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BORDEN LADNER GERVAIS

September 21, 2010

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th floor
Toronto, ON M4P 1E4

Dear Ms Walli,

2010 Natural Gas Market Review Announcement
Board File No.: EB-2010-0199
Our File No.: 339583-000080

Pursuant to the Board's letter dated August 20, 2010, please find attached the Report of John A. Rosenkranz, the expert retained by the following seven intervenors:

- Consumers Council of Canada ("CCC")
- Canadian Manufactures & Exporters ("CME")
- City of Kitchener ("Kitchener")
- Federation of Rental-housing Providers of Ontario ("FRPO")
- London Property Management Association ("LPMA")
- School Energy Coalition ("SEC")
- Vulnerable Energy Consumers Coalition ("VECC")

This report is being filed in advance of the Stakeholder Conference scheduled for October 7 and 8, 2010.

Yours very truly,

Peter C.P. Thompson, Q.C.

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Ontario Energy Board

2010 NATURAL GAS MARKET REVIEW

EB-2010-0199

Prepared for

Consumers Council of Canada
Canadian Manufacturers & Exporters
City of Kitchener
Federation of Rental-housing Providers of Ontario
London Property Management Association
School Energy Coalition
Vulnerable Energy Consumers Council

September 21, 2010

John A. Rosenkranz
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ONTARIO ENERGY BOARD
2010 NATURAL GAS MARKET REVIEW
EB-2010-0199

September 21, 2010

1. INTRODUCTION

The Ontario Energy Board has initiated a process to consider how changes in the North American natural gas supply markets could impact the Ontario energy sector, and to determine what actions, if any, the Board should take to respond to these changes. As the first step in this process, the Board commissioned a report by ICF International, which was issued on August 20, 2010. The Board is now requesting stakeholder input.

This report has been prepared for a group of intervenors representing the interests of Ontario natural gas consumers. This group consists of the following entities:

- Consumers Council of Canada
- Canadian Manufacturers & Exporters
- City of Kitchener
- Federation of Rental-housing Providers of Ontario
- London Property Management Association
- School Energy Coalition
- Vulnerable Energy Consumers Coalition

The report is organized as follows:

Section 2 provides comments on the report prepared by ICF.

Section 3 considers how changes in the natural gas supply markets could affect natural gas consumers in Ontario. A principal concern is that as gas utilities' transmission systems are modified to adapt to changes in inter-regional flows, distribution rates for Ontario consumers will increase as a result of costs incurred to provide new transportation services to ex-franchise customers. Regulatory action may also be needed to ensure that as new gas supplies become available, Ontario consumers do not face unnecessary costs because of utilities' long-term commitments to upstream transportation services, or restrictions in utility distribution services that lock consumers into relatively high-cost sources of natural gas.

Section 4 describes specific regulatory actions the Board should consider to maximize the consumer benefits of new gas market opportunities, while ensuring that consumers are not subject to additional costs and risks. Recommendations include: (a) changing how the Board evaluates system expansions for ex-franchise services; (b) requiring incremental rates for ex-franchise services to avoid subsidies by existing customers; and (c) putting utility shareholders at risk for project expenditures that only benefit ex-franchise customers. The Board should also consider a requirement for gas utilities to file long-term resource plans, and direct utilities to eliminate any unnecessary restrictions on gas supply access or other barriers to competition.

Section 5 answers the questions posed by the Board in its August 20, 2010 letter.

2. ICF REPORT

2.1 ICF's Findings

The ICF report highlights two major trends in the North American natural gas supply markets:

1) The continuing decline in available gas supplies from the Western Canadian Sedimentary Basin (WCSB).

2) The dramatic increase in unconventional gas production, including production from the Marcellus shale in West Virginia, Pennsylvania and New York.[1]

These changes are expected to impact the Ontario natural gas market in several ways.

1) Natural gas flows into and out of Ontario will decline.

   ICF expects that the loss of throughput on the TransCanada PipeLines (TCPL) mainline will continue. Although TCPL may be able to retain some of its mainline business by discounting tolls, the fundamental cause of lower throughput—the decline in available gas supplies from the WCSB—will remain. ICF also projects a sharp drop-off in exports at Niagara and Iroquois, as Canadian exports are displaced by domestic production (including Marcellus shale gas) and LNG imports. Gas flows into Ontario from Michigan, however, are expected to increase.

2) Natural gas consumption in Ontario will continue to grow.

   More of the gas flowing into Ontario will remain in the province to meet growing demand. Although residential and commercial gas consumption is expected to increase slightly, growth will be mainly driven by the power generation sector.

3) Natural gas prices in Ontario will be higher.

   The ICF forecast indicates that natural gas prices at Dawn will increase, both in absolute terms and relative to the Henry Hub benchmark price. The higher relative price (the "basis") is explained by higher gas prices in Western Canada and increases in long-haul TCPL tolls.

2.2 Comments on the ICF Report

ICF presents a comprehensive overview of developments in the North American natural gas market and a forecast of gas flows and prices through 2020. This high-level approach is useful, but it cannot capture all the factors that need to be considered when assessing the implications of these changes for Ontario consumers.

1) The ICF report is based on a single forecast scenario from ICF's proprietary modeling system, with only limited references to other sources. While some

[1] ICF expects that gas production from the Marcellus shale will reach 6 Bcf/day by 2020.

sensitivity modeling is presented, the use of a single scenario understates the variability of potential outcomes.

2) Modeling results are presented as average annual physical flows. The ICF report does not address peak day requirements, which are important determinants of demand for new transmission and storage capacity. The report also does not consider contractual arrangements, such as long-term transportation contracts and gas utility tariffs, that affect the prices paid by natural gas consumers.

3) ICF does not consider some of the other natural gas market developments that could affect the Ontario market. While these additional factors may not change the basic conclusions from the ICF report, they do contribute to the uncertainty faced by Ontario natural gas consumers.

   First, ICF does not discuss the potential for gas production from the Utica shale in Quebec. Several companies are actively exploring the Utica shale in the St. Lawrence Lowlands between Montreal and Quebec City. Although the Utica shale area is much smaller than the Marcellus and is at a much earlier stage of development, positive results have been reported from recent testing. One analyst has suggested that Utica shale gas production could reach 500 MMcf/day by 2020, an amount roughly equal to Quebec's current rate of natural gas use.[2] However, even a relatively modest amount of Utica shale production could substantially reduce the amount of gas flowing through Ontario to Quebec.

   Another significant supply market change is the completion of three new LNG import terminals in New England and New Brunswick with a combined sendout capacity of 2 Bcf/day (see Table 2.1). ICF does discuss LNG imports, and includes supply from these terminals in its forecast, but the report does not address the potential for wide variability in LNG imports, particularly over a period of years. Swings in natural gas imports caused by increases or decreases in LNG supplies, or changes in relative prices across the Atlantic Basin, can have a significant impact on the utilization of gas supply infrastructure serving the New England market, including gas transmission and storage facilities in Ontario.

Table 2.1: LNG Import Terminals Supplying the New England Market

LNG Terminal	Location	In Service	Sendout Capacity	Sendout, 7/09 - 6/10 Average	Peak Mo.
			(MMcf/d)	(MMcf/d)	(MMcf/d)
Distrigas	Everett, MA	1971	715	439	493
Northeast Gateway	Offshore MA	2008	600	49	250
Canaport	Saint John, NB	2009	1,000	200	437
Neptune LNG	Offshore MA	2010	400	n.a.	n.a.
			2,715	688	1,180

Source: U.S. Department of Energy and National Energy Board

[2] "Quebec Mulls New Law to Attract Oil, Gas Investment" Financial Post, April 26, 2010.

3. IMPLICATIONS FOR ONTARIO CONSUMERS

These anticipated natural gas supply market changes create two main areas of concern for Ontario gas consumers. First, there is the risk that the magnitude and variability of the anticipated changes in natural gas flows will cause uneconomic expansions of utility gas transmission facilities. This concern is heightened by the fact that the Ontario gas utilities have unregulated storage and non-utility transmission ventures that are tied, physically and commercially, to their regulated gas transmission businesses. Under the current regulatory structure, utility shareholders may benefit from transmission expansions while gas consumers who receive no benefits pay increased rates because of high incremental facilities costs. Ontario consumers then face the risk of even greater costs if these facilities are subsequently underutilized.

Second, there is a risk that Ontario consumers will be locked into high-priced gas supplies or upstream transportation services when less-expensive alternatives are available. This is a concern for consumers in markets, such as the Union Northern Delivery Area, that depend entirely on TCPL for upstream gas transmission capacity, but the same risk applies to consumers in other areas as well.

3.1 Natural Gas System Expansion

The Dawn Hub and Union's Dawn-Trafalgar transmission system are key components of the Ontario natural gas supply system. The Dawn-Trafalgar system supports Union's gas distribution operations, both directly for its Southern Delivery Zone, and to provide storage and balancing for Union's Northern and Eastern zones. Other Ontario gas utilities, power generators and industrial gas consumers also use Dawn-Trafalgar transportation services to access gas supplies and underground gas storage at the Dawn Hub. Finally, TCPL holds contracts for transportation service from Dawn to both Kirkwall and Parkway. This capacity is treated as part of TCPL's integrated transmission system and is used to supply markets in Ontario, Quebec and the Northeast U.S. An increase in the cost of transporting gas away from the Dawn Hub therefore affects natural gas consumers throughout Ontario.

Union provides transportation services from Dawn to Kirkwall and Parkway under its M12 Rate Schedule. For the 2007-2008 gas year, Union reported the total demand for capacity on the Dawn-Trafalgar system to be 6.5 PJ/day, of which 4.8 PJ/day (74 percent) was used for M12 transportation services. This total system demand was met using 5.8 PJ/day of physical design day capacity, by requiring in-franchise transportation customers to deliver 0.64 PJ/day at Parkway (the "Obligated DCQ"), and by purchasing 0.09 PJ/day of services at Parkway.[3]

Union's Index of Customers report shows that total M12 contract demand has grown to 5.1 PJ/day as of 9/1/2010 (see Table 3.1). Ontario gas utilities are the largest M12 customers, with 44 percent of the total. Enbridge Gas Distribution holds most of this capacity, with Kingston and Kitchener contracting for smaller amounts. TCPL has contracted for 36 percent of the M12 service, and Ontario power generators and Gaz Metro hold 10 percent and 6 percent, respectively. The remaining M12 service is sold to marketers, U.S. gas distribution companies, and industrial end users.

[3] EB-2005-0550 "Decision and Order" issued June 12, 2006, p. 3.

Table 3.1: Union Gas M12 Transportation Customers

Shippers	Contract Demand	
	(PJ/day)	(Percent)
Ontario Gas Utilities	2.242	44%
TransCanada PipeLines	1.826	36%
Ontario Power Generators	0.509	10%
Gaz Metropolitain	0.287	6%
Other	0.247	4%
TOTAL	5.111	

Source: Union Gas Index of Customers Report for Sept. 2010

Going forward, an increase in gas flows from Michigan to Ontario may create demand to expand the Union Dawn-Trafalgar transmission system. For example, the proposed Dawn Gateway pipeline would add 360 MMcf/day of deliverability into Dawn, and this gas will presumably need to be delivered to downstream markets.[4]

Under Union's standard rate design, any expansion of the Dawn-Trafalgar system for ex-franchise or ex-provincial markets is likely to cause increased costs for Ontario natural gas consumers. There are two reasons for this:

1) Ontario consumers will pay higher distribution rates if the incremental cost of expansion exceeds the existing transportation rate.

   Under rolled-in pricing, the rates for in-franchise services and existing M12 transportation services will increase if the incremental expansion cost is greater than the current per-unit rate. This indeed appears to be the case. Information provided by Union Gas shows that the per-unit cost of expanding the Dawn-Trafalgar system is three to four times greater than the per-unit plant cost used to calculate the transmission rates that are currently in effect (see Table 3.2).

Table 3.2: Union Gas Dawn-Trafalgar Expansion Costs

	Design Day Capacity	Facility Capital Costs	Capital Cost per Unit of Capacity
	(MMcf/day)	($000)	($/Mcf/day)
Net Plant (2007 Rates)	5,678.7	772,646	136.1
2006 Expansion	371.6	157,338	423.4
2007 Expansion	488.1	128,000	262.2
2008 Expansion	322.2	57,400	178.2
Subtotal	1,181.9	342,738	290.0
Future Expansion Plans:			
Lobo "C" Compressor	218.9	94,542	431.9
Brantford-Kirkwall/Dawn	259.1	122,970	474.6
Lobo "D: Compressor	136.3	81,370	597.0

Source: EB-2007-0606/EB-2007-0615, Exhibit JTA.24, filed October 11, 2007

[4] EB-2009-0422

2) Ontario consumers' costs will increase if transmission capacity is underutilized.

   With the uncertainty about future gas flows into and through Ontario comes the risk that existing transmission facilities could be underutilized, or new expansion facilities stranded. Union Gas notes this risk in its most recent Annual Report.

   > "The ex-franchise storage and transportation market is impacted by commodity prices and changing gas supply flows related to the changes and developments of new unconventional shale supplies in North America. Weak commodity prices and seasonal pricing spreads combined with changes in traditional gas flow patterns will impact the value of unregulated storage services in 2010. Further, there is a risk of continued contraction in the storage and transportation customer base as a result of changes and restructuring within the storage and transportation market."[5]

   The Board recently found that underutilization of the St. Clair pipeline cost Union's in-franchise customers $6.4 million between 2003 and 2010.[6] The potential cost to Ontario consumers from underutilization of the much larger Dawn-Trafalgar system is substantially greater.

   Changes in natural gas supply markets could create a whipsaw effect, where transmission facilities are expanded to meet current demands, but then become underutilized when gas requirements in downstream markets are met by new sources of supply, such as an increase in LNG imports into New England or Utica shale gas in Quebec. In the case of the Dawn-Trafalgar system, the risk of stranded capacity is heightened by the fact that much of the existing firm transportation service is provided under contracts that are near expiration. A review of the Union Gas Index of Customers report shows that, of the 5.1 PJ/day of M12 transportation service in effect as of September 1, 2010, over 70 percent (3.6 PJ/day) was provided under contracts that will expire before the end of 2014, unless the customer chooses to renew.

3) Ontario utilities may over-build transmission facilities to benefit their own non-utility transportation and storage businesses, or those of an affiliate.

   The major Ontario natural gas utilities and their affiliates have a range of commercial interests, including non-utility ventures that have connections to their regulated utility services. In the case of Union Gas, for example, the demand for Dawn-Trafalgar transmission capacity is tied to the deliverability from underground storage fields connected to the Dawn Hub and transmission capacity into Dawn from Michigan. Conversely, investments to develop natural gas storage in and around the Dawn Hub or expand pipeline capacity into Dawn from Michigan have little value without adequate transmission capacity from Dawn to markets. As long as transmission costs can be recovered in utility rates, utility shareholders will enjoy the benefits, but assume none of the risks, of expanding transmission capacity out of Dawn. This could easily create an incentive to over-expand these facilities.

[5] Union Gas Limited, 2009 Annual Report, p. 18.
[6] EB-2008-0411

3.2 Gas Supply Diversification

The ICF report indicates that Ontario consumers will have opportunities to lower their gas costs by diversifying supply sources away from Alberta supplies and TCPL long-haul transportation service. The Chicago and Dawn hubs are alternatives to purchasing gas at Empress, and Niagara and Iroquois are likely to become more active gas supply points in the future.

Ontario consumers may be restricted from optimizing their gas supply portfolios to adapt to changes in the gas supply markets in two ways:

1) A utility may enter into long-term contracts for transportation and/or supply that commit its customers to a high-cost supply source.

   The costs incurred by Ontario consumers when a gas utility fails to conduct an adequate evaluation before entering into a long-term supply or transportation contract has been an issue in other Board proceedings. In the EB-2001-0032 Decision with Reasons, for example, the Board found that Enbridge Gas Distribution failed to adequately consider the options of purchasing gas at the Chicago hub or waiting until the pipeline was built before entering into a long-term capacity commitment with Alliance Pipeline.[7] The Board noted that Enbridge could have demonstrated the prudence of its decision by providing evidence that it considered and analyzed the full range of reasonable alternatives. The uncertainty created by expected changes in North American gas supply markets makes the evaluation of supply and transportation options by utilities even more complex, and increases the costs of making a bad decision.

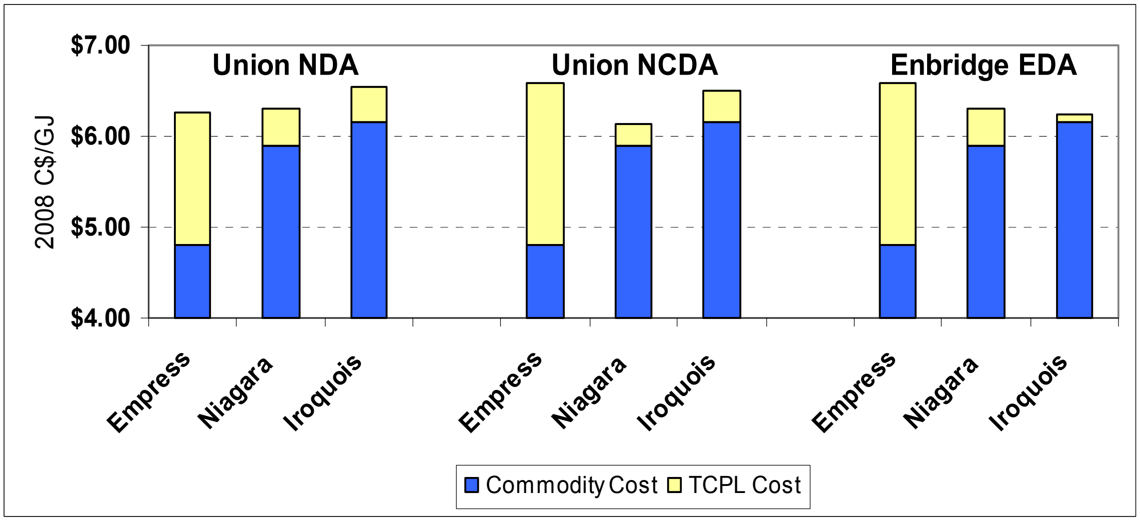
2) Utility services may require customers (or their suppliers) to deliver gas at a specific delivery point, such as Empress or Parkway.

   Ontario gas utilities continue to base much of their gas supply and upstream transportation on the Alberta market. For consumers in Union's Northern delivery zone, for example, system sales are priced against an Alberta reference price, and direct supply customers deliver gas to Union at Empress. However, the fact that certain markets in Ontario are dependent on TCPL for transportation does not mean that gas must continue to be sourced at Empress. As noted previously, the Niagara and Iroquois border points are likely to develop as viable market centers for the Ontario market. Given the potential for further increases in TCPL mainline tolls, the delivered cost of gas from these points is likely to be significantly less than the delivered cost from Empress.

   Figure 3.1 illustrates the potential savings from purchasing gas at points other than Empress to supply Ontario markets. The natural gas prices shown are based on the information contained in the ICF report, and the TCPL transportation costs are the posted zone or point-to-point toll that are currently in effect.[8] These simple examples suggest that the citygate delivered cost of gas to certain Ontario markets could be reduced by sourcing natural gas at Niagara or Iroquois instead of Empress.

[7] Enbridge's contract with Alliance Pipeline extends through November 2015.
[8] See Attachment A.

Figure 3.1: Delivered Cost of Gas by Delivery Area and Supply Location



4. RECOMMENDED REGULATORY ACTIONS

Regulatory changes should be considered to protect Ontario consumers from unreasonable costs and risks related to utility transmission expansions and to ensure that all Ontario consumers benefit from opportunities to reduce natural gas costs by diversifying sources of supply.

4.1 Protect Ontario consumers from subsidizing facilities expansions and shouldering the risk of unutilized transmission capacity.

There are several questions relating to the approval of transmission expansions, the pricing of ex-franchise services, and the appropriate allocation costs and risks between consumers and utility shareholders that should be considered by the Board:

1) How should the Board assess the economic feasibility of transmission expansions used to provide ex-franchise services?

   When applying for leave to construct new facilities, Ontario gas utilities use economic feasibility tests based on the Board's E.B.O. 134 report.[9] The Board should consider whether these guidelines, which were developed to evaluate local distribution system expansions to serve new communities within Ontario, are appropriate for large capital projects to provide additional gas transportation services to markets located outside the province. These are not the same long-lived investments in local infrastructure that the E.B.O 134 guidelines were meant to address.

[9] "Review by the Ontario Energy Board of the Expansion of the Natural Gas System in Ontario". This report was issued June 1, 1987.

2) Should utilities be required to use incremental rates for ex-franchise transmission services?

   The Board has generally accepted the use of rolled-in rates for gas utility services, which is consistent with the policies adopted by the National Energy Board. In the U.S., however, the Federal Energy Regulation (FERC) has taken a different tack. In its "Certificate Policy Statement" issued in 1999, the FERC observed that rolled-in pricing sends the wrong price signals by masking the real cost of expansions, and often results in projects that are subsidized by existing ratepayers. The FERC therefore rejected its previous policy, which included a presumption in favor of rolled-in pricing, with a policy that generally favors incremental pricing of expansion facilities.[10]

   Recently the Board approved a proposal by Union Gas to use incremental rates for a new Dawn to Dawn-TCPL transportation service.[11] Instead of combining the facilities needed to provide the service with Union's existing transmission plant and depreciating costs over a standard 40-year period, the Board approved a new C1 toll that recovers the incremental cost of service from Union's $3.3 million capital investment over a period of just five years. This rate design addresses the risk that customer commitments for the new service will not be renewed after the initial five-year term. As Union explains in its application, if the ex-franchise customer contracting for the new service does not renew its contract upon expiration "the traditional rate design methodology would not recover all of the capital costs required to construct the facilities….This approach is appropriate given the short term nature of the service and to ensure that the costs associated with the capital investment are not borne by other ratepayers."[12]

   The same principles apply to other transmission facilities built to provide services for the ex-franchise market. The rates for these services should recover all incremental costs, and make a positive contribution to the existing system, over the initial term of the expansion shippers' contracts. If this requirement is not satisfied using roll-in rates, a higher incremental rate should apply to the service. Requiring utilities to use incremental rates for ex-franchise transportation services would ensure that in-franchise gas consumers do not subsidize ex-franchise customers, and would create appropriate price signals to discourage uneconomic investments in new facilities.

3) Should utility shareholders be at risk for the costs of expansions undertaken for the ex-franchise market?

   To ensure that utilities do not recover the costs of underutilized gas transmission facilities from captive in-franchise customers, the Board should designate facilities to serve ex-franchise markets as "at risk" investments. The incremental capital and operating cost of these facilities would be tracked separately, just as the utilities now do for their new competitive storage facilities, and allocated entirely to the ex-franchise services when calculating rates.

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[10] 88 FERC ¶ 61,227(1999)
[11] EB-2010-0207
[12] EB-2010-0207, Exhibit A, p. 8.

4.2 Ensure that utilities make good transportation and supply portfolio decisions.

Regulators in other jurisdictions have recognized that gas distribution utilities will continue to have a role in contracting for upstream transportation capacity to make certain that adequate gas delivery capacity is available to the local market, and that consumers, regulators and other stakeholders have an interest in how the utility manages its contracts for upstream transportation services. It is therefore common to require a gas utility to file a long-term gas resource plan, with forecasts of requirements and a description of the utility's long-term gas supply strategy, for formal regulatory review.

In Ontario, the cost and prudence of gas utility supply portfolio decisions has typically been addressed in rate proceedings. Under the utilities' current incentive rate programs, however, the time between full rate cases is much longer and, as a consequence, the opportunities for a comprehensive review of a utility's gas contracting strategies are less frequent.

Implementing a long-term resource planning process for Ontario natural gas utilities would have several benefits:

- A resource plan documents the assumptions and the process the utility uses to assess the need for gas supply assets and to evaluate the available gas supply options. Making this information open to review before contract commitments are made should help to avoid after-the-fact prudence reviews.

- A resource plan would provide the necessary context for evaluating proposals under the Board's optional procedure for approving long-term contracts established in EB-2008-0280, since contract decisions are best considered in the context of an overall supply portfolio.

- Implementing a separate resource planning process could simplify rate cases by removing demand forecasting and gas supply contracting from the issues list.

A number of implementation questions will need to be addressed:

- How frequently should resource plans be filed with the Board?

- Should the Board approve or reject the utility's resource plan, or should the plan only be subject to review?

- Should the scope of the resource plan only include services and facilities used by in-franchise customers, or should it include all utility services and facilities under Board jurisdiction?

- What should be the length of the forecast period?

- Should all utilities be required to use a common set of assumptions for certain forecasting inputs (e.g. economic growth, price inflation, exchange rates, Henry Hub gas prices)?

- What should be the process for reviewing the proposed resource plan?

Examples of gas utility resource planning requirements in other Canadian and U.S. jurisdictions can be found in Attachment B.

4.3 Eliminate barriers to diversifying natural gas supplies.

To ensure that Ontario consumers are able to take advantage of opportunities to lower their costs by diversifying their source of supply, the Board should require utilities to offer all direct purchase customers firm access to alternate delivery points. If there are physical or contractual restrictions that limit access at certain locations, the available capacity should be allocated on a non-discriminatory basis. The terms of service governing access to gas supplies under utility services should also avoid any bias between system supply and direct purchase options.

5. DISCUSSION QUESTIONS

The Board has provided a list of topics for discussion at the stakeholder conference scheduled for October 7 and 8, 2010.[13]

1. ***Given the changes identified in the ICF Market Report, what might be the opportunities for Ontario gas market participants?***

   From the perspective of Ontario natural gas consumers, changes in the natural gas supply markets should create opportunities to lower delivered natural gas costs by further diversifying the sources of natural gas supply entering the province.

2. ***What might be the challenges for Ontario gas market participants?***

   Declining throughput on TCPL could lead to further toll increases that will raise the price of natural gas for Ontario consumers. Other challenges for Ontario gas consumers will be to ensure that gas utility projects for ex-franchise markets are not subsidized by in-franchise customers, and that gas utility contracting decisions and distribution service terms allow utilities, consumers and natural gas suppliers to optimize their gas acquisition activities in response to anticipated changes in the gas supply markets.

3. ***Should potential impacts on existing pipeline facilities in the market be considered in the pre-approval of long-term supply and/or transportation contracts?***

   Yes. To protect the interests of consumers the Board should consider all factors that could affect the cost of gas or the quality of service. At the same time, however, the Board must consider the potential competition, supply reliability or supply diversity benefits of approving new long-term supply or transportation contracts.

[13] Attachment A to the Board's August 20, 2010 letter.

4. What further actions should the Board undertake on its own or in conjunction with others?

The Board should consider action in the following areas:

a) Modify the economic feasibility test the Board uses to evaluate proposed utility investments for the provision of ex-franchise services to require that all incremental costs are recovered over the initial contract terms of the expansion shippers. If this requirement is not satisfied, the Board should require the ex-franchise services associated with the project to be priced at an incremental rates. The Board should also ensure that any unrecovered costs related to such projects—whether they are the result of construction cost overruns, contract termination, or the utility's inability to sell unused capacity—are the responsibility of the utility's shareholders, not the utility's in-franchise consumers.

b) Implement a long-term gas resource planning process. The content, format, and filing schedule for long-term resource plans would be determined by the Board.

c) Ensure consumers have reasonable access to new sources of natural gas supply. The Board should direct utilities to modify their tariffs to provide customers with firm access to alternate delivery points. If there are physical or contractual restrictions that limit access to certain points, the available capacity should be allocated on a non-discriminatory basis.

ATTACHMENT A

Delivered Cost of Gas by Delivery Area and Supply Location

(2008 $C/GJ)

	TCPL Delivery Area		
	Union NDA	**Union NCDA**	**Enbridge EDA**
Henry Hub Price	5.35	5.35	5.35
Empress			
Basis	-0.55	-0.55	-0.55
Commodity Cost	4.80	4.80	4.80
TCPL FT Cost	1.36	1.64	1.64
Fuel Cost	0.11	0.14	0.14
Citygate Cost	***6.27***	6.58	6.58
Niagara			
Basis	0.55	0.55	0.55
Commodity Cost	5.90	5.90	5.90
TCPL FT Cost	0.37	0.20	0.37
Fuel Cost	0.04	0.02	0.04
Citygate Cost	6.31	***6.12***	6.31
Iroquois			
Basis	0.80	0.80	0.80
Commodity Cost	6.15	6.15	6.15
TCPL FT Cost	0.35	0.30	0.08
Fuel Cost	0.04	0.04	0.01
Citygate Cost	6.54	6.49	***6.24***
Empress Premium	-0.04	0.46	0.34

Data Sources:

1. Henry Hub price and basis are based on the ICF report (Exhibit ES 5, p. 11).
2. The TCPL FT cost is the applicable 100% load factor NEB-approved toll for 2010.
3. Fuel costs are based on actual fuel ratios for the 12 months ending September 2010.

ATTACHMENT B

Gas Utility Long-Term Forecast and Resource Planning Requirements in Canada and the United States

British Columbia

Electric and natural gas utilities in British Columbia must file a long-term Resource Plan to be approved by the British Columbia Utilities Commission (BCUC) every two years. The Resource Plan has 20-year planning horizon and includes a 4-year action plan. The process for developing and reviewing of the Resource Plan, as set out in the BCUC Resource Planning Guidelines, includes the following steps:

1. Identification of the planning context and the objectives of a resource plan
2. Development of a range of gross (pre-DSM) demand forecasts
3. Identification of supply and demand resources
4. Measurement of supply and demand resources
5. Development of multiple resource portfolios
6. Evaluation and selection of resource portfolios
7. Development of an action plan
8. Stakeholder input
9. Regulatory input
10. Consideration of government policy
11. Regulatory review

In addition, natural gas utilities must, on an annual basis, obtain BCUC acceptance of their contracting plans prior to entering into significant gas supply arrangements for the coming year. The annual gas contracting plan must be consistent with the Resource Plan, set out a gas supply portfolio that will reliably meet customer needs at reasonable cost, and provide for:

- Sufficient supply to meet the utility's total firm requirements at the level of the current year, and a mix of one year and longer terms contracts that is appropriate for the security needs of its customers, considering current market conditions;

- Diversity of supply, including where possible a range of suppliers positioned behind alternative processing facilities, or with backstopping arrangements; and

- Diversity of pricing arrangements and other price risk management measures.

Georgia

Georgia enacted legislation that allows, but does not require, natural gas utilities to fully unbundle natural gas sales from distribution service. A gas utility that elects to cease providing system sales service must still contract for upstream transportation and storage services to supply gas to the utility franchise area. The gas utility is required to file a Capacity Supply Plan with the Georgia Public Service Commission ("GPSC") describing the portfolio of interstate capacity assets that will be used to provide firm gas supply deliveries to retail customers for the following three-year period. The Capacity Supply Plan will:

- Specify the range of requirements to be supplied by interstate capacity assets;
- Describe the array of interstate capacity assets selected to meet these requirements;
- Describe the criteria for entering into individual contracts within the array for interstate capacity assets included in the Capacity Supply Plan;
- Specify the portion of the interstate capacity assets that the utility will retain in order to manage and operate its system.

Following a hearing, the GPSC will issue an order within 45 days either approving the Capacity Supply Plan filed by the utility or adopting a Capacity Supply Plan that the GPSC finds appropriate. If the GPSC does not act within the prescribed period, the Capacity Supply Plan filed by the utility is deemed approved.

New Hampshire

Natural gas utilities are required to file an Integrated Resource Plan (IRP) for approval by the New Hampshire Public Utilities Commission (NHPUC) every three years. The IRP covers a forecast period of five years. The NHPUC has found that the filing of IRPs helps promote communication between the utility and the NHPUC regarding the utility's supply needs and gas resource decisions: "Integrated resource planning helps the Commission to assess a utility's comprehensive supply-side and demand-side resources and the utility's ability to satisfy customer's short-term and long-term energy needs at the lowest overall cost consistent with maintaining supply reliability."[14]

The IRP includes the following elements:

1. Demand forecasts, including a description of the demand forecast methodology.
2. A resource balance showing the difference between requirements and resources, based on existing contracts.
3. Assessments of the available supply-side and demand-side resources.
4. A description of the utility's preferred portfolio of supply-side and demand-side resources.

[14] "Order Approving Stipulation and Settlement Agreement" DG 06-098, April 5, 2010.

John A. Rosenkranz

Mr. Rosenkranz is an energy consultant with experience in natural gas supply planning, pipeline and storage development, and utility regulation. Clients include developers and operators of electric generation facilities, energy regulators and other public agencies, and natural gas consumers.

Mr. Rosenkranz began his career as a market analyst and supply planning consultant to natural gas pipeline and distribution companies. As a project manager with J. Makowski Company, Mr. Rosenkranz directed gas market studies and participated in the development, marketing, and financing of gas pipeline and storage projects. At PG&E Gas Transmission he evaluated midstream investment opportunities, managed a geologic test program at a potential natural gas storage site, and represented the company on the management committees of two interstate pipeline partnerships.

Mr. Rosenkranz has developed and implemented gas supply and transportation strategies for electric generating plants in the U.S. and Canada. These assignments include negotiating gas supply and pipeline service agreements, restructuring existing fuel arrangements, and supporting litigation and arbitration related to long term contracts.

Mr. Rosenkranz has participated in pipeline rate cases and other regulatory proceedings. He has submitted testimony at the Federal Energy Regulatory Commission, and appeared as an expert witness before the Ontario Energy Board and state utility commissions. Mr. Rosenkranz received a BA in economics at George Washington University and completed all course and examination requirements for a doctorate in economics at Northwestern University.

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