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Ontario Energy Board

SPEECH

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Check Against Delivery

It's a real pleasure to be with you this year at your Annual Conference.

It's been an extremely busy and productive 12 months for the OEB since the last Annual Conference last year.

At that time, the OEB was preparing for one of the most ambitious years in its history. We had four high-profile key initiatives that we were working on:

- The Regulated Price Plan
- The Smart Meter Implementation Report
- Approving new Distribution Rates for Electricity Distributors and
- The Natural Gas Forum Report

I am pleased to report today that, while we are awaiting a public announcement by the government on smart meters, all of these projects have either been completed or are now in subsequent implementation stages.

This would have been a satisfying year even if those initiatives were all that we had on our plate. But we also had one of the busiest years ever in terms of hearing applications.

Just to give you an idea of the pace, during one five week period, the Board released a total of 186 decisions: 90 applications for approval for conservation and demand management plans and 96 distribution rate applications.

But, as the saying goes, nothing is harder on your laurels than resting on them. That's why today, I want to look forward and outline a few of the major initiatives that the Board is undertaking in this current year.

Keeping in mind that the OEA's membership includes both the natural gas and the electricity sectors, I will mention a natural gas initiative, some electricity initiatives, and an initiative that transcends both sectors. Each of these projects will provide important insight both for the industry and the regulatory *structure* of the sector for many years to come.

They also demonstrate the Board's efforts to stay ahead of the curve, to get out in front of issues, to be proactive not reactive. We want to heed the advice of Walter Gretzky who told Wayne to go, not where the puck *is,* but where it's *going*. That more or less indicates our vision at the OEB and where we are going.

Let me begin with incentive rate regulation in natural gas.

As you may know, this was a recommendation of the Board's Natural Gas Forum, the NGF, which issued its report on March 30th of this year.

Just to remind you of the context, the Forum was initiated, not because the regulatory structure of the gas sector was fundamentally flawed, but because it needed direction. That's why we initiated the Forum.

Both major gas utilities had completed performance-based regulation programs – Union had a comprehensive regimes which was completed in December 2003 and Enbridge had a targeted program which was completed in 2002.

I think it's fair to say that no one – not the utilities, not the stakeholders and not the Board - was satisfied with the results of those programs. The question was, "where do we go from here?"

There was a need for a clear course for the future. And, with the NGF Report, that course was set.

The key component of the future rates plan is that the Board will put in place incentive rate regulation. There are a number of reasons for this.

First, *annual* rate setting does not facilitate long-term investment planning. We want to send a clear message that Ontario has a stable plan in place that can sustain long-term investment in infrastructure and services. We also want to provide customers with a longer term pricing horizon so that they can operate in a more predictable environment. In the NGF report, the Board recommended a plan term of three to five years.

Second, cost of service does not provide sufficient incentives for efficiency, since utilities have little reason to reduce their costs. We believe utilities will benefit if they are encouraged to find efficiencies within their operations. Moreover, consumers will benefit from those efficiencies, during the plan term – through a rate adjustment mechanism – and at the end of the plan term – through robust rebasing.

Finally, a longer term incentive regulation scheme reduces time and resources spent in hearings before the Board. The Board is trying to meet public interest goals in ways other than through typical hearings.

Let me give you an example.

A key component of the incentive regulation plan for the gas industry is the need to ensure that appropriate service quality levels are maintained. In the past, we relied on the hearing process to address service quality levels through changes in budgets. But there are limitations to that approach.

For example, the hearing process does not provide good data about ***which*** service standards are most important to consumers. Nor does it provide an effective method to improve service levels or to address remedies for not meeting service expectations.

The NGF Report sets out, as a prerequisite to the development of Incentive Regulation, the setting of service level standards. This is necessary to ensure that economies and cost reductions chosen by the distributors do not reduce services to consumers. The Board has initiated a process and will consult widely to set service quality requirements through rules as opposed to traditional hearing processes.

Overall, the NGF Report received a positive response, but there was one question which came up over and over: "why should it take so long to implement?"

The original timeframe for implementing the final component of the Incentive Regulation Plan was the end of 2008. As a result of concerns expressed, we have adjusted that schedule so that the last component will be completed by the middle of 2007 – a full 18 months sooner. This is an aggressive target. But I expect we will reach it.

So that's an initiative in natural gas that we have planned for the coming year.

Turning to electricity, there's the York Region supply situation.

Going back to 2003, Independent Electricity System Operator forecasts had identified the need to meet rapid growth in this area. Everyone agreed that something had to be done – Hydro One, the local municipalities and local Distributors.

However, in the Spring of this year, it appeared that events were conspiring to prevent any solution from moving forward. Significant public opposition had arisen over Hydro One's proposal to build a new 230 KV transmission line from Markham to Newmarket and Hydro One had withdrawn its class environmental assessment.

To further complicate matters, the responsibilities that various public agencies in the electricity sector should have for addressing this issue had to be sorted out.

So let me tell you how we view this issue.

Our role is unique in that the Board maintains regulatory oversight over other public agencies and companies. With that comes two important authorities: one is the responsibility to require organizations to do things, such as provide information and, in the case of transmitters and distributors, to reinforce their systems if the Board considers it necessary. The second important authority is to approve, in certain situations, the use of ratepayers' money to pay for projects. Moreover, our job is to ensure that ratepayer money is used efficiently to serve the public interest in terms of reliability and quality of service.

This is an important public interest role – and one we take very seriously.

So that's part of the context for York Region. Multiple players. New roles and responsibilities. And things somewhat in abeyance. Of course, the OEB wasn't the only one to recognize the problem.

The Ontario Power Authority, for example, is fully engaged with respect to electricity supply in York Region. Going forward, the OPA will be preparing an integrated power system plan to consider the integrated system. As part of that, the OPA can contract for new supply and demand management in accordance with a Board approved procurement process.

At the moment, however, the IPSP is not in place. Obviously there is insufficient time to wait until the Power System Plan and the procurement process are finalized. The time to determine whether and how to address this issue is now. As such, the OEB directed Hydro One and the LDCs to provide us with specific options for meeting the York Region supply situation.

This they did, presenting three well-developed options that consider plans for new distribution and transmission.

While the OPA was already fully engaged, in order to formalize the process under Bill 100, we asked the OPA to consider whether there were generation or demand management alternatives to distribution and transmission and, if so, to apply to the Board to seek cost recovery for contracts to implement those alternatives.

The OPA announced its preliminary recommendations last week, in which it recommended a "basket" of solutions to overcome an urgent need for reliable power in this region. The final recommendations will be provided to the OEB by the end of September.

The York Region experience is a good example of how the Board can play a constructive role exercising its authority and coordinating a response. Of how we can address an emerging issue without waiting for all of the formal institutional arrangements to fall into place. While maintaining our independence as a regulator is essential, we must, where appropriate, work closely with other public institutions, such as the OPA and the IESO, to get ahead of potential problems.

As another example, a senior staff member of the OEB sits as an observer on the IESO technical panel. We do that so we can monitor developments in the market, identify problems that may arise and that will necessitate a Board review at a later date. This way, the Board is better informed about issues, in the day ahead market for example, and better prepared to consider market rule amendments in a timely way. We appreciate the IESO's cooperation in enabling this.

We also have been working constructively with the IESO on NERC reliability issues. The OEB takes part in the stakeholders' committee of the North American Electric Reliability Council **(NERC)** as the Canadian provincial representative. The new US Energy Policy Act will make compliance with electric reliability standards mandatory in the US – as it already is here in Ontario.

The implementation of mandatory reliability standards in the US has implications for us across Canada and for us here in Ontario. The US Federal Energy Regulatory Commission **(FERC)** is taking the lead role in overseeing the transformation of the industry reliability body – **NERC** – into an Electric Reliability Organization **(ERO).** Provincial energy regulators may be expected to play – it's not clear yet – a similar role in overseeing the ERO. The OEB has been working closely with CAMPUT and NERC on the development of a Memorandum of Understanding to clarify these relationships. I mention this to give you an understanding of these other roles and responsibilities.

Let me give you another example of co-operation that is pretty obvious considering that we're meeting here in Niagara Falls. In August, the OEB released a statement and public notice announcing its commitment to develop filing requirements for transmission infrastructure investment.

The need for this project was highlighted by the Board's recent consideration of the Niagara reinforcement project. The OEB has approved this project and we expect Hydro One will be moving ahead with it shortly.

However, during the application proceeding, the Board recognized the need for greater clarity around what types of information are needed when it considers leave to construct applications for electricity transmission infrastructure – and who will provide that information.

The Board has not considered many reinforcement projects – just four since 2000. And no standardized and comprehensive approach to assessing the costs and benefits around those projects.

We viewed it as a Board responsibility to provide guidance on such matters. We're pleased that Hydro One has committed to participate in the review and sees its merits. An Advisory Team of experts will assist the Board in developing these filing requirements to support the evaluative criteria – criteria, we believe, will ensure that the public interest is protected and enhance regulatory certainty and predictability around these projects.

Let me turn now to another initiative and that's the gas electricity interface review.

As you know, the Board oversees aspects of both the natural gas and electricity sectors. Further, neither sector, on its own, necessarily anticipates the needs of the other.

Indeed, an important part of the interface between gas and electricity is the need for better coordination among system operations. I am encouraged that the major utilities, Union and Enbridge, along with TransCanada Pipelines and the Independent Electricity System Operator, are working together to address these concerns. I also want to note the valuable contributions that the Ontario Energy Association is making by supplying information and helping to facilitate discussion. Thank you for that.

As Ontario increases its reliance on gas fired generation, we need to ensure that we clearly understand the issues in order to make it work.

Specifically, we need to know what the new demands will be, what the capacity is of current infrastructure and services to meet this demand and, perhaps most importantly, if there ***are*** going to be new infrastructure and services, what they are going to cost and who should pay for them.

To address these kinds of issues, the Board established the Natural Gas Electricity Interface Review. It involves two stages. The first stage is the research project that we are carrying out this Summer and Fall to elaborate the issues I just identified. We recently issued a summary of the research on the demands that gas-fired generation will place on Ontario's natural gas system. Research is also underway on the estimated costs to meet those demands. We are bringing stakeholders together at a public meeting next Monday, the 19th, to discuss the implications of the research findings.

The second phase will be a regulatory process to provide answers to those questions. The results of the research project will be published as a Board Staff Report early in October. The details of the second phase of this process will be announced at that time.

Why are we undertaking the Gas Electricity Interface Review now? Two reasons.

First of all, we need more information than we obtained through the Natural Gas Forum. By undertaking a comprehensive study now, we will be well prepared for the applications that will be forthcoming, such as upgrading existing infrastructure, creating new infrastructure or providing new services.

The second reason we're doing this preparation now is that since our work on the Natural Gas Forum, a number of generation projects have been announced, making these issues both more immediate and concrete. There's nothing hypothetical about the move toward greater gas-fired generation. It's real and it's here and we need to be ready.

Now, I've been talking a lot about our efforts to be proactive on issues of supply and transmission. We've worked hard at planning ahead to ensure we are ready to meet future needs. But that doesn't mean our current responsibilities are any less important.

I'm going to conclude my remarks today by talking about something that is very apparent to all of us in light of the long, hot summer and its impact on electricity commodity prices. As I mentioned earlier, this past year, the OEB established the new Regulated Price Plan or ***RPP*** for residential and other designated consumers.

The Board's goal was to develop electricity prices which better reflect the prices paid to electricity generators – and to do so in a way that smoothes the volatility inherent in wholesale electricity pricing.

The RPP, which took effect in April, is based on a forecast of a number of factors. Among them are: availability of supply, fuel prices, projected demand and market prices for electricity, known contract and regulated prices for prescribed generators – and the weather. We developed the forecast using our view of the ***most likely*** outcome for each of these significant factors. ***Normal*** weather is assumed in the RPP forecast.

We forecast that the cost of supplying the entire group of RPP customers would average out at just over 5.3 cents per kilowatt hour over the course of the plan, once certain factors were taken into account. By the end of July, it was more in the area of 5.9 cents, the heat wave certainly being a major contributing factor.

Further, some base load generation was unavailable for most of the first quarter of the RPP term. And reduced water availability because of the dry weather, in turn, reduced the supply of hydro electricity. So, compared to our forecast, the hourly electricity prices have been set more often by the higher cost generators such as gas-fired plants.

There are many variables that can affect electricity costs and therefore actual outcomes, no matter how carefully-crafted a forecast. Anticipating this reality, the RPP provides for a variance account, held by the OPA, to collect the difference between the actual costs of RPP supply and the payments by RPP consumers.

Tomorrow, as we do each month, we will be posting the **net** variance account balance for the price plan, after we receive the most up to date information on the previous month's electricity spot market prices from the IESO. The figure we publish will show the ***net*** variance as of the end of August, which was another month of hot weather and high spot prices.

While demand tends to level out in the autumn, the high demand days of winter are still ahead, complicated this season by rising natural gas prices, which also affect prices for electricity. At the OEB, we believe consumers need to understand this and to see this in context.

First, if we had asked price plan consumers to close the cost gap - between their RPP prices and the prices paid to generators - at the end of July, the typical residential consumer using 1000 Kilowatt hours per month of electricity would have paid about $18.50 over the next RPP period - or just over $1.50 a month.

Second, consumers are not being asked to pay that difference **now** unless they leave the plan. As you know, government regulation requires that prices remain the same for the first year of the plan.

The impact consumers see on their bills this fall for the summer's use will be based strictly on consumption and not on fluctuating prices.

Third and finally, whatever amount the variance is at the end of the price plan period, it will be blended into the next year's prices. Consumers will ***not*** be hit with one-time, lump-sum, retroactive charges.

What's more, next year's prices will be adjusted more frequently – up or down every six months as needed - to be more responsive to market prices and reduce the potential for large variance account balances.

I cannot predict what prices will be next year. Much depends on supply and demand conditions for the next six to seven months. I can say that the OEB is watching the trends closely and will carefully consider what has taken place so far this year when it comes to the assumptions and conclusions we make about setting next year's prices.

So while we have kept a watchful eye on these current concerns, our longer term goal remains the same: to establish electricity prices that better reflect the actual costs paid to generators for generating the electricity in a way that consumers can manage.
Again, we want to stay ahead of the curve – in the short and the long term. Anticipating developments. Protecting the interests of consumers and fostering a healthy and efficient energy sector.

Those are the goals set out in the legislation, and we are attempting to achieve them in our work.

Thank you.