond management control". Only the most basic Z-factors such as changes in taxation, legislation, and accounting rules should be acceptable Z-factors. Again, the Board may wish to stipulate a quantified impact before Z-factors could be passed through to the rate-payer.

It is also strongly suggested that capital allowances should be addressed through something other than a Z-factor associated with a stipulated Board practice to ensure gold-plating does not occur.

2.5 Off-Ramps

The general consideration of off-ramps is inextricably linked to the determination of plan-term. If a very short plan-term is adopted by the Board, then it is suggested that off-ramps may be excluded from the plan. If, however, the Board adopts a longer plan term (i.e. greater than 3 years) then very limited off-ramps may be more appropriate.

The general applicability of off-ramps may be largely affected by the procedural mechanism available in the event that an off-ramp is triggered. It was suggested that if an off-ramp is triggered, then the triggering utility bears the onus of having an alternate plan proposal which must then be approved by the Board.

The appropriateness of off-ramps may also be linked to the Board's determinations regarding sharing mechanisms and service quality penalties. It was agreed that, in the absence of sharing mechanisms and service quality penalties, there should be an off-ramps to protect rate payers from the possibility of the utility earning windfall profits.
The Use of Off-ramps in the Event of Mergers, Acquisitions, Amalgamations and Divestitures

Although it may be possible to promulgate some initial rules for the fate of PBR plans in any of the above-mentioned events, there was no consensus as to what those rules should be. The sub-committee agreed that the Board's administrative burden could, however, be decreased if a M&A induced review of a PBR plan would only be triggered if there was a change in the PBR grouping of one, both, or all parties. Specifically, there was a definite concern that the administrative burden associated with a M&A induced review of a PBR plan (for the both Board and the MEUs considering M&A opportunities) would disincent mergers and acquisitions. There was general consensus that the burdens associated with reviewing PBR plans should not act to disincent mergers or acquisitions.

The members of the working group generally agreed on the following. The above summation is based on the initial suggestions presented below:

2.6 Exit Ramps

It was generally agreed that:

1. Exit ramps should be used cautiously in established PBR mechanisms;
2. The longer term the greater the need for exit ramps; and
3. Good items for exit ramp consideration are amalgamation-related activities, re-classification to a new yardstick grouping, new PBR mechanism, and 'lumpy' investments.

Further discussions are required on:

1. Whether or not exit ramps should include exogenous costs such as storm damage, extraordinary changes in the financial market, Y2K expenses, unusual capital expenditures, and regulatory expenses; and

2. The uses of PBR parameters to incent productivity gains and avoid or minimize excessive earnings to preclude the use of exit ramps.

Fairly liberal exit ramps are recommended for the first PBR. Exit ramps should include exogenous costs (e.g., storm damage, unique tax, accounting, regulatory expenses) outside of some pre-set $ limit. The $ limit should be tied to each utility's own financials so as to identify a $ threshold that preserves the financial integrity of the utility and only puts the utility at risk for a base, consistent level of $.

Other carve/outs/exit ramps could include significant changes in financial markets (e.g., a 150+ basis point change in the bond market) in which case the utility could either suspend PBR or automatically adjust prices – recommend that the utility have the discretion to do whichever makes sense, after notifying the OEB.

In addition to exogenous costs and financial market fluctuations, we could include a measure for unusual capital expenditures (e.g., O&M, replacement) to account for utility-specific concerns. Also, restructuring-related expenditures and Y2K-related expenditures could be carved out or treated separately above some threshold.

Carve-outs are included in the discussion of exit ramps because they are related in that exit ramps need to consider what cost categories or levels will be treated outside of the mechanism or will provide for an "automatic" (post-OBE notification) adjustment.

Initial Suggestions: Mary Ellen Richardson, Econalysis Consulting Services

Experience with PBR in other jurisdictions and in other sectors (e.g. telecommunications) suggests that it is prudent to be very cautious in the use of exit ramps, except in perhaps very unusual circumstances, which I have discussed below.

Caution is advised because the use of exit ramps often leads to some 'gaming of the system' so as to either avoid or to trigger exit ramps. Instead, we would rather see other PBR parameters used to incent productivity gains, and avoid or minimize excessive earnings. For example, utilities could be given the option to choose amongst several aggressively set productivity indices. Higher productivity indices would be coupled with lower ratepayer sharing, and vice-versa.

In short, we would support a relatively short PBR term, with no exit ramps, provided that other PBR parameters, such as those mentioned above, are included.

There is no need for Variations in PBR Mechanisms because of Utility Size and Potential Inefficiencies.

We recognize that some there has been concern expressed as to the need for special consideration for smaller utilities, specifically, in the case of amalgamations. However, upon reflection, we would argue that an exit ramp is not the appropriate solution in this instance. Presumably, in the case of an amalgamation, data will be submitted to, and approval sought from, the Ontario Energy Board. In any case, on an annual basis, information will be filed with the OEB. In either case, this information may indicate that a re-classification into another yardstick grouping is warranted. (As a simple example, a larger number of customers served may mean a move to a different yardstick group, which includes larger utilities, is warranted.) Thus, upon application, and where appropriate, a utility could be moved from one yardstick group to another, while still remaining within the PBR yardstick mechanism. In short, the utility is not 'exiting' from the PBR mechanism altogether. We would continue to suggest that in these cases, the onus be placed on the parties involved to provide the necessary data which demonstrates the need for a re-classification as part of the licensing approval mechanism.

Some ‘closing-off’ and ‘re-opening’ of the utility’s books for PBR performance tracking purposes would be part of this process.

A second possible need for off-ramps might be to provide for the “lumpiness” of utility capital investment for smaller utilities. A bigger company can smooth out a large supply increment through corporate financing, but smaller utilities may not have the same resources. As such, under PBR, special consideration may be required to increase flexibility for smaller utilities in very unique circumstances, as approved by the OEB. However, we would argue that, again, this does not warrant an exit from the PBR mechanism, but rather an inclusion of a ‘z’ factor.

Initial Suggestions: Lisa DeMarco (Donahue & Partners)

The possible inclusion of off-ramps is inextricably linked to the choice of plan term. As plan term increases so too does the likelihood of an extraordinary event or result which may warrant a mid-period review or termination of the plan. As a result, the Board may wish to seriously consider: (I) avoiding the inclusion of off-ramps if a very short plan term is adopted (less than 2 years); and (ii) including off-ramps if a plan term of more than 3 years is adopted.

The Board may also wish to consider if there should be an initial threshold criteria to ensure that a proposed off-ramp is truly an extraordinary or extreme event that warrants mid-period review or termination of the plan. It may wish to quantify this initial threshold by indicating that it will only consider proposed off-ramps which affect return on equity by more than “x” basis points. This suggestion may lead to gaming to ensure performance within a predetermined band-width which in turn may exacerbate the information asymmetry problem by further concealing the full amount of productivity which may be achievable[2]. As a result, the Board must balance the down-side risks to rate-payers with its administrative efficiency concerns and only proceed with the full knowledge that an ROE based off-ramp threshold may compromise the MEU’s full market impetus to achieve maximum productivity.

[2] The same phenomena is also likely to be associated with earnings sharing mechanisms – particularly sharing mechanisms that have an associated dead-band.

The procedural fairness of any proposed system of off-ramps would be substantially bolstered by ensuring that both ratepayers and the MEU have at least some ability to trigger the proposed off-ramp.

Given the expected number of mergers, acquisitions, and divestitures, all plans must have some mechanism to address the continued operation/conclusion of individual PBR plans in such events. A stipulated off-ramp for the acquired utility may be one of many possible alternatives to be considered.

2.7 Earnings-Sharing[3]

There was considerable debate on the appropriateness of earnings-sharing mechanisms, and if implemented, what an earnings-sharing mechanism should look like. Although the group considered earnings sharing mechanisms in the context of utilities with the objective of earning commercial rates of return, it was acknowledged that some municipalities may choose to operate their utilities as not for profit enterprises to enhance the competitiveness of their local economies. These utilities will target their operations to earn little or no profits, thus making earnings-sharing irrelevant.

There was consensus that utilities that were not earning commercial rates of return should not be required to share increased earnings from productivity gains with customers until they had reached commercial rates of return. Further discussion on earnings sharing is restricted to utilities with the objective of commercial operations.

The group found it difficult to assess the appropriateness of earnings sharing in isolation without knowing more about how the PBR plans will impact utilities. Allowed rates of return, commercial capital structures and the new taxes that are to be imposed were major concerns.

Given the Provincial pronouncements on the wholesale cost of power rate freeze, and on the impact of electric industry restructuring, the $0.072/kWh provincial average rate may not have

[3] This section was prepared by work group 1, and is the only section in Chapter 2 not prepared by work group 3.

enough margin in it for utilities to achieve commercial rates of return. Further, the political climate may make it difficult to increase rates significantly.

For some utilities, contributed capital represents a significant portion of the total asset base. For these utilities, the inclusion of contributed capital in the asset base on which a return on equity is earned is an important issue. While utilities had varying opinions about whether contributed capital should be included in the base for calculating equity earnings, the inclusion or exclusion of contributed capital has significant impacts on the valuation of the businesses of those utilities with significant amounts of contributed capital. (See Report of the Distribution Rates Task Force for further discussion on market-based rate of return and taxes, and treatment of contributed capital).

However, given that a review of PBR will occur after an initial PBR period there will be ample opportunity to ensure that major mistakes are corrected before plans can go too far off course. Setting aside all the above-mentioned difficulties the group made a number of observations.

Basic PBR schemes are inherently asymmetrical and result in some risk ordinarily borne by customers being shifted to utility shareholders. The shift in risk is not necessarily bad as it comes with increased incentives for utilities to increase efficiency which ultimately gets passed on to customers, but which allows utilities to earn superior returns in the short term. The nature of the asymmetry of PBR schemes is two-fold. First, a productivity hurdle or X-factor is set, and rates during the PBR period are immediately reduced for the forecast level of productivity. Customers enjoy these lower rates whether or not the utility is able to accomplish the productivity improvements and the forecast productivity improvement effects are embedded in rates permanently. Utility shareholders have no opportunity to achieve superior earnings from productivity initiatives until the utility has delivered productivity improvements equivalent to the X-factor. Second, any productivity improvements over and above the X-factor result in superior earnings for utility shareholders within a PBR period only. This benefit will be for one to four years depending on when in the PBR period the improvement is achieved, and on the length of the PBR period. After a PBR period, rates are rebased over the next PBR period and afterwards customers enjoy the benefits of the productivity improvement forever.

These asymmetries mimic competitive markets in that competitive companies will make productivity improvements and enjoy superior earnings for a few years until their competitors catch up making the similar productivity improvements and then competitive pressures drive prices down to bring margins to sustainable levels. So while these asymmetries exist, they are not inherently undesirable. However, regulators must be careful not to overly increase these asymmetries so that utilities face significantly greater constraints than in the competitive model.

The group also noted that earnings-sharing mechanisms inherently act to dampen the incentive to achieve efficiencies. In a taxable environment, utilities pay approximately half their earnings in income tax. Earnings-sharing mechanisms take the remaining amount and share it between shareholders and customers. For example, in the case of a 50/50 sharing mechanism, once in the share band, shareholders keep roughly $0.25 for every additional dollar earned. Further, that dollar earned represents a fraction of the dollars spent to achieve those earnings. What regulators need to be aware of is that there is a point at which the effort to achieve the next increment of productivity outweighs the benefit to shareholders. Earnings-sharing mechanisms can slow down the implementation of efficiency measures rather than promote their implementation if not carefully designed.

Despite the potential problems with earnings-sharing, the group recognized that there is a point at which earnings become unacceptable to customers and regulators. When those events occur it is important to have a mechanism to deal with them so that all stakeholders are treated fairly. In the UK, utility earnings exceeded acceptable limits and the result was a retroactive windfall profits tax. Such a situation is not in the interests of customers or utility shareholders. Customers considered that they paid too much and the shareholders that paid the windfall profits tax were most likely not the same shareholders that enjoyed the higher earnings that caused the concern. Therefore an earnings-sharing mechanism that engages at the point earnings become unacceptable will ensure that everyone is treated fairly.

The group considered that to address the tendency of earnings-sharing mechanisms to dampen the incentive to achieve efficiencies, a fairly wide deadband around the allowed rate of return on equity should be set. Outside this dead band earnings-sharing would take place. The group discussed what would be the point to which earnings would be acceptable, from which point on an earnings-sharing mechanism would take effect. The general consensus was that earnings above 15% in today's economic environment would likely be considered unacceptable. This politically acceptable rate of return 15% is not the allowed rate of return for utilities. It is the highest rate of return that a utility achieving the highest efficiency gains could earn.

The 15% was considered reasonable for the high end of the earnings range based on the returns achieved by a number of regulated companies. It was noted that Canadian Utilities earned approximately 15% in 1996 and 1997[4]. The Toronto Dominion Bank, which is also subject to regulation, earned between 15.4% in 1996, 16.6% in 1997 and 15% in 1998[5]. CIBC earned 16.73% in 1996 and 17.72% in 1997, while return on equity dipped to 10.5% in 1998.[6] Although, these banks exhibited returns on equity greater than the 15% chosen as the maximum acceptable for the electrical industry in today's economic climate, the banks are subject to more competition and a lesser degree of regulation.

The 15% recommendation for the top end of the dead band is also reasonable when compared with the historic returns of low risk Canadian industrial companies. A review of a sample of returns on equity for 21 low risk Canadian industrials between 1989 and 1997 shows that, although the average return on equity was 11.8%, the average earnings over the period for specific companies ranged from 6.4% to 20.9%.[7] Under this proposal on earnings sharing, utilities would earn on average the allowed returns on equity (ranging 9% to 10%), and those few utilities with superior productivity improvement performance could achieve superior earnings of up to 15% prior to being constrained by the earnings sharing mechanism. Even under this proposal, the superior earnings will be earned only during the PBR period, as the productivity improvements are flowed back to customers over subsequent PBR periods. In contrast, those low risk Canadian industrials in the sample achieving superior earnings averaged those earnings throughout the period 1989 to 1997, and actually earned returns higher than 20.9% in certain years.

[4] The Appropriate Return on Equity for the Transco and Disco Business Operations of the Ontario Hydro Services Company, report of Dr. William T. Cannon and Reed Consulting Group, prepared for OEB Staff, dated January 22, 1999, Appendix B, Schedule 2.

[5] TD Bank 1998 Annual Report, Key Performance Measures and Goals, October 31, 1998.

[6] Bloomberg Financial Analysis, 24 March, 1999

[7] Capital Structure and Fair Rate of Return on Common Equity for Ontario Hydro Services Company, statement of Kathleen C. McShane, filed with the OEB on January 14, 1999, Schedule 25.

The culture of the electrical utility industry is one of cost recovery, not efficiency and profit making. Therefore it was considered that a 15% earnings potential should be available to provide the strong commercial incentives that will drive efficiencies in the businesses at the earliest stages. Customers will receive the benefits of any efficiency gains in subsequent PBR periods and the group considered that it was important to change utility thinking dramatically and early if the benefits of PBR are to be quickly realized.

It was considered that earnings greater than 15% should be shared 75% with customers and 25% with shareholders. The high customer weighting in the sharing mechanism was considered appropriate because of the wide deadband implied by the 15% start point for the earnings sharing. The consensus was that the narrower the deadband, the more the weighting should be directed to shareholders to counteract the disincentive to achieve efficiencies introduced by earlier imposition of the sharing mechanism.

The group discussed whether the deadband and sharing mechanism should be symmetric. The consensus was that they should be symmetric in the interests of simplicity, regulatory certainty and so as not increase the asymmetries inherent in PBR schemes already discussed. The OEB Act has as one of its objects to facilitate the maintenance of a financially viable electricity industry so, barring imprudence of utility management, the utility should have some symmetric protection below the allowed rate of return. If the OEB is concerned that a return that falls too low might be a sign that management might not be effective, it could trigger a plan review through which this could be assessed.

2.8 Earnings-Sharing under a Price or Revenue Cap PBR Mechanism

It is our recommendation that the PBR scheme adopted in Ontario explicitly recognize that there is a trade-off between the productivity offset that is selected and the adoption of an earnings-sharing mechanism. The selection of a combined X-factor and earnings-sharing mechanism from a menu of possible options would allow the company to choose the combination that best meets their PBR expectations at the outset of the PBR period (e.g., there could be several X-factors, some of which would involve earnings-sharing, while another, set at a more challenging level, would not).

This approach makes a great deal of sense. The disadvantage to ratepayers that results from the inherent bias in setting the productivity offset can be mitigated by building in a mechanism for sharing the over-earnings. Specifically, part of the earnings can be retained by the company so that it still has an incentive to improve productivity as much as possible. At the same time, ratepayers gain some of the benefit of these gains.

The appropriate degree of sharing at any level of productivity offset is a matter of judgement. Considerations in setting the split between shareholders and ratepayers, should include the following:

- The higher the productivity offset the larger should be the shareholders' share of total gains. That is, if a company were to choose an aggressively high productivity factor, they would be able to keep a high share– up to 100% - of the earnings in excess of this level. Ratepayers are already benefiting from the high - factor implicit in the plan.

- Small gains above forecast could be treated differently than large gains (a large gain is more likely to reflect erroneous assumptions rather than management effort). For example, if a company were to choose a low "x" factor, it is likely that they will achieve this level. A large improvement relative to this level may be the result of a technological change, or a relatively simple operational change to remove an obvious inefficiency. Under this scenario, ratepayers should receive a large percentage of any gains above the forecast level.

- There must be sufficient incentive, and the review period must be long enough, to warrant investing in productivity measures that may take several years to pay back the investment. Hence, the longer the review period, the smaller the necessary shareholder share of excess productivity gains.

In setting the sharing mechanism, it would not be appropriate to adopt the premise that a larger incentive (i.e., larger share to the shareholder) is always better than a smaller one. There is no evidence that the incremental benefit of providing the maximum incentive, relative to sharing 50:50 for example, justifies the higher rates that ratepayers will have to pay. The unresolved question is whether earnings-sharing will have a significant impact on productivity performance, and if it does, whether the impact outweighs the cost to ratepayers of a more generous incentive. In theory, the appropriate sharing mechanism would be the one that results in the lowest present value of rates for customers (i.e., the optimal balance between higher rates in the short run to pay the incentive and lower rates in the long run due to higher productivity gains).

Furthermore, it is possible that too strong an incentive (e.g., the opportunity to retain 100% of super-normal earnings) could lead to counter-productive efforts to increase earnings. For example, if the rewards associated with higher earnings are too large, management may be enticed to take excess risk and reduce quality or service even if there is a risk of incurring penalties.

It should also be noted that during the initial period, where experience with PBR is limited and the risk of setting a productivity offset that deviates significantly from the ideal rate is the greatest, the need for a sharing mechanism is most important.

Earning-Sharing under a Yardstick Approach

With a yardstick PBR scheme, there will obviously be inconsistencies in the operational efficiency of the companies that are grouped together. Some will therefore find it relatively easy to achieve the yardstick measures identified, while others will find it relatively more difficult. In either case, earnings-sharing can be regarded as an effective way to mitigate the risk to both ratepayers and shareholders inherent in this system as ratepayers share in both the over-earnings and under-earnings of the company. In this approach, we recommend symmetrical earning-sharing (both upside/downside earnings are shared 50:50).

A position paper on issues discussed in Sections 2.3 to 2.6 submitted by Econalysis Consulting Services to the Implementation Task Force in presented in Appendix A.

2.9 Relationship between Earnings-Sharing and Productivity

This note discusses the relationship between the earnings sharing mechanisms and productivity factor that is adopted for the PBR mechanism. The latter is brought into this discussion because all these factors are inextricably linked such that it is difficult to consider one in isolation of the other. Indeed, as is discussed below, the level at which both the productivity factor and the plan term is established, will affect the choice of an appropriate sharing mechanism. The converse is also true.

2.10 Demand-side Management (DSM)

2.10.1 DSM for the Electricity Distributors in Ontario

Work Group Recommendation

It was understood by the participants of the task force sub-committee that one of the policy tenets of the new energy legislation was to foster energy efficiency, and that this was to be facilitated through the auspices of the OEB. It is not difficult to support the concept of energy efficiency and conservation, and initiatives that reduce consumers' overall energy bill. The real issue is to ensure that these initiatives are delivered in a cost-effective way. Participants of the task force agreed that, while DSM, is generally accepted as a laudable policy direction, it is difficult to determine how the benefits of DSM can, practically speaking, best be achieved. The task force members discussed the following key points.

Timing of DSM Introduction

Overall, PBR represents a significant change in regulation for all electricity distributors utilities. Many details of PBR have yet to be finalized. The distributors are dealing with numerous regulatory and business initiatives in the next eighteen to twenty-four months. In this environment and context, the development and factoring-in of DSM initiatives into the regulatory process, while important, was considered to be a level of sophistication that could wait until Phase II of the PBR regime. Since Phase I is relatively short, this delay could take place without substantial societal cost.

Important DSM Debates and considerations

The task force members were aware of the ongoing philosophical and practical questions associated with the delivery of DSM. Specifically:

- The debate concerning the appropriateness of using regulated entities as delivery vehicles of societal policy, such as DSM. It was recognized that this was an important question to consider. While the task force participants could likely have debated this philosophical question at length, the members felt that this debate would not be productive without meaningful policy direction by the OEB or MEST.

- The debate around the likelihood of DSM initiatives to be undertaken without regulatory intervention. The task force members recognized that it was not well understood whether market participants operating in a free market environment would be incented to offer for sell or purchase energy and energy products in a way to achieve reductions in energy consumption deemed 'sufficient' to meet societal goals.

In light of the significant challenge that PBR represents and the myriad of details to be addressed before the Rate Handbook is produced, the members felt that the debate should be left until after Phase I of PBR is underway. This debate could then take place through a facilitated task force process.

Bi-phasal Approach:

In Phase I of PBR, it was agreed that a voluntary approach to DSM would be acceptable. In addition, since 1993, in the context of the rate hearings for the gas utilities, several DSM cost recovery mechanisms have been recognized and gained some acceptance with key industry stakeholders (see Section 2.7.2). These mechanisms were believed therefore to be acceptable for approval in the context of the electric utility proposals. The task force members felt that most key stakeholders, OEB staff, and members understood these methods. This voluntary approach would offer several benefits, including:

- The opportunity for entities that were ‘ready and able’ to put forward DSM proposals for consideration. Those entities that could not undertake DSM initiatives would not be required to. For those entities this would be less burdensome than having DSM mandated;

- DSM initiatives may not be economic for all entities to undertake. A voluntary approach would allow each distributor to evaluate the costs and benefits of DSM benefits, with each distributor required to put forward a business case to support any DSM proposals;

- A small ‘market experiment’ to see what level of DSM would be voluntarily delivered by the market participants, absent a ‘regulatory push’.

- It is unclear what DSM initiatives are appropriate in the context of an ‘unbundled’ utility. This is something that will be determined for both gas and electric entities. In the interim, it is wise not to mandate DSM programs which may have to later be dismantled.

Phase I initiatives, introduced in advance of the stakeholder process would be subject to OEB approval of individual DSM initiatives. DSM programs could be initiated to support ‘market transformation’. In this context, the utility could deliver educational material, and perhaps help to establish codes/standards as a means to move the market in a specific direction. While recognizing that it is even more difficult to truly justify that this kind of spending drives/contributes to the realization of any energy savings, this investment might be justified as a ‘public good investment’ in the same way as a public education campaign around electricity safety.

- During Phase I, a *facilitated stakeholder process* in which the gas utilities, electricity distributors and interested industry stakeholders would be invited to participate, on a funded basis. The task force members understood that there was an opportunity to re-think and introduce new types of DSM programs, appropriate to the electric business and appropriate to the new business environment. The group felt that groups of DSM professionals, working in Phase I, would likely be able to identify these programs. The process could include both an education process as well as a discussion forum, and would have the mandate to produce DSM proposals for implementation by both energy utilities, subject to OEB approval. This process was deemed important, since:

- the gas utilities have offered DSM products, with mixed success, since approximately 1993, and there is a significant learning opportunity from the years of experience gained by them;

- It could ensure consistency of approach and recovery treatment between energy utilities';

- It appears that much of the energy savings in the gas industry have been realized by customers moving to higher efficiency appliances. Clearly, within the PBR framework, and in consideration of both the unbundling of the electricity distributors and the terms of the Standard Supply Service Code a different approach to DSM programs is warranted. Moving to more efficient appliances is a key DSM initiative, and in the future will need different delivery vehicles, as utilities will not be in the appliance sales or rental businesses;

- DSM professionals from both energy utilities, working together, may be able to develop sensible DSM offerings which are practical to implement in this new regulatory framework;

- In the gas industry, the tracking of DSM costs, benefits and company performance has been difficult, and monitoring and evaluation methods (and programs) still need to be refined; and

- DSM programs require a precise definition of acceptable DSM initiatives. Cost efficiencies would be achieved since the approach for energy utilities (acceptable programs, monitoring systems and definitions) would be considered in parallel, and involve key stakeholder participants.

Other Principles and Processes

- DSM initiatives should be evaluated under a separate, parallel structure within the PBR framework.
- Public review mechanisms are necessary
- DSM spending, performance need to be presented annually in an auditable form
- New DSM initiatives need to be separately identified and approved prior to implementation

Procedural/Rules

- DSM should be included as part of the PBR process and should include regular reporting, audit, and stakeholder review.
- All DSM initiatives need to be separately identified at the beginning of the PBR period.
- The DSM costs should be accounted for within the regulated distribution company, and be separately justified, tracked, and reported annually. As with all other reported statistics, these costs and any associated results should be auditable.
- Any additional DSM initiatives should be separately reviewed, justified, and approved. This review could take place as part of the annual submission of results. The review would be subject to intervention, by written submission.

2.10.2 DSM in the Ontario Natural Gas Sector

Prepared by Hima Desai, Regulatory Officer, Ontario Energy Board for the Implementation Task Force

History

After a long generic hearing, in the summer of 1993, the OEB released its report on the demand-side management aspects of gas IRP. The Report included a set of DSM guidelines for utilities to follow in their first attempt at developing DSM Plans. The three main natural utilities (which were Centra, Union and Consumers at that time) were required to file Demand-Side Management (or DSM) plans for their 1995 test year. In their plans the utilities were asked to include stakeholders input and they were also asked to ensure that plans were developed within the context of just and reasonable rates.

In general the utilities were allowed to pursue the development of their DSM plans as they saw fit because ultimately they would be held accountable for them in rate hearings. And currently each utility has a distinct set of programs which reflects the unique market characteristics of its franchised area.
Under the old and existing regulatory framework, the utility was rewarded for expanding rate base as it earned a return on this investment and there was not much incentive to promote

energy efficiency. As a result the regulator played a key role in reviewing and approving the plans. The Board's primary concerns were to ensure that there had been meaningful consultation and that DSM programs & portfolios were effective (in terms of promoting DSM objectives) and cost effective.

It has taken considerable time to implement these programs and the appropriate monitoring and evaluation methods, and even today these monitoring and evaluation methods (and programs) are being refined. Appropriate monitoring and evaluation methods are essential because without them it would be impossible to track performance. Adequate monitoring and evaluation will be even more important in a competitive environment where companies strive to minimize costs and maximize customer value.

It is also important to remember the context in which DSM activities were initiated. They commenced when utilities were monopolies, and when utilities had more influence over the customer and greater contact with the customers and, also when regulators played a key role in the review of DSM programs. Of course under competition this is expected to change somewhat.

Recently, the Consumers Gas EBRO 497 Decision, the Board indicated that the scope of DSM was likely to change.

The Board said in paragraph 3.5.8 that:

> "Both the unbundling initiatives of the Company and the proposed move to incentive based regulation will likely have an impact on the future scope of DSM. (the Board will likely be considering these matters in the near future, and is therefore reluctant in this Decision to direct any changes that will have a material effect on the Company's present DSM Plan.)"

With respect to the most recent Union Gas Decision, the situation is a little different, as there was a comprehensive settlement agreement for most of the issues on the issues list. Also all parties agreed the Alternate Dispute Resolution (ADR) agreement would be an "all or nothing agreement". And in fact the Board had also given signals that it would accept a reasonable "all inclusive" agreement. In that situation if Board had decided not to accept the ADR in its entirety, or as certain parties would say had “cherry picked” elements of agreement, that would have rendered the agreement null and void. As a result of the comprehensive ADR, there were very few issues remaining which required Board adjudication.

Gas Utilities

With respect to the two remaining gas utilities, their own DSM experience has been varied. Union started off slowly but in each year from 1995 to 1998 it exceeded its target of gas volume savings and customer participation in programs. While Consumers was the first utility to file a DSM plan, in each year from 1995to 1998 it has not met its target of gas volume savings or customer participation. One reason may have been difference in approach by the two utilities to implement DSM. Consumers started with an ambitious plan and ambitious targets, while Union’s plan was constantly in transition.

In terms of types of programs that these utilities pursue: Union has 3 residential, 3 commercial, 1 industrial and 1 agricultural DSM programs. While Consumers has 5 residential, 4 commercial & apartment, and 1 industrial program.

Competition

In a competitive market, utilities will have to concentrate more closely on the level, quality and mix of customer services they provide. DSM programs which were often funded by ratepayers will have to move to being funded to greater degree by participants who reap the benefits.

Today, at least one of the utilities is moving in that direction. In the current market many jurisdictions are starting to question the viability of DSM and suggesting that societal goals are properly performed by governments rather than utilities and their regulators. For DSM to survive in the current environment, programs will have to be cost effective, customer-focused and value driven.

Issues for the Task Force to Consider

1. Are DSM programs are appropriate for electricity distributors? And if so, what should be the scope of these programs? And are they revenue neutral?

2. Will the market place and DSM programs provide equal access and equitable outcomes?

3. If DSM is to be pursued, how should they be integrated into a competitive market? Should guidelines be developed? Will consultations be necessary? Would DSM be something that is included on the license or in a "code", or perhaps not?

Recent performance on DSM Programs

Union Gas

	1995	1996	1997	1998 estimate
Gas saved	6,100 10^3m^3 or 167% of budget	8,600 10^3m^3 or 135% of budget	16,360 10^3m^3 or 145% of target	31,00 10^3m^3 or 125 % of target (or 24,962 10^3m^3 E vs 27,531 10^3m^3 Actual)
Participation	95% of target or 20,141	133% of target or 99,317	162% of target or 129,999	108% of target or 110,014 (Actual - 146,352)
Expenses	127% of budget or $483,000	202% of approved or $2,624,000	95% of target or $3,532,000	100% of budget or $3,566,00/ $3.064 m Act.

Residential

1. New Home Construction
2. Home Equipment Replacement
3. Home Retrofit

Commercial

1. New Building Construction
2. Building Equipment Replacement
3. Building Retrofit

Industrial & Agriculture

1. Industrial Process Improvement

2. Agriculture

Consumers

	1995	1996	1997	1998 estimate
Gas saved	3.9 10^3m^3 Act. vs 27.4 10^3m^3 F (14% of budget)	29 10^3m^3 A vs 18.8 10^3m^3 F (65% of budget)	47 10^3m^3 A vs 18.6 10^3m^3 F (39% of budget)	44.6 10^3m^3 A vs 36 10^3m^3 F (81% of budget)
Expenses	$1m A vs $2.6 F (39% of target)	$1.6m A vs $3.7m F (42% of target)	$1.6m A vs $4.7m F (35% of target)	$2.7m A vs $3.5m F (79% of target)
O&M/ vol saved	0.265$mm/$10^6m^3$=O& M exp /unit of gas saved	0.085	0.088	0.075

Residential: Most of these rely on ancillary programs for delivery, therefore will have to be modified.

1. Residential Efficient Water Heating - (labeling program to meet DSM standard & negotiate w/ co's)
2. Residential Water Usage Conservation Program (contract w/ co.'s renting water heaters to install water conservation measures)
3. Residential Space Heating Efficiency
4. Residential Home Retrofit Program
5. Green Communities

Apartment and Commercial

1. Energy Efficient Design
2. Apartment Space & Water Heater Efficiency
3. Apartment & Commercial Water Management Program
4. Apartment & Commercial Large Projects

2.10.3 Initial Suggestions on DSM for Electricity Distributors

The discussions on DSM were based on the following initial suggestions.
Price cap mechanisms are similar to traditional cost-of-service rate making in that they provide a financial incentive to increase sales, thus discouraging energy efficiency program development and implementation.

Revenue cap mechanisms on the other hand effectively remove the financial incentive to increase sales and the corresponding disincentives surrounding energy efficiency program development and implementation.

Under a price cap mechanism, DSM costs may be treated as a cost pass-through and/or provided a specific performance incentive. Targeted incentives may be used as a stand-alone PBR mechanism, or as a component of a comprehensive PBR (i.e., with a cap or yardstick).

Energy efficiency incentives are more commonly included in more comprehensive PBR mechanisms where the utility has regulator-approved DSM or other energy efficiency programs in place. Energy efficiency incentives are generally similar in scope to universal service incentives, with some tailored elements such as:

- Pass through of program costs.
- Success of programs relative to target (e.g., participation rates, load shifting, energy savings).
- Including sales and/or revenue adjustments in price cap or benchmarking mechanisms to remove potential disincentives to reducing sales.
- Integrated resource planning requirements to ensure that the utility is considering DSM, distributed generation and other non-T&D asset investments to meet system requirements.

The first two incentives are the most commonly used. Similar to universal service incentives, for a utility with energy efficiency programs or requirements, energy efficiency incentives are a positive enhancement to a comprehensive PBR mechanism. As a minimum, cost recovery and program success incentives should be employed. In addition, energy efficiency incentives can offset some of the concerns about a price cap mechanism's disincentive to energy efficiency.

Recommendation

Energy efficiency incentives (especially program cost recovery and program success) are recommended for utilities' with energy efficiency programs or requirements. Energy efficiency incentives are especially important for utilities using price cap PBR mechanisms.

Position on DSM for electricity distributors provided by Jack Gibbons on behalf of the Canadian Institute for Environmental Law and Policy for discussion by the work group is presented in Appendix B.

3. CUSTOMER SERVICE PERFORMANCE STANDARDS

3.1 Identification of Customer Service Performance Measures

The intent of setting the customer service standards is to provide for a minimum standard of service. They are intended to act as safe guards to protect against the utility striving for increased profits at the expense of the minimum level of service consumers should be entitled to. This minimum level of service is considered to be quality service. It is acknowledged that actual average service levels may exceed these minimum standards. However, it would not be appropriate to set the standards at the average performance level because actual performance is clustered around the average. Setting the minimum standard at the average would set in motion an ever-increasing minimum standard to be met as utilities that performed below the average strive to achieve the average. Since the standards to be met have a direct impact on the revenue requirements of the utilities, such an increasing standard would put upward pressure on rates. Accelerating quality of service is not the purpose of the standards. Instead the standards are meant to maintain service quality while the PBR mechanism encourages utilities to increase efficiency and produce a declining real cost of service.

The standards also include a requirement that the standard be met a portion of the time instead of 100% of the time. This allows for unforeseen events that are beyond the control of the utility or for instances where the cost of meeting the higher standard is not balanced by the benefit provided by meeting that higher standard. For example, the capacity of a call centre may be established to handle peak calling activity under normal circumstances. Installing capacity to meet all calling activity during rare events such as a severe ice storm would require customers to pay for that capacity every year even though it might not be needed in most years.

In assessing what customer service standards might be appropriate, the group reviewed PBR experiences of other utilities and jurisdictions. Potential standards were selected for evaluation and others were rejected as inappropriate. For example, employee and public safety measures were considered and explicitly excluded because safety is regulated and monitored by other regulatory bodies. An informal confidential telephone survey was conducted of 12 utilities of varying size, to assess current service levels against which the appropriateness of standards could be judged. From this preliminary work the group began to compile a list of potential performance measures that could be used by the OEB to measure the utilities' performance over time and to compare with other utilities. A survey was mailed to all utilities to test the appropriateness of eight potential measures. The survey solicited input on the appropriateness of the suggested measures, the utilities' ability to measure and report their performance for each measure, any start up costs of implementation and ongoing costs of measurement and reporting. A copy of the survey form and a summary of some of its results are provided in Appendices C and D, respectively. It should be noted that the most useful feedback obtained through the survey were the respondents' comments.

A common comment by the respondents to the survey was that the standards should be more stringent. The work group interpreted these comments as a misunderstanding of the purpose of the measures as minimum standards. There was not sufficient time to pretest the survey, and a clear explanation of this intent was not included in the survey questionnaire. Setting stringent standards for the first PBR period is ill advised because utilities do not have a good handle on what actual average performance is. Once the OEB has obtained performance results for the first PBR period, it will be in a better position to assess whether tightening the standards is necessary, and what impact on rates tighter standards might have. The group's recommendations explicitly discard these recommendations consistent with the intent of the group to develop standards which provide quality service together with flexibility to tailor service levels to the demands of customers.

Unfortunately, a very limited amount of time was available to the work group for review of the complete survey data. As a result, some of the final changes to the performance measures do not reflect the input of all work group members. Nonetheless, the performance measures were refined on the basis of some of the more prevalent concerns raised by the survey respondents. On the basis of the survey response the number of performance measures were reduced in number from eight to seven. These seven performance measures are presented in Table 3.1.1

Performance measures considered by the work group but discarded, although viewed as reasonable measures for utilities to track internally, were judged as unnecessary because a broad assessment of a utility's customer service level could be made from the reduced set. A material failure by a utility to meet the performance measures of the reduced set is likely indicative of a problem with quality of service that the OEB may then want to examine further. Discarded measures tended to be more complex and concerned issues with larger, more sophisticated customers, who are aware of the channels to use to address unsatisfactory service from the utility. The discarded measures are described in Table 3.1.2 along with the reason for discarding the measures.

Even with seven customer service measures, the OEB will be receiving at least ten performance measures once reliability measures are included. The smaller set of measures is desirable to keep reporting requirements to the minimum level necessary while providing the OEB with the necessary information on performance standards. Also, PBR plans would then not become overly complex or so rigid that little flexibility was left to the utility to tailor its service level to the demands of its customers.

Each of the seven recommended measures (Table 3.1.1) should be calculated on an annual basis for each utility. Therefore, variation throughout the year does not necessarily imply that the performance target will be missed.

3.2 Other Issues around Customer Service Performance Measures

3.2.1 Standard Setting

It may be difficult to set standards in the initial PBR term because many utilities might not track the proposed performance measures or definitions of the measures may vary. The initial PBR period (first generation PBR) could be used to get consistent tracking and reporting. Minimum standards might then be set for the second PBR period. It may cost utilities a significant amount to set up proper measurement and recording procedures for these performance measures. These transitional costs may make it necessary for some utilities to implement rate increases during the initial PBR period.

Table 3.1.1 Recommended Customer Service Performance Measures

Service	Minimum Performance Level and Method of Measurement *	Comments	Estimated Compliance Costs **
1. Emergency response	Emergency trouble calls (i.e. fire, ambulance, police, etc.) will be responded to within 120 minutes in rural areas and 60 minutes in urban areas, 80% of the time. The arrival of a qualified service person on site will constitute response.	Few utilities currently measure trouble response times. It is suggested that such measurements be mandated in the first year of regulation, and that a performance standard then be set for subsequent years. It is noted that definitions of urban and rural utilities are needed but these definitions will be worked out as utilities come forward with their PBR applications, advocating whether they should be considered urban or rural.	Start Up: $9,100 Annual Operating: $5.400 to $6,400
2. Connection of new services	After all conditions of service are satisfied, including an electrical safety inspection, low voltage services (less than 750 volts) will be connected within 5 working days, and high voltage services (750 volts and above) within 10 working days, 90% of the time **Note: Conditions of service to be satisfied may include payment of connection fees, signing of service contracts, completion of distribution system extensions, provision of adequate lead times for delivery of equipment and receipt of an electrical safety inspection certificate.**		Start Up: $8,400 Annual Operating: $3,200 to $6,900
3. Underground cable locates	Underground cable locates will be completed within 5 working days of a customer's request, 90% of the time. For customers requesting a specific date, the locate will be completed within 5 days of the requested date.	This benchmark is not intended for application to 'emergency locates' for other utility service providers.	Start Up: $16,800 Annual Operating: $3,100 to $4,500

Service	Minimum Performance Level and Method of Measurement *	Comments	Estimated Compliance Costs **
4. Telephone accessibility	During normal office hours, incoming telephone calls to the main general access customer inquiry telephone number will be answered within 30 seconds, 65% of the time. The provision of a voice mailbox does not constitute compliance with this standard.	It is recommended that an exemption be considered for small utilities, as it may not be practical for them to purchase the equipment necessary to monitor performance. Implementation of this standard should be done in conjunction with monitoring of call abandonment rates.	Start Up: $17,700 Annual Operating: $5,200 to $9,900
5. Notice of supply interruption	<u>Residential</u>: For scheduled power interruptions of 15 minutes in duration or longer, all affected customers will receive telephone or written notice 1 day in advance, 90% of the time. <u>Commercial / Industrial/Agricultural/Institutional</u>: For all scheduled power interruptions, regardless of duration, all affected customers will receive telephone or written notice 3 days in advance, 90% of the time. *Notes: 1) Scheduled interruptions are defined as interruptions that can reasonably be planned in advance. This excludes interruptions taken on short notice to alleviate an immediate safety concern or to maintain the integrity of the distribution network.* *2) In some service areas mass media notification may be sufficient for residential customers.*		Start Up: $20,000 Annual Operating: $2,700 to $31,900
6. Appointments	When it is necessary to meet customers at their premises or at their work site to conduct utility business, customers must be offered a minimum of morning or afternoon appointments and the appointments must be honoured 90% of the time.		Start Up: $3,100 Annual Operating: $2,500 to $2,900
7. Written response to inquiries	Requests for information by a customer or their agent, relating to their account and requiring a written response, will be responded to in writing within 10 working days after receipt, 80% of the time.	This measure was restricted to requests for account information for simplicity so that the measure could be easily defined, tracked and audited. This measure excludes responses to complaints, which will be governed by the complaint process required by the utility's license.	Start Up: $7,800 Annual Operating: $2,400 to $12,300

* All compliance targets are based on a one-year reporting interval.

** Estimated costs are based on the average of utility survey responses (see Appendix D)

Table 3.1.2: Discarded Customer Service Performance Measures

Service	Minimum Performance Level and Method of Measurement	Comments
8. Service disconnect / reconnect for maintenance and upgrades of customer equipment and service	Requests for service disconnects will be accommodated within 3 days of the date requested by the customer, 90% of the time. Requests for service reconnects will be accommodated within 24 hours of the date requested by the customer, 90% of the time.	**Not recommended**. The volume of this activity is small because new connections are captured by measure (2) and in most instances of a change of tenancy the system is not disconnected. The measure was a viewed as difficult to track and verify because times are usually offered to customers based on availability.
9. Investigation of voltage or power quality complaints	**Not recommended**	These problems are very complex with multiple causes. Solutions can range from simple maintenance to expensive capital additions. It is not reasonable to set common performance standards for such diverse situations.
10. Meter reading	**Not recommended**	Utilities will have an economic incentive to read revenue meters on a regular basis, therefore, a performance benchmark is not necessary.
11. Estimating charges for distribution system extensions/alterations	**Not recommended**	It was determined that there are too many variables to consider implementing an effective performance measure for this service. Also, there are relatively few customers affected, and they are likely to be vocal and knowledgeable (i.e. developers, etc.).
12. Service restoration	**Not recommended**	Reliability benchmarks are under consideration by the Reliability Sub-Committee.
13. Investigation of reported meter problems	**Not recommended**	Industry Canada already regulates the meter dispute settlement process.

3.2.2 Penalties

Penalties were considered over several meetings. The general conclusion was that penalties could induce perverse behaviours. In California, utilities elected to reduce performance and pay penalties because the penalties were smaller than the cost of maintaining performance. Further, until proper controls and quality assurance procedures are in place and tested for the reporting of these measures across all utilities, confidence in the accuracy of past performance is not sufficient to ensure that penalties would be properly employed.

It was decided that penalties should not be implemented, especially in the initial term. It was thought that the utilities should be required to address shortfalls in meeting customer service standards by explaining why the shortfall occurred and how the utility will achieve compliance in the future. Further, if a utility continually failed to comply, the OEB could make a prospective adjustment to the utility's allowed return at the start of the next PBR period. Publishing utility performance statistics could also be used as an incentive to induce maintenance of performance levels.

4. DISTRIBUTION SYSTEM RELIABILITY PERFORMANCE MEASURES

4.1 Overview

The working group on reliability has prepared the following report outlining the framework for the introduction of reliability standards under the new PBR system. During the preparation of this brief many factors were considered with respect to the collection, reporting, and enforcement. In addition to the work performed by the task force, a survey of various utilities was conducted and the findings of the results are incorporated as appropriate.

The working group is still of the opinion the existing structure developed by the CEA and further by the MEA, be adopted as the basis for the measurement, collection of data, and reporting on the various indices. It is also suggested, and further supported by the survey, that the adoption and reporting requirements set forth in the rate application handbook be graduated to allow for maturation of the process across all electric utility sectors. The time frame should correspond with the overall PBR implementation schedule.

4.2 Introduction

Utilities have been collecting outage statistics for many years. In the past these have been used internally by utilities to track how well their system was performing. It also provided the basis for companies to allocate funds to specific capital projects and to develop maintenance programs to target areas or equipment that performed below self-set performance criteria.

In the last few decades the recording and capturing of data became more formalized when agencies such as the CEA and the MEA became interested in providing national and provincial databases. The CEA through numerous working groups developed several indices and cause categories, which are listed later in this document. The CEA continues to revise and improve their collection database. The work by the MEA parallels the CEA process and provides a local flavor. The purpose of developing these indices and cause categories was to provide a common benchmark to compare to other utilities that are part of the database.

There are a number of reliability indices that could be monitored. However, it is important to consider the rational for introducing standards in order to determine which of the indices are appropriate for PBR. The PBR process is designed to take advantage of opportunities to maximize efficiency in operations. The objective of these improvements is to maximize the return that a company can earn within the limits of its approved rate allowance. Given that there is a cap to this allowance there will be increased pressure to squeeze service standards. In some instances this may be appropriate, especially in cases where "gold plating " has occurred. In other situations the results could be deterioration in service to the detriment of the customer. Monitoring service standards acts as a safety net to ensure service is not compromised.

To provide meaningful discussion the following terms are defined:

Distribution System

A distribution system is that portion of an electric power system, which links the bulk power source or sources with the customer’s facilities. Subtransmission lines, distribution substations, primary feeders, distribution transformers, secondaries and customer’s services all form parts of what can be generally called Distribution Systems.

Customers

This means the number of customer services fed at secondary, primary and subtransmission voltages.

Interruption

An interruption is the loss of service to one or more customers and is the result of one or more component outages. A momentary interruption is defined as an interruption with duration of less than one (1) minute.

Interruption-Duration

This is the period from the initiation of an interruption to a customer until service has been restored to that customer.

Customer-Hours of Interruption

This is the product of the customer services interrupted by the period of interruption.

Customer-Interruptions

This is the sum of the products of customer services interrupted by the number of interruptions that affect those customer services.

From the work that the task force has completed over the last several months and the resulting discussions that followed, the following indices of reliability are recommended as the ones to be reported and monitored:

SAIDI – System Average Interruption Duration Index

This is one indicator of reliability of the distribution system, which expresses the length of outage each customer experiences. It is defined as the total number of power interruptions normalized per customer served. Mathematically expressed as:

$$\text{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

This shows the average length of time a customer was without power in the year. All planned and unplanned interruptions of one minute or more are used to calculate this ratio.

SAIFI – System Average Interruption Frequency Index

This is one indicator of reliability of the distribution system, which expresses the number of interruptions normalized per customer served. Mathematically expressed as:

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

This shows the average number of interruptions per customer. All planned and unplanned interruptions of one minute or more are used to calculate this ratio.

CAIDI **– Customer Average Interruption Duration Index**

This is one indicator of reliability of the distribution system, which expresses the speed of which power is restored. Mathematically expressed as:

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Customer Interruptions}}$$

This shows the average duration of each interruption in the year. All planned and unplanned interruptions of one minute or more are used to calculate this ratio.

In addition to the above indices, the nature of the interruptions has been defined in terms of primary causes of the interruption. The causes and their codes are listed below. Some utilities further sub-divide these causes according to their own needs. Monitoring the cause of outages as well as the indices can provide valuable information as to the nature of any remedial works that is required.

0 - Unknown/Other
Customer interruptions with no apparent cause or reason which could have contributed to the outage.

1 - Scheduled Outage
Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

2 - Loss of Supply
Customer interruptions due to problems in the bulk electricity supply system.

3 - Tree Contacts
Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.

4 - Lightning
Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flashovers.

5 - Defective Equipment
Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

6 - Adverse Weather

Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

7 - Adverse Environment

Customer interruptions due to equipment being subjected to abnormal environments such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

8 - Human Element

Customer interruptions due to the interface of the utility staff with the system.

9 - Foreign Interference

Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects.

4.3 Information Collection and Reporting

To determine if it was reasonable for utilities to report on these indices a survey was conducted (see Appendix E). The results are as expected - mixed. There were 126 utilities that responded to the survey. Out of these, 56 (45%) indicated that they collect reliability statistics in some form or other. While 45% appears to be low, it is important to consider that the 56 utilities represent 81% of the customers (3,167,673 out of approximately 3,889,546). Additionally, the level of automation and the methodologies used to collect the data is all over the map ranging from sophisticated distribution automation to the utilization of employee time cards. These findings are not surprising. They support the view that while data collection and reporting should commence immediately, there should be a graduated timeline for the application of penalties for non-compliance. Based on the survey comments and results and the opinion of the working group, there is a large requirement for education for many of the utilities. Those utilities that have the capabilities to produce this type of reporting could assist the smaller utilities in reaching the target level. The report also showed that although there was reporting it is varied and inconsistent. This will have to be addressed through education and perhaps through the rate handbook or other companion guideline document.

However, not withstanding the diversification, the working group is of the opinion that the requirement for compliance with the reliability standards should not be relaxed. The need for reliable power is increasing, as consumer products become more power sensitive, customer lifestyles rely more and more on technology, and companies are moving towards distributed office environments. The need for reliable service now extends farther then it ever did before and customer expectations in all regions are geared towards reliable value added service.

Another area that will have to be addressed is the aspect of how the OEB will monitor and audit the numbers. The working group suggests that the first objective is to get all of the utilities to collect the data and to report the indices. This will be a substantial undertaking for some. Once all of the utilities are reporting then the recommendation is that there would be a random auditing process established wherein the OEB would randomly audit utilities to evaluate the appropriateness of the data collection and reporting process. It is suggested that the industry would be given one reporting period, say the first year, to set up and report and then the audit process could start. Again, the introduction of penalties for non-compliance should be graduated in over the PBR time frame such that when the Utility made its first PBR submission, it would be assumed that it would have all of its reporting functional and be ready to roll.

4.4 Reliability Benchmarks

One of the problems with reliability and indeed all statistical reporting is that an abnormal event such as a season with severe thunderstorms, can distort the picture. To avoid skewing of the indices it is recommended that the reporting be on an annual basis and also on a rolling five-year average. This will provide the smoothing required to adjust for anomalies while still providing an indication as to the overall trend of the utility's reliability level.

The benchmarks for reliability should be based on a utility's size and type - small, medium, or large - rural, urban, or mix.

Currently the MEA has posted indices for large medium and small utilities. Additionally, the CEA has posted composite units and has permitted utilities to describe themselves as urban or mixed. The indices are shown below. Examination of the various reported indices shows a large variation in the numbers. This is borne out by the various submissions from the utility survey.

To this end the group is of the opinion that the reliability levels for individual utilities should be based on a five-year average for that utility. Each utility should include in its PBR submission a proposed reliability benchmark. This benchmark should be supported by historical evidence an appropriate supporting documentation such as the methodology used to collect the data. Assuming reasonableness of the submission the Board would then use that value to determine the performance. Reasonableness could be established by comparing the submitted levels with those published by the CEA and the MEA (shown below).

Indices	MEA			CEA (Composite)
	Large	Medium	Small	
SAIDI	1.12	1.31	0.09	3.70
SAIFI	1.71	1.55	0.04	2.35
CAIDI	0.68	1.02	1.69	1.57

* Based on 1997 data

In the event data is unavailable or has not been collected then the reliability indices should be set in accordance with the average of the other utilities in the yardstick grouping. The survey showed that there was a cross-section of utilities reporting which means that this approach will be able to be used.

One other factor that needs to be considered when calculating the indices is the effect of external causes. These causes include outages and interruptions on the transmission system, and on feeders used jointly with another utility. It is recommended that the reliability indices reported by a utility be adjusted so that they truly represent situations under its control.

4.5 Non-performance

To ensure that PBR functions according to the rate handbook, there has to be consequences for non-compliance. The following is suggested:

There will be a penalty for late or no annual filing of PBR information. The OEB will impose a fine of $/day until the PBR submissions are received at the OEB offices. The payment of this fine shall accompany the submission.

The OEB will review the PBR submissions to ensure compliance with the established benchmarks. If the Board determines the utility's repeated submissions to be "Non Compliant", the Board shall issue an "Order to Comply". The Order to Comply will initiate a formal process as described here.

Once the Order to Comply is issued, the LDC has a three-month period to prepare and submit a "Compliance Plan" to the Board. This plan should outline in general terms the steps that the utility plans to take to bring the utility's PBR indices back in line with the benchmark. The Plan should be as specific regarding the estimated budgets for this work and the expected term of the Plan.

Once received, the Board will review the Plan. Comments and/or questions will be returned to the utility within thirty days. The Board may impose conditions on the funding models or enforce a shareholder re-investment into the program as it sees fit.

The LDC will submit a revised Compliance Plan within fifteen days of the date it receives a notice from the Board.

Once approved by the Board, the LDC will implement the Compliance Plan immediately. The LDC shall submit progress reports to the Board as required, but no longer than every six months during the term of the Plan.

At the completion of the Plan term, the LDC shall submit a Final Progress Report. This report shall outline the details of the work performed, the actual expenditure information, as well as identify any areas where the Plan failed to meet its objectives.

Failure to submit a compliance plan or to follow through will lead to a series of interviews that may, at the Boards discretion, result in escalating financial penalties up to a revocation of the licence.

APPENDIX A - ECONONALYSIS CONSULTING SERVICES - SUBMISSION TO THE PBR IMPLEMENTATION TASK FORCE

Introduction

The PBR task force participants were invited to comment on several inter-related issues related to the PBR mechanisms. This paper has been prepared for the *"PBR Implementation Task Force"* on behalf of Econalysis Consulting Services ("ECS"). ECS is an interested party representing consumer stakeholders in the 1999 PBR Task Force process hosted by the Ontario Energy Board.

All of the factors in a PBR scheme are inextricably linked making it difficult to consider one in isolation of the other. For example, as is discussed below, the level at which both the productivity factor and the plan term is established will affect the choice of an appropriate sharing mechanism. The converse is also true. As a result, once the Draft PBR Rate Handbook is published and the proposed PBR scheme has been determined, ECS, or its clients, may have to alter some positions it has taken at this initial stage.

It must be recognized that it is impossible to design a PBR plan that will work flawlessly. As a result, "self-correcting" mechanisms, such as earnings sharing, a limited plan term, and exit ramps in the event of particularly serious problems are important considerations. These are designed to protect ratepayers, shareholders and the OEB itself from the risk inherent in introducing a new PBR plan. It is our position that this risk is significant in the introduction of the PBR plan in the Ontario electric industry, as discussed below. It is for this reason that we recommend considerable caution in the approach to this new scheme.

Exogenous Factors ("Z" Factors)

Exogenous factors may be defined as occurrences that:

(i) are beyond the control of the regulated company that result in changes to the company's revenues and expenses,

(ii) are not reflected in the other elements of the PBR plan, and

(iii) do not provide for any future benefit to the company. In general, exogenous factors may be defined to be legislative, judicial or administrative actions that are beyond the control of the company, and have a significant impact on the company such that, barring an adjustment to the regulation plan, unreasonably high or low rates may result.

The primary danger with taking exogenous factors into account explicitly is that there will be double counting if the factor is also partially or wholly reflected in other elements of the PBR plan. The difficulty is that every cost factor that is directly or indirectly reflected in the PBR mechanism is not explicitly enumerated. Many cost factors are explicitly measured in deriving inflation measures. Furthermore, to the extent that past events that would have qualified as exogenous factors have affected the reference productivity rate, exogenous factors will be implicitly incorporated into the productivity offset used in the PBR scheme.

As a consequence, each cost factor that the company wishes to recognize as an exogenous factor will have to be examined with care to determine whether it is recognized either explicitly or implicitly by any other element of the price cap plan. It is not adequate to rely on a conceptual or general definition, as stated above. Instead, it is necessary to explicitly, precisely and unambiguously identify costs factors that will be treated as exogenous. General or conceptual definitions are open to interpretation and dispute. Furthermore, the less precise the definition, the more necessary it will be to permit a public process to assess any proposed exogenous cost factor. Conversely, with a very precise list, a public process would only be required if a utility were to seek to add an additional factor to the list.

A further concern is that there will be a bias in the exogenous factors that will be introduced into the price caps because the companies have an incentive to only bring forward those exogenous factors that increase costs and can therefore be used to increase the cap. Representatives of consumers, who would be the beneficiaries of adjustments for exogenous factors that decrease costs, may have limited opportunity to identify and initiate adjustments that reflect exogenous factors that will reduce the companies' costs.

For this reason, it seems appropriate to include exogenous factors only if they are explicitly identified and are automatically incorporated into the annual "price cap determination" process. In this case, any changes will flow through to the cap automatically and with minimal regulatory cost.

This narrow definition leads to a very restrictive view of what should be included as “z” factors in the PBR plan. The following implications, for example, are important to consider.

1. First, legislative, judicial or administrative actions that will be reflected in other elements of the price cap plan should not be treated as exogenous factors. For example, an increase in tax rates might be reflected in other elements in two ways. To the extent that the productivity offset is based on past experience, that experience may reflect a trend toward increasing tax rates; hence, the impact of future tax increases may be implicit in the productivity offset. A general tax increase (e.g., an increase in the rate of tax on corporate income) will affect the rate of inflation for all goods and services, hence, may be reflected in the inflation measure that is used in the price cap plan.

2. Second, there should be some threshold below which the dollar impact of a change is deemed to be too small to result in unreasonably high or low rates. Thus, an appropriate threshold should be included in the plan specifications.

3. Third, legislative, judicial or administrative actions that will result in the company making certain business decisions and incurring costs based on the expectation of future resulting benefit should not be included as an exogenous factor. For example, the costs associated with a corporate restructuring to create a regulated or unregulated affiliate to handle the sale of default supply would not be deemed as a “z” factor. The company would only undertake this restructuring investment if they expected that they would reap

some future benefit from this investment that would compensate and justify the current expenditure. The treatment of transition costs should be dependent on the causes of the costs as well as the likely ratepayer impacts. Transition costs should not be recovered from ratepayers unless they result from mandatory expenditures imposed by regulators (e.g. expenditures to implement telephone number portability which was mandated, by the CRTC were accepted as an acceptable exogenous factor by that regulator). In other cases, they are either fully attributed to shareholders or shared among stakeholders, especially if clear benefits of the measure causing the transition costs can be demonstrated.

The productivity factor (The "X" factor)

The discussion of the productivity factor is only important to the larger municipal electric utilities which will be subject to either a revenue of price cap scheme.

It is generally understood by the participants that the move towards a PBR regulatory system is in part motivated by the belief that, in general, PBR regulation allows for more efficient and effective regulation than rate of return regulation. It follows that the essence of the rationale for moving from rate base-rate of return (RB-ROR) regulation to any other form of Performance Based Regulation (PBR) is to remove embedded, non-quantifiable inefficiencies.

It seems difficult to conceive that any party that supports the adoption of PBR could deny that the differences in incentives under the alternate regimes affect efficiency. Accepting this premise leads to the necessary conclusion that there is a significant amount of inefficiency embedded in the existing cost structure of the regulated companies. If there were no significant embedded inefficiencies, there would be no justification for incurring the regulatory and other transitional costs and risks that are involved in moving from RB-ROR regulation to a PBR mechanism.

Furthermore, the adoption of the PBR mechanism would not be necessary if it were not for the practical reality that the amount of embedded inefficiency cannot be quantified with an acceptable level of confidence or precision. If tools were available to quantify the embedded inefficiency, there would be no need to introduce Performance Based Regulation -- costs allowed under traditional RB-ROR regulation could simply be reduced to reflect the embedded inefficiency and the regulated companies would either have to eliminate the inefficiency or shareholders would earn a substandard return. The reason that traditional RB-ROR regulation is considered to be inadequate is that the embedded inefficiency cannot be fully identified, hence it is passed through to ratepayers. In these circumstances, where traditional PB-ROR regulation has not been in place, the setting of appropriate productivity factors is that much more difficult, and the risk, therefore, of "getting it wrong" that much higher.

In short:

- historical productivity gains (under the existing Ontario Hydro regulatory oversight) underestimate the expected, and reasonable, productivity gains that should be realized under Performance Based Regulation;
- achievable productivity gains cannot be accurately estimated because the amount of embedded inefficiency cannot be determined; and
- the appropriate productivity offset cannot be quantified with a reasonable level of confidence and precision.

The effectiveness of PBR regulation is dependent on establishing a plan in a manner that fairly balances the interests of ratepayers, shareholders and other affected parties over the time frame of the PBR. The comments that follow are based on the view that a plan that fairly balances the interests of the affected parties, would, among other things, use a productivity offset that is a proxy for the efficiency gains that the regulated company would be expected to achieve under competitive market conditions. This implies that above-normal returns should be earned if, and only if, the company is able to achieve exceptional productivity gains. Thus, the reason that the company retains the benefits of any efficiency gains achieved in excess of the level set by the X-factor is that they have been achieved through exceptional performance.

Furthermore, under an ideal PBR regime, the opportunity to realize these excess earnings would be offset by a symmetrical risk that it will perform below the norm and earn a sub-standard return. In either case, the rates that ratepayers would pay would reflect efficiency gains that the company subject to PBR would be expected to achieve under competitive market conditions.

Under an “ideal” PBR mechanism, it would be expected that not all regulated utilities would earn a return that is above the return that would be permitted under RB-ROR regulation. In fact, the probability of earning less than a competitive, or normal, return would be roughly equal to the probability of earning an above-normal return. The intent of moving to PBR is to set an offset that reflects the gains that can be reasonably expected. I.e., there should be no bias in favour or against company over- or under-earning. The incentive to improve productivity comes both from the danger of under earning and the opportunity to earn an above-normal return -- the carrot and the stick.

Furthermore, it is understandable that regulators may set the productivity target that is embedded in the price cap formula conservatively because the risks associated with over-and underestimating the reasonably achievable productivity gains are asymmetric. The risk associated with overestimating productivity gains is that the incumbents will not earn an adequate return, will have difficulty raising adequate new capital, and may be put financially at risk by the regulatory regime. This risk is far more serious than the risk associated with of underestimating the achievable rate of productivity improvement which is simply that shareholders will earn a high return.

In designing the overall price or revenue cap mechanism, it is therefore reasonable to base it on the presumption that the productivity offset that is adopted is likely to be conservative. That is, the productivity offset will not fully recognize embedded inefficiency that can be eliminated under a PBR regime or the full extent of productivity improvements that are reasonably achievable. Put simply, the mechanism will be biased, making it far more likely that the regulated companies will earn a higher return under PBR than they would under rate base rate of return regulation than that they will earn a lower return.

For the reasons noted above, it is reasonable to anticipate that the PBR regime will not achieve this ideal symmetry. In the interest of caution and conservatism, the PBR regime that is implemented will almost certainly be biased in favour of the incumbents being able to earn an above-normal return because the productivity offset that is adopted will be low.

Earnings Sharing

(a) Under a price or revenue cap PBR mechanism:

The disadvantage to ratepayers that results from in setting the productivity offset too low can be mitigated by building in a mechanism for sharing the over earnings. Specifically, part of the earnings can be retained by the company so that it still has an incentive to improve productivity as much as possible. At the same time, ratepayers gain some of the benefit of these gains (which would have been given to them in full if the reasonable productivity offset could have been estimated more accurately in the first place.).

Another way to mitigate the bias would be to establish a productivity offset that better balances the interests of shareholders and ratepayers, despite the risk that shareholders will underearn even if a reasonable job is done of improving productivity. Imposing this risk on the company would be more acceptable if the company is given a choice in adopting an aggressive productivity target.

The appropriate degree of sharing at any level of productivity offset is a matter of judgement. Considerations in setting the split between shareholders and ratepayers, should include the following:

- The higher the productivity offset the larger should be the shareholders' share of total gains. That is, if a company were to choose an aggressively high productivity factor, they would be able to keep a high B if not 100%- of the earnings in excess of this level. Ratepayers are already benefiting from the high x factor implicit in the plan.

- Small gains above forecast may be treated differently than large gains (a large gain is more likely to reflect erroneous assumptions rather than management effort). For example, if a company were to choose a low “x” factor, it is likely that they will achieve this level, particularly in light of the imbedded inefficiencies in their operation. A large improvement relative to this level may be the result of a technological change, or a relatively simple operational change to remove an obvious inefficiency. Under this scenario, ratepayers should receive a large percentage of any gains above the forecast level.

- There must be sufficient incentive, and the review period must be long enough, to warrant investing in productivity measures that may take several years to pay back the investment. Hence, the longer the review period, the smaller the necessary shareholder share of excess productivity gains.

In setting the sharing mechanism, it would not be appropriate to adopt the premise that a larger incentive (i.e., larger share to the shareholder) is always better than a smaller one. There is no evidence that the incremental benefit of providing the maximum incentive, relative to sharing 50:50 for example, justifies the higher rates that ratepayers will have to pay. The unresolved question is whether earnings sharing will have a significant impact on productivity performance, and if it does, whether the impact outweighs the cost to ratepayers of a generous incentive. In theory, the appropriate sharing mechanism would be the one that results in the lowest present value of rates for customers (i.e., the optimal balance between higher rates in the short run to pay the incentive and lower rates in the long run due to higher productivity gains).

Furthermore, it is possible that too strong an incentive (e.g., the opportunity to retain 100% of super-normal earnings) could lead to counter-productive efforts to increase earnings. For example, if the rewards associated with higher earnings are too large, management may be enticed to take excess risk and reduce quality or service even if there is a risk of incurring penalties.

It should also be noted that during the initial period, where experience with PBR is limited and the risk of setting a productivity offset that deviates significantly from the ideal rate is the greatest, the need for a sharing mechanism is most important.

Given the interplay between the productivity factor and earnings sharing, it is our recommendation that the PBR scheme adopted in Ontario explicitly recognize that there is a trade-off between the productivity offset that is selected and the adoption of an earnings-sharing mechanism. The selection by the muni of a combined X-factors and earnings sharing mechanism from a menu of possible options would allow the company to choose the combination that best meets their PBR expectations at the outset of the PBR period (e.g., there could be several X-factors, some of which would involve earnings sharing, while another, set at a challenging level, would not). This approach deals with the incentive for companies to understate their ability to achieve productivity improvement by providing an incentive to "reveal" their true expectations. In addition, it would allow MEUs to make different choices based on their individual circumstances.

(b) Under a yardstick approach

With a yardstick PBR scheme, there will obviously be inconsistencies in the operational efficiency of the munis that are grouped together. Some will therefore find it relatively easy to achieve the yardstick measures identified, while others will find it relatively more difficult. In either case, earnings sharing can be regarded as an effective way to mitigate the risk to both ratepayers and shareholders inherent in this system as ratepayers share in both the over-earnings and under-earnings of the company. In this approach, we recommend symmetrical earning sharing (both upside/downside earnings are shared 50:50).

Plan term and review period

Assuming that the review period is the period until a revised PBR regime is implemented, it appears that the maximum initial period that would be reasonable would be 3 years. It would be appropriate to gain at least 1-3 years experience with the initial PBR regime before evaluating it. A shorter period would not provide a fair test of the level of productivity improvement that is realistically achievable on an on-going basis. Also a shorter review period would provide little opportunity to realize the benefit of reduced regulatory burden.

As noted above, however, the review period that is appropriate is interrelated with the earnings sharing mechanism that is adopted, for two reasons. First, the smaller the company share of earnings, the longer the review period in order to provide adequate opportunity to earn a payback on productivity initiatives that have a high up-front cost. Second, the larger the ratepayer share of excess productivity gains, the less is the need to quickly correct the mechanism if the productivity offset has not been set at the right level (i.e., less need to correct if it was too low, because harm to ratepayers is lessened, and less need to correct if rate was set too high, because harm to shareholders is lessened).

It is clear that over a three-year period the cumulative excess profits, or losses, that could accrue if the productivity offset is set incorrectly are very large. Adoption of an earnings sharing mechanism would significantly reduce the potential impact and may therefore be an important protection against the risk that very high or very low earnings could discredit an PBR regime in the eyes of Ontarions.

Early Modification (Exit Ramps) Based on Financial Performance

Experience with PBR in other jurisdictions and in other sectors suggests that it is prudent to be very cautious in the use of exit ramps, except in very exceptional circumstances, as discussed below.

Caution is advised because the use of exit ramps often leads to some “gaming of the system” so as to either avoid or to trigger exit ramps. Instead, we would rather see other PBR parameters used to incent productivity gains, and avoid or minimize excessive earnings. For example, utilities could be given the option to choose amongst several aggressively set productivity indices. Higher productivity indices would be coupled with lower ratepayer sharing, and vice-versa.

In short, we would support a relatively short PBR term, with no exit ramps, provided that other PBR parameters, such as those mentioned above, are included.
There is no need for Variations in PBR Mechanisms because of Utility Size and Potential Inefficiencies.

We recognize that there has been some concern expressed as to the need for special consideration for smaller utilities, specifically, in the case of amalgamations. However, upon reflection, we would argue that an exit ramp is not the appropriate solution in this instance. Presumably, in the case of an amalgamation, data will be submitted to, and approval sought from, the Ontario Energy Board. In any case, on an annual basis, information will be filed with the OEB. In either case, this information may indicate that a re-classification into another yardstick grouping is warranted. (As a simple example, a larger number of customers served may mean a move to a different yardstick group, which includes larger utilities, is warranted.) Thus, upon application, and where appropriate, a utility could be moved from one yardstick group to another, while still remaining within the PBR yardstick mechanism. In short, the utility is not ‘exiting’ from the PBR mechanism altogether. We would continue to suggest that in these cases, the onus be placed on the parties involved to provide the necessary data which demonstrates the need for a re-classification as part of the licensing approval mechanism. Some ‘closing-off’ and ‘re-opening’ of the utility’s books for PBR performance tracking purposes would be part of this process.

A second possible need for off-ramps might be to provide for the ‘lumpiness’ of utility capital investment for smaller utilities. A bigger company can smooth out a large supply increment through corporate financing, but smaller utilities may not have the same resources. As such, under PBR, special consideration may be required to increase flexibility for smaller utilities in very unique circumstances, as approved by the OEB. However, we would argue that, again, this does not warrant an exit from the PBR mechanism, but rather an inclusion of a z- factor.

An inherent feature of a PBR regime is the risk that companies can earn returns that are either above or below the returns that would be earned under RB-ROR regulation. For this reason, the utilities should not be permitted to justify rate increases on the basis of financial performance unless they can demonstrate not only that the PBR regime is both very damaging to the ability of the market as a whole to deliver electricity services to consumers but also that the reason for the poor financial performance is the PBR mechanism, not the failure of management to meet the demands of the competitive marketplace.

In order to ensure symmetry, it would be desirable to specify a maximum and minimum return that would trigger a review proceeding. However, such a trigger would remove the incentive to achieve productivity gains that cause profits to exceed the trigger, and possibly encourage a company that is doing poorly to ensure that a hearing is triggered.

Hence, a better way to deal with this problem would be to introduce a sharing mechanism, possible with only large variances from the expected return being shared.

IMPLEMENTATION CONSIDERATIONS

Need for Consistency

Wherever possible, we believe that the same plan term should be used for all utilities. Otherwise, the ‘playing field’ for Ontario utilities will not be level, and differences in the regulatory treatment may impact investment and other business decisions. The selection of a regulatory system will probably affect the future structure of the industry. If different mechanisms are introduced to account for size variation, it is important that these mechanisms do not provide the incentive for utilities to bias corporate size in order to fall into a particular regulatory system. In particular, we are concerned that a more flexible mechanism for smaller utilities might provide incentive to remain small. Due to the nature of the Ontario utility industry, an incentive to maintain an inefficient structure is clearly not in the interests of consumers.

Instead, incentives should be build into the system to encourage conformity with industry levels. Having said this, we recognize that there exists an important variation in size among Ontario's utilities. We understand that the concern was expressed that it may be prudent to provide different PBR terms mechanisms for smaller sized utilities due to the cost inherent in shorter plans and more frequent PBR reviews. Thus, although, we are not in favour of a radically different term being approved for smaller utilities, we believe the review process and the initialization of the plan could accommodate differences to reduce the cost for smaller utilities. These are discussed below.

Variations in PBR Mechanisms by Utility Size

We envision that a regulatory review will be required for any factor which is not pre-defined in the PBR Handbook. For example, if a productivity factor is established for the entire initial term of the PBR scheme, it will not require a review. However, if there is a mechanism or formula to calculate the productivity factor over the initial term of the PBR scheme which is based on either the financial reporting or the accounting methods adopted by individual companies, the derived figure would need to be subject to public review. Similarly, other factors which require some interpretation of principles by submitting utilities, such as which factors should be included as exogenous factors and exit ramps, should be expressed explicitly by each utility, and should be subject to public review.

A streamlined regulatory review approach, which offers more flexibility, may be suitable for smaller utilities. For the annual public reviews of the PBR plans, the Board could assemble all the submissions from the smaller utilities into a single filing and consumer organizations and individual customers could review it. For example, there could still be a public review of all the exogenous factors for several small utilities in a single proceeding. Smaller utilities could be reviewed on an exception or complaint-driven basis, as opposed to the company-specific approach, in which larger utilities are subject to regular public scrutiny. For the larger utilities, individual review of each submission would probably be necessary. These annual reviews would not constitute a full hearing, but would allow all the parties to monitor the industry, to voice complaints, and to participate in ongoing dialogue.

Secondly, the OEB may wish to consider 'phasing-in' the PBR plans by utility size. The individual plans for the larger MEU's should be introduced early. The yardstick plans, however, could be phased-in in order of the size 'groupings' (e.g. large, medium, and small could be phased in sequentially). This would allow the time for the smaller utilities to be better prepared for the new regulatory regime (this preparation might include some amalgamations). It would also seem to relieve some of the practical challenges that we envision from starting all the utilities at the same time. We would support this 'phasing-in' approach provided that a 'date certain' was provided to all participants stating the final date by which PBR material must be filed.

Implementation Time-line

As stated above, there is considerable uncertainty in the short to medium term future of the Ontario electricity industry. This uncertainty translates into greater regulatory risk that a new PBR plan will further confuse corporate decision-makers with respect to ownership, consumers with respect to understanding the new marketplace and the players, and the risk of larger rate impact than are already likely.

We understand that the plan is currently scheduled to begin in mid-2000, which coincides with the time when the existing Ontario Hydro-approved rates end. We believe that the initial term of a PBR plan starting at this point should be, at most, three years. We believe that it will take two years for the regulated entities to collect representative auditable data, through third party surveys, or through internal collection mechanisms. Two years will provide a reasonable time to collect the required data for all of the financial and standards specified in the PBR plan. One or two subsequent years would give both regulators and interested parties the confidence in the sustainability of plan elements, or the elements in need of change, and time for a review to be initiated.

We are concerned that an early commencement of a full PBR plan will neither allow the MEUs the time to properly prepare and present the PBR financial data, nor consider alternate corporate strategies in response to the dramatic changes in the PBR business and regulatory environment. Instead, a longer transition time in which, for example, current rates were frozen would allow for greater time for this preparation. This longer time, however, should only be considered if the parties are given clear instruction as to the ultimate start time, and the initial data requirements.

Our belief is that with a longer phasing-in period than is currently contemplated, interested parties will have an increased level of confidence with the integrity of the initial base year data, greater knowledge of individual MEUs corporate (and cost) structures, and the broader regulatory framework which will impact corporate decision making (i.e. OEB interpretation of MDC, Licensing implementation rules, etc.).

OTHER ISSUES

Recovery of stranded investment

If the OEB decides that it is appropriate for the utilities to recover any stranded investment, then there should, in effect, be a temporary rate adder which would increase the going in rates. This adder would be removed after pre-determined period of time (depending on the period required to recover the recognized amount of stranded investment), after which rates would be reduced (i.e., the adder would be removed). No other special treatment of this factor would be required under PBR.

Customer Service and Reliability Standards

Our belief is that it may be prudent to introduce different standards for different size utilities that have different reporting and tracking capabilities. For example, those utilities with highly automated systems, might be asked to track momentary interruptions and call answering statistics more rigorously than other smaller utilities that do not have automated systems.

We believe that these standards should form part of the PBR Rate Handbook such that the requirement for data collection, the definition of how standards should be calculated, and the audit provisions will be clearly stated. In addition, a note that other standards may be added from time to time should be included.

It is our belief that these standards should be subject to periodic and random audit. The audit would verify the integrity of both the calculation method as well as the underlying data.
In addition, we believe that penalties should be an inherent part of the PBR process. Without them, it seems wasteful to collect and audit annual data on company performance. Penalties would be imposed subject to the company explaining that there were circumstances beyond their control which meant that standards could not be achieved. The company would bear the burden of proof in this respect. Penalties could be introduced in a step-wise way, with increasing severity as time passes for non-compliance and non-correction. A process to determine non-compliance needs to be introduced at the same time as the PBR Handbook is finalized. The reporting time schedule, the audit process, and the penalty regime should also be defined.

We believe that a customer satisfaction survey is <u>one</u> of several useful audit tools to determine corporate performance. It is a way to monitor whether cost cutting is impacting upon elements which deliver value to the customer. It is a useful tool to assess the performance relative to defined PBR measures, as well as to ascertain other performance indicators which are of importance to customers. The latter could form the rationale for expanding the list of performance indicators over time. Again, this could be used as an indicator that a problem exists and that there is a need for further investigation.

APPENDIX B - INITIAL SUGGESTION: JACK GIBBONS, CANADIAN INSTITUTE FOR ENVIRONMENTAL LAW AND POLICY

Rationale for DSM

- Reduce customers' bills. For example, the Consumers Gas and Union Gas DSM programs will reduce their residential, commercial and industrial customers bills by more than $108 and $187 million respectively.
- Protect public health and the environment by reducing the emission of 38 air pollutants (e.g. arsenic, cadmium, chromium, lead, mercury and nickel) associated with coal-fired power plants.
- Fulfill section one of the Ontario Energy Board Act.
- Create goodwill for electric utilities.
- Reduce customers' incentive to fuel switch (by lowering their costs of using electricity).
- Create an additional profit opportunity for electric utilities.
- In its most recent Union Gas rates Decision the Board ruled that it will only allow Union Gas to promote fuel switching to gas if it also promotes the efficient use of gas:

> "the Board finds that the accessibility of gas appliances efficiency information needs to be improved and as long as the Company includes promotion of gas appliances in its advertising paid for out of the cost of service, it must play a direct role in disseminating information on, and promoting, energy efficient choices." (E.B.R.O. 499, Decision, p. 10, para. 2.1.11) and Decisions.

Consultation

Electric utilities should be encouraged to develop their DSM programmes in consultation with their customers, local public interest groups and OEB intervenors.

APPENDIX C

Customer Service Performance Benchmarks Survey

This survey is being conducted to assist the Ontario Energy Board in the establishment of measurable performance benchmarks for electric utilities. Such benchmarks will be used in the future Performance Based Regulation (PBR) environment.

The survey asks your opinions on several performance benchmarks that are under consideration. If adopted, these benchmarks would be based on a twelve-month reporting interval. This will serve to dampen the impact of extraordinary events.

When assessing the costs of compliance for these benchmarks, please note that it will be necessary to maintain transaction records for the purpose of OEB audits.

Utility Name: ____________________ (Optional)

Contact person: ____________________ (Optional)

No. of customers: ______________

Phone No. ______________

Fax No.: ______________

E-mail address: ______________

1. PERFORMANCE BENCHMARK #1 - EMERGENCY RESPONSE

   Emergency trouble calls (i.e. fire, ambulance, police, etc.) will be responded to within 120 minutes in rural areas and 60 minutes in urban areas, 80% of the time.

   a) Is this performance measure clearly defined? Yes ☐ No ☐

      If not, please explain why: ______________________________________

      ____

      ____

   b) Do you think this is a reasonable standard? If not, why and what would be reasonable?

      ____

      ____

      ____

c) Could you measure your utility's performance under this benchmark using existing staff and equipment?

Yes ☐ No ☐

If not, what is your best estimate of the costs to do so?

- Start up / initial costs $________
- Annual cost of measurement after startup $________

If your utility can currently measure this performance benchmark what is the annual cost of doing so?

$____________

2. PERFORMANCE BENCHMARK #2 - CONNECTION OF NEW SERVICES

After all conditions of service are satisfied, including an electrical safety inspection, low voltage services will be connected within 5 working days and high voltage services within 10 working days, 90% of time.

a) Is this performance measure clearly defined? Yes ☐ No ☐

If not, please explain why: ____

____

____

b) Do you think this is a reasonable standard? If not, why and what would be reasonable?

____

____

____

____

c) Could you measure your utility's performance under this benchmark using existing staff and equipment?

Yes ☐ No ☐

If not, what is your best estimate of the costs to do so?

- Start up / initial costs $________
- Annual cost of measurement after startup $________

If your utility can currently measure this performance benchmark what is the annual cost of doing so?

$____________

3. PERFORMANCE BENCHMARK #3 - UNDERGROUND CABLE LOCATES

Underground cable locates will be completed within 5 working days of the customer's request, 90% of the time.

a) Is this performance measure clearly defined? Yes ☐ No ☐

If not, please explain why: ____

____

____

b) Do you think this is a reasonable standard? If not, why and what would be reasonable?

____

____

____

____

c) Could you measure your utility's performance under this benchmark using existing staff and equipment?

Yes ☐ No ☐

If not, what is your best estimate of the costs to do so?

- Start up / initial costs $________
- Annual cost of measurement after startup $________

If your utility can currently measure this performance benchmark what is the annual cost of doing so?

$____________

4. <u>PERFORMANCE BENCHMARK #4 - TELEPHONE ACCESSIBILITY</u>

During normal office hours, incoming telephone calls will be answered within 30 seconds, 65% of the time.

a) Is this performance measure clearly defined? Yes ☐ No ☐

If not, please explain why: ____

____

____

b) Do you think this is a reasonable standard? If not, why and what would be reasonable?

____

____

____

____

c) Could you measure your utility's performance under this benchmark using existing staff and equipment?

Yes ☐ No ☐

If not, what is your best estimate of the costs to do so?

- Start up / initial costs $________
- Annual cost of measurement after startup $________

If your utility can currently measure this performance benchmark what is the annual cost of doing so?

$____________

5. <u>PERFORMANCE BENCHMARK #5 - SERVICE DISCONNECT/RECONNECT</u>

Requests for service disconnects will be accommodated within 3 days within the date requested by the customer, 90% of time, and

Requests for service reconnects will be accommodated within 24 hours of the date requested by the customer, 90% of the time.

a) Is this performance measure clearly defined? Yes ☐ No ☐

If not, please explain why: ____

____

____

b) Do you think this is a reasonable standard? If not, why and what would be reasonable?

____

____

____

____

c) Could you measure your utility's performance under this benchmark using existing staff and equipment?

Yes ☐ No ☐

If not, what is your best estimate of the costs to do so?

- Start up / initial costs $________
- Annual cost of measurement after startup $________

If your utility can currently measure this performance benchmark what is the annual cost of doing so?

$____________

6. <u>Performance Benchmark #6 - Notice of Supply Interruption</u>

Residential: For scheduled power interruptions of 5 minutes in duration or longer, all affected customers will receive telephone or written notice 1 day in advance, 90% of the time.

Commercial/Industrial: For all scheduled power interruptions, regardless of duration, all affected customers will receive telephone or written notice 3 days in advance, 90% of the time.

a) Is this performance measure clearly defined? Yes ☐ No ☐

If not, please explain why: ____

____

____

b) Do you think this is a reasonable standard? If not, why and what would be reasonable?

____

____

____

____

c) Could you measure your utility's performance under this benchmark using existing staff and equipment?

Yes ☐ No ☐

If not, what is your best estimate of the costs to do so?

- Start up / initial costs $________
- Annual cost of measurement after startup $_________

If your utility can currently measure this performance benchmark what is the annual cost of doing so?

$____________

7. PERFORMANCE BENCHMARK #7 – WRITTEN RESPONSE TO INQUIRIES

Requests for information requiring a written response (i.e. lawyer's title searches, historical account information, etc.) will be responded to within 10 working days after receipt, 80% of the time.

a) Is this performance measure clearly defined? Yes ☐ No ☐

If not, please explain why: ____

____

____

b) Do you think this is a reasonable standard? If not, why and what would be reasonable?

____

____

____

____

c) Could you measure your utility's performance under this benchmark using existing staff and equipment?

Yes ☐ No ☐

If not, what is your best estimate of the costs to do so?

- Start up / initial costs $________
- Annual cost of measurement after startup $________

If your utility can currently measure this performance benchmark what is the annual cost of doing so?

$____________

8. <u>PERFORMANCE BENCHMARK #8 – APPOINTMENTS</u>

Customers must be offered a minimum of morning or afternoon appointments and appointments must be honoured 90% of the time.

a) Is this performance measure clearly defined? Yes ☐ No ☐

If not, please explain why: ____

____

____

b) Do you think this is a reasonable standard? If not, why and what would be reasonable?

____

____

____

____

c) Could you measure your utility's performance under this benchmark using existing staff and equipment?

Yes ☐ No ☐

If not, what is your best estimate of the costs to do so?

- Start up / initial costs $________
- Annual cost of measurement after startup $________

If your utility can currently measure this performance benchmark what is the annual cost of doing so?

$____________

9. GENERAL

Do you have any general comments on the performance benchmarks under consideration?

____
____
____
____
____
____
____

APPENDIX D - CUSTOMER SERVICE STANDARDS SURVEY RESULTS

	YES	NO	AVERAGE $
1. EMERGENCY RESPONSE			
a) Is this performance measure clearly defined?	115	46	
b) Do you think this is a reasonable standard?	93	68	
c(i) Could you measure your utility's performance under this benchmark using existing staff and equipment?	115	41	
c(ii) If not, what is your best estimate of the costs to do so? Start up/initial costs?			9,101
c(iii)Annual cost of measurement after startup?			5,438
c(iv) If your utility can current measure this performance benchmark what is the annual cost of doing so?			6,413
2. CONNECTION OF NEW SERVICES			
a) Is this performance measure clearly defined?	130	31	
b) Do you think this is a reasonable standard?	107	54	
c(i) Could you measure your utility's performance under this benchmark using existing staff and equipment?	126	35	
c(ii) If not, what is your best estimate of the costs to do so? Start up/initial costs?			8,410
c(iii)Annual cost of measurement after startup?			6,892
c(iv) If your utility can current measure this performance benchmark what is the annual cost of doing so?			3,163
3. UNDERGROUND CABLE LOCATES			
a) Is this performance measure clearly defined?	144	17	
b) Do you think this is a reasonable standard?	107	54	
c(i) Could you measure your utility's performance under this benchmark using existing staff and equipment?	126	35	
c(ii) If not, what is your best estimate of the costs to do so? Start up/initial costs?			16,793
c(iii)Annual cost of measurement after startup?			4,511
c(iv) If your utility can current measure this performance benchmark what is the annual cost of doing so?			3,086
4. TELEPHONE ACCESSIBILITY			
a) Is this performance measure clearly defined?	131	27	
b) Do you think this is a reasonable standard?	100	15	
c(i) Could you measure your utility's performance under this benchmark using existing staff and equipment?	86	75	
c(ii) If not, what is your best estimate of the costs to do so? Start up/initial costs?			17,737
c(iii)Annual cost of measurement after startup?			5,180
c(iv) If your utility can current measure this performance benchmark what is the annual cost of doing so?			9,855
5. SERVICE DISCONNECT/RECONNECT			
a) Is this performance measure clearly defined?	87	31	
b) Do you think this is a reasonable standard?	110	51	
c(i) Could you measure your utility's performance under this benchmark using existing staff and equipment?	115	46	
c(ii) If not, what is your best estimate of the costs to do so? Start up/initial costs?			8,336
c(iii)Annual cost of measurement after startup?			5,548
c(iv) If your utility can current measure this performance benchmark what is the annual cost of doing so?			3,138
6. NOTICE OF SUPPLY INTERRUPTION			
a) Is this performance measure clearly defined?	139	22	
b) Do you think this is a reasonable standard?	88	73	
c(i) Could you measure your utility's performance under this benchmark using existing staff and equipment?	109	52	
c(ii) If not, what is your best estimate of the costs to do so? Start up/initial costs?			19,949
c(iii)Annual cost of measurement after startup?			31,872
c(iv) If your utility can current measure this performance benchmark what is the annual cost of doing so?			2,763
7. WRITTEN RESPONSE TO INQUIRIES			
a) Is this performance measure clearly defined?	137	23	
b) Do you think this is a reasonable standard?	109	52	
c(i) Could you measure your utility's performance under this benchmark using existing staff and equipment?	113	48	
c(ii) If not, what is your best estimate of the costs to do so? Start up/initial costs?			7,785
c(iii)Annual cost of measurement after startup?			12,340
c(iv) If your utility can current measure this performance benchmark what is the annual cost of doing so?			2,424
8. APPOINTMENTS			
a) Is this performance measure clearly defined?	117	44	
b) Do you think this is a reasonable standard?	103	58	
c(i) Could you measure your utility's performance under this benchmark using existing staff and equipment?	99	62	
c(ii) If not, what is your best estimate of the costs to do so? Start up/initial costs?			3,157
c(iii)Annual cost of measurement after startup?			2,505
c(iv) If your utility can current measure this performance benchmark what is the annual cost of doing so?			2,886

APPENDIX E

Part B. Reliability Performance Benchmarks Survey

This survey is being conducted to assist the OEB in the establishment of the measurable performance benchmarks for electric utilities. Such benchmarks will be used in the future Performance Based Regulation (PBR) environment.

The survey asks your opinion and requests information on industry-standard reliability performance benchmarks that are under consideration. If adopted, these benchmarks would be based on an annual reporting interval. It is probable that the benchmarks will be smoothed over an interval period of three to five years to dampen the impact of extraordinary events.

Utility Name: ______________________________

Contact Person: ______________________________

Number of Customers: ______________________________

District Size (km^2) ______________________________

Fax No.: ______________________________

Phone No.: ______________________________

E-mail address: ______________________________

To measure reliability performance the OEB is considering monitoring several indices. These are indices that are standard to the electric industry and are defined in CEA and MEA documentation. The indices under consideration are SAIDI, SAIFI and CAIDI. These are defined as:

SAIDI – System Average Interruption Duration Index

This is one indicator of reliability of the distribution system, which expresses the length of outage each customer experiences. It is defined as the total number of power interruptions normalized per customer served. Mathematically expressed as:

$$\text{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

This shows the average length of time a customer was without power in the year. All planned and unplanned interruptions of one minute or more are used to calculate this ratio.

SAIFI – System Average Interruption Frequency Index

This is one indicator of reliability of the distribution system, which expresses the number of interruptions normalized per customer served. Mathematically expressed as:

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

This shows the average number of interruptions per customer. All planned and unplanned interruptions of one minute or more are used to calculate this ratio.

CAIDI – Customer Average Interruption Duration Index

This is one indicator of reliability of the distribution system, which expresses the speed of which power is restored. Mathematically expressed as:

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}} = \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Customer Interruptions}}$$

This shows the average duration of each interruption in the year. All planned and unplanned interruptions of one minute or more are used to calculate this ratio.

In addition to the indices, there are specified cause categories that are to classify the various reasons for interruptions. A customer interruption has been defined in terms of primary causes of the interruption. The causes and their codes are listed below. Some utilities further sub-divide these causes according to their own needs.

0 - **Unknown/Other**

Customer interruptions with no apparent cause or reason which could have contributed to the outage.

1 - **Scheduled Outage**

Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

2 - **Loss of Supply**

Customer interruptions due to problems in the bulk electricity supply system.

3 - **Tree Contacts**

Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.

4 - **Lightning**

Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flashovers.

5 - **Defective Equipment**

Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

6 - **Adverse Weather**

Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

7 - **Adverse Environment**

Customer interruptions due to equipment being subjected to abnormal environments such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

8 - **Human Element**

Customer interruptions due to the interface of the utility staff with the system.

9 - **Foreign Interference**

Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects.

1: Does your utility currently collect information for the purposes of calculating the above noted reliability indices? ____________________

2: If you do, what do you estimate the cost is to collect and report this data?

____

3: If you don't collect this data what do you anticipate the cost will be to start the collecting the data? ____________________

4: If you collect the data, do you categorize the causes in accordance with the above list?

____

5: If not, what categories do you use? (Please feel free to use additional paper)

____

____

____

6:If you collect the data do you have a five year historical data history? ____________________

or some other time frame? ____________________

7: What level of automation do you have in your system (SCADA, remote load-break switches, etc.)? ____________________

____

____

____

____

____

8: If you collect the data, describe the methods used to gather the information?

9: To assist us in determining benchmarks, please complete the following table as completely as possible?

Index	1994	1995	1996	1997	1998
SAIDI					
CAIDI					
SAIFI					

10: Do you have any general comments on the performance benchmarks under consideration?