Natural Gas Regulation in Ontario:

A Renewed Policy Framework

Report on the Ontario Energy Board

Natural Gas Forum

March 30, 2005

MESSAGE FROM THE CHAIR

I am pleased to present the Ontario Energy Board's report from the Natural Gas Forum (NGF). This report outlines our vision for a regulatory framework for the sector and lays the groundwork for improved efficiency and effectiveness in the regulation of natural gas.

The Board has regulated the natural gas sector for many years and has overseen the development of the competitive market. Although the gas market is functioning well in Ontario, there are improvements to the regulatory framework that are in the public interest.

First, we believe that all stakeholders will benefit from a more predictable and longer-term treatment of rates. Utilities will benefit because they can make longer-term decisions and customers will benefit through downward pressure on rates. The Board's report identifies the specific components of the incentive regulation plan that the Board believes will lead to these results.

Second, we believe that Ontario's transportation and storage infrastructure is important to our energy future. The province benefits from having a natural gas hub, with a number of interconnecting pipelines and an abundance of natural gas storage. The Board will ensure that the regulatory treatment of Ontario's storage and transmission assets optimizes the value of the opportunities that accompany having a hub. Most immediately, the Board will commence a process to review the infrastructure needs of natural gas-fired generation. More generally, the Board will review the appropriate pricing and access entitlements for storage and transportation assets and services.

Third, the role of the utility in natural gas supply and transportation goes to the core of two intersecting principles. On the one hand, it is important to ensure the strength of retail and wholesale competition as a way to ensure optimal commodity supply. On the other hand, the Board recognizes that there may be the need for regulated utilities to participate in ensuring the adequacy of pipeline infrastructure to serve the province.

With respect to commodity, the Board has concluded that natural gas utilities should continue to provide a regulated gas supply option for consumers. The Board has also determined that the costs of regulated natural gas supply need to be reviewed in order to make it easier for consumers to compare their options in the marketplace.

The Board is not currently in favour of utilities entering into long-term supply contracts, but it may be appropriate for utilities to enter into long-term transportation contracts to support security of supply. The Board will provide a process whereby utilities can apply for pre-approval for either type of contract.

The plan laid out in this report is substantive and thorough. Its implementation over the next several years will lead to improved regulation in the province. The Board is committed to its timely and effective implementation.

The Natural Gas Forum has been an open and transparent initiative that, over a year, fostered a dialogue in the sector among utilities, marketers, sector associations, storage developers, municipalities, and consumer and other public interest groups. Their contributions were immeasurable. On behalf of the Board, I want to thank them.

The Board looks forward to implementing the report's conclusions over the next several years through public processes where stakeholder participation will continue to play a vital role.

Sincerely,

Howard I. Wetston, Q.C.
Chair
Ontario Energy Board

March 30, 2005

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EXECUTIVE SUMMARY

The natural gas market is changing. On the supply side, conventional supply sources are expected to experience flat to declining production. The anticipated increased reliance on non-conventional supply sources has raised questions about the need for infrastructure within Ontario to meet changing flow patterns and about the adequacy of the current regulatory treatment of utilities' acquisition of upstream gas supply and their transportation arrangements. On the demand side, the anticipated expansion of gas-fired power generation will affect the extent and type of investment required in gas infrastructure in Ontario and will drive the convergence (financial and operational) of the gas and electricity markets.

In light of these developments, the Board believed that it was time for a deliberate analysis and review of the policy underlying the key structural components of the natural gas regulatory system: rate regulation, storage and transportation, and regulated gas supply. The Board initiated the Natural Gas Forum as a means of investigating these issues, to get the input of stakeholders and to help the Board develop its policies in these areas. In the Board's view, important incremental changes can and must be made to the structure of natural gas regulation in Ontario. These changes are needed to address the emerging trends in the industry and to fulfil the Board's legislated objectives.

Summary of Conclusions

Rate Regulation

To fulfil its statutory objectives related to consumer protection, infrastructure development and the financial viability of the industry, the Board has determined that the gas rate regulation framework must meet the following criteria:

- establish incentives for sustainable efficiency improvements that benefit customers and shareholders
- ensure appropriate quality of service for customers

- create an environment that is conducive to investment, to the benefit of customers and shareholders

The Board believes that a multi-year incentive regulation (IR) plan can be developed that will meet these criteria. A properly designed plan will ensure downward pressure on rates by encouraging new levels of efficiency in Ontario's gas utilities. By implementing a multi-year IR framework, the Board also intends to provide the regulatory stability needed for investment in Ontario.

The following are the Board's conclusions on the key parameters:

In a multi-year IR plan, the **annual adjustment mechanism** embodies the combined assessment of cost changes and productivity improvements. The Board concludes that making an appropriate determination of this component will ensure that the benefits of efficiencies are shared with customers during the term of the plan. The Board will determine the methodology for the annual adjustment mechanism through a generic hearing.

The Board's view is that a thorough cost-of-service **rebasing** must occur at the end of each IR plan's term before a new plan is put in place. Rebasing is an important consumer protection feature. Through robust rebasing, efficiency improvements will be revealed and the benefits passed on to customers through base rates for the next period. The Board will determine the base rates through a hearing for each utility.

The Board does not intend for **earnings sharing mechanisms** to form part of IR plans. The Board views the retention of earnings by a utility within the term of an IR plan to be a strong incentive for the utility to achieve sustainable efficiencies. The Board will ensure that the benefits of efficiencies are shared with customers through the annual adjustment mechanism and thorough rebasing.

The Board expects that the **term** of IR plans will be between three and five years.

In the Board's view, an appropriate balance of risk and reward in an IR framework will result in reduced reliance on **deferral or variance accounts**, and reliance on **off-ramps** or **z-factors** in limited, well-defined and well-justified cases only.

The Board will develop the **service quality framework** and will undertake a consultation to finalize the measures, standards and reporting mechanism.

The Board will consult with stakeholders and modify the Gas Reporting and Record Keeping Requirements (RRRs) as necessary to meet the requirements for **financial reporting** in the new ratemaking framework. While the Board intends to conduct this consultation and modify the RRRs before the development of the first IR plan, it expects that these RRRs may be further refined in the context of specific IR plan development.

The Board will undertake a review of the gas utility **data filing guidelines** for the rate hearing process, and then develop a set of draft filing guidelines, which it will distribute for consultation.

The Board will not decide at this time the precise structure of the **alternative dispute resolution (ADR) process** for the IR framework. The Board has already undertaken a review of the ADR process, and it will consider the submissions made through the Natural Gas Forum before releasing its conclusions in the ADR review.

Storage and Transportation

The Board believes that it is necessary to ensure that Ontario has adequate gas infrastructure and the appropriate rate design to facilitate the anticipated increased reliance on gas-fired power generation. The Board will hold a review to determine the impact of increased gas-fired power generation on storage and transportation infrastructure and services in order to ensure a reliable supply of electricity and gas. This review may lead to a formal proceeding resulting in orders setting rates, granting leave to construct or other remedies.

The Board will hold a hearing to determine whether it should refrain, in whole or in part, from regulating the rates charged for natural gas storage in Ontario.

The Board will not restrict the rates charged for new storage developed by new independent storage operators. However, the Board will develop, through a consultative process, filing guidelines for proponents of new independent gas storage facilities.

Regulated Gas Supply

The Board concludes that the utilities should continue to provide a regulated gas supply option. However, the regulated gas supply option should be seen as a default supply option and structured to facilitate customer choice.

The Board will hold a generic cost allocation hearing to review the costing of regulated gas supply. As part of this hearing, the Board will also assess whether further unbundling is required and how any further unbundling will be implemented.

The Board will develop guidelines for the standardization of the quarterly rate adjustment mechanism process. As part of this activity, the Board will consult in more detail on the underlying pricing that should be incorporated.

The Board believes that a utility-provided fixed-term, fixed-price contract is inappropriate at this time. The fixed term could reduce the utilities’ ability to ensure the full mobility of customers, and the fixed-price aspect would compete with the product offered by the retail marketers.

The Board believes that there is a role for utilities in long-term upstream transportation contracting, but the Board is not in favour of new long-term utility supply contracts at this time. However, the Board will offer utilities the opportunity to apply for pre-approval of long-term supply and/or transportation contracts. Further, the Board will consult on the development of guidelines that will inform all stakeholders of the principles and issues the Board will consider when evaluating an application for contract pre-approval.

INTRODUCTION

In view of the changing environment for the natural gas market, the Ontario Energy Board initiated the Natural Gas Forum in late 2003 to review the policy underlying key structural components of the natural gas regulatory system. After consulting with stakeholders, it was determined that the Forum would focus its investigation on rate regulation, storage and transportation, and regulated gas supply. This report sets out the conclusions reached by the Board as a result of the Natural Gas Forum process.

Structure of the Report

The report is organized into five sections, as follows:

- The **Introduction** offers a brief history of natural gas regulation in Ontario, the context for the Board's initiation of the Natural Gas Forum and a description of the Natural Gas Forum process.
- **Rate Regulation** describes the overall framework for ratemaking and the specific parameters of an incentive regulation framework. It also contains related discussion about service quality, financial reporting, data filing requirements and the alternative dispute resolution process.
- **Storage and Transportation** addresses the issues raised by an increase in gas-fired power generation, competition in storage and new independent storage developments.
- **Regulated Gas Supply** discusses whether a regulated supply option should be retained. Related issues include cost allocation, unbundling, pricing and long-term supply and transportation contracts.
- **Implementation** describes the Board's regulatory instruments and the anticipated timing for implementation of this report's conclusions.

Appendix 1 provides background information on Ontario's natural gas market, and Appendix 2 lists the Natural Gas Forum participants.

History of Natural Gas Regulation in Ontario

The recent history of natural gas regulation in Ontario has had two major phases to date.

The first of these phases covered the period 1985–96, when the Board reformed its regulatory structure to facilitate the deregulation of wellhead natural gas prices in Canada. Although the initiative to deregulate upstream prices was led by the governments of Canada and the producing provinces (Alberta, British Columbia and Saskatchewan), Ontario, as the major consuming province, played a crucial role in ensuring that customers realized the benefits of deregulation.

The Board's role in this phase was to facilitate access to upstream markets through the unbundling of gas supply and long-haul transportation arrangements from the intra-Ontario transmission, storage and distribution functions. These changes allowed large-volume Ontario customers to access their own arrangements for gas supply and transportation. The Board held a series of regulatory proceedings in 1986–88 to identify and implement the key regulatory changes required to implement the new market structure. Areas where changes were made included the unbundling of contract carriage rates, the creation of the buy/sell methodology, the treatment of stranded costs, and the legal and regulatory treatment of competitive gas suppliers.[1]

The second major phase of gas regulation commenced in 1996 with the *Report on the Ten-Year Market Review of Natural Gas Deregulation*,[2] which in turn led to a number of workshops and reports to address concerns about the market and possible changes. The Ten-Year Market Review culminated in the *Advisory Report to the Minister of Energy, Science and Technology on Legislative Change Requirements for Natural Gas Deregulation*[3] (December 16, 1997) (the advisory report). This report identified a series

[1] See, for example, Energy Board Rate Orders 410, 411 and 412, April 4, 1986.
[2] Available on the OEB Web site under "Natural Gas Forum."
[3] Available on the OEB Web site under "Natural Gas Forum."

of legislative and regulatory changes aimed at enhancing retail competition within Ontario.

The legislative changes recommended in the advisory report were largely realized in the *Ontario Energy Board Act, 1998*, which:

- removed the legislative restrictions on gas sales within Ontario;
- authorized the Board to license retail gas marketers and to enact rules addressing issues such as relationships between utilities and affiliates and access to gas distribution, storage and transmission; and
- gave the Board the power to refrain from regulation where competition is sufficient to protect the public interest.

However, many of the regulatory changes contemplated in the advisory report did not come to fruition. For example, the Board had proposed a restructuring of gas utility supply services to separate load balancing from the regulated utility supply option and a further unbundling of monopoly utility services, neither of which occurred. As well, the Board had encouraged the utilities to come forward with applications for performance-based regulation (PBR) plans. Plans were proposed, and they were reviewed and implemented by the Board, but they did not meet the expectations of the Board or the stakeholders, including the utilities. The Board's experience with the challenges related to unbundling and PBR informed the issues it asked the Natural Gas Forum to consider.

Natural gas regulation in Ontario will enter its third phase with the policy choices and processes developed through the Natural Gas Forum process and outlined in this report. The Board will achieve the outcomes identified in the report by being practical and thorough and by demonstrating leadership.

- **Practicality** requires that the Board identify the changes to the regulatory structure that it considers priorities, and the Board has done so. It has identified the key areas that it believes should be addressed now. Other, less pressing issues, will be addressed in due course but they will not distract the Board from achieving the outcomes identified in this report. The agenda coming out of this report is ambitious, but it is achievable.

- **Thoroughness** requires that the Board establish a clear road map and a logical time frame for change. Many of the conclusions reached in this report overlap. The new policies must be implemented in a coherent sequence and in a manner that allows them to interact effectively. The steps involved in the Board's implementation of its plans will be managed and purposeful.

- **Leadership** requires that the Board set the direction for change, then use its resources, skill and authority to implement that change.

The Board benefits from a stakeholder community – including utilities, customer groups and other participants – that presents positions forcefully and effectively. However, the stakeholders, individually and collectively, do not represent the entire public interest in regulatory outcomes. The Board will provide leadership on the goals of and expectations for regulatory policy.

Context of the Current Policy Review

The Board notes that stakeholders are largely satisfied with many of the current regulatory arrangements, and it has determined that the sector will benefit more from specific, incremental structural improvements than from transformative change. However, it would be a mistake to conclude that the required incremental change is optional: the regulatory structure of the industry must evolve to meet two key concerns.

First, new dynamics are in play in both the supply and demand for natural gas. (Appendix 1 contains background information about the natural gas system in Ontario, including a brief discussion of the major trends in supply and demand.) On the supply side, it is anticipated that conventional supply sources will experience flat to declining production, and that, as a result, there will be increased reliance on non-conventional supply sources. These expectations have raised questions about the need for infrastructure within Ontario to meet changing flow patterns and the adequacy of the current regulatory treatment of utilities' acquisition of upstream gas supply and their transportation arrangements. On the demand side, the anticipated expansion of gas-fired power generation will affect both the extent and type of investment required in gas infrastructure in Ontario and will drive the convergence (financial and operational) of the gas and electricity markets. The Board will anticipate and facilitate these new demands through the policies and processes set out in this report.

Second, and more generally, in establishing the Natural Gas Forum the Board believed that it was time for a deliberate analysis and review of the policy underlying the key structural components of the regulatory system: rate regulation, storage and transportation infrastructure, and regulated gas supply. The regulatory treatment of each of these components has evolved over the last 10 years without specific regulatory direction. In some ways this evolution has been positive, as the industry has experimented with various directions largely in response to stakeholder priorities. As well, an evolutionary approach has avoided dramatic and traumatic policy shifts. However, this approach has limitations, which can be seen in each of the three Natural Gas Forum focus areas – rate regulation, storage and transportation, and regulated gas supply.

- In the absence of explicit regulations, the future direction of the sector is left unclear. For example, with respect to rate regulation, the Board has left the initiative to develop PBR proposals with the utilities in consultation with intervenors, and has adjudicated these proposals in a largely reactive manner. The results have been unsatisfactory, and all parties are waiting for the Board's direction on the next steps. That direction is provided in this report.

- Structural policy decisions have resulted from a number of individual decisions in specific applications brought before the Board. These policy decisions, which responded to specific situations, served a purpose, but they are now starting to show strains. For example, the regulatory treatment of storage involves complex choices and tradeoffs – both among classes of customers and among policy goals

– in assessing entitlements to cost-based (“heritage”) storage and the role of competition in storage services. These choices and tradeoffs should be made more deliberately, in a rigorous and thorough manner, as fundamental policy decisions. The Board believes that it is important to address the specific issues raised by the expected increase in gas-fired power generation within the same context. The financial and operational interfaces between the gas and electricity markets have important ramifications for Ontario storage and transportation, which are best addressed on an industry wide basis.

- It appears that the retail (commercial and residential) direct purchase market may have matured, or even receded. The number of retail customers on direct purchase plans has decreased from a high of 60 per cent after the introduction of agent billing and collection service to a current figure of approximately 50 per cent. As well, the number of suppliers serving the retail market has decreased substantially. It is not clear whether these developments represent customer choice or whether they are the result of a regulatory system that encourages customers to stay on regulated gas supply by making their retail choices too expensive or too confusing. The Board will ensure that customers are given the option of being served by regulated supply or competitive supply, and that they will be able to make their choice on the basis of a meaningful comparison between the two options, facilitated by a proper allocation of costs that will remove any undue distortions. Details about the implementation of these changes are provided in this report.

In the Board’s view, important incremental changes can be made to the structure of natural gas regulation in Ontario. The Natural Gas Forum process, described below, has provided the Board with the input of stakeholders on the key issues of rate regulation, storage and transportation, and regulated gas supply. The sections of the report that follow set out the Board’s direction in these areas.

The Natural Gas Forum Process

The first Natural Gas Forum meeting took place in November 2003. At that one-day meeting, the Board heard stakeholders' views on the priority issues for natural gas regulation.[4] From that initial discussion, the Board identified the priority issues for the Natural Gas Forum:

- system supply
- storage and transportation
- rate regulation

To stimulate the review, the Board sponsored a discussion paper on each topic. The discussion papers contained market research, recounted the experiences of other jurisdictions and identified policy options. The Board received 24 initial written submissions in response to these discussion papers.

In the fall of 2004, the Board hosted a second Natural Gas Forum meeting. This six-day technical consultation provided an opportunity for stakeholders to present their views to the Board and for all participants to discuss these views. There were 31 oral presentations and 9 panel discussions. After completion of the technical consultations, the Board received 35 final written submissions. Appendix 2 lists the parties that made oral presentations and final submissions.

Because the Natural Gas Forum is a policy initiative, the Board's statutory power to grant cost awards in "proceedings" did not apply to the Forum. However, the Board made funding available from its own budget to facilitate the participation of a number of stakeholders, including residential customers and environmental groups.

The Board would like to thank all the Natural Gas Forum participants who took the time to make presentations during the technical consultations and who participated in the exchange of views that took place.

[4] The *Report of the Ontario Energy Board Natural Gas Forum* (2003) is available on the OEB Web site under "Natural Gas Forum." Also available at that location are the discussion papers, initial and final written submissions, and slides of oral presentations referred to in the following paragraphs.

RATE REGULATION

Background

For many years, the Board has employed the traditional cost-of-service ratemaking (COSR) methodology to set the rates for the gas utilities under its jurisdiction. In the late 1990s, the Board encouraged Union Gas Limited (Union) and Enbridge Gas Distribution Inc. (Enbridge) to bring forward applications for performance based regulation (PBR) plans. Each company did so, and the Board subsequently reviewed the plans and approved them for implementation.

Because these two plans involved the first PBR experience in the Ontario gas industry, they were viewed as trial plans of three years' duration. However, they did not have the same degree of comprehensiveness. Enbridge's plan covered only the operations and maintenance portion of its costs and was termed a "targeted" PBR, while Union's plan provided comprehensive PBR coverage for its full revenue requirement, with a price cap.

Upon the expiration of the trial PBR plans, the companies were asked to file new cost-of-service (COS) applications to set base rates for what were expected to be new PBR proposals. However, both companies chose not to update their PBR plans, and instead resumed filing applications based on traditional COS methods. At present, both utilities are operating under COS rates.

However, for some time stakeholders have expressed concerns about perceived inefficiencies in the current ratemaking framework, such as a resource-intensive hearing process and weak incentives for utilities to perform efficiently. As a result, the Natural Gas Forum focused on broad questions related to determining an appropriate ratemaking framework and, in particular, whether the current framework should be maintained or changed.

The Regulatory Framework: Cost-of-Service Ratemaking or Performance Based Regulation?

Many of the submissions expressed a degree of support for PBR because of its incentive properties and the desirability of increasing utilities' efficiency. This support partly reflected the acknowledged weaknesses in the COSR model, including weak efficiency incentives and the high regulatory burden of annual rate hearings. However, endorsement of PBR was delivered with caution, particularly by the customer groups. A number of these groups expressed a preference for COSR at the present time, because, in their view, it has proven to be an effective methodology.

Many of the submissions (and the initial Board-sponsored discussion paper) commented on the experience of Enbridge's and Union's trial PBR plans. The reluctance of many stakeholders to endorse PBR is related to their dissatisfaction with these initial trial PBR plans. The PBR trials were widely considered unsuccessful, and the Board must consider this experience in determining future direction.

Stakeholders identified six factors to be considered in designing a ratemaking plan:

- whether the plan is targeted or comprehensive
- the sharing of benefits/earnings between ratepayers and shareholders
- the complexity of the rate adjustment mechanism
- the term of the plan
- transparency of information during the term of the plan
- the clarity of the Board's expectations for the plan

These six factors are discussed below.

Whether the plan is targeted or comprehensive: Most PBR plans are comprehensive, to create stronger and more balanced incentives. For example, a plan that focuses only on operating and maintenance expenses may weaken incentives to control capital costs, with the effect that overall performance incentives may not be improved. A plan that targets only certain areas may unintentionally create incentives for firms to allocate costs differently than they otherwise would. The targeted nature of the Enbridge PBR plan may have played a role in the general dissatisfaction for this type of plan. In particular, the outsourcing Enbridge undertook may have been less controversial if Enbridge's PBR had been more comprehensive.

The sharing of benefits/earnings between ratepayers and shareholders: Many ratepayer groups in particular criticized the Enbridge PBR plan because it did not contain explicit provisions to share benefits with its customers. The lack of this feature contributed to stakeholder perceptions that the Enbridge plan was poorly designed. It also elevated concerns about regulatory gaming with respect to Enbridge's outsourcing arrangements. Many customer groups were disappointed by what they saw as the absence of any explicit or tangible benefits resulting from the trial PBR plans, and they viewed earnings sharing mechanisms as a way to address this shortcoming. Rebasing at the end of the plan's term is another mechanism for ensuring that benefits flow to ratepayers. Rebasing also avoids the incentive-diluting effects of earnings sharing mechanisms during the term of the plan.

The complexity of the rate adjustment mechanism: Another factor that, it was felt, limited the effectiveness of the PBR plan was the acknowledged need for technical expert opinion and input on the specific parameters of the PBR mechanism. A number of stakeholders expressed concern that the technical debates related to the Union PBR plan were time consuming and expensive. Others pointed out the risk of arbitrary decisions on the parameters. The wish to avoid high costs and, more importantly, the risk of arbitrary regulatory decisions have contributed to a desire to implement a more simplified approach to PBR plans. All else being equal, simplicity in the design of PBR plans is seen as a virtue, but the Board must ensure that the resulting rates are just and reasonable.

The term of the plan: Both of the Ontario PBR trial plans had three-year terms, to reflect the plans' experimental nature. Typically, PBR plans are designed so that incentives are naturally strengthened as the PBR plan's term and the period between rate reviews increase. Generally, five-year plans are the standard in PBR regimes, but plans as long as 10 years have been implemented. The long terms allow utilities to implement long-term efficiency improvements.

Transparency of information during the term of the plan: Customer groups were concerned that the framework of PBR plans is less transparent than that of COS plans, and that, therefore, customers were more excluded from the PBR process than from the COS process. Also, stakeholders were concerned about the lack of public reporting of the utility's results. Stakeholders wanted this information to assess whether the regulatory framework was working.

The clarity of the Board's expectations for the plan: Stakeholders perceived a lack of direction from the Board and exhibited a degree of scepticism in the trial PBR process. The submissions indicated that greater understanding and consensus on PBR would likely emerge if the Board clearly articulated its views about the purpose, application and most appropriate design of PBR plans. Several parties contrasted the gas experience with that in electricity, noting that in the case of electricity the Board took an active role in evaluating PBR options and in working with stakeholders to arrive at a preferred PBR model. These parties observed that, in contrast, the natural gas PBR plans were based on company proposals, with subsequent input from intervenors, Board hearings and then the Board's ultimate decisions.

There was widespread agreement that the Board should develop guidelines to outline its ratemaking expectations of all parties, irrespective of the model it chooses. The rationale was that, due to the expected longer term of the new ratemaking regime, clear and consistent long-term policies are needed to reduce the regulatory risk and to ensure that productivity targets are understood and met.

The Board's Conclusions

The Board believes that the level of scepticism is due in part to the different expectations held by utilities and customers, which in turn are due to the absence of a clearly articulated ratemaking framework. The Board will establish a firm framework to ensure that consistent expectations are held by both utilities and customers.

As a first step, the Board must take account of its legislated objectives, and in particular, the following:

- to protect the interests of consumers with respect to prices and the reliability and quality of gas service
- to facilitate rational expansion of transmission and distribution systems and rational development and safe operation of gas storage
- to facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas

To fulfil these statutory objectives, the Board must determine the most effective ratemaking framework. Accordingly, it has determined that the gas rate regulation framework must meet the following criteria:

- establish incentives for sustainable efficiency improvements that benefit both customers and shareholders
- ensure appropriate quality of service for customers
- create an environment that is conducive to investment, to the benefit of both customers and shareholders

The Board believes that a ratemaking framework that meets these criteria will ensure that the statutory objectives of consumer protection, infrastructure development and financial viability will be met, and that rates will be just and reasonable. Each of the above criteria is discussed further below.

Sustainable efficiency improvements: It is important that the rate regulation framework creates incentives for the implementation of sustainable efficiency improvements and that it is structured to ensure that ratepayers share the benefits of these efficiencies. Traditional COSR plans generally provide only limited incentives for efficiencies. A PBR framework, on the other hand, is generally recognized to provide efficiency incentives.

The challenge is to ensure that the efficiencies do not result just in short-term shareholder benefits, but rather sustainable improvements that benefit ratepayers through lower utility costs and lower rates. A properly designed ratemaking framework will provide incentives for utilities to find cost efficiencies, and thereby to increase their earnings over the course of the plan. A properly designed plan will also ensure that customers benefit from efficiency gains both during the plan's period, through an appropriate adjustment or earnings sharing mechanism, and upon rebasing for the next plan period. The Board recognizes the importance of ensuring that customers achieve benefits from the beginning of the plan's term.

Appropriate quality of service: Appropriate quality of service is at the core of consumer protection. It is generally believed that the gas utilities provide good customer service. There is a risk that the introduction of strong incentives to implement efficiencies could result in reduced quality of service. To meet its objective to protect consumer interests, the Board must address this issue. At the same time, the Board recognizes that some efficiencies may involve finding more effective ways to deal with customer issues. Further, the Board must be open to arguments that it may be reasonable to reduce some service levels if they are not cost effective to maintain.

An environment conducive to investment: The Board is committed to creating a predictable and stable regulatory environment that encourages continued investment in the sector. A strong, financially viable sector will help to sustain a robust gas market in Ontario, which will benefit consumers in terms of price and security of supply. In the Board's view, while Ontario's natural gas sector does not now suffer from an overall lack of investment, it is important to examine the incentives for investment to ensure they create a stable financial base for the utilities.

In particular, the Board is concerned about the infrastructure needs associated with the expected increase in gas-fired power generation, the changing flow patterns that may result with market developments (for example, if there were a liquefied natural gas terminal in eastern Canada) and the need to maintain Ontario as a location with a strategically important natural gas hub. Infrastructure is addressed in detail in the section of this report called “Storage and Transportation,” but infrastructure needs are an underlying element that must also be considered in developing the overall rate regulation framework.

Given the criteria set out and explained above, a fundamental issue for the Board is whether COSR or some form of PBR should be implemented to regulate the rates of the gas utilities, or whether the Board should consider the range of options available on the continuum that runs between the COSR and PBR frameworks. COSR, as it has been applied in Ontario, presents fewer risks in some respects, but it also lacks strong incentives to increase operating efficiencies and to reduce costs. The regulatory burden of annual or bi-annual rate cases associated with COSR is also high. In contrast, PBR can be designed to create strong performance incentives and to reduce regulatory costs, by extending the term of the plan to three years or more. However, PBR involves issues related to the ongoing transparency of costs and the need to ensure that customers share the benefits of the efficiencies implemented. These issues, and the six factors (discussed earlier) that were identified as a result of the experience with the Union and Enbridge trial PBR plans, need to be addressed for PBR to be successful.

In North America, PBR plans have been encouraged and implemented in several jurisdictions, including Ontario. Outside North America, many regulators addressing market restructuring have chosen PBR instead of COSR, so that PBR is now a widely used form of energy utility regulation in the world. PBR is also employed in other regulated industries, most notably telecommunications.[5]

In the Board’s view, it is the parameters of the framework that will determine whether the framework meets the criteria. For example, the COSR framework could be refined to

[5] Further information on the experience with PBR in other jurisdictions is available in the discussion paper “Rate Regulation in Ontario,” prepared for the Natural Gas Forum and available on the OEB Web site under “Natural Gas Forum.”

enhance the efficiency incentives by extending the term of the plan and to reduce regulatory costs by introducing process reforms. However, COSR requires a utility to forecast its costs and revenues. It is unlikely that a utility could make this forecast with an acceptable level of precision beyond two years, and a two-year term provides a limited efficiency incentive. Setting rates for any longer period would require the Board to consider external measures of cost inflation. As well, to ensure that customers share in the benefits when a utility outperforms its forecasts, some form of earnings sharing would be required.

If external measures of cost and some mechanism for benefit sharing were both added to the framework, the multi-year COSR plan would take on the characteristics of PBR. However, if this quasi-PBR framework were structured with an inadequate consideration of inflation and productivity potential, with z-factors (for non-routine rate adjustments intended to safeguard customers and the utility against unexpected events that are beyond management's control) and with an earnings sharing mechanism within the term of the plan, then the efficiency incentive would be reduced. Likewise, if onerous annual reviews were required, the regulatory costs could remain high. The resulting framework may be less satisfactory than that of a traditional COSR.

On the other hand, some forms of PBR may involve a de-linking of rates and costs, as well as a loss of transparent cost data and cost analysis. The Board does not support a complete de-linking of rates and costs, and it is not prepared to forgo the benefits of a transparent review of costs.

A rigorous multi-year framework can ensure that there is downward pressure on rates and that customers and shareholders benefit from efficiency improvements. The key determinant of success, though, is the particular parameters of the plan. The Board intends to adopt the best aspects of both the COSR and PBR approach. It will therefore focus on specifying its expectations for the specific parameters of the rate regulation framework.

The Board believes that a multi-year incentive regulation (IR) plan can be developed that will meet its criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment. A properly designed plan will ensure downward pressure on rates by encouraging new levels of efficiency in Ontario's gas utilities – to the benefit of customers and shareholders. By implementing a multi-year IR framework, the Board also intends to provide the regulatory stability needed for investment in Ontario. The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan.

A related matter is whether the IR framework should be comprehensive or targeted – in other words, whether the plan should apply to all costs or only some costs. The targeted approach was tried with the Enbridge plan. The comprehensive approach was used for Union and for Ontario's local electricity distribution companies, and it is the more common approach in other jurisdictions. The Board's view is that the targeted approach did not work effectively because it diluted and distorted the incentives, and that a comprehensive model is preferable. Although a comprehensive approach may involve greater regulatory costs to implement and may be considered by some to involve greater risks, it offers more balanced incentive properties and may be expected to reduce the overall regulatory burden.

Similarly, the Board concludes that the utilities should not alternate between a COSR and an IR framework. Switching between rate frameworks could make robust benefit sharing harder to achieve and introduce confusion and mistrust.

With respect to concerns that incentive regulation should not be used until a stable environment exists, we acknowledge that the industry continues to experience change, but we do not believe that this situation is inconsistent with an IR framework. Rather, the Board is of the view that a properly constructed IR framework should address expected changes and establish a balance of risks and rewards for the utilities.

A further related matter is the treatment of the utilities' role in and policies for conservation and demand management. It will be necessary to ensure that the rate regulation framework and the conservation and demand management policies are compatible. The Board expects that this issue can be addressed in the rate application process.

The following key parameters of the ratemaking framework are addressed below:

- annual adjustment mechanism
- rebasing
- earnings sharing mechanism
- the term of the plan
- off-ramps, z-factors and deferral or variance accounts
- service quality monitoring
- financial reporting
- filing guidelines
- the role of alternative dispute resolutions

Annual Adjustment Mechanism

The annual adjustment mechanism is the means by which rates are changed each year within the term of the plan. In many respects, this feature is the most important one in the plan. The adjustment mechanism captures expected annual changes in costs (such as inflation) and the utility's productivity improvements. The choice of the productivity factor has been controversial in past rate cases, as discussed earlier, but it is one of the ways that the benefits of efficiency improvements can be shared with customers during the term of the plan. The issue is how rates should be adjusted within the term of an IR plan.

Stakeholders' Views

Stakeholders offered a variety of views. Enbridge said that it would be appropriate to use the Ontario consumer price index (CPI) to adjust rates annually, along with a discount factor to reduce the forecast inflation number. This plan would have no separate productivity factor. Union said that setting an accurate productivity factor can be a controversial process, and suggested that adopting an earnings sharing mechanism with no deadband would act as a form of implicit productivity factor.

Other suggestions included a rate freeze in the second and third years of a three-year plan, which would eliminate the need for controversial issues such as inflation and productivity factors. Another suggestion was to use 50 per cent of the Ontario CPI in each year, with the remaining 50 per cent being deemed to cover all other adjustments, such as productivity, stretch factors and so on.

The Board's Conclusions

In a multi-year IR plan, the annual adjustment mechanism embodies the combined assessment of cost changes and productivity improvements. Various methods can be used to evaluate these trends (inflation factors, industry productivity factors, and so on), and the resulting adjustment mechanism could be a complex formula or it could be a single factor, taking the form of an increase, a decrease or a rate freeze. The Board understands that determining an appropriate productivity factor may be challenging. It concludes, however, that making an appropriate determination of this component will ensure that the benefits of efficiencies are shared with customers during the term of the plan. As stated above, the Board believes that ensuring that customers share in the benefits of efficiencies is a key criterion for an effective rate regulation framework.

Some stakeholders submitted that separate earnings sharing mechanisms could be used instead of specific productivity factors. The Board does not believe that using an earnings sharing mechanism is the appropriate approach. Its reasons are discussed in the section below on earnings sharing.

The Board will hold a generic hearing to determine the appropriate basis for setting the annual adjustment mechanism. The Board expects that once the generic methodology is determined, its application to each utility may result in different specific adjustments.

Rebasing

Rebasing is the exercise that takes place at the expiry of an IR plan in preparation for setting rates for the subsequent period. Essentially, it is a review of the utility's financial position on both an historic and prospective basis, including an examination of the efficiency improvements realized under the IR plan. In a practical sense, rebasing reviews are very similar to traditional COSR reviews, except that they include a focus on the achievements reached in the IR plan. Rebasing also provides some assurance that there is an up-to-date and meaningful relationship between costs and rates. The issue addressed here is whether rebasing should occur.

Stakeholders' Views

Most stakeholders, with the exception of Union and Enbridge, submitted the view that rebasing is an essential component of an incentive-based ratemaking framework. The Canadian Manufacturers & Exporters submission made the point that rebasing should take account of actual performance in the final year of the plan. Enbridge asserted that the development of the second-generation PBR plan should be negotiated with stakeholders without rebasing, and that utilities' periodic information filings should be adequate to satisfy the Board that the relationship between costs and rates is reasonable.

The Board's Conclusions

Each IR plan must begin with a robust set of cost-based rates, based on a thorough and transparent review. The Board's view is that a thorough cost-of-service rebasing must occur at the end of each IR plan's term before a new plan is put in place. Rebasing is an important consumer protection feature. Through robust rebasing, efficiency improvements will be revealed and their benefits passed on to customers through base rates for the next period. The Board will determine the base rates through a hearing for each utility.

As described above, the benefits of efficiencies can be shared with customers in two ways – during the term of the plan, through the adjustment mechanism, and in the base rates for the subsequent plan. With robust rebasing, all of the efficiency improvements achieved during the term of a plan would be built into the base rates for the subsequent plan. In this way, shareholders retain the benefits of any efficiency gains (that is, any achieved over and above the productivity factor) during the term of the initial plan, and all of the benefits flow to customers during the term of subsequent plans.

During rebasing, the Board will be particularly interested in determining whether the efficiency improvements achieved by the utility are temporary or sustainable, and it will expect to receive a thorough analysis of this issue. For example, the Board will be interested in the relationship between operation, maintenance and administration costs and capital expenditures, the timing of capital expenditures and the associated impacts on shareholders and customers. The Board will also expect to see, during the plan's term, measures that are designed to improve the utility's productivity on a sustained basis – not temporary, unsustainable budget cuts. The Board's determination of the new base rates and forward plan will reflect its assessment of all of these factors. The Board also cautions that it will take an unfavourable view of sudden and significant increases in costs at the time of rebasing, unless thoroughly justified.

Earnings Sharing Mechanisms

Earnings sharing mechanisms (ESMs) are sometimes employed in incentive-based ratemaking schemes to provide for the sharing of earnings in excess of a pre-established level between the utility's shareholders and ratepayers, usually during the term of the plan. That is, ESMs are intended to return some of the productivity improvements to ratepayers during the term of the plan.[6] ESMs are generally tied to the utility's return on equity (ROE), although the specific features of the ESM may vary from plan to plan. The features include the level at which sharing takes place, the ratio of sharing between shareholders and ratepayers and whether the ESM is symmetrical (that is, whether it

[6] In this discussion, the Board is not referring to the earnings sharing associated with transactional services, storage and transportation services or demand-side management.

applies when earnings are both above and below the target ROE). The issues we address here are whether there should be an ESM in the IR plans and, if so, what form it should take.

Stakeholders' Views

Stakeholders were divided on this issue. A number of stakeholders, primarily customer groups, were of the view that an ESM assures customers that they will benefit from the productivity gains made by the utilities. For example, the Consumers Council of Canada and the Vulnerable Energy Consumers Coalition suggested that earnings sharing could be incorporated into a COSR framework over a multi-year period. London Property Management Association and Wholesale Gas Service Purchasers Group made the point that an asymmetrical ESM applicable only to earnings above the target ROE would provide utilities with a significant incentive to increase efficiencies.

Union and Enbridge took the view that a symmetrical ESM could be developed around a benchmark ROE.

Others took the view that an ESM should not be adopted, because it would reduce the efficiency incentives of a PBR plan.

The Board's Conclusions

Customers can benefit from productivity improvements during the term of an IR plan in two ways: through the productivity factor in the price adjustment mechanism and/or through an ESM. If the productivity factor is low, customers may be dissatisfied with the expected level of benefits, and may view earnings sharing as an appropriate means by which to realize benefits within the plan's term. Stakeholders may also rely on an ESM as a way to mitigate the effects of an incorrect or uncertain productivity factor (which may be the result of utilities and stakeholders not having the same information).

In addition to the benefits that would accrue during the plan's term, customers could also benefit from productivity improvements through robust rebasing at the beginning of the next plan, as has already been described.

The regulatory challenge is to provide strong incentives to promote efficiency, while at the same time achieving customers' acceptance of the IR plan by ensuring that the benefits of the efficiencies flow to them. In the Board's view, ESMs would reduce the utility's productivity incentives and introduce a potentially costly additional regulatory process – results that are not in accordance with the Board's criteria for the regulatory framework. The Board recognizes that, without an ESM, the determination of the adjustment factor will be particularly important to ensure that customers benefit from productivity gains during the plan's term. For this reason, as noted earlier in this report, the Board has concluded that a generic hearing should be held to determine the annual adjustment mechanism.

The Board views the retention of earnings by a utility within the term of an IR plan to be a strong incentive for the utility to achieve sustainable efficiencies.

The Board does not intend for earnings sharing mechanisms to form part of IR plans.

The Term of the Plan

Stakeholders' Views

On the issue of the optimal term for the ratemaking plan, stakeholders were generally divided into two camps – customer groups generally favoured short terms of two to three years, while the utilities and the School Energy Coalition (SEC) favoured longer terms of five years or more.

Union submitted its view that the term of a plan should be long enough to provide the utility with incentives to pursue productivity improvements, and noted that the "payoff" for some productivity improvement measures may not be realized for some time. In recognition of these factors, the minimum term of plans approved in some jurisdictions is five years, with some terms as long as 10 years.

The Industrial Gas Users Association (IGUA) suggested that the term be one of the elements negotiated by the parties. IGUA indicated a preference for a shorter term, but said that a longer term may be acceptable if provision were made for an automatic review or reopening of the issue under defined circumstances. SEC proposed an initial five-year term, subject to a single off-ramp. SEC also proposed that, at the end of four years and before any rebasing application, the Board hold a hearing to determine whether it would be appropriate to extend the incentive plan for a further period of up to five years or to require a rebasing exercise.

The Board's Conclusions

The Board's view, shared by most stakeholders, is that the current system of annual rate cases is inefficient – it is costly and time consuming. The challenge for the Board is to implement a regulatory model that contains incentives for utilities to make productivity improvements and that reduces the annual regulatory burden, while ensuring both that customers benefit from productivity improvements and that an appropriate level of transparency is maintained. The Board believes that IR plans must contain longer rate-approval periods to ensure an incentive for utility shareholders to make productivity improvements and to benefit from them.

The Board expects that the term of IR plans will be between three and five years. The Board's view is that three years represents the minimum term that may be expected to give rise to productivity incentives, and its preference is for a plan of five years. The Board is reluctant to approve a term greater than five years at this time, given the importance of ensuring that productivity gains are passed on to customers in subsequent periods. The term of the plan will be determined in the generic hearing on the annual adjustment mechanism.

The Board is of the view that a plan should not be reopened during its term except for the most compelling reasons. Off-ramps are addressed below.

Off-Ramps, Z-Factors and Deferral or Variance Accounts

Various mechanisms can be established as part of the overall ratemaking framework, but designed to operate outside the plan itself. An *off-ramp* is a pre-defined set of conditions under which the plan would be terminated before its end date, usually because of some unforeseen event. A *z-factor* provides for a non-routine rate adjustment intended to safeguard customers and the utility against unexpected events outside of management control. *Deferral accounts* are formalized accounts that track an amount that cannot be forecast. *Variance accounts* are formalized accounts that track a variance around a forecast. These mechanisms are often called risk-mitigation tools, as they create a regulatory "buffer" against unforeseen circumstances.

Stakeholders' Views

Most stakeholders advocated limits on the use of off-ramps, z-factors and deferral or variance accounts. In their view, these mechanisms inappropriately mitigate the utility's risk in an incentive-based system. In general, customer groups would like to see utilities assume more risk by consenting to PBR agreements that eliminate deferral or variance accounts, as well as any side agreements that shelter the utility from unforeseen events. It is recognized that a balance exists between eliminating these mechanisms and allowing shareholders to reap the benefits of good performance. Striking this balance was viewed as more in keeping with the objectives of incentive-based ratemaking.

Union, on the other hand, argued that off-ramps are designed to protect both customers and the utility, and that customers benefit from being served by a financially viable utility. In Union's trial PBR, off-ramps were restricted to a serious decline or significant improvement in Union's financial position. Enbridge's view was that deferral or variance accounts and z-factors provide justifiable regulatory relief from cost elements beyond the control of management.

The Board's Conclusions

The Board's view of off-ramps, z-factors and deferral or variable accounts is guided by the need for an appropriate balance of risks and rewards in the incentive regulation model. As stated earlier, the Board believes that it is appropriate for the utility's shareholders to retain all earnings during the plan's period. The Board believes that this is a very strong incentive. The Board also believes that, as a balancing factor, the utility should assume an appropriate level of business and financial risk.

In the Board's view, an appropriate balance of risk and reward in an IR framework will result in reduced reliance on deferral or variance accounts, and reliance on off-ramps or z-factors in limited, well-defined and well-justified cases only.

Service Quality Monitoring

When a regulated utility seeks cost-saving (efficiency) initiatives under an incentive plan, there is a danger that the quality of service experienced by its customers will suffer. The Board has identified appropriate quality of service as one of its criteria for the ratemaking framework. Service quality indicators (SQIs) have been used in Ontario, but they have been limited to measures such as telephone response time, emergency response and pipeline corrosion surveys. The issue before the Board is how a service quality framework should be developed and regulated.

Stakeholders' Views

Stakeholders generally agreed that quality of service is an important matter. Union suggested that SQIs should relate to those aspects of the utility's service that are important to customers, and that SQI targets should be derived from the historical performance levels of the utility. Enbridge also generally supported SQIs, noting that they provide assurance that operating efficiencies are not achieved at the expense of either customer service or the safe operation of the distribution system.

Union maintained that performance rewards and penalties would be inappropriate. In its view, SQIs are intended to ensure that minimum standards are maintained in an environment where the utility has incentives to improve productivity, not to give the utility an incentive to offer higher service standards than customers may need or want. Enbridge, on the other hand, indicated that it was open to considering service incentives with SQIs.

The Board's Conclusions

In keeping with the Board's consumer protection goal for the rate regulation framework, it considers quality of service of great importance. While service quality measures and standards could be developed as part of the IR plans, the Board believes that there is merit in setting the service quality measures and standards first. Then the IR plans can be developed with the knowledge that the service quality aspect is fixed.

The Board will develop the service quality framework, and will undertake a consultation to finalize the measures, standards and reporting mechanism. The Board expects to use its rule making tools to implement this framework.

At this point, the Board does not foresee incorporating direct financial incentives into the service quality framework. However, the Board will monitor performance, and the utilities will be subject to the Board's compliance process. In the event of substandard performance, the compliance process may involve negotiated solutions or, potentially, enforcement action, either of which could include penalties.

Financial Reporting

Financial reporting refers to the flow of information from the utility to the Board (and, potentially, stakeholders) during the term of an IR plan. The Board needs to consider issues related to financial reporting in its development of the regulatory framework, keeping in mind the appropriate level of transparency and the current rules for financial reporting and record keeping.

Stakeholders' Views

Union and Enbridge expressed dissatisfaction with the high level of financial monitoring and the associated costs. Customer groups maintained, however, that increased financial scrutiny is needed, especially for an incentive-based plan, arguing that incentive-based regulation would presumably involve a more light-handed approach to regulation, and, hence, there was a risk of a reduced emphasis on financial monitoring.

Customer groups stated that the utilities need to provide financial information as a matter of course. Some suggested that cost and revenue data should be filed on a quarterly basis.

The Board's Conclusions

The Board has concluded that regular financial reporting by the utilities is necessary, and must be made available to stakeholders. The purpose of this reporting and the associated analysis is to allow the Board to discharge its responsibilities respecting the financial viability of the utilities and the transparency and the ongoing information about costs that are required by the IR framework. Rather than establishing a separate financial reporting system, the Board will use the Gas Reporting and Record Keeping Requirements (RRRs) to ensure that the objectives of transparency and financial viability are met.

The Board will consult with stakeholders and modify the Gas Reporting and Record Keeping Requirements (RRRs) as necessary to meet the requirements for financial reporting in the new ratemaking framework. While the Board intends to conduct this consultation and modify the RRRs before the development of the first IR plan, it expects that the RRRs may be further refined in the context of specific IR plan development.

The Board will ensure that appropriate financial information is accessible to stakeholders, but it does not intend to institute a formal process for reviewing this information within the term of the IR plans. The Board may consider whether to use informal stakeholder conferences.

Data Filing Guidelines

It has been 15 years since the Board has undertaken a review of rate application filing requirements. Over the years, due to changing circumstances, the utilities have departed from the guidelines, a situation that has led to some confusion and difficulty in understanding the rate filings, particularly among intervenor stakeholders.

Stakeholders' Views

Virtually all of the stakeholders indicated that the Board needs to standardize the filing requirements to ensure that the appropriate data are available to all parties early in the rate setting process. Union and Enbridge supported the concept of developing filing guidelines. In addition, it was noted that the rate hearing process would be less burdensome on all parties, less costly and less adversarial if Enbridge's and Union's filings were identical to the extent possible.

The Board's Conclusions

The Board concludes that standardizing the data filing requirements will assist in streamlining the regulatory process and in ensuring the appropriate level of transparency with respect to costs and utility operations.

The Board will undertake a review of the gas utility data filing guidelines for rate hearing processes, and then develop a set of draft filing guidelines, which it will distribute for consultation. Wherever possible, the Board will seek to develop consistent guidelines for Union and Enbridge, and will consider issues such as electronic filings.

The Role of Alternative Dispute Resolutions

Alternative dispute resolution (ADR) is a key feature of the Board's current natural gas rate hearing process. In an ADR, stakeholders attempt to resolve as many issues as possible through negotiation, although the Board must approve the ADR settlement for it to take effect. The ADR process aims to reduce the number and complexity of issues that the Board must determine at a hearing. Although the Board did not specifically request stakeholder comments on the ADR process, it did ask for general comments about the ratemaking process, and a number of stakeholders addressed ADR. The Board must determine the role of ADR in an IR framework and whether changes should be implemented in the interim, while a COS framework is in place.

Stakeholders' Views

The great majority of stakeholders felt that some form of ADR would be a useful part of the process. However, stakeholders disagreed about exactly what form the ADR should take. Some parties advocated minor changes to the current process, while others favoured substantial changes. The suggestions included the following:

- Fewer parties should participate in ADR. Nominating only one party to represent each interest would avoid duplication.
- The ADR should occur at the beginning of the process, before the formal discovery process.
- A technical conference should precede the ADR, to clarify the evidence and issues following the receipt of interrogatory responses.
- Intervenor funding should create incentives for intervenors to settle issues.
- The mediator should have in-depth knowledge of the subject matter and the authority and skills to use whatever methods are deemed most appropriate to reach a negotiated settlement.
- The Board should accept comprehensive settlements without requiring further evidentiary support where parties representing a broad range of interests reach an agreement.
- An effective monitoring and evaluation system would ensure the ongoing success of the program.

The Board's Conclusions

The Board is mindful of the concerns stakeholders have expressed and the efforts they have made to propose improvements to the ADR process. The Board will not decide at this time the precise structure of the ADR process for the utility-specific IR plans. The

Board has already undertaken a review of the ADR process, and it will consider the submissions made through the Natural Gas Forum before releasing its conclusions in the ADR review. The Board expects that the ADR process will evolve further in the process leading to the first IR applications.

Conclusions on Rate Regulation

The Board has set out its expectations for an IR framework. A number of issues must be addressed before this framework can be implemented and plans approved:

- service quality framework
- financial reporting framework
- data filing guidelines
- base rates for each utility
- the annual adjustment mechanism and the term of the plan

The Board's implementation plan for the IR framework, and the specific steps involved, are set out in the "Implementation" section of this report.

STORAGE AND TRANSPORTATION

Background

Natural gas storage facilities in Ontario have traditionally been used to provide seasonal load balancing. Gas can be purchased and shipped to Ontario-based storage during the spring, summer and fall when prices are lower and when pipeline capacity to market is underutilized, and delivered from storage to market during the winter when prices are higher and upstream capacity may be limited. Storage has also served to reduce the reliance on pipeline gas to meet peak demand, reducing the need for investment in pipeline capacity and enhancing economic efficiency by reducing both prices and price volatility.

In 1962, the Ontario government adopted the findings and recommendations of the *Report of the Committee on Oil and Gas Resources* (the Langford report) on underground natural gas storage. The recommendations included the following:

> The role of the Provincial Government with respect to storage should be that of controlling and regulating it only so far as is necessary to ensure efficient and economical development of the industry. The Committee therefore recommends the following:
>
> 1. The right to develop and operate storage areas should be granted only to experienced and competent companies .…
> 2. The use of storage facilities should be placed on a priority basis with the distributing companies having first call .…
> 3. Storage rights should remain under the jurisdiction of the province .…
> 4. Storage rights in Ontario should be used primarily for the people of Ontario .…
> 5. An authoritative body should be created to regulate and advise on all phases of the natural gas industry in Ontario.[7]

[7] Committee on Oil and Gas Resources, *Report of the Committee on Oil and Gas Resources*, “Part II: Underground Storage of Natural Gas” (Toronto: Queen’s Printer for Ontario, 1962), at 56–60.

Since that time underground natural gas storage has been accorded the status of a provincial asset and the Board has regulated it accordingly.

The *Ontario Energy Board Act, 1998*, sets out a number of objectives that guide the Board in carrying out its responsibilities, including facilitating the rational development and safe operation of gas storage. Part III of the Act sets out the Board's specific statutory responsibilities in regard to storage as follows:

- designating areas as gas storage areas
- authorizing a person to inject, store and withdraw gas
- setting compensation for landowners in the absence of an agreement on compensation between the landowners and the storage operators
- providing binding reports on applications to drill wells to the Minister of Natural Resources
- making just and reasonable rates for the sale of gas and for the transmission, distribution and storage of gas by storage companies

Three recent developments have put storage and transportation on the Natural Gas Forum's agenda.

Growth in gas-fired power generation: Although events elsewhere in North America can influence Ontario's natural gas market, perhaps the most profound impact in the near future will arise from the anticipated rapid growth in gas-fired power generation. Over 1000 megawatts (MW) of gas-fired capacity have been added recently. The Ontario government has issued a Request for Proposals (RFP) for 2500 MW of capacity to come into service over the next few years, and natural gas-fired power generation is expected to account for nearly all the successful bids received in response to this RFP.

Growth in Ontario gas-fired power generation could increase natural gas demand in the province by around 200 billion cubic feet (Bcf) annually, about one quarter of current Ontario gas demand. Furthermore, since Ontario's electricity demand has a double peak (with roughly equal maximum demand in winter and summer), there will be increased demand for deliverability from storage. The incremental capacity could lead to an incremental gas demand of 1 Bcf per day (Bcf/d) on a cold winter day, about a third of current peak gas demand of 3 Bcf/d.

Higher natural gas prices and greater price volatility: Enormous growth in natural gas-fired power generation in the United States (about 180 gigawatts over the period 1999–2004) has increased demand for natural gas. Although this new demand has been met with increased drilling activity, the growth in gas production has not kept pace with the growth in demand. The consequent increases in price and greater price volatility have raised the value of storage as a physical hedge against prices that vary by season and that, within a season, vary by day or even by hour (in the case of gas-fired power generation). Indeed, the quantity of gas in storage during the winter season is one of the most closely watched measures affecting the price of natural gas in the North American market. Storage in Ontario has become more valuable as a consequence.

Storage also plays a role in helping to reduce volatility in the market within a short time frame. The flexibility value of storage is now monetized as an arbitrage opportunity – a chance to make money by buying gas when it is cheaper and using (or reselling) it when it is more expensive. This development has put stress on storage itself to be more operationally flexible to take advantage of short-term fluctuations in gas prices. Storage owners are now managing storage more dynamically and pressing regulators to allow market pricing of storage. A secondary market for storage has emerged in North American markets.

Some storage, including high-deliverability storage, allows for withdrawals during the off-peak season (summer) and injections during the winter. More flexibility in storage operations would allow for tighter management of the resource with fewer contingency reserves required for the later parts of the winter season.

Changing structure for natural gas demand: Power generation is expected to become the most important source of natural gas demand growth in North America in the coming years, followed by residential and commercial demand growth, with the lowest growth expected from industrial demand. Although electricity demand in much of the U.S. peaks in the summer, meaning that U.S. gas-fired generation could actually reduce demand for seasonal storage, the increase in residential and commercial demand in the U.S. will increase the need for seasonal storage (estimated at an additional 1000 Bcf by 2025). This situation will require increased investments to ensure that more storage is available to the market. In addition, gas-fired generators will require higher and more flexible deliverability of natural gas to and from storage. Ontario, as an integral part of the North American gas market, will be affected by these changes.

Taken together, these factors point to an increasing demand for Ontario's existing storage capacity, and a probable need for investment in storage capacity, deliverability and transportation. Stakeholders identified storage and transportation as a key issue early in the Natural Gas Forum process, and the final submissions coalesced on three main issues:

- Should storage continue to be priced at cost-of-service (COS) rates for "in-franchise" customers (along with revenue sharing from sales to "ex-franchise" customers), or should it be priced at market rates? Or put another way, is the market for storage and associated transportation services competitive for Ontario customers?
- How should the storage and transportation needs of gas-fired power generators be met?
- Are changes needed to OEB regulatory policy to encourage new independent storage development?

Each of these issues is addressed in turn below.

Storage Pricing and Storage Competition

Prices for storage are regulated. There are two principal factors determining the pricing of storage. The first is whether the storage service is operated by the utility to serve its in-franchise customers. These customers are entitled to a quantity of storage for seasonal load balancing at a price based on COS. This price is available to the customer whether or not the customer receives supply from the regulated utility or from a competitor. However, other storage customers do not qualify for the COS rates. These customers include:

- shippers (U.S. or Canadian) taking physical positions for hedging or to capture arbitrage opportunities and to manage long-haul gas transportation;
- direct-purchase customers whose demand for storage exceeds the storage allocated by the utility at COS rates; and
- utilities purchasing storage from each other (e.g., Utilities Kingston purchasing from Union Gas).[8]

Storage capacity that is surplus to in-franchise needs is offered to these ex-franchise parties at market-based rates. These market-based rates are estimated to be 30 per cent to 50 per cent higher than regulated COS rates. Between 75 per cent and 90 per cent of the profits from market-based sales are returned to the storage operator's in-franchise customers through reductions to the COS rate.

Stakeholders' Views

Not surprisingly, nearly all parties expressed strong views about the pricing of storage. In general, those supporting market-based rates were of the view that the storage market is competitive, and those supporting COS rates for Ontario customers were of the view that the market is not competitive.

In its final submission, Union argued that all storage in Ontario should be priced at market rates. In particular, with regard to Union's own storage, it stated that ratepayers have no entitlement to storage assets that have been "financed by Union's shareholders and creditors." In Union's view, the Board should minimize barriers to entry, allow

[8] Enbridge currently purchases about 20 Bcf of storage from Union at COS rates. The Board recently denied Enbridge's request for recovery of the costs of a new storage contract with Union at market-based rates until the existing contract based on COS rates expires in 2006. The City of Kitchener also receives storage at COS rates from Union, but purchases additional quantities at market-based rates.

owners to keep their profits, ensure a level playing field and allow market pricing to encourage economically efficient development of infrastructure. Union also noted that the regulatory requirements for storage contracts (with Board approvals required for contracts longer than 17 months) were an impediment to the efficient operation of the market, and that longer-term contracts would be needed to support new storage construction. Union acknowledged that a transition period may be needed to get to this state. In its view, the move to market-based prices would cost residential customers about $15 per year.

Union submitted a study prepared by Energy and Environmental Analysis Inc. (EEA) that argued that storage is in fact workably competitive, based on comparing gas prices at different delivery points in Ontario, Michigan and New York. The main points of the study can be summarized as follows:

- Storage has a number of functions that drive its value in the North American gas market. In addition to seasonal load balancing, storage can be used for short-term deliveries, can act as a substitute for pipeline capacity and has optional value both seasonally and for very short terms.
- Storage in Ontario competes not only with storage in neighbouring jurisdictions, but also against pipeline capacity, spot gas, fuel switching and liquefied natural gas peaking services.
- Based on an analysis of the price behaviour and the physical infrastructure, including pipeline interconnections, the core competitive market for Union's storage includes Michigan, northern Illinois, northern Indiana, Ontario, western New York and Pennsylvania.
- New investment in storage is feasible at market-based rates. Storage has been developed in neighbouring Michigan and in New York on this basis. Ontario proposals to develop third-party storage at market-based rates have also been made.
- Given the size of the market (1153 Bcf) and the ability of other entities to enter it, Union does not possess sufficient market power in either total capacity or in

> deliverability to influence the market price of natural gas storage. Therefore, the market for this storage is workably competitive.

Enbridge concurred with the EEA analysis. However, in its submission, Enbridge took the view that while unregulated storage pricing is a desirable end-state, the rate consequences of such a shift would be significant. It proposed a policy that would retain COS rates for the utilities' "in-franchise" customers, but that would see all growth in storage demand (both in-franchise and ex-franchise) priced at market-based rates. Enbridge proposed that new storage, whether developed by the utility or by independent operators, not be rate regulated and that new gas-fired power generators be required to pay market prices for storage. Enbridge suggested that there was a "very good likelihood" that increased storage capacity in the Great Lakes region would bring prices down, thus limiting the price gap between storage at COS rates and at market prices and making a shift to unregulated pricing at that time less onerous for consumers.

Kitchener favoured the availability of utility storage at COS rates for all Ontario customers or, if storage moves to market-based pricing, that Ontario customers receive the "economic rents" from these higher prices.

Many of the submissions from customer groups argued that storage must continue to be regarded as a provincial asset for the benefit of provincial gas consumers. Although the impact on costs for a single residential gas consumer of moving to market-based rates for storage may not be great, in the view of customer groups the collective impact could be significant. The Industrial Gas Users Association (IGUA) cited two assessments of these potential costs from a previous rate case, which estimated that moving to market-based pricing would lead to an annual transfer of $120 million to $150 million from customers to storage providers. In IGUA's view, if this kind of increase were involved, it would not be in the public interest to move to market-based rates, even if the market was considered to be workably competitive.

Most customer stakeholders were also of the view that new storage developed by utilities for in-franchise customers should be rate-regulated, with the costs rolled into tariffs. Some suggested that all provincial customers should have access to this new storage at COS rates. However, one group suggested that new power generators should pay market rates for storage.

Generators argued for the need for regulated rates based on COS, with incremental costs rolled in. One existing power generator expressed concern about potential "rate shock," if storage charges for power generators moved to market-based rates.

A common view expressed by customer groups was that the competition analysis prepared by EEA and submitted by Union has yet to be tested, and therefore can be given only limited weight. In any event, these groups raised a number of points that suggested they were unconvinced by the EEA study:

- Distribution customers do not have the same access to storage outside Ontario as large pipeline companies, distributors or marketers.
- Transportation limitations, particularly between Dawn and Trafalgar, limit access to storage in neighbouring jurisdictions.
- Out-of-province options are more expensive, not competitive with Ontario gas storage.
- Union's control of storage and of the Dawn-Trafalgar transportation system makes it a non-independent gas system operator. For storage to be competitive, a competitive open-access transportation system is needed as well. The Dawn-Trafalgar system would require expansion on a competitive basis, not financed by distribution customers. The Board needs to develop rules for independent access to storage and for related transportation.
- Gas-fired power generators need services that do not exist today, such as intra-day nominations (requests for gas that do not start at the start of the "gas day"), higher deliverability from storage and increased flexibility with respect to consumption requirements. Therefore, it is not possible to argue that the market is workably competitive for these services.

Marketers also supported cost-based storage rates, and noted an asymmetry in the treatment of regulated-utility supply customers and direct-purchase customers seeking access to storage at COS rates. They submitted that current policies allow regulated-utility supply customers to increase their allocation of COS storage as their demand increases. However, direct-purchase customers must purchase incremental storage at market prices, leaving marketers at a disadvantage.

Marketers also took a sceptical view of the EEA analysis. Some argued that storage is not competitive because utilities have significant market power related to their control over storage and the associated transportation, and that the Board prohibition on utilities using system operations control to preclude competition should continue. One submission argued that, to increase competition in storage, the Board should require utilities to release enough storage to allow for customer efficiency and choice in load balancing, foster an environment where non-utility storage can be sustained and regulate storage more consistently.

The Board's Conclusions

Most of the Board's legislated objectives are relevant to the issues related to gas competition, consumer interests, infrastructure development and the financial viability of the industry.[9]

The basic question facing the Board is whether *any* action is required with respect to its policies for gas storage and transportation. In some respects, the current situation for storage in Ontario appears to be quite satisfactory:

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[9] The five objectives of particular relevance are:

- to facilitate competition in the sale of gas to users;
- to protect the interests of consumers with respect to prices and the reliability and quality of gas service;
- to facilitate rational expansion of transmission and distribution systems;
- to facilitate rational development and safe operation of gas storage; and
- to facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

- There is ample storage capacity available to support the seasonal load-balancing needs of Ontario customers and to provide the additional services that have led to the development of Dawn as a gas trading hub.
- Recent new investment by utilities has added 21 Bcf of storage in Ontario, with a further 6 Bcf proposed by independent storage operators.
- COS-based prices for in-franchise customers ensure that most Ontario gas customers benefit from low-cost storage.
- Ontario customers served by Union benefit as well from the sale of excess storage at market rates.

At the same time, the Board acknowledges that the current policy imposes certain tradeoffs that benefit some customers more than others. In part to encourage further storage development, the Board has gradually widened the scope for the owners of storage to charge market-based rates since the RP-1999-0017 Decision allowed Union to renew gas contracts, originally at cost-based rates, at market rates. As a consequence, gas customers in Kingston now pay market rates for storage, and customers in Union's area are the substantial beneficiaries of this policy. While Enbridge's existing storage contract with Union is based on COS rates, a new contract effective in 2006 will charge market-based rates for this storage. Direct-purchase customers with growing demands must purchase their incremental needs at market rates, while those remaining on regulated utility supply have access to storage services at COS rates. In addition, storage charges vary widely over the province because of differences in the cost of the associated transportation. These factors suggest that there is an issue as to whether the current pricing structure for storage is inappropriately discriminatory.

A larger issue is how to ensure that the Board's objectives with respect to storage and transportation can be achieved in light of anticipated growth in demand, driven primarily by anticipated new gas-fired power generation. The anticipated growth is expected to place new demands on storage, not just in terms of the additional volume of storage required (with electricity demand peaking in both winter and summer), but also in terms of the short-term high-deliverability needs of new gas-fired generators to respond to the volatile demand for electricity in Ontario.

In other words, do the current economic regulation of storage and the structure of the Ontario storage market ensure the achievement of the Board's objectives of rational infrastructure development, competition, consumer protection and a financially viable gas industry?

To achieve these objectives, the Board must address a number of issues when determining how storage and transportation should be regulated – that is, whether storage should be rate-regulated and how associated transportation rates and terms of access should be regulated. The Board does not yet have sufficient information to come to definitive conclusions, but it sees the preliminary issues as follows:

- What additional incentives (if any) are needed to ensure adequate storage and transportation development?
- How should storage services be developed for gas-fired power generators?
- Do Union's transportation rates or its operation of its system discriminate against customers, including independent storage operators?[10]
- Are Union's incentives for operating and expanding storage aligned with the public interest?
- Would additional storage development benefit Ontario gas customers by enhancing the liquidity of trading in Ontario?
- If market-based rates are used to expand utilities' storage, should shareholders be asked to bear the associated greater risk?

While the Board is not yet able to reach conclusions on these issues, it has decided to launch a process that will decide them. Section 29 of the *Ontario Energy Board Act* contains a specific provision requiring the Board to refrain from regulating a service, in

[10] In RP-2003-0063, the Board directed Union to review cost causality associated with independent storage operations. In response, Union has proposed a revised rate design, which includes interruptible transportation services through modifications to the existing M16 rate. This matter is currently before the Board. Depending on the outcome of that hearing, this issue may need to be addressed further.

whole or in part, if it makes a determination that a service "is or will be subject to competition sufficient to protect the public interest."[11]

While the Board has never specifically applied this section in any proceeding involving the regulation of gas storage, it has been moving in this direction by allowing market-based rates. It has also established a boundary (between in-franchise and ex-franchise customers) that defines where COS rates apply and where market-based rates apply.

The EEA study submitted by Union suggested that Union's storage competes in a much broader market than that of Ontario and that the market for its storage is workably competitive. However, this analysis is not only untested; it does not address the broader questions related to storage services, questions that include non-discriminatory access to and prices of associated transportation. Some anecdotal information was submitted, but there was little detail, about how easily associated transportation could be obtained and

[11] Section 29 of the *Ontario Energy Board Act, 1998*, sets out the terms under which the Board is to refrain from regulating storage, as follows:

"**Refrain from exercising power**
"29. (1) On an application or in a proceeding, the Board shall make a determination to refrain, in whole or part, from exercising any power or performing any duty under this Act if it finds as a question of fact that a licensee, person, product, class of products, service or class of services is or will be subject to competition sufficient to protect the public interest. 1998, c. 15, Sched. B, s. 29 (1).

"**Scope**
"(2) Subsection (1) applies to the exercise of any power or the performance of any duty of the Board in relation to,
"(a) any matter before the Board;
"(b) any licensee;
"(c) any person who is subject to this Act;
"(d) any person selling, transmitting, distributing or storing gas; or
"(e) any product or class of products supplied or service or class of services rendered within the province by a licensee or a person who is subject to this Act. 1998, c. 15, Sched. B, s. 29 (2).

"**Where determination made**
"(3) For greater certainty, where the Board makes a determination to refrain in whole or in part from the exercise of any power or the performance of any duty under this Act, and does so refrain, nothing in this Act limits the application of the Competition Act (Canada) to those matters with respect to which the Board refrains. 1998, c. 15, Sched. B, s. 29 (3).

"**Notice**
"(4) Where the Board makes a determination under this section, it shall promptly give notice of that fact to the Minister. 1998, c. 15, Sched. B, s. 29 (4)."

the implications for the geographic scope of the storage market for customers in different regions of Ontario.

Furthermore, the anticipated rise in demand for storage and for flexible storage services from the new gas-fired generators raises questions related to:

- whether they can access storage at COS rates in Ontario for any part of their storage needs;
- the pricing of the more flexible storage services that may be needed; and
- the costs and availability of associated transportation, particularly when the associated transportation would require additional investments.[12]

The above points underscore the importance of the availability of non-discriminatory access to the transportation and distribution systems under transparent conditions. Utility control of most of the key infrastructure surrounding the Dawn Hub and the lack of transparency in gas transportation system operations raise the question of whether the systems operations function of Union is non-discriminatory or whether unbundling these operations from the utility would be desirable.

Therefore, while it is clearly premature, based on information presented to date, for the Board to make any finding related to whether storage services are subject to competition "sufficient to protect the public interest," it would be timely for the Board to consider whether it should, in whole or in part, refrain from regulating storage services in Ontario.

The Board will determine, through a generic hearing, whether it should refrain, in whole or in part, from regulating the rates charged for natural gas storage in Ontario.

In conducting this proceeding, the Board will be guided by the objectives set out for it in the *Ontario Energy Board Act* and by the requirements of section 29 of the Act. That is, it

[12] Union Gas's parent company, Duke Energy, has made the point in another forum that it will not be possible for independent storage developers to compete with incumbent storage owners if they have to pay incremental rates for gas transportation. See Comments of Gregory J. Rizzo, Group Vice-President, Duke Energy Gas Transmission, re: State of the Natural Gas Industry Conference, Federal Energy Regulatory Commission Docket No. PL04-17, October 21, 2004.

will not simply make a determination of whether the market for storage services is competitive, but a determination of whether storage services (or some part thereof) are "subject to competition sufficient to protect the public interest." In addition to the broad storage and transportation issues identified above, the following issues will need to be addressed in determining whether the Board should refrain from regulating storage rates:

- the appropriate product and geographic market for Ontario storage for consumers in different regions of the province
- whether any supplier of storage services has market power in these markets
- the associated transportation issues and the potential impact on competitive storage offerings by utilities and by independent operators
- whether a move to market-based rates for all or some customers is in the public interest, even if the market is competitive
- what, if any, approvals may be required for long-term storage contracts
- the impact of competition on rational development of storage facilities in Ontario

If the Board determines that it will refrain from regulating storage, it will also have to decide a number of additional issues, including the following:

- transitional arrangements for moving from COS to market-based rates
- whether changes are needed to ensure transparent, non-discriminatory access to the gas transportation system around Dawn

The Board has concluded that it will not fix COS rates for new storage developed by independent storage operators – that is, those storage operators that have no affiliation with gas distributors or transmitters. Stakeholders offered widespread support for this approach. The storage proceedings will therefore focus on storage as it relates to storage operators that are affiliated with distributors and transmitters.

Gas-Fired Power Generation

The anticipated growth in gas-fired power generation emerged, in the Natural Gas Forum's discussions, as the most important challenge affecting the natural gas sector in

Ontario in the next few years. Three factors suggest that accommodating this growth in natural gas demand will present new challenges:

- **Magnitude of growth:** Each of the large gas-fired generators will be among the largest consumers of gas in the province. Together they may increase the annual demand for gas by 25 per cent. Even more striking, on a cold winter day when demand for gas peaks, these plants will be operating at full capacity, which may increase the peak demand for gas in Ontario by a third.
- **Need for flexibility:** Retail gas customers use most of their gas for heating, and their demand for gas is therefore highly seasonal. The demand from large industrial customers, by contrast, is relatively stable. The new gas-fired generators are expected to operate as mid-load or peak-load plants, and they will want the flexibility to acquire and dispose of gas at very short notice, as prices in the electricity market fluctuate.
- **Security of supply:** Security of supply during extreme weather may be an issue. The peaking of natural gas and electricity demand on very cold winter days can strain the supply of both natural gas and electricity, as it did in New England in January 2004.[13] Concerns remain that, under such weather conditions, gas and electricity markets could be subject to manipulation.[14]

These issues go beyond the storage-related aspects discussed in the previous section.

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[13] Since 1990, most of the new generating capacity in New England has been gas-fired. Gas-fired generation now accounts for approximately 30 per cent of all available generating capacity. In January 2004, a cold snap drove demand for both electricity and natural gas to new winter peaks. The resulting high gas prices, nearly 10 times their normal level, led some generators to sell their gas supplies rather than use them to generate electricity, despite electricity prices nearing $1,000 (U.S.) per megawatt hour. New England got through the snap without electricity or gas shortages, but the event did illustrate some shortcomings in the interaction of the two markets.

A review of the event by the electricity system operator ISO New England found that inadequate understanding and coordination between the gas and electricity systems was a major factor in the event. ISO New England's main recommendations affecting the gas sector were to improve electricity system operator understanding and coordination with the gas industry and to evaluate ways to better coordinate gas and electric market timing to allow maximum utilization of gas system infrastructure.

[14] The US Federal Energy Regulatory Commission investigated the behaviour of market participants during the New England cold snap and determined that their behaviour was competitive and that prices reflected the underlying demand and supply conditions.

Stakeholders' Views

While there was broad agreement among stakeholders as to the importance of gas-fired power generation, they expressed different views about what to do to supply the new demand. Power generators explained that they will be looking for additional storage, and will want to draw on it much more frequently than traditional gas customers.

One submission noted that gas-fired generators need services such as intra-day nominations, higher deliverability from storage and increased flexibility with respect to consumption requirements, and that these services do not exist in Ontario's gas market today. Union, by contrast, noted that all the needed services could be developed and offered, but that it would take time to do so, and that users of such services had to be prepared to pay the true cost of the services.

Others noted that non-discriminatory access to the gas transportation system is essential to ensure fair competition, and that, while the Board has taken a positive step in addressing this issue by prohibiting utilities from using system operations control to preclude competition, it needs to develop its approach further. Several stakeholders raised the questions of how and from whom the costs of additional infrastructure investment would be recovered.

The issue of a special rate for gas-fired generation also arose in Union's 2005 rates hearing with respect to the distribution of gas to the Brighton Beach gas-fired generation facility.[15] Brighton Beach is producing electricity for the grid only during those hours when electricity prices are sufficiently high to cover the operating costs of the plant. Coral Energy Inc., which supplies gas to the facility, sought a particular rate treatment for the Brighton Beach facility that would recognize its operating characteristics, citing the broader energy market implications – particularly the impact on electricity prices – of gas distribution charges for power generators.

[15] The Board's decision is this case is available on the OEB Web site. See file RP-2003-0063, March 18, 2004.

In its decision, the Board considered that the important public interest issues raised by the prospect of a new rate class for gas-fired generation warranted a more detailed examination. The Board directed Union to submit detailed evidence about the anticipated load profile and to determine whether a basis exists for a new rate class, and, if so, to apply for Board approval. While Union has suggested that a separate rate class is unnecessary, it is anticipated that the new gas-fired generators will operate in a similar manner to the Brighton Beach facility and may seek special rate treatment.[16]

The Board's Conclusions

The Board is of the view that the factors identified above make the impact of gas-fired generation on the Ontario gas market difficult to deal with in specific rate proceedings. For example, one issue identified is the ability (or inability) of generators to move gas between the Union and Enbridge systems. This issue suggests that the Board needs to be satisfied that access to Enbridge's and Union's systems is not only non-discriminatory, but also well coordinated and sufficiently transparent, and that gas transportation infrastructure development needs to be considered in a more integrated way.

The Board also recognizes that Ontario has some advantages that could ease the development of gas-fired generation. Ontario is the location of the confluence of several major pipelines, and this confluence, combined with gas storage facilities in the same area, has led to the development of the Dawn Hub. The Dawn Hub is an important source of flexibility for gas trading and for gas customers in Ontario. The Board wants to ensure that liquidity continues to develop to benefit Ontario consumers.

Furthermore, there are broad questions related to the security of supply and the competitiveness of the gas and electricity markets during extreme weather. Gas and electricity systems operations must be adequately coordinated to deal with extreme weather events. In the United Kingdom, the regulator requires the operators of the electricity and gas systems to coordinate their operations to ensure adequate flexibility in responding to demand during abnormally cold conditions. And although the U.S. Federal

[16] The issue has also arisen in the context of the redesign of Enbridge's 300-series rates.

Energy Regulatory Commission determined that the gas and electricity markets were not manipulated during the January 2004 New England cold snap, the Board recognizes that it needs to be in a position to make such a determination should the issue arise in Ontario.

In responding to the Brighton Beach issue in the Union case, a number of intervenors requested that the Board initiate a separate process to address the issues of gas distribution rate design and the infrastructure requirements related to gas-fired power generation. The Board has determined that ensuring the adequacy of natural gas infrastructure to meet the demands of natural gas-fired power generation is an important and immediate priority.[17]

The Board will hold a review to determine the impact of increased gas-fired power generation on storage and transportation infrastructure and services in order to ensure a reliable supply of electricity and gas. This review may lead to a formal proceeding resulting in orders setting rates, granting leave to construct or other remedies. The Board's storage proceeding will also be informed by the gas-electricity interface review.

The participation of gas utilities, other pipelines, gas-fired generators, customers, the Independent Electricity System Operator and the Ontario Power Authority will be important in this gas-electricity interface review. Issues to be covered include the following:

- the identification of gas-storage and transportation-network expansion needs to accommodate additional gas-fired generation
- the allocation of costs of any additional infrastructure investment
- rate design for storage and transportation services for gas-fired generators
- coordination mechanisms between gas and electricity system operations

[17] Union recently filed an application for leave to construct in order to expand the Trafalgar system by around 0.38 Bcf/d to accommodate increased demand for transportation east of Dawn (EB-2005-0201). This expansion is not aimed at satisfying demand from new gas-fired generators, but is in response to an open season. In its pre-filed evidence, Union indicated that it has a plan to expand its system capacity by an additional 1.3 Bcf/d at an estimated cost of $263 million.

New Independent Storage Development

The Board has had the opportunity to consider applications for approval of storage developments from both traditional utilities and independent storage companies (that is, companies that have no affiliation with gas distributors or transmitters). The Board's consideration of the issues, and its scrutiny of them, is in support of its duty to act in the public interest. The Board endeavours to ensure that:

- storage is developed and operated in a safe manner so that the public is protected and the provincial asset is not harmed;
- all technical codes, standards, guidelines and so on, are adhered to and respected;
- there is a need for the project;
- the proposed project is an economically viable means of satisfying that need;
- rates for storage services are just and reasonable; and
- the storage operators have the financial and operational ability to carry out a viable storage operation.

Prior to 2002, the only applicant other than Enbridge and Union to come before the Board requesting orders to develop and operate storage was CanEnerco Limited (CanEnerco). In 1997, CanEnerco applied for the orders necessary to develop and operate the Chatham D storage pool. CanEnerco was a gas marketer, and it intended to use the storage pool to support its gas marketing activities. While the technical issues were no different from those raised in storage applications made by traditional utilities, the business issues were different. For example, there was a heightened need to understand CanEnerco's capitalization and access to capital to ensure that its storage development and operations would be sufficiently well funded to sustain long-term operations. The Board granted CanEnerco's application on certain conditions. CanEnerco failed commercially in 2001, and Enbridge subsequently acquired CanEnerco's storage pool.

The only open application for storage at this time is from Tribute Resources, which proposes to develop the Tipperary storage pool.[18] The Board found in a partial decision with reasons (RP-2003-0253) that the proponents had not provided sufficient business or

[18] An application by Northern Cross Energy to develop a storage facility was adjourned in early 2004.

financial information relevant to the development and operation of the proposed project, and, consequently, the Board did not grant a storage and withdrawal order. However, the Board left the proceeding open and specified the additional information that would be needed to complete the application and for the Board to further consider granting the order.

An issue raised at the Natural Gas Forum was whether the Board should develop a policy to facilitate new independent storage developments. It was agreed that more storage development would likely be necessary because of the demands of the new gas-fired power generators. Development would include investment in existing facilities to increase injection and withdrawal rates, as well as expansion of storage facilities and associated transportation. Storage development could also be expected to enhance security of supply within Ontario and to further mitigate price volatility.

Stakeholders' Views

Tribute Resources, an independent storage developer that currently has an application before the Board, submitted that there is no need to regulate the rates of independent storage operations. In its view, regulatory certainty in approvals would reduce barriers to develop new storage, and these approvals should deal with safety and environmental questions only.

In fact, most submissions supported a narrower scope for storage approvals in order to encourage new storage development. One submission noted that existing storage offerings from utilities were not sufficiently flexible and that independent storage operators, able to sell at market rates, would be more flexible.

The Board's Conclusions

The Board is aware of the need for regulatory certainty, particularly for independent storage operators that develop storage facilities and need to recover the costs of such development from the market. The Board is currently hearing cases on independent storage development and is in the process of developing policies related to the financial requirements for such applications. In its partial decision on Tribute’s application to develop the Tipperary pool, the Board acknowledged that, because very few applications of this nature have come before the Board, the Board’s policy in this area may not have been clearly established.

To encourage the rational development of storage, particularly by independent storage operators, the Board will set out its requirements for the content of an application.

The Board has concluded that it will not fix cost-of-service rates for new storage developed by independent storage operators (that is, those storage operators that have no affiliation with gas distributors or transmitters).

The Board will develop, through a consultative process, filing guidelines for proponents of new independent gas storage facilities.

REGULATED GAS SUPPLY

Background

"Regulated gas supply" (or "system gas" or "system supply") refers to the sale of gas by utilities primarily to their core, typically small-volume, customers. Beginning in 1985, the wholesale gas market was opened to competition from third-party gas marketers. Retail competition proceeded to take hold gradually through the early 1990s. A gas utility supplies natural gas to customers who have not switched to a marketer or who have defaulted back or switched back to the utility.

The overall market share of regulated gas supply has declined since 1985. Over the last three years, however, this market share has increased somewhat, and today regulated gas supply serves approximately one third of the gas volume and approximately 60 per cent of customers (of which the majority are residential customers). Conversely, the sale of gas by independent marketers to customers and the direct purchase of gas by many large-volume customers accounts for two thirds of Ontario's total gas volume and approximately 40 per cent of the customer base (of which the majority are commercial and industrial customers). Currently, two marketers – Direct Energy Marketing Ltd. (Direct Energy) and Ontario Energy Savings Corporation – dominate the Ontario competitive residential retail market.

There are two aspects to the price of regulated gas supply: the underlying commodity, the cost of which is passed through to the customer, and the related services. Utility supply rates are set through a quarterly rate adjustment mechanism (QRAM) process, where every three months (January 1, April 1, July 1 and October 1) the price of gas is set based on a 12-month forecast of commodity prices. This forecast is based on the average of the 12-month New York Mercantile Exchange "strip" over a 21-day period just prior to the time of the application. The difference between the quarterly price and the actual utility gas supply costs is collected in a purchased gas variance account (PGVA).

Every three months, in addition to reforecasting prices, Union, Enbridge and Natural Resource Gas (NRG) establish a rate adjustment that is intended to clear the PGVA over time. Union and NRG spread the amount in the PGVA over projected gas consumption for the following 12 months. Enbridge spreads it across projected gas use for the remaining months of the fiscal year.

The Natural Gas Forum focused on broad questions about the regulated gas supply option, and, in particular, whether a regulated gas supply option should be maintained and whether and how it should be redefined or changed. Stakeholders reiterated concerns about perceived inefficiencies in the current arrangements and about barriers arising from the current regulated gas supply pricing structure that prevent new competitors from entering the market.

As a result, the Board has decided to focus on the following issues:

- Should a regulated gas supply option be retained?
- If the regulated gas supply option is retained:
    - What is the appropriate cost allocation between supply and distribution, and what is the appropriate level of unbundling?
    - What is the appropriate pricing mechanism?
    - What are the appropriate long-term supply and transportation contracting policies?

Stakeholders' views on each of these issues are analyzed below, followed by the Board's conclusions.

Should a Regulated Gas Supply Option Be Retained?

Stakeholders' Views

Most stakeholders argued that a regulated gas supply option should be retained, although their reasons varied. Residential customer groups believed that the regulated gas supply option provides consumers with choice. Industrial and commercial customer groups claimed that the regulated gas supply helps to underpin the utilities’ market coordination role. Other stakeholders concluded that the regulated gas supply option is not an impediment to the competitive supply market; that it offers economies of scale and competitive price benchmarking. Many stakeholders were of the view that the regulated gas supply supports necessary infrastructure investment.

The utilities had similar views. In particular, they cited their own market research, which, in their view, shows that customers want the regulated gas supply option retained. The utilities also emphasized the benefits that the regulated gas supply provides to the operation of the distribution function and the integrated nature of distribution and the regulated gas supply.

Others, including some marketers, also supported the continuation of the regulated gas supply option, but concluded that it should be modified to resemble a default supply and/or supply of last resort. As one marketer explained it, competition could be achieved more effectively and with less disruption through the natural attrition of regulated gas supply customers rather than through forcing the utilities to exit from the supply role.

However, two stakeholders – the Federation of Northern Ontario Municipalities, Timmins and Greater Sudbury and Direct Energy – maintained that the utilities should exit from the supply function. Another marketer, Superior Energy Management, concluded that, while structural separation is a desirable end state that the Board should work towards, the significant practical challenges in making such a change suggested that smaller incremental changes should be pursued.

These stakeholders concluded that the regulated gas supply option should be eliminated for a truly competitive market to exist. In particular, they made the following points:

- A competitive market would expand customer choice and improve market signals.
- There is no evidence to support a conclusion that regulated gas supply underpins major infrastructure investment.
- Gas supply is not a natural monopoly.

- Utility exit from the supply function would remove the need for regulatory oversight.

In addition, Direct Energy suggested that the regulated gas supply option (while it still exists) should be subject to the same requirements as other supply options in the marketplace, including a positive customer election to take the option and a signed contract outlining the terms and conditions. Others were of the view that the regulated gas supply option should have no requirement for positive election or a written contract.

The Board's Conclusions

The Board is guided primarily by two legislated objectives in this area: to facilitate competition in the sale of gas and to protect the interests of consumers with respect to price, reliability and quality of service. With respect to the issue of regulated gas supply, these objectives are complementary. On the direct purchase side, the Board believes that consumers' interests are best protected through the development of robust competition, oversight of gas marketers and effective customer education. On the utility side, consumers' interests require appropriate regulation of the utilities, including limiting the utilities to providing only a default supply option.

Customer choice is a key component of a competitive market. Many of the presentations and submissions explored the question of what customers want. The Board's view is that customers are primarily concerned with price and service. With respect to price, some customers want a stable price, and therefore a fixed-price contract for a specified term, while others are willing to tolerate volatility in the hopes of achieving an overall lower price. Some customers choose actively, by selecting a gas marketer or by choosing to remain on, or return to, regulated gas supply; others choose passively, by remaining with a regulated gas supply. With respect to service, customers expect reliability and need to have confidence in their supplier.

Some stakeholders are of the view that the regulated gas supply option is better for customers than the competitive supply option, because there is no profit margin on the regulated option, whereas competitive supply is provided at a market price. The Board disagrees with this analysis. Competitive suppliers have a profit margin because they assume risk, and they will only acquire and retain customers if they provide and maintain effective customer service and competitive prices. Utilities are also profit-driven enterprises, but, because there is no profit margin on the utility's commodity, the ratepayer effectively bears most of the risk.

The sale of natural gas has been a competitive activity in Ontario for close to 20 years. In theory, if the market is competitive, it need not be regulated, and competitive forces can be relied on to set market prices at a level that provides value to customers. Competitive markets also allow for the removal of onerous regulatory processes around pricing, contracting and risk management. However, many argue that a robust competitive retail market has not developed in Ontario. Some stakeholders are concerned that there is concentration – and the potential for market power – because of the limited number of competitive suppliers serving this market.

The Board understands that, even with full competition, a default supplier and/or supplier of last resort would still be necessary. There would also need to be a transition from the current situation, where the utility supply and distribution functions are integrated, to the point where utility supply could be deregulated, either through separation and eventual forbearance or through divestment. Experience in other jurisdictions suggests that forcing full retail competition and utility exit from the supply function can be a costly and difficult process. The Board concludes that this approach would not be in accordance with its regulatory policy. In the Board's view, competition is more successful if customers embrace choice, rather than have it forced upon them.

The Board concludes that the utilities should continue to provide a regulated gas supply option. However, the regulated gas supply option should be seen as a default supply option and structured accordingly. For that reason, the Board does not believe it is necessary or appropriate to require customers to sign contracts with a utility. This approach will ensure that customers have full mobility, and it will assist customers in

distinguishing and comparing the regulated and competitive supply options. Also, the Board does not believe it is appropriate for the utilities to promote and/or to market the regulated gas supply option to their customers. The Board does believe, however, that it is appropriate to inform customers of the terms and conditions related to the regulated gas supply option and, in particular, of their unilateral right to switch to a competitive supplier.

The Board will continue to facilitate competition and to protect consumer interests through a number of initiatives, including the following:

- **education** of customers so that they understand their options and the associated risks. The Board has produced a number of customer fact sheets and brochures on the natural gas market, but needs to do more;

- **oversight** of competitive suppliers to ensure customer protection. The Board has a comprehensive code of conduct for gas marketers, and violations may be subject to penalties or licence suspension. In addition, the Board has a compliance group that is responsible for ensuring that market participants comply with the OEB's licences, codes, rules and regulations;

- **regulation** of the utility gas supply option to ensure that customers are able to make their choice in a transparent market, where they can understand their options and manage their risks, including price volatility.

The balance of this section of the report addresses the last point, which is the proper structure of the regulated gas supply option. To move the natural gas market in the direction of greater transparency and reduced barriers to entry, the Board considers the proper costing and pricing of services within the regulated gas supply option to be essential. The key issues of cost allocation and unbundling, the pricing adjustment mechanism and supply and transportation acquisition policies are addressed in the next three subsections.

Cost Allocation and Further Unbundling

Stakeholders' Views

Most stakeholders supported a review to ensure proper cost allocation between the regulated supply function and the distribution function. However, stakeholders disagreed on the issue of further unbundling and/or separation of services within the regulated supply and distribution functions.[19]

On one hand, Union and Enbridge recommended that further unbundling should not be undertaken because the current integrated approach is working well and because the integrated structure has benefits, such as load balancing, backstopping and long-term planning for infrastructure and supply. Furthermore, Enbridge expressed the belief that costs could increase with unbundling and/or separation. Some of the industrial and commercial customer groups took the same view, explaining that interdependencies exist in the regulated gas supply function, and that unbundling could mean that services currently provided by the utilities would no longer be offered.

On the other hand, many stakeholders maintained that further unbundling is required. The utility owned and operated by the City of Kitchener submitted that it has already implemented unbundling through cost allocation. Some voiced concerns about whether the playing field was level, and noted that an examination of the cost allocation methods would set the stage for whether, and how, the utilities' delivery and gas supply functions should be further unbundled. In particular, stakeholders raised the issue of unbundling load balancing activities and the need for the utilities to incur the same balancing obligations as those faced by competitive suppliers.

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[19] The Board defines *unbundling* as identifying and costing discrete services. These discrete services can then be offered individually to customers. *Separation*, on the other hand, represents the separation of the regulated utility's supply services into a distinct entity, or the functional separation, within the utility, of the employees involved in each of the two services.

Some of these stakeholders expressed the belief that unbundling is an integral element of facilitating competition, because, with unbundling, the market could provide these services to customers. This situation would increase customer choice by enabling customers to purchase the service or services that best suit their needs. Also, unbundling would ensure that the appropriate costs are included in the supply and delivery services and, as a result, customers could accurately compare costs between the different options in the marketplace.

The Board's Conclusions

Cost Allocation

The Board believes that the regulated gas supply option must be structured in a way that facilitates competition. The integrated nature of the supply and distribution services potentially makes the comparison between the regulated supply option and competitive supply options unbalanced. The current regulated gas supply costs include the cost of the commodity and limited overhead costs (such as risk management activities). Other overhead costs associated with the purchase, scheduling and management of gas supply and customer care costs are recovered through the distribution charges. Competitive supplier commodity charges reflect the overhead costs of sourcing, purchase and management of the gas function, including return. Therefore, questions are continually raised with the Board about whether distribution rates include supply costs and whether the rates for the regulated supply option hinder a viably competitive market where customers make decisions based on price.

In the Board's view, the pricing of the regulated gas supply option should minimize the potential for cross-subsidization between utility supply rates and distribution rates. The Board is not convinced one way or the other yet on the question of whether the current rates and/or rate structures contain cross-subsidies. It is of the view that the issue should be examined in a generic cost allocation hearing to determine the issue conclusively. The majority of stakeholders support this approach.

The Board will hold a generic cost allocation hearing.

<u>Further Unbundling</u>

Some stakeholders advocated further unbundling to ensure transparency and to facilitate customer choice. These stakeholders clearly identified a set of discrete services for the regulated gas supply option and a separate set of discrete services related to the distribution function, as follows:

- delivery services: transportation and delivery of gas, including seasonal and peak load balancing of gas to end-use locations; emergency response and repair services
- supply services: purchase and sale of the gas commodity; price risk-management of gas commodity; customer care (which includes billing costs); annual (or three-point) load balancing

The Board believes it is necessary to make a clear distinction between the services provided as part of the regulated supply function and the services provided by the distribution function, and to consider unbundling these services to a greater extent. The Board is not convinced that further unbundling will jeopardize the utilities' ability to provide load balancing and other services to customers. Rather, the Board believes that further unbundling of utility services can bring the following significant benefits:

- improve market efficiency for all customers by increasing price transparency
- facilitate competition by moving the regulated gas supply option and competitive options towards a level playing field

The Board also believes that there is merit in moving towards policies that are consistent between utilities. At present, the load balancing policies of the two largest utilities differ – Enbridge has an annual obligation, while Union has a three-point obligation.[20] The Board will examine the issue of harmonizing the load balancing obligations between utilities in the generic cost allocation proceeding.

[20] In Union's latest rate case, RP-2003-0063, Union was asked by the Board to file a report regarding load balancing obligations and the regulated gas supply.

The Board will not go beyond unbundling to pursue functional separation at this time. While some stakeholders were of the view that the synergies between the supply and distribution functions underpin the utilities' ability to provide certain services, the Board does not agree that the integration of functions is absolutely necessary. The utilities could act as system operators and continue to provide their current services without having an integrated customer supply portfolio. However, the Board does not intend to pursue functional or structural separation of the supply and distribution functions. Further analysis is necessary to ensure that the benefits of such a change exceed the costs, and the Board does not consider this issue to be a priority at this time.

The Board will examine the issues related to further unbundling as part of the generic cost allocation hearing. This process will incorporate the work already under way on this topic.

The Pricing Mechanism

Stakeholders' Views

Most stakeholders expressed the view that there should be greater standardization of the QRAM process across utilities and that the QRAM should be more formulaic. Both Union and Enbridge expressed interest in further harmonizing the QRAM process, and Enbridge expressed the belief that consistency could be enhanced.

However, stakeholders expressed a variety of views about the pricing structure of the regulated gas supply option. Some stakeholders said that the existing quarterly revisions are appropriate, while others suggested that monthly revisions would better reflect the true cost of gas. The residential customer groups and the utilities supported quarterly price updates. The residential customer groups argued that quarterly price updates contribute to price stability, while the utilities said that quarterly updates help strike the correct balance between the desire for accurate price signals and the desire for reduced price volatility.

On the other hand, most of the marketers believed that the price should be revised monthly, to more accurately reflect gas price volatility and to reduce the PGVA and associated carrying costs. One stakeholder expressed the belief that a quarterly adjustment dampened the daily and monthly price fluctuations. This dampening reduced the difference between the marketers' fixed-price options and the regulated gas supply option, and possibly created a barrier to entry of new competitors into the market.

In terms of pricing, there was some support among stakeholders, including Union and Enbridge, for a regulated-utility, fixed-price, one-year contract offer to customers. However, the majority of stakeholders said that the utilities should not have the flexibility to provide fixed-term, fixed-price gas contracts. In particular, stakeholders argued that a fixed-term, fixed-price offer could:

- impede customer mobility;
- create a vested interest for utilities to maintain a minimum number of customers;
- create barriers to entry for new competitors; and
- compete directly with marketers.

Some support also existed for a spot price pass-through, to eliminate the utilities' risk-management activities and to accurately reflect the market price of gas.

The Board's Conclusions

In determining the appropriate pricing structure for regulated gas supply, the Board must consider the trade-off between a price signal that accurately reflects market prices and price stability. The current pricing process, whereby the price is set every three months on the basis of a 12-month price forecast, represents a balance between market-price signals and price stability. Therefore, from one perspective, the regulated gas supply price could be said to reflect a rolling one-year price.

The Board needs to consider whether the current balance between price signals and price stability is appropriate. In particular, it needs to address two key concerns:

- Is a 12-month price outlook appropriate as the basis for pricing the regulated gas supply option?
- Is the frequency of the price adjustment appropriate?

On the first issue, it may be appropriate for the price to reflect some other level of variation. In other words, instead of reflecting a rolling one-year price, the price could reflect a different time period. The question is, over what time period should the price outlook be based? The Board is not of the view that a spot price pass-through would be appropriate, because of the potential for volatility that would result. On the other hand, a reflection of seasonal price fluctuations could strike a reasonable balance among market price signals, administrative simplicity and customer acceptance. The Board would also need to consider the impact of such a change on the PGVA.

On the second issue, the Board recognizes the link between the utilities' actual procurement costs and the price set through the QRAM process. The utilities acquire supply in the marketplace primarily through monthly indexed contracts. The difference between the actual procurement costs and the price set through the QRAM process is collected in the PGVA. The amount in the PGVA is then recovered from customers. Customers, therefore, receive a supply that is priced monthly, although the price they see is smoothed over a specific time frame. At this time, the Board sees no compelling reason to depart from a quarterly price adjustment. However, if the time period of the price outlook were redefined, then the frequency of the price adjustment would need to be re-examined.

The Board believes that the QRAM price should be a transparent benchmark that reflects market prices, and, therefore, the methodology for calculating this price should be similar for all utilities. The market needs an accurate and consistent price signal, most stakeholders agree. Therefore, the Board believes, the method for determining the reference prices should be formulaic and consistent and, similarly, the methods for determining the PGVA and for disposing of PGVA balances should also be formulaic and consistent.

The Board will develop guidelines for the standardization of the quarterly rate adjustment mechanism, with the above objectives in mind. As part of this activity, the Board will consult in more detail on the underlying pricing that should be incorporated.

With respect to whether utilities should be able to offer fixed-term, fixed-price contracts, the Board concludes that it would not be appropriate at this time. The regulated gas supply option should be seen as a default supply – a no-written-contract, no-obligation, market-priced choice – where the mobility of the customer is essential. The Board believes that introducing a utility-provided fixed-term, fixed-price contract offer at this time would present two risks. First, the fixed-term aspect could reduce the utility's ability to ensure full customer mobility. Second, the fixed-price aspect would compete with the product offered by the retail marketers. It would move the regulated supply away from being a default supply, and result in more direct competition between the utility and competitive suppliers. A fixed-term, fixed-price contract offer would require substantial additional regulatory oversight related to the underlying contracting, the customer-utility interface and the allocation of risk. The Board does not believe that this is the appropriate direction to take, and most stakeholders shared this view.

The Board believes that a utility-provided fixed-term, fixed-price contract offer is inappropriate at this time.

Long-Term Supply and Transportation Contracts

Stakeholders' Views

Many of the stakeholders (including customers, upstream players and utilities) asserted that the regulated gas supply is implicitly used to underpin future infrastructure development in the natural gas market. Some emphasized the importance of the utilities' creditworthiness, noting that utilities are among the few parties able to enter into the long-term contracts needed for infrastructure development. Views on the appropriate length and mixture of contracts within the portfolio were consistent among these stakeholders – the utilities should be allowed to enter into a range of contract terms from short-term to long-term. This mixture of contract terms would facilitate the development of infrastructure for new supply and allow the utilities to manage their risk, and thereby minimize price volatility for the customer. The only stakeholder that did not support a mixture of contract terms was the Vulnerable Energy Consumers Association, which stated that the regulated gas supply procurement portfolio should be based on an average of one-year forward gas supply contracts.

Other stakeholders, including the marketers, were not convinced that the utilities' role in regulated gas supply was essential to support upstream infrastructure investment. Noting the prominence of the Dawn Hub with its many counterparties and the large size of the Ontario natural gas market, these stakeholders questioned the claim that major capacity infrastructure additions depend on the utilities. In addition, one submission stated that the availability of substantial surplus capacity in TransCanada PipeLines' Mainline system suggests that utilities do not need to make any major decisions in the immediate future about contracts for new capacity.

Stakeholders who expressed the views outlined in the previous paragraph also expressed concerns about the risks associated with long-term supply commitments by the utilities, including stranded costs, reduced customer mobility and commitments that favour the upstream investments of the utility's parent company or affiliates. In their view, the utilities should be allowed to enter into only short-term commitments of one year or less.

Some stakeholders suggested that the Board develop guidelines or a regulatory framework and, in some cases, provide pre-approval of contracts to allow the utilities to make the necessary commitments in a timely manner. Others felt that the current review process was sufficient. Many stakeholders, including the ones that favoured long-term contracts for the utility, stated that the Board needed to verify that any actions taken by the utility were truly market driven and/or were the least-cost option, and not related to the utility's other commercial interests.

The Board's Conclusions

The Board believes that it is useful to separate the consideration of upstream transportation contracting from long-term supply contracting. The utilities currently undertake these activities separately: supply is contracted primarily on a short-term basis, whereas there is a "portfolio" of terms for upstream transportation contracts. And whereas supply contracting is related primarily to the regulated supply function, transportation contracting extends beyond that function.

The Board is mindful of the importance of security of supply. However, it is not convinced that long-term utility supply contracts are essential for security of supply. The Board is of the view that access to a liquid hub provides the best assurance of secure access to competitively priced supply. In contrast, the Board is concerned that the potential risks to ratepayers from long-term supply contracts could be significant. Further, the Board views the regulated supply option as a default supply, which means that customer mobility is essential, prices need to reflect the market and retroactive adjustments (related to the PGVA) are kept to a minimum.

The Board is not in favour of new long-term utility supply contracts at this time.

The Board agrees that, to some extent, utility upstream transportation contracts provide benefits to all customers, may reduce barriers for competitive suppliers who want to enter the market and help reduce gas price volatility. The trade-off is the potential risk involved, and the Board believes that utilities need a diversified portfolio to reduce that risk. To the extent that upstream transportation contracts underpin security of supply to the whole market, the Board believes that all customers should bear the costs.

The Board believes that there is a role for utilities in long-term upstream transportation contracting, subject to a prudence review.

Given the importance of security of supply and to provide greater clarity in the marketplace, the Board will offer utilities the opportunity to apply for pre-approval of long-term supply and/or transportation contracts. Further, the Board will consult on the development of guidelines that will inform all stakeholders of the principles and issues the Board will consider when evaluating an application for contract pre-approval.

The guidelines could include the following considerations:

- risk allocation – the appropriate allocation of risk between ratepayers and shareholders
- the impact on competition – an assessment of customer mobility, market entry, supplier flexibility and affiliate relationships
- the public interest – an assessment of just and reasonable rates and enhanced reliability/service quality
- a diversified portfolio of contract terms – the appropriate balance of short-, medium- and long-term contracts
- the least-cost option – a detailed description of the proposed project with an outline of the costs, benefits and timelines involved, and an assessment of the proposal against the alternatives

IMPLEMENTATION

This section begins with a description of the Board's key processes and then presents the Board's plan to implement the conclusions of this report.

The Board's Processes

The Board's implementation plan will rely on orders, rules and guidelines. These regulatory instruments, the processes by which they are implemented and the ways in which they will be used to implement the conclusions of this report are discussed briefly below.

Orders

The conventional way in which the Board has decided issues in the natural gas sector has been through formal orders. Subsection 19(2) of the *Ontario Energy Board Act, 1998* (the Act), provides that the Board "shall make any determination in a proceeding by order." As a result, orders result from proceedings, which are adjudicative and largely subject to court-like procedural requirements set out in the Act and in the *Statutory Powers Procedure Act*. Proceedings are used to, among other things, fix rates for gas distribution, storage and transportation (section 36 of the Act), consider the designation of storage areas (sections 37–40 of the Act) and determine whether the Board should refrain from regulation (section 29 of the Act).

Rules and Guidelines

Rules and guidelines are established by the full Board, not by a panel in a hearing. Rules may be issued under section 44 of the Act in relation to a very broad range of issues. The Board has passed several rules in the gas sector, including rules governing the conduct of gas marketers (the Gas Marketers Code of Conduct) and gas distributors in relation to affiliates (the Affiliate Relationships Code) and gas vendors (the Gas Distribution Access Rule or GDAR). The Board's rules in the gas sector are similar to the codes issued by the Board in the electricity sector, where the practice has been more extensive.

Rules are fundamentally different from orders; as Evans, Janisch, Mullan and Risk state in *Administrative Law: Cases, Text and Materials*, "The essence of a rule, as opposed to an adjudication, is that the former lays down a norm of conduct of general application while the latter deals only with the immediate parties to a particular dispute."[21] As a result, rules are useful tools for implementing policy.

Rules are developed by the Board under section 45 of the Act through a notice-and-comment process. Because the Board initiates the rule making process, it is necessarily more proactive in developing the substance of a rule than it is in proceedings where a party commences an application. In the rule making process, the Board drafts a rule and circulates it, often with a discussion paper, for comment by interested parties.

Guidelines do not necessarily have a statutory basis, nor are they established through a statutory process. Like rules, guidelines are also concerned with conduct. However, unlike rules, guidelines are not binding. As Professor Hudson Janisch states in the work cited above:

> Terminology here is very fluid as "policy" may include "manuals," "guidelines," "standards" and the like. Nothing turns on the precise term employed. The important thing is that unless an agency is given legislative authority to make binding rules, it must always consider exceptions to its general approach. [22]

The courts have encouraged agencies to adopt policy guidelines in the absence of express statutory authority to bring about greater predictability in decision making. The Supreme Court of Canada upheld the authority of the Canadian Radio-television and Telecommunications Commission to issue policy guidelines, despite the lack of specific statutory authority, as part of its role in implementing the Government of Canada's broadcasting policy. According to Chief Justice Laskin: "An overall policy is demanded

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[21] J.M. Evans, H.N. Janisch, David J. Mullan and R.C.B. Risk, *Administrative Law: Cases, Text and Materials* (Toronto: Emond Montgomery, 2003), at 675. See Chapter 8 for a discussion of rule making.
[22] Ibid., at 266.

in the interests of prospective licensees and of the public under such a public regulatory regime as is set up by the *Broadcasting Act*. Although one could mature as a result of a succession of applications, there is merit in having it known in advance."[23]

Other agencies have also adopted policy guidelines without specific statutory authority, the most well-known of which are the guidelines issued under the *Competition Act (Canada)* respecting matters such as mergers, predatory pricing and price discrimination. Again, these guidelines are not legally binding, but a regulatory innovation that serves the goals of clarity and predictability. As the Federal Court of Appeal put it in reviewing these guidelines:

> In addition, the possibility that a reviewing court may not agree with an agency's view of the law is an inevitable risk associated with the administrative practice of issuing non-binding guidelines and other policy documents to shed light on agency thinking and to assist those subject to the regulatory regime it administers. The risk should deter neither the courts from deciding what the law is, nor the agencies from engaging in the often useful exercise of administrative rule making.[24]

As the above comments indicate, there are no statutory procedural requirements for the establishment of guidelines, while the Board can satisfy the statutory requirements for establishing rules by inviting written comments. However, the Board's practice with respect to establishing rules has been to encourage a level of stakeholder participation well beyond statutory requirements. For example, on occasion (for example, in developing the GDAR) the Board has asked parties to appear before it and to make oral submissions on particular issues, and has considered the records of those proceedings as part of its deliberations. However, hearings are not considered to be the only, or even the primary, way of obtaining stakeholder input.

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[23] *Capital Cities Communications Inc.* v. *Canadian Radio-television and Telecommunications Commission*, [1978] 2 S.C.R. 141 at 171.
[24] *Canada (Commissioner of Competition)* v. *Superior Propane Inc.*, [2001] 3 F.C. 185, para. 146.

The use of non-hearing processes for rule making has been commented on by a number of observers. For example, the *Final Report of the Ontario Task Force on Securities Regulation,* which made recommendations about the role of rule making in the context of securities regulation, specifically did not advocate that a hearing be a mandatory component of the notice-and-comment procedure. Professor Ron Daniels, who authored the report, would only go so far as to endorse "the use of public hearings to the extent they may enhance the development of certain policy instruments in appropriate circumstances."[25]

Others have been more critical of the use of public hearings in rule making. Professor David Mullan, commenting on the history in the United States, where rule making is used much more extensively than in Canada,[26] stated:

> The anxious experimentation with more detailed procedures by Congress and the agencies themselves has demonstrated that the rule-making process should seldom, if ever, be surrounded by all the procedural requirements which attend a court-like adjudication.[27]

Similarly, Professor Hudson Janisch has identified and analyzed the following reasons why rule making (whether through a binding process or through non-binding guidelines) is preferable to an "*ad hoc* order":[28]

- public participation
- legitimacy
- visibility
- comprehensibility

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[25] Ontario Task Force on Securities Regulation, *Responsibility and Responsiveness: Final Report of the Ontario Task Force on Securities Regulation* (Toronto: Queen's Printer for Ontario, 1994), at 36.

[26] For a discussion of the American experience, see K.C. Davis, *Administrative Law of the Seventies* (Rochester and San Francisco: LCP BW Publishing, 1976).

[27] D.M. Mullan, "Rule-Making Hearings: A General Statute for Ontario?" prepared for the Commission of Freedom of Information and Individual Privacy, 1979, at 11. See also the discussion at 156–157, where Professor Mullan quotes from the Administrative Conference's recommendation that it "emphatically believes that trial-type procedures should never be required for rule-making except to resolve issues of specific fact."

[28] H. Janisch, "The Choice of Decision-Making Method: Adjudication, Policies and Rule Making" (1992), *Law Society of Upper Canada Lectures* 259 at 266. Professor Janisch is referencing A.E. Bonfield, "State Administrative Policy Formulation and the Choice of Law Making Methodology" (1990), 42 Admin L.R. 121 at 122–131.

- efficiency
- abstraction
- appropriate factual basis
- initiative
- easier participation
- prospective application
- consistency

As a result, the Board, like many tribunals, faces a number of challenges and opportunities in developing new types of policy instruments. The Board firmly believes that stakeholder consultation is important, and it will continue to pursue innovative ways to facilitate it. The implementation of this report will involve a variety of procedures, as set out in the implementation plan described below.

Implementation Plan

The conclusions in this report will require implementation in an orderly manner over the next few years. This implementation plan groups the processes required to implement these changes into four categories of issues: (1) infrastructure; (2) rate setting; (3) gas supply and transportation; and (4) miscellaneous. The following describes the processes involved in each of these categories of issues.

1. Infrastructure Issues

There are two main processes that will involve a review of infrastructure issues: The Gas-Electricity Interface Review and the Storage Proceeding. These two are related because the result of the review of the requirements for gas-fired power generation could have a significant impact on the issues that have to be addressed in determining the best way to regulate gas storage. The process contemplated for each is set out below.

(i) Gas-Electricity Interface Review

The Board will hold a review to determine the impact of increased gas-fired power generation on storage and transportation infrastructure and services in order to ensure a reliable supply of electricity and gas. This review may lead to a formal proceeding resulting in orders setting rates, granting leave to construct or other remedies. The details and timing of this review will be provided shortly so that the review may commence as soon as possible.

(ii) Storage Regulation

The Board will hold a proceeding to determine whether, or to what extent, it should refrain from regulating the rates for gas storage services. This determination will take into account traditional concerns respecting allocation of cost of service storage and whether market rates are appropriate from the perspective of ratepayers and utilities. In addition to this, the Board's storage proceeding will also be informed by the review of gas infrastructure in the context of the gas-electricity interface review. As a result, the storage proceeding will commence after the implications from the gas-electricity interface review become clearer.

2. Rate Setting Issues

There are several interconnected processes that will combine to permit the implementation of the incentive regulation plan. To make this incentive regulation plan enduring, there are a number of prior decisions that must be determined. These decisions involve determining the allocation of costs between distribution and supply; setting a cost of service base for regulated delivery activities; setting the service levels; determining the financial reporting requirements that must be met during the term of the IR plan; and determining the appropriate annual adjustment mechanism and the term of the IR plan. The process for each of these is discussed below.

(i) Generic Proceeding on Cost Allocation of Regulated Gas Supply

The Board will hold a generic cost allocation proceeding to ensure proper costing of regulated gas supply. As part of this hearing, the Board will also assess whether further unbundling is required and how any further unbundling will be implemented. This will determine the base regulated delivery activity for the term of the IR Plan. This determination will be made by mid-2006.

(iii) Develop Filing Guidelines for Rate Applications and Setting Base Rates

The cost of the base regulated delivery activity must be established. This requires both clear direction on the information that should be filed to provide an evidentiary basis to set the cost of service base and a hearing to determine the appropriate base. Generic filing requirements will be established using a consultation process and completed by the end of 2006. Decisions on the appropriate base for each of the utilities will be made in separate proceedings and be provided by the end of 2007.

(iii) Service Quality Monitoring and Financial Reporting

All parties must have a clear understanding of both the service levels and the financial reporting requirements that must be met during the term of the IR plan. The Board will develop the service quality and financial reporting frameworks through consultative processes. The Board expects to use its rule making authority to implement these frameworks. This will be completed by the end of 2006.

(iv) Generic Proceeding on the Annual Adjustment Mechanism

The final terms of the IR plan will be set after the processes outlined above are completed. The Board will determine the appropriate annual adjustment mechanism and the term of the IR plan following a hearing. This will be completed by the end of 2008.

3. Gas Supply and Transportation

The two interconnected issues in this area are the review of the quarterly rate adjustment mechanism (QRAM) methodology and the treatment of utility long-term gas supply and transportation contracts.

(i) Standardize Quarterly Rate Adjustment Mechanism Methodology

The Board will develop guidelines that will ensure a consistent and formulaic approach across utilities in calculating the Reference Prices and the purchased gas variance account (PGVA), and for disposing of the PGVA balances. The consultation process on these guidelines will also consider the underlying price. This process, as well as the related process for long-term contracting is expected to be completed in 2006.

(ii) Develop Prior Review Process for Long-Term Contracts

The Board will develop guidelines to consider applications for prior approval of long-term supply and/or transportation contracts. This process, as well as the related process for QRAM pricing is expected to be completed in 2006.

4. Miscellaneous

(i) Practice Direction on Alternative Dispute Resolution (ADR)

The Board has already undertaken a review of the ADR process. However, it will consider the submissions made through the NGF before releasing its conclusions of that review. The Board expects to publish any changes to the ADR process in 2005.

(ii) Develop New Independent Gas Storage Filing Guidelines

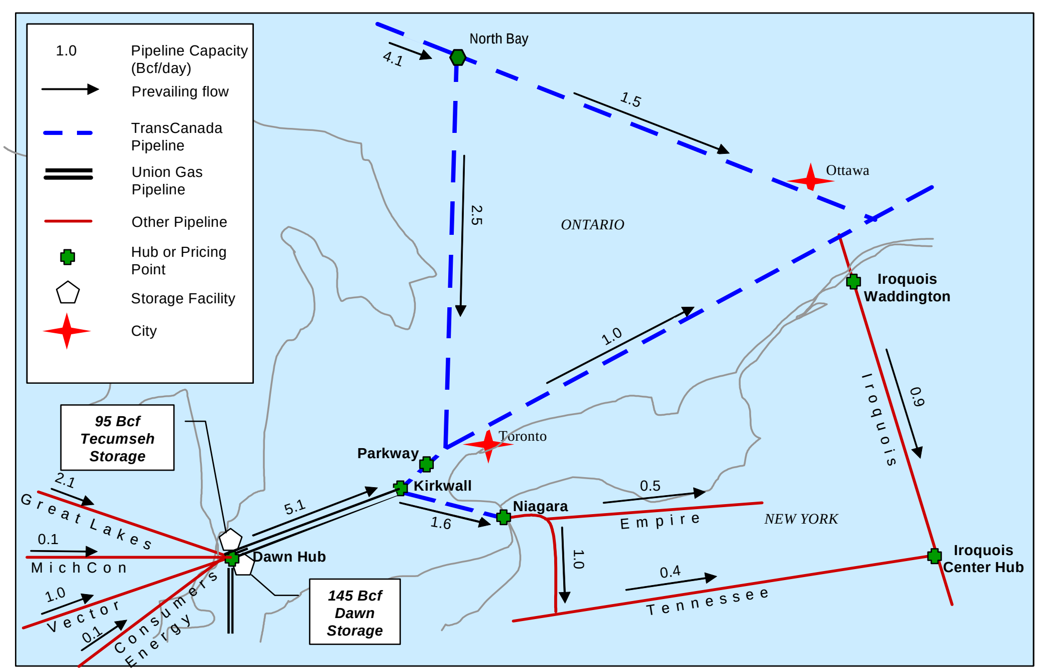
The Board will develop guidelines on new independent gas storage (i.e., those storage operators that have no affiliation with gas distributors or transmitters). These guidelines will be distributed for stakeholder comment. The development of these guidelines is expected to take place in 2005.

APPENDIX 1. Ontario's Natural Gas Market

Ontario is one of Canada's largest consuming gas markets, with a total market size approaching 800 billion cubic feet (Bcf) annually, with a peak demand around 3 Bcf per day. Over 95 per cent of Ontario's supply comes from outside the province, principally from the Western Canadian Sedimentary Basin (WCSB), with additional supplies from the U.S.

Natural gas enters Ontario over the northern Mainline of TransCanada PipeLines Limited (TCPL) and through Dawn in southwestern Ontario (see Figure 1). TCPL's northern mainline has a capacity of 4.1 Bcf per day at the Manitoba border, being directly interconnected with the WCSB. Dawn has a receipt capacity of about 3.9 Bcf per day from the following pipelines crossing the border: ANR Pipeline, Michigan Consolidated Gas, Great Lakes Gas Transmission, CMS Enterprises, Trunkline Gas Company and Vector Pipeline.

Figure 1. Ontario Gas System Schematic



Source: "Discussion Paper on System Supply in Ontario," prepared for the OEB by ICF Consulting and PEG and Excel Consulting (available on the OEB Web site)

Dawn also has multiple pipeline takeaway interconnections. From Parkway there are interconnections with Enbridge Gas Distribution (Enbridge) and TCPL. From Kirkwall there are interconnections to Tennessee, Empire and National Fuel. Gas can also be delivered from Dawn into Michigan at St. Clair, Bluewater and Ojibway. Pipeline capacity in excess of Ontario's needs is used to transport and deliver gas to the U.S. and Quebec. It has been reported that approximately 60 per cent of the gas entering Ontario is moved across the province into these markets.

Dawn is also the location of large concentrations of underground storage capacity, estimated at about 240 Bcf. Union Gas Limited (Union) owns underground storage facilities with a capacity of 149.6 Bcf and with 2.3 Bcf per day deliverability in the Dawn area. Enbridge owns Tecumseh Gas Storage, also near Dawn, which has a total storage capacity of 98 Bcf and deliverability of 1.75 Bcf per day. The two companies have developed about 21 Bcf of storage within the past five years.[29] The Board has received applications for two independent storage operations[30] that would, if developed, add another 6 Bcf.

Ontario's two major gas utilities are Enbridge and Union. Other smaller systems include Natural Resource Gas, the City of Kitchener and Utilities Kingston. Union serves 1.2 million customers, delivering 525 Bcf per year. Union also transports 730 Bcf on behalf of others, with much of this flowing to the U.S. Enbridge delivers about 162 Bcf per year of gas to 1.7 million franchise customers and transports an additional 296 Bcf per year.

From a pricing standpoint, the Ontario gas market has evolved dramatically over the past decade. Dawn has emerged as a frequently tracked, increasingly liquid, and transparent market hub in the Ontario gas market. The large amount of nearby storage, combined with a convergence of pipelines linking the U.S. and Ontario gas markets, have made Dawn the most liquid trading location in Ontario. In 2004, around 7 Bcf of gas per day

[29] The Ladysmith pool (7 Bcf, Enbridge) and the Century pool (14 Bcf, Union)
[30] From Tribute and Northern Cross Energy

was traded at the Dawn Hub. Ontario is now highly integrated into the North American natural gas market. Gas prices in Ontario reflect not only local conditions, but also broad North American gas market developments. The result has been a very high correlation between gas prices at Dawn and those at Henry Hub (in Louisiana) and other major hubs.

Two major trends in the North American market will have a significant impact on Ontario:

- the expected decline of conventional gas production and increase in non-conventional supply sources, including frontier supplies and imports
- the growth in demand, throughout North America, from gas-fired power generation

Conventional production from the WCSB has plateaued and begun to decline. The National Energy Board expects total production from the WCSB to decline from about 16 Bcf per day in 2001 to about 14 Bcf per day by 2025.[31] This decline in conventional production will be offset with increased output from non-conventional supply sources such as coal-bed methane production, liquefied natural gas and new frontier supplies, including gas from the Mackenzie Delta and Alaska. Gas flow patterns within North America will change as a consequence.

Coupled with this changing supply base is the dramatic increase in demand arising from the growth in gas-fired power generation, which has both a North American and an Ontario context. Across North America, an enormous investment has been made in gas-fired power generation in the past few years. This development has led to a fundamental shift in the supply-demand balance, has raised the prices for natural gas and is driving the convergence of natural gas and electricity markets.

In summary, the gas market in the past could be characterized as "supply push" – that is, the supply-demand balance was tipped in favour of customers because of the supply "bubble," which in turn encouraged expansion of gas demand. Today, the gas market is

[31] National Energy Board, *2003 Canada's Energy Future*, available at www.neb.gc.ca.

increasingly being characterized as “demand pull,” because growing demand is outstripping conventional resources, which will lead to pulling in new, unconventional sources of supply.

APPENDIX 2. Participants in the Natural Gas Forum

The following parties made presentations at the Technical Consultation sessions:

Canadian Association of Petroleum Producers

Anbrer Consulting (work sponsored by Canadian Gas Association)

Coral Energy Canada Inc.

Direct Energy Marketing Limited

Energy Probe Research Foundation

Enbridge Gas Distribution Inc.

Energy and Environmental Analysis, Inc. (for Union Gas Limited)

Federation of Northern Ontario Municipalities, Timmins and Greater Sudbury

Industrial Gas Users Association

Northern Cross Energy

Ontario Energy Savings Corporation

Pollution Probe

Purvin & Gertz, Inc. (work sponsored by the Canadian Gas Association)

Peter Milne with the School Energy Coalition

Superior Energy Management Inc.

TransCanada Gas Transmission East

TransAlta Energy Corporation

Union Gas Limited

Vulnerable Energy Consumers Coalition

The following parties made final submissions:

Aegent Energy Advisors Inc.

Association of Major Power Consumers in Ontario

Association of Power Producers of Ontario

BP Canada Energy Company

Calpine Corporation

Canadian Association of Petroleum Producers

Canadian Manufacturers & Exporters

City of Kitchener

Coalition for Efficient Energy Distribution

Commissioner of Competition

Conference Board of Canada (work sponsored by the Canadian Gas Association)

Consumers Council of Canada

Coral Energy Canada Inc.

Direct Energy Marketing Limited

ECNG Limited Partnership

Enbridge Gas Distribution Inc.

Enbridge Inc.

Energy Probe Research Foundation

Federation of Northern Ontario Municipalities, Timmins and Greater Sudbury

Green Energy Coalition

Inco Limited

Industrial Gas Users Association

London Property Management Association and Wholesale Gas Service Purchasers Group

MxEnergy (Canada) Ltd.

Natural Gas Exchange Inc.

Ontario Energy Savings Corporation

Pollution Probe

School Energy Coalition

Sithe Canadian Holdings, Inc.

Superior Energy Management Inc.

TransAlta Cogeneration L.P. and TransAlta Energy Marketing Corporation

TransCanada PipeLines Limited

Tribute Resources Inc.

Union Gas Limited

Vulnerable Energy Consumers Coalition