

Reconnecting Supply and Demand:

**How Improving Electricity Pricing Can Help Integrate
A Changing Supply Mix, Increase Efficiency
and Empower Customers**

**Report of the Chair of
the Electricity Market Forum**

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INTRODUCTION

Background and Context

The wholesale electricity market sets the price of electricity through the intersection of supply and demand of producers and consumers. This price performs important economic and policy functions.

From an economic perspective, price reveals the incremental cost of energy production and thus provides producers and consumers a signal about when it is economic to produce or consume energy. This encourages efficient behaviour. This behavioural response can also be reflected through technology. Smart grid technology can be triggered by the price signal thus automatically managing distributed demand and generation response to price signals. In this way, price can be the central organizing principle that incents economic supply and demand response throughout the electricity system.

From a policy perspective, the price signal operates within the context of a broader electricity policy structure that also uses a number of other instruments, including central planning, long-term supply and conservation procurement contracts, rate-regulated generation facilities, and regulated prices for residential and small business consumers (although with retail competition, consumers may opt to sign contracts). This structure is based on the premise that energy policy is designed to meet environmental and social goals, as well as the goal of economic efficiency. Refining and strengthening the role of price is consistent with and enhances the achievement of all of those policy goals.

Specifically, the price of electricity is incorporated into each of the policy instruments used to further broad energy policy goals. These instruments continue to use price as a trigger to address issues such as measuring revenues under procurement contracts or regulated rates. Indeed, of all the policy instruments, price is unique because it states, in a clear and verifiable way, the incremental cost of energy production. In this way, the price signal is the single most transparent and fact-based policy instrument in the energy sector.

Because many policy instruments involve the exercise of regulatory and administrative discretion, it is important that they be grounded in the basic economic facts. In other words, price is an important part of all of the energy policy instruments in the province and can help them all operate in an integrated and coherent way to meet both the short and longer-term challenges and opportunities for the energy sector in a cost-effective and transparent way.

Some of the challenges and opportunities are currently being experienced. They include the need to ensure power system flexibility in light of a supply mix that removes coal-fired generation and places greater reliance on renewable power and natural gas fired generation. This is being combined with the reality of reduced demand in light of economic restructuring and conservation.

However, many of the more fundamental challenges and opportunities that the sector will be facing are at early stages of their evolution. Potential “game changers” that are expected to have significant impacts on the Ontario electricity system in the medium and long-term include the adoption of electric transportation on a commercial scale, the full deployment and utilization of smart grid technologies to assist electricity management and demand management, and the need to adapt to one or more carbon-pricing or environmental cost regimes.

A competitive market that offers a transparent price reflecting real supply and demand conditions can help Ontario to address its short and long-term electricity challenges and opportunities in a manner that is consistent with broad energy policy goals. Focussing on the demand-side of the market in particular can provide guidance to conservation and supply procurement decisions, thus allowing avoidance of costs for excess generation resources. Also, by signalling the value of electricity, a high fidelity electricity price can facilitate electricity consumers’ ability to benefit from technological advances and gain savings through market efficiencies, increased choice, and modified consumption facilitated by service providers or other means.

The Market Forum

Recognizing changes to the Ontario electricity market as well as the market's potential to help resolve some current issues encountered today by electricity generators and consumers led the IESO to initiate a consultation process to identify issues and opportunities for the IESO-Administered Markets. The interrelated roles of the Ontario Power Authority (OPA) for resource contracting¹ and the Ontario Energy Board (OEB) for regulation were critical characteristics that were considered during the consultation.

The Electricity Market Forum was established in March 2011 to identify the principal issues being encountered or anticipated in the operation of and participation in the IESO-Administered Markets and to make recommendations that address those issues in light of the respective roles of the market, contracts, and regulation.²

To complete its work, two committees were struck, drawing on the expertise of Stakeholder Advisory Committee members and the broader stakeholder community. The Market Development Committee (MDC) was the working group, which met every two weeks to discuss and consider issues, options and priorities. At the conclusion of each stage of work, the Executive Steering Committee (ESC)³ reviewed the work of the MDC and provided perspective, feedback and broad consensus.⁴ The IESO and OPA were represented on these committees, and the meetings were attended by observers from the Ministry of Energy, the OEB, the Market Surveillance Panel, and the Ontario Electricity Financial Corporation.

The Market Forum's Approach and Outcome

The Market Forum's approach was to focus on "on the ground" challenges and not broader energy policy. As a result, it did not seek out views on the appropriateness of the main pillars of energy policy, such as the hybrid market, the number and role of agencies, sector rationalization, and the incorporation of social and environmental goals into energy policy. Instead, its focus was on challenges and solutions that arise under the current structure and would be relevant under any industry structure. This approach was consistent with the message of most stakeholders that the sector could benefit from continued stability and implementing already ambitious energy policy goals. As a result,

the Market Forum's initiatives proposed in the Road Map can be addressed without legislative change, the establishment of any new government programs or spending; or changes to current contractual obligations.

The Market Forum was conducted in three stages.

- In May, 2011, it approved a list of issues;
- In August, 2011, it approved a list of options to address those issues; and
- In September, it approved a prioritization of those options in the form of a Market Road Map with deliverables and time-lines for the implementation of market improvements.⁵

The Road Map identifies issues that should be addressed in order to achieve improvements to the market. These issues will be addressed in a number of decision-making forums, such as consultations carried out respecting how decisions of the agencies (the IESO, the OPA and the OEB) may impact electricity market and system efficiency. It is expected that these agencies will hear a number of varied perspectives on these issues, including those from members of the Market Forum. The Market Forum Road Map is meant to identify and prioritize these issues in a strategic and sequential manner. It is not meant to conclude how those issues will be decided. Each of the decision making agencies will have their own processes and criteria that they will of course apply to those issues.

The Road Map initiatives address changes that are incremental to current approaches, but the benefits of re-orienting the market around supply and demand fundamentals could be significant, resulting in potential savings of billions of dollars over the next 20 years. These savings can result from a renewed focus on customers, empowering them to obtain the long-term benefits of:

- reduced costs by focusing on the needs of electricity customers, including the need for reliable, clean and cost-effective supply consistent with government policy;
- enhanced technology to cost effectively manage electricity use through a smart grid that allows customer-based responses to system requirements;
- more efficient market price signals and operations that allow generators and customers to participate and effectively contribute to the operability needs of the electricity system.

¹ While the OPA is the main contracting entity in Ontario's electricity market, the Ontario Electricity Financing Corporation manages Non-Utility Generator (NUG) contracts, therefore all references to contracting really account for OPA and NUG contracts

² See Appendix A for the Market Forum's Terms of Reference.

³ See Appendix B for a list of the ESC and MDC members.

⁴ See Appendix B for the collection of Issues and Options and Appendix D for the Road Map.

⁵ See Appendix D, Market Forum Road Map.

CONTEXT: THE STATE OF THE MARKET

On the whole, Market Forum members were of the view that the electricity market is largely working well. No participant or presenter recommended fundamental change. To the contrary, a strong sentiment expressed throughout the Market Forum meetings was that any proposed change should have to be justified by reference to its costs and benefits.

In this context, the Road Map reflects a need for some fairly significant refinements of the electricity market.

The most significant refinement is with respect to the need to orient the broader electricity market around supply and demand fundamentals. This took shape in a number of discussions and recommendations, the most important of which related to the need to ensure that both the demand-side and the supply-side have the opportunity to meet system needs.

The Road Map initiatives can be grouped into three broad categories: (i) Integrating the Changing Supply Mix; (ii) Engaging and Empowering Consumers, and (iii) Improving Efficiency. Each will be addressed in turn.

INTEGRATING THE CHANGING SUPPLY MIX

The Supply Situation

In January, 2004, the Energy Conservation & Supply Task Force reported that “Ontario faces a looming electricity supply shortfall in the years ahead.” The province responded to that challenge and, since 2005, has added approximately 7,700 MW of supply capacity.⁶ The result is that Ontario no longer faces a looming supply shortfall. To the contrary, it now has the luxury of sufficient and even excess supply. Further, although there is a potential “capacity gap” arising in around 2018, that gap can be filled if existing infrastructure is re-contracted and reconfigured.

The supply-side challenge now is therefore not driven by the need to procure new generation capacity, but to manage supply to meet the needs of electricity customers. This challenge provides context for the recommendation that procurement decisions should be informed by market and power system needs and system limitations. It also informs recommendations respecting power system operability, including the treatment of surplus baseload generation⁷ and ramping.

With respect to how the recommendation that procurement should meet system demands would work in practice, it is helpful to look concretely at current information on power system needs and how that could inform procurement decisions.

System Requirements: The Demand Situation

Developing and maintaining accurate information on electricity demand is key to understanding system requirements and, therefore, the requirements that the power system is meant to achieve. This is an ongoing process because a forecast of demand, however accurate at a moment in time, will quickly prove to be overtaken by experience. As the OPA noted, forecast scenarios do not pretend to predict the future. Rather, “demand projections help establish the context against which planning decisions and options can be explored.”⁸

As a result, forecasting is “an ongoing cycle of monitoring new information and incorporating it into ever-evolving long-term potential scenarios.”⁹ It is therefore prudent to continually take timely information into account when considering what power system requirements are and how they should be met.

The OPA has prepared forecast scenarios to support the 2007 IPSP and the LTEP. The LTEP used the Medium Growth forecast to quantify the capacity targets for

⁶ Ontario Power Authority, Integrated Power System Plan, Planning and Consultation Document (“IPSP Document”), pp. 3-3 to 3-5, www.powerauthority.on.ca/process

⁷ Surplus baseload generation is defined by periods where baseload supply e.g. nuclear, wind, solar, must-run hydro electric exceeds Ontario demand requirements.

⁸ IPSP Document, p. 2-5.

⁹ IPSP Overview, p. 2-6.

planned conservation and supply resources¹⁰ and is thus the starting point for understanding changing system requirements.

To illustrate how system requirements change and evolve over time, it is helpful to compare forecasted demand and actual demand. This comparison for the years 2010 and 2011 is set out below:¹¹

In this case, actual changes in demand for 2010 and 2011 are significantly lower than forecasted increased demand. Although such a comparison is insufficient for considering important factors such as energy production and operability, it is helpful to evaluate assumptions for peak capacity demand for the periods for which there are actual results. From this perspective, the data suggests that, for the years 2010 and 2011, actual peak demand (weather normalized) was approximately 600 and 850 MW less, respectively, than the Medium Growth scenario which underlies the conservation and supply capacity targets, and is even less than the Low Growth scenario.

This Report will not attempt to provide an alternative demand forecast. However, it does appear that the reduction in demand from forecast is not a temporary phenomenon. The IESO's Long Term Reliability Assessment filed with the North American Electric Reliability Corporation (NERC) indicates a continual reduction in demand from the Medium Growth scenario out to 2015, culminating in a projected peak demand reduction of over 1,300 MW from the Medium

Growth scenario in that year.¹²

To put these figures in some context, under the Medium Growth scenario, the forecast for demand is flat and it is not until 2027 that peak demand is expected to grow by 1,000 MW. Even under the High Growth scenario, peak demand does not grow by 1,000 MW until 2022. Under the Low Growth scenario – which appears to be higher than where demand is trending – peak demand does not increase by 1000 MW prior to the end of the Plan term (2030).¹³ Thus, while the longer-term implications of current data are not certain, it appears peak demand requirements are not likely to meet forecasted increases for the foreseeable future.

The point here is not to criticize previous forecasting methodology or results. Rather, the point is that, information on demand is an important consideration to be taken into account when considering new supply procurement decisions. While many procurement decisions have already been made, it appears that there are several decisions that still remain. According to the OPA, there are approximately 1,000-2,000 MW of “Projected” procurements that have not yet been committed to.¹⁴ In addition, the OPA has indicated that there has been attrition in a number of procurement programs that “could potentially enable additional energy projects.”¹⁵ These options are all premised upon respecting existing contracts and nothing in this Report or the Road Map should be taken to suggest that existing contracts should not be respected.

Comparison: Growth Scenarios vs Weather Normalized Demand

Year	IPSP Overview Low Growth Scenario	IPSP Overview Medium Growth Scenario	IPSP Overview High Growth Scenario	Actual Demand (Weather Normalized)	Difference between Actual Demand (Weather Normalized) and Medium Growth Scenario
2010	24,343 MW	24,528 MW	25,056 MW	23,916 MW	(612 MW)
2011	24,155 MW	24,351 MW	24,425 MW	23,501 MW	(850 MW)

¹⁰ The capacity targets for conservation and supply resources in the LTEP are:

- Conservation: 7,100 MW by 2030
- Nuclear: 10,000 MW refurbished and 2,000 MW new build
- Hydroelectric: 9,000 MW by 2018
- Non-Hydroelectric Renewables: 10,700 MW by 2018
- See: IPSP Document, p. 1-3.

¹¹ Source: IPSP Document, p. 3-19, Figure 10. IESO 18-Month Outlook Update - Table 3.3.2, released November 24, 2011.

¹² North American Electric Reliability Corporation, Long Term Reliability Assessment: http://www.nerc.com/files/2011LTRA_Final.pdf, page 54

¹³ IPSP Document, p. 3-19, Figure 10.

¹⁴ OPA, Outlook for Electricity Demand and Supply in Ontario, APPRO 2011, Presentation by Amir Shalaby, November 15, 2011, slide 9.

¹⁵ IPSP Document, p. 3-11,

Further, it is my view that deferring or avoiding new supply until it is required to meet electricity system requirements is not a change in government policy.¹⁶ The LTEP's supply targets were expressly premised upon forecasted market demand for electricity. It is only prudent to consider the relative benefits of acquiring or deferring additional supply capacity in light of reduced demand. The benefit of acquiring a large supply surplus is that it can provide some flexibility to meet unanticipated short-term demand fluctuations. The benefit of avoiding or deferring additional capacity is the avoided costs of new generation that is no longer required to meet peak demand requirements.

If actual market demand is below forecast such that new supply resources can be avoided or deferred, then customers can benefit considerably in avoided costs, both with respect to the cost of procurements themselves and the costs of managing any excess supply resulting from those procurements. The Market Forum's facilitator, Power Advisory, has estimated that the cost of 1,000 MW of new supply would be in the billions of dollars.¹⁷

System Requirements: Flexibility

In addition to meeting peak demand, generation supply must meet other system requirements, including energy and operability. The need to address operability informed several recommendations.

The operability challenge arises because Ontario's supply mix is changing. With the removal of coal-fired generation and increased reliance on renewable power, the resource mix in the future will be considerably cleaner than it has been in the past. It will, however, be less flexible. This is an inevitable trade off when a jurisdiction decreases reliance on flexible coal-fired generation and increases reliance on intermittent renewable sources of power.

It is important in this regard to emphasize that the challenge is not one of insufficient or inadequate

resources. Existing, committed and planned resources will be sufficient to meet Ontario's capacity, energy and operability requirements using existing market operations. However, managing power system operability will become increasingly difficult as greater quantities of less flexible resources are added to the supply mix.

The issue is how to meet power system requirements in an efficient and transparent way, one that allows all market participants – producers and consumers – to have better information and price signals by which they can make decisions and take actions in a more flexible and nimble way.

The three specific areas of operational flexibility that require examination relate to surplus base load generation (SBG), ramp and load following.

With respect to SBG, the minimum level of electricity demand that needs to be supplied on any given day can be as low as 10,000 MW to 12,000 MW. Given the supply resources that have 'must-run' attributes (i.e., either fuel is present and electricity must be produced, or the operational characteristics of the generation requires steady and constant electricity output) there is a potential for 16,000 MW of baseload generation in today's market.¹⁸ Therefore, because baseload generation can be greater than the average minimum level of electricity demand, Ontario experiences many hours of SBG. This poses power system operability challenges.

Ramp is the ability to schedule and dispatch resources to produce electricity or consume less electricity in order to match changes in electricity demand over one or more hours. Ramping requirements therefore require supply and demand resources that can respond in fairly short order.

Load following is the ability of resources to continuously and quickly produce electricity or not consume electricity in order to meet demand

¹⁶ Although this approach could involve acquiring less supply than the specific targets in the Long Term Energy Plan, this is not a departure from the principles and policies underlying the LTEP. As indicated, the specific resource targets in the LTEP are informed by system demand forecasts. If forecasted demand does not materialize, one would expect that the specific LTEP targets can be adjusted accordingly. If any adjustment to the Long Term Energy Plan is involved, that adjustment is one of timing. As indicated in footnote 10, the targets for generation technology types are largely time driven so that targets are to be met within a certain period, for example 2018. The contribution of generation types from 2018 onward are to be made on an economic basis. For example, with respect to non-hydro renewable facilities, the LTEP states that: "For the period after 2018, depending on changes in demand, Ontario will look for opportunities to increase the development of renewable energy projects and expand renewable energy capacity in the Province." As a result, the LTEP takes demand for electricity into account for future procurements.

¹⁷ The actual cost of new supply will be based on the specific terms of contracts, which can differ significantly by reference to the fuel type and technology of the generating facility.

¹⁸ Baseload generation comprises of approximately: 11,500 MW of nuclear; 2,000 MW of run-of-river hydro; 1,000 MW of co-generation (i.e., NUGs); 1,500 MW of wind.

requirements on a very short-term basis. The variability of renewables can translate into more pronounced ramp and load following requirements. As a result, even greater levels of operational flexibility will be needed.

The IESO currently meets power system operability requirements using its existing tools and capabilities. To better manage the operability challenges in the future, changes to present tools and capabilities may well be required, and new solutions developed and deployed. Doing so will likely involve:

- increased ancillary services such as operating reserve and regulation requirements;
- increased use of IESO control actions, for example:
 - manual dispatch;
 - nuclear manoeuvring; and
 - intermediate dispatch arrangements for renewable resources.

The potential concern with respect to these current tools is that they often involve a manual intervention in dispatch decisions – they are blunt instruments that lack transparency and are often less efficient and therefore can be costly. They are best considered as temporary workarounds.

Whether these manual interventions should continue to be used as a primary tool to manage flexibility requires a review of the costs and benefits of these interventions and the costs and benefits of more market oriented responses. The Road Map therefore includes a recommendation that the IESO should examine whether new ancillary services should be developed to better manage the operability issues associated with the changing supply mix. Any new solutions should allow both generators and loads to bid on cost-effective ways of supplying greater flexibility to the system. The first step in this examination is to identify the precise scope and requirements for products to address SBC, ramp and load following. Once this is completed, it will be possible to identify and select feasible options, such as:

- Ramp and/or load following ancillary service;
- Co-optimization of energy/operating reserve/regulation; and
- Changes to generation unit commitment.

At the same time, as these efforts are being carried out, it is important that there be a coordinated response to these challenges. Representatives of both the OEB and the OPA attended the Market Forum and made presentations on how their main policy instruments may have an impact on this issue.

The OEB's regulatory authority is engaged in two areas that are relevant to this point.

First, the OEB sets payment amounts for prescribed generation assets that provide baseload power (namely, Ontario Power Generation's nuclear and baseload hydro resources). It currently designs payment amounts for the nuclear facility on the basis of a uniform rate that provides OPG with revenues that are based, subject to minor exceptions, on output produced without regard to power system needs. The consequence is that OPG is not always incented to manage its facilities to meet system needs and benefits. OPG's hydro electric baseload facilities do have market based incentives, however the design mechanism may not provide the full incentives for the plant to operate efficiently when prices are negative. It should be noted that there are significant restrictions on the flexibility of nuclear assets in light of the physical restrictions and limited flexibilities of OPG's nuclear fleet. OPG's nuclear units were not designed for frequent output reductions; they are baseload assets, designed for sustained operation at full power.

In this context, the OEB's 2011-2014 Business Plan includes as an objective that "the Board's approach to determining the payments to OPG in respect of its prescribed generation facilities encourages efficiency in both OPG's operating costs and its investments." To address that objective, the Board plans to conduct a review of "alternative approaches for determining the payments to OPG, and update filing guidelines as appropriate". In order to ensure that broader system issues are also considered, in addition to considering efficiency in OPG's operating costs and investments, the OEB's review should also consider efficiency in power system operations.

Second, the OEB sets export tariffs that it applies to transmission rates. The OEB has addressed this issue in a number of proceedings and intends to do so again in Hydro One's next rates case. This review would benefit from a consideration of the effect that the export tariff has on the efficiency of using interjurisdictional trade as a way to help manage SBC.

A particularly important consideration of the impact on power system operations is the structure of OPA procurement contracts.

The OPA has many types of procurement contracts for supply. Virtually all generation facilities constructed since 2002 are subject to OPA procurement contracts. As a result, those contracts have a significant influence on the incentives for generation operations in Ontario.

Many of the OPA contracts, especially the Clean Energy Supply¹⁹ contracts contain strong incentives for generators to operate efficiently in response to market conditions.

With respect to renewable power, both the variable fuel source and the nature of generator expectations make it more challenging to incent generator behaviour to follow system needs.

A review of the FiT contract structure is currently ongoing. This review should include consideration of incentives to generators to operate at times of high demand and to reduce their production at times of SBG, i.e., they should be responsive to the market price.

In terms of OPA supply contracts, it is important to appreciate that some of these contracts may be impacted by changes in market rules. As such, the potential impacts should be part of the rule change process so that any changes to Market Rules are coordinated with existing OPA contract provisions.

ENGAGING AND EMPOWERING CONSUMERS

One of the greatest challenges in energy markets is how to incorporate a vigorous demand-side.²⁰ Ontario has been investing significantly in conservation and demand management over the last several years. The challenge now is how to make use of that investment in a way that engages and empowers customers so that they can exercise greater control, choice, market participation and other benefits.

The opportunity to engage the demand-side is, challenging as it is, worth pursuing. Consumers have been able to benefit from technological and service developments in virtually every other product and service in our economy. These benefits should derive from electricity services as well. A customer-focussed electricity system would look to consumers as a key resource to help meet its capacity and operability needs.

Understanding the needs of customers requires both a clear understanding of future system requirements that present opportunities for customers to respond, and directly engaging with customers to identify and reduce barriers to their participation in IESO-Administered Markets.

There are a number of initiatives in the Road Map aimed at pursuing the demand-side opportunities.

First, the IESO will be launching a consultation so that it can hear from customers (including loads, LDCs,

retailers, aggregators, etc.) and understand what the barriers are to increased demand-side participation. The purpose of doing this is to determine the opportunities for cost-effective demand-side participation in the supply of necessary system services and enhancing responsiveness to real-time system conditions.

In this regard it is important to bear in mind that many customers are not necessarily interested in or in a position to directly manage their electricity consumption. Even large customers are in the primary business of producing products and services to meet the needs of their customers; electricity consumption is incidental to this goal. This can be contrasted with electricity suppliers, who employ teams of people conducting sophisticated analysis to effectively participate in the electricity market.

The real opportunity for engaging the demand-side of the market is less through expecting customers to manually change their energy usage than through aggregation of customer demand and the use of smart grid and smart home technology. An enhanced price signal (discussed in greater detail below) can provide a triggering mechanism that will allow the smart grid to automatically adjust customer electricity usage. To address the opportunity for this, the consultation on the opportunities for demand-side participation includes looking at how customers can engage in the market to cost effectively provide:

- peak management and load shifting;
- supply of established ancillary services (e.g. regulation and operating reserve) into IESO Administered Markets; and
- supply emerging system services (e.g. ramp, load following, SBG relief).

In order to avoid confusion in the marketplace it will be necessary to ensure that there is coordination of demand response program development among providers. Accordingly, this consultation should correspond with and provide input into a number of OPA initiatives, namely, the OPA's review of its demand response program which is currently underway; and the development of the next generation OPA/LDC Master Agreement on Conservation.

The OEB has less of a direct role in demand response. However, it has many policies that have an impact on how customers are incented to use energy. The OEB intends to conduct a review of its Regulated Price Plan (including time-of-use prices), customer classifications and the structure of utility rates. All of these policies

¹⁹ Most gas-fired generation facilities are under Clean Energy Supply contracts.

²⁰ See, for example, Paul Joskow, Lessons Learned from Electricity Market Liberalization (December, 2007)

provide the potential to provide signals that customers can rely upon to manage their electricity usage.

It is important that all of these signals be aligned so that customers are incented to manage their demand use in light of system needs and costs.

IMPROVING EFFICIENCY

Improving efficiency in the IESO-Administered Markets is primarily about having a higher fidelity energy price signal. The current Hourly Ontario Energy Price (HOEP) provides a reasonable approximation of the marginal costs of energy in the province. However, there are ways in which the fidelity of this market price could be improved. For example, there are components of the hourly market uplift that represent the marginal cost of energy. These costs could be reflected in the HOEP but currently are not. This results in a less refined HOEP, and therefore impacts the size of Global Adjustment.

The exclusion of these components from the HOEP tends to produce a less refined price signal that will tend not to incent customer and supply-side behaviour. Addressing this issue is timely: given the presence of natural hedges in the market place (through the capacity component of global adjustment), the lack of scarcity in supply, and the low cost of natural gas (which often sets the marginal price for electricity), increasing the fidelity of the price signal should not lead to consumer backlash. Indeed, demand representatives consistently advised the Market Forum that an enhanced price signal is necessary to encourage customer engagement.

There are four recommendations respecting enhancing the price signal.

First, the IESO should review its current programs, products, and mechanisms for potential efficiency improvements, for example: real-time generation cost guarantees, control action operation reserve, Enhanced Day-Ahead Commitment. The purpose of this review is to identify and mitigate unintended inefficiencies resulting from these programs to identify whether they include components that unnecessarily dampen real-time price signals.

Second, and related, there should be greater transparency of the costs that comprise the global adjustment and a review be performed of how to best recover those costs. The objective is to allow greater responsiveness from customers for costs that are now included in global adjustment. For example, the review should include consideration of:

- unbundling of global adjustment into its component parts by reference to the types of costs it recovers (for example, separating capacity from energy costs);
- allocating global adjustment components appropriately in light of these costs;
- the potential to expand the definition of customers who are charged global adjustment on the basis of peak demand; and
- developing market mechanisms for customers and others to manage global adjustment costs (e.g. capacity mechanisms).

Third, the IESO should consider replacing the two-schedule price setting system. This is a complex task, but one that is overdue. The scope and requirements of such a review could include:

- addressing Congestion Management Settlement Credits;
- reducing design complexity;
- improving compatibility with other markets; and
- potential for a day ahead market.

This review is also timely given the IESO's need to upgrade its settlement software. It will therefore be developing an infrastructure which will either continue with the current two-schedule system or use a replacement system.

Finally, one of the advantages of increasing price fidelity is that it should facilitate easier trade with our neighbouring jurisdictions. This will provide one more source of needed flexibility to our system. This can be encouraged through changes to the market rules that govern intertie transactions. The scope and requirements of such a review would include addressing feasible options and potential solutions, such as:

- more frequent scheduling of intertie transactions;
- long-term capacity and/or operating reserve; and
- load following and/or regulation services.

APPENDICES: THE ISSUES, OPTIONS, ROAD MAP AND RECOMMENDATIONS

Market Forum members consisted of a Market Development Committee and an Executive Steering Committee, representing consumers, suppliers and distributors. It was also joined by representatives of the OPA and the OEB. The Market Forum also heard from a number of industry stakeholders who made presentations to and shared insight with the members of the Market Forum.

The Market Forum's approach was to focus on "on the ground" challenges and not broader energy policy. As a result, it did not seek out views on the appropriateness of the main pillars of energy policy, such as the hybrid market, the number and role of agencies, sector rationalization, and the incorporation of social and environmental goals into energy policy. Instead, its focus was on challenges and solutions that arise under the current structure and would be relevant under any industry structure. This approach was consistent with the message of most stakeholders that the sector could benefit from continued stability and implementing already ambitious energy policy goals. As a result, the Market Forum's recommendations focused on initiatives that would not require legislative change, the establishment of any new government programs or spending; or changes to current contractual obligations.

Within this context, the Market Forum followed a thorough review of current issues, options and recommendations for improving the electricity market. The focus on this review was with respect to the IESO-Administered Markets. To the extent that there were linkages between the IESO-Administered Markets and other energy policy instruments — particularly OPA contracts and OEB regulation — the recommendations took those instruments into account as well so that the market could be looked at in a more holistic way and to facilitate a coordinated response among all of the agencies.

Appendix A

Terms of Reference: Electricity Market Forum

1. Introduction

The Ontario electricity market opened in May 2002. While the Market Surveillance Panel Reports continue to assess the market as operating reasonably well according to its design, the Panel, IESO and market participants have identified potential opportunities for improvement, reflecting experience to date with market operations and outcomes.

Today, the electricity sector in Ontario is undergoing major changes as a result of government policy, the dramatic change underway in the characteristics of the province's resource mix, and technological advances that will increasingly enable consumer response. Major sector developments that are or will impact on the operation of the wholesale market include:

- Coal retirement and the anticipated addition of substantial variable generation to Ontario's electricity system, through the Feed-in-Tariff program.
- OPA resource contracting.
- Proliferation of demand-side management resources, at residential, commercial and industrial levels, enabled by smart grid investments.
- Potential introduction of carbon pricing policies with responsibilities placed upon GHG emitting facilities.
- Growth in Plug-In Hybrid Electric Vehicles in the transportation sector.

In light of these factors, and ongoing change across the sector, the IESO is initiating a forum to address the future role and development path for the IESO-Administered Markets.

2. Statement of Objectives

The efficient functioning of Ontario's electricity market is important to achieving the province's goals for and within the sector. Within that context the Forum will:

- Develop an understanding of the principal issues being encountered or anticipated in the operation of and participation in the IESO-Administered Market.
- Identify and assess the practicality of market changes aimed at improving the ability of the market to efficiently deliver reliable and sustainable electricity, promote transparency, meet customer requirements, align contract and market incentives, and support the operability of the electricity system.
- Develop an actionable set of recommendations for the implementation of market improvements. These would include sequencing, timelines, enablers and barriers – developed to sufficient detail to support implementation within the time horizons outlined.
- Address the respective roles of the market, contracts, and regulation.
- Describe the anticipated outcomes and their benefits for the province, and identify the actions needed to overcome barriers to achieving those benefits.

3. Criteria

Recommendations to be made by the Forum shall be developed on the following premises:

- Ontario and the IESO remain committed to the North American reliability framework managed by the North American Electric Reliability Corporation (NERC).
- The recommendations will not negatively impact the reliability of the Ontario electricity system or compromise standards to which Ontario is committed under national and international arrangements.

Recommendations shall also:

- Balance efficiency, fairness, reliability, transparency, robustness, enforceability and practicality;
- Take into account both consumer and producer interests, including any potential interplay with conservation and demand response initiatives.
- Be consistent with government policy and environmental objectives for Ontario's Long Term Energy Plan.
- Promote the resolution of operational challenges.

4. Scope

The Forum will:

- Focus on Ontario, but recognize market developments occurring elsewhere and any necessary or opportune linkages.
- To the extent Ontario's resource mix is relevant to its deliberations, assume a resource mix (generation, demand response and conservation) that is consistent with the quantities anticipated by the OPA for Green Energy Act initiatives, and for nuclear generation in the province.
- Focus on preferred arrangements for:
 - achieving efficient real-time operation of Ontario's future power system;
 - encouraging and facilitating competitive market-based responses and options for meeting overall system needs; rather than on industry institutional structures.
- Not be an advocacy group for any particular industry sector.

5. Sponsor/Audience

The Forum is intended to engage the industry generally. The report will be a key planning document for the IESO management and Board of Directors, and in all likelihood, for advice to the Minister of Energy and the Ontario Government.

6. Products

A comprehensive report that will contain findings and recommendations for Ontario's electricity sector and will form a basis for further action and discussion among policy makers, regulators and industry participants.

7. Forum Structure

- The Forum will be roughly modeled after Ontario's Electricity Conservation and Supply Task Force (ECSTF – January 2004) and the Smart Grid Forum (February 2009.) That is, the Forum will represent industry leaders presented with a variety of information and arriving largely to a consensus view.
- The Forum is entirely voluntary in nature and apart from consistent participation, no obligation will be placed on participating organizations.
- George Vegh, of McCarthy Tétrault, will serve as Chair for the Forum.

- A final report will be prepared and published. The Forum will engage a consultant to assist in this effort. The consultant will also assist in preparing for and conducting the meetings.
- The Forum will consist of two inter-related committees:

THE MARKET DEVELOPMENT COMMITTEE

- Consider alternatives for the evolution of Ontario's electricity market and develop preferred arrangements for:
 - achieving efficient real-time operation of Ontario's future power system;
 - encouraging and facilitating competitive market-based responses and options for meeting overall system need.

THE EXECUTIVE STEERING COMMITTEE

- With the IESO, and with input from the Market Development Committee, establish the priorities and workplan for the Forum:
- Meet with the Market Development Committee bi-monthly to review and focus the development of alternative proposals, provide advice as to their relative merits, and provide guidance on achieving consensus-based recommendations.
- Review and approve the Report of the Forum.
- The facilitator will work with the Chair to ensure that the development of agendas, selection of presenters, papers and presentations will facilitate the achievement of consensus-based recommendations.

8. Membership

- Forum members will represent a broad industry view.
- The Ministry of Energy and the OEB may each nominate an individual to attend meetings in an ex-officio capacity.
- Advice may be sought from the Market Surveillance Panel.

ADMINISTRATION

The IESO, working with the Chair and the Consultant/Facilitator, will provide the following functions to support the work of the Forum:

- Prepare draft agendas for each meeting.
- Identify and arrange for appropriate presenters for each session's topic.

- Develop list of points to guide post-presentation discussion.
- Conduct additional research as directed by the Forum.
- Provide technical input to the drafting of the Final Report.

CONSULTANT/FACILITATOR:

- Jason Chee-Aloy, Power Advisory LLC

9. Forum Practices

- Substitution – while consistent participation is the normal expectation, each Forum member may, when necessary, name a delegate of equivalent management level in order to maintain continuity and consistency of member participation.
- Voting/Decision making – largely by consensus, dissenting parties and reasons for dissent to be noted.

10. Costs

- The IESO will cover the costs associated with engagements to support the work of the Forum, as well any costs related to disseminating information on its public web site.
- Meeting incidental costs to be covered by the organization hosting the meetings.
- Individual members will normally cover their own travel and incidental costs.

11. Meeting Locations

- Generally to be located in Toronto at IESO's Minto office 655 Bay Street, Suite 410.

12. Schedule

It is anticipated:

- The Forum is expected to meet over the period to September/October, 2011 and will produce a final report that will be made public prior to year-end, 2011.
- Schedules for the meetings of the Committees for the entire period will be established, normally at two to three week intervals for the Market Development Committee, and bi-monthly for the Executive Steering Committee.
- Typical meetings will consist of a morning of presentations followed by a general discussion by Forum members in the afternoon.

Additional meetings may be held as necessary, including to finalize the Forum's report.

Appendix B

Electricity Market Forum Members

Chair – George Vegh - McCarthy Tétrault

Facilitator – Jason Chee-Aloy – Power Advisory LLC

Executive Steering Committee

Brian Bentz	President and CEO - PowerStream
Michael Bernstein	President and CEO - Capstone Infrastructure Corporation
Bruce Boland	Senior Vice President, Corporate Affairs - OPG
JoAnne Butler	Vice President, Electricity Resources - OPA
Bruce Campbell	Vice President, Resource Integration - IESO
Ron Dizy	President & CEO - ENBALA Power Networks Inc.
Paul Dottori	Vice President, Energy & Major Projects - Tembec Inc.
Janet Holder	President - Enbridge Gas Distribution
Carmine Marcello	Executive Vice President, Strategy - Hydro One Networks Inc.
Pamela Nowina	Former Vice-Chair, Ontario Energy Board
Allen Wiley	Vice President, Development, Canada and Northeast US - NextEra Energy Canada

Market Development Committee

François Abdelnour	Energy Manager - Ivaco Rolling Mills 2004 LP
Brian Bell	Director, Energy Markets Support - OPG
Jack Burkom	Vice President of Trading - Brookfield Energy Marketing Inc.
Indy Butany-DeSouza	Vice President, Regulatory & Government Affairs - Horizon Utilities Corporation
Mike Crawley	President, International Power Canada
Barbara Ellard	Director, Policy & Analysis, Electricity Resources - OPA
Paul Ferguson	President - Newmarket-Tay Power Distribution Ltd.
Richard Horrobin	Vice President, Power Marketing - Bruce Power
Jon Kieran	Director, Solar - EDF EN Canada
Adèle Malo	Executive Vice President, Government and Regulatory Affairs and General Counsel - Direct Energy
Craig Martin	Director, Eastern Canada Power - TransCanada Energy Ltd.
Mark Schembri	Vice President, Supermarket Systems and Store Maintenance - Loblaw Properties Limited
Ersilia Serafini	CEO - Summerhill
Adam White	President - Association of Major Power Consumers in Ontario (AMPCO)
Mark Wilson	Director, Corporate Planning - IESO

Observer

Peter Fraser	Managing Director (A), Regulatory Policy - OEB
Rick Jennings	Assistant Deputy Minister - Energy Supply, Transmission and Distribution Policy - Ministry of Energy
Scott Nelms	Senior Manager, Financial Advisory Services - Ontario Financing Authority
Glenn McDonald	Director, Market Assessment and Compliance - IESO

Appendix C Issues and Options

ISSUE 1: INTEGRATING THE SUPPLY MIX

The LTEP supply mix will bring about challenges in operability, price transparency and appropriate price signals. What are costs and benefits of addressing these issues through changes in: design of the IAM; OPA procurement contracts; pricing mechanisms (including treatment of GA and the Hourly Ontario Energy Price; and OEB regulation?

ISSUE 1A: What changes are required to the design of the IAM to improve power system operability in light of a changing supply mix that requires additional resource flexibility?

ISSUE 1B: In designing future OPA contracts and OEB regulation, what changes would incent actions by generators, demand-side participants, transmitters, Local Distribution Companies (LDCs), and other initiatives (e.g., aggregators, etc.) to improve power

system operability in light of a changing supply mix that requires additional resource flexibility?

ISSUE 1C: What changes are required to the design of the IAM to address and mitigate SBG?

ISSUE 1D: What other changes outside of the IAM through OPA contracts and OEB regulation are required to address and mitigate SBG?

ISSUE 1E: In managing the IAM, what changes will provide more timely, accurate and transparent information (e.g., forecasts, price signals, IESO control actions, etc.) to help generators and demand-side participants more effectively participate in the IAM? What changes are required by the OPA and the OEB to provide contract and regulatory information that is either not publicly available or that can be presented more simply to facilitate this participation?

OPTIONS

		Short Term (now to 2014)	Medium Term (2015 – 2018)	Long Term (2019 & beyond)	
SBG and Operability	1.1 Existing Tools/Capabilities	<ul style="list-style-type: none"> Increase Operating Reserve/Regulation requirements Increase use of IESO control actions, e.g. manual dispatch, nuclear manoeuvres, curtail renewable resources 			
	1.2 Ancillary Services (e.g. develop new products)	Identify scope & requirements, e.g.: <ul style="list-style-type: none"> Ramp Load Following SBG Identify and select feasible options, e.g.: <ul style="list-style-type: none"> Ramp and/or load following service Co-optimization of energy/OR/regulation Changes to unit commitment Opportunities for smart grid-enabled tech. Forecasting, visibility, dispatch of renewable resources (SE 91) 	Implementation (timing will depend on scope and options selected)		
	1.3 OEB Regulation	Review of OEB processes to ensure coordination between regulation, contracts, & market to encourage supply operations to meet system needs and limitations Examples: OPG prescribed assets, export tariff			
	1.4 OPA Contracts	Review OPA procurement processes to better ensure: 1) procurement decisions are informed by market/system needs & system limitations; 2) contracts (new and existing) contain strong market incentives; 3) changes to Market Rules are coordinated with existing OPA contract provisions			
Information	1.5 Improving Access to Information	Review accessibility, relevance, and timeliness of info/data provided by various agencies to market participants and policy makers, e.g. <ul style="list-style-type: none"> Market information OPA contract provisions OEB rate orders for LDCs 	On-going refinement and Implementation		
	Game Changers	Smart Grid	Data/information/metering standards under development	Ancillary services capabilities emerging from distribution system	Non-traditional energy storage available
		Electric Vehicles	Pilot projects	Emergence of workplace/public charge stations	Mass market adoption (1 in 20) & vehicle-to-grid (V2G) charging
Carbon Pricing		Regional GHG Initiative Western Climate Initiative	Carbon Pricing		

ISSUE 2: ENGAGING AND EMPOWERING CONSUMERS

How can challenges to more effectively engage and empower the demand-side of the market be addressed in a cost effective manner through: IAM market design; OPA/LDC conservation programs; OEB regulation; and other initiatives (e.g., aggregators, etc.)?

ISSUE 2A: What changes are required within the IAM to increase the level of demand-side participants in the IAM?

ISSUE 2B: What other changes outside of the IAM through OPA programs/contracts, OEB regulation, and other initiatives are required to increase the level of demand-side participants in the IAM?

ISSUE 2C: What changes are required to better align and increase participation in demand-management programs and activities that are administered through the OPA, OEB, LDCs, and offered by third parties to facilitate use when the power system most requires this participation?

ISSUE 2D: Should changes be considered to the current method of charging the components of generation costs (currently, GA and HOEP) to consumers in order to incent increased demand-side participation when it is valuable to do so and if so how should this be carried out?

ISSUE 2E: What changes are needed to better engage consumers regarding additional data & information and to improve communications regarding electricity sector matters, issues and opportunities?

OPTIONS

	Short Term (now to 2014)	Medium Term (2015 – 2018)	Long Term (2019 & beyond)	
2.1	Increasing Demand-Side Participation in IESO-Administered Markets			
	Consult with customers (including LDCs, retailers, aggregators, etc.) to understand barriers to increased demand-side participation and to identify needs/opportunities for different categories of customers to meet system requirements in an economic way.			
2.2	OEB Review of Rate Design			
	Analysis of rate design and cost allocation to customers with potential for new price-setting methodology to meet system requirements in an economic way. Examples: RPP/TOU, customer classifications, utility rates			
2.3	Improving Capabilities & Utility of Demand Side Mgt.			
	Determine opportunities and barriers to more pervasive and cost-effective demand side participation in the supply of necessary system services and enhancing responsiveness to real time system conditions, including: <ul style="list-style-type: none"> • Peak management and load shifting (review of OPA demand response contracts; OPA/LDC Master Agreement, re: next generation; coordination of demand response program development among providers); • Supply of established ancillary services (e.g. Regulation and OR) into IESO Administered Markets • Explore capabilities to cost effectively supply emerging system services (e.g. Ramp, load following, SBG relief) 			
Game Changers	Smart Grid	Data/information/metering standards under development	Ancillary services capabilities emerging from distribution system	Non-traditional energy storage available
	Electric Vehicles	Pilot projects	Emergence of workplace/public charge stations	Mass market adoption (1 in 20) & vehicle-to-grid (V2G) charging
	Carbon Pricing	Regional GHG Initiative Western Climate Initiative	Carbon Pricing	

ISSUE 3: IMPROVING EFFICIENCY

Ontario uses a mix of instruments (e.g., regulation, contracts, IAM market design) to different degrees in order to regulate the electricity market. Given that each of these instruments has its own strengths and limitations, and given that a lack of coordination between them can frustrate their intended goals, what is the right balance to address in a coordinated and cost effective way: the allocation of existing costs; efficient system operations; and necessary investments in supply and conservation resources?

ISSUE 3A: Should the IAM evolve beyond the current two-sequence market structure to improve efficiency, to reduce complexity, and improve price signals for generators, demand-side participants, and participants of inertie transactions?

ISSUE 3B: What changes are required regarding the protocols, rules, and eligibility (e.g., products other than energy such as capacity, etc.) for inertie transactions in the short-term (e.g., day-ahead and real-time) and longer-term (e.g., timeframe between days and years) in order to maximize the gains from trade from other jurisdictions into and out of Ontario’s electricity market?

ISSUE 3C: What process and protocols can be established to better align changes in Market Rules with changes to OPA supply contracts?

OPTIONS

	Short Term (now to 2014)	Medium Term (2015 – 2018)	Long Term (2019 & beyond)
3.1 Existing Tools/Capabilities	Review of current programs, products, and mechanisms for potential efficiency improvements, e.g. real-time generation cost guarantees, control action operation reserve, EDAC Market rule amendments to address unanticipated inefficiencies		
3.2 Replacing Two-Schedule System	Identify scope & req'ts e.g.: addressing CMSC; reducing design complexity; improving compatibility with other markets; potential for a DAM	Identify feasible options & select solution(s) IESO Business Plan IT infrastructure upgrades Implementation	
3.3 Changes to Intertie Transactions	Identify scope & req'ts	Identify feasible options and select solution(s) e.g.: • More frequent scheduling • Long-term capacity and/or OR • Load following and/or regulation services Implementation	
3.4 Pricing and Costs	Assess methodologies to improve price signals that better reflect system value while increasing customer responsiveness e.g.: GA allocation and potential to expand definition of Class A customers; energy price fidelity; unbundling GA; allocating GA components appropriately; market mechanisms to manage GA costs (e.g. capacity mechanisms)		
Game Changers	Smart Grid	Data/information/metering standards under development	Ancillary services capabilities emerging from distribution system Non-traditional energy storage available
	Electric Vehicles	Pilot projects	Emergence of workplace/public charge stations Mass market adoption (1 in 20) & vehicle-to-grid (V2G) charging
	Carbon Pricing	Regional GHG Initiative Western Climate Initiative	Carbon Pricing

Appendix D

Market Forum Roadmap

OPTIONS AND GAME CHANGERS	SHORT-TERM (PRESENT TO END OF 2014)			MEDIUM-TERM (2015 TO 2018)		LONG-TERM (2019 AND BEYOND)	
	2012	2013	2014				
3.4	Pricing & Costs: Review and Study						
1.6	IESO-led review (with OPA and OEB participation) of publicly available information and consultation with stakeholders on Improvements to Access Information	IESO, OEB and OPA (and other entities) to make changes to the accessibility of information	Assess, review and evolve Access to Information based on, but not limited to: system changes; market changes; while considering development of a central data/information repository				
1.2a	IESO and OPA continue to develop solutions to address SBG challenges and implements solutions as appropriate in a transparent manner	IESO and OPA re-assess need for solutions to address SBG challenges and implements solutions as appropriate	IESO and OPA re-assess need for solutions to address SBG challenges and implements solutions as appropriate				
1.4	OPA Contracts: Review procurement processes to better ensure (1) procurement decisions are informed by market/system needs and system limitations; (2) contracts - new and existing - contain strong market incentives; (3) changes to IESO Market Rules are coordinated with existing OPA contract provisions, all while considering results from the Pricing and Costs Study.						
2.1 and 2.3	IESO consultation to investigate how to Increase Demand-Side Participation in the IAM to improve capabilities and utility of Demand-Side Management.	IESO implementation of Action Plan to Increase Demand-Side Participation in the IAM to improve capabilities and utility of Demand-Side Management.	Increasing Demand-Side Participation in the IAM while decreasing barriers to participate	Increasing Demand-Side Participation in the IAM while decreasing barriers to participate: including facilitating and capturing changes in technology; use in non-traditional ways (e.g., ancillary services, storage, etc.)			
2.2	OEB Review of Rate Design: review methodology to set RPP and utility rates	OEB setting new RPP and utility rates based on Review and considering results of Pricing & Costs Study	Timing and cycle for the OEB to set all applicable rates should consider: policy; system conditions; market conditions; etc.				
1.2b	IESO assesses need for new Ancillary Services to help enhance efficiency of system operability	If required, IESO designs new Ancillary Services and applicable market rules	If required, IESO to implement new Ancillary Services, IESO re-evaluates need for new Ancillary Services based on: system conditions; market conditions; etc.	IESO re-evaluates need for new Ancillary Services based on: system conditions; market conditions; etc.			
3.2	IESO to assess and review workability of Two-Schedule system and identify issues and improvements	IESO to identify options to Replace the Two-Schedule System	IESO to begin design work on preferred option to Replace the Two-Schedule System	IESO completes design/market rule changes to Replace Two-Schedule System and Changes to Intertie Transactions	IESO to implement Replacement for the Two-Schedule System and Changes to Intertie Transactions	New scheduling/dispatch, price system and changes for intertie transaction operational	
3.3		IESO assesses, reviews and potentially implements interim Changes to Intertie Transactions related to tradeable products (e.g., capacity) not requiring changes to systems and tools	Incorporated with design work to Replace the Two Schedule System, Changes to Intertie Transactions (e.g., products, scheduling frequency, etc.) to be included in the design work				
1.3	OEB Regulation: Review of OEB processes to ensure coordination between regulation, contracts, and market to encourage supply operations to meet system needs and limitations						
1.1 and 3.1	IESO use of Existing Tool/Capabilities: based on the need to maintain the reliability of the power system and to improve market efficiency, as required, the IESO will use existing tools/capabilities by way of the Market Rules						
Smart Grid	Data/Information/metering standards under development			Ancillary Services capabilities emerging from distribution system		Non-traditional energy storage available	
Electric Vehicles	Pilot Projects			Emergence of workplace/public charge stations		Mass market adoption (1 in 20) and vehicle-to-grid (V2G) charging	
Carbon Pricing	Regional GHG Initiative/Western Climate Initiative			Carbon pricing			

Appendix E

Electricity Market Forum - Recommendations

1. The IESO should review how its current programs, products, and mechanisms impact the structure of the HOEP. The purpose of this review is to identify whether the HOEP includes components that unnecessarily dampen real-time price signals.

2. The IESO should commission a review of global adjustment to allow greater responsiveness from customers for costs that are now included in global adjustment. Specifically, the review should include:

- the unbundling of global adjustment into its component parts by reference to the types of costs it recovers (for example, separating capacity from energy costs);
- allocating global adjustment components appropriately in light of these costs;
- considering the potential to expand definition of customers who are charged global adjustment on the basis of peak demand; and
- developing market mechanisms for customers and others to manage global adjustment costs (e.g. capacity mechanisms).

3. The IESO, the OPA and the OEB should jointly engage in a consultation to review the accessibility, relevance, and timeliness of information and data provided by them to market participants and policy makers.

4. The IESO should examine whether new ancillary services or changes to market design should be developed to better manage the changing supply mix. Any new products or changes should allow both generators and loads to participate. Any new products or changes should promote cost effective ways of supplying greater flexibility to the system as a way to mitigate operability challenges, particularly surplus baseload generation. New products or changes could include:

- Ramp and/or load following service;
- Co-optimization of energy/operating reserve/regulation; and
- Changes to unit commitment

5. Any potential Market Rule changes should be coordinated with and include consideration of existing OPA contract provisions.

6. The OPA's procurement process should seek to better ensure that:

- procurement decisions are informed by market and system needs and system limitations; and
- new and existing contracts contain strong market based incentives.

7. The OEB's approach to determining payments to OPG's prescribed assets and the OEB's treatment of export transmission tariffs should be reviewed in regards to their efficiency in the market.

8. The IESO should engage in a stakeholder consultation focussed on customers (including loads, LDCs, retailers, aggregators, etc.) to understand the barriers to increased demand-side participation in order to determine the opportunities for cost-effective demand side participation in the supply of necessary system services and enhancing responsiveness to real time system conditions. This includes looking at how customers can engage in the market to cost effectively provide:

- peak management and load shifting;
- services in established IESO Administered Market ancillary services (e.g. Regulation and Operating Reserve); and
- new services or products to benefit system operability (e.g. Ramp, load following, SBG relief).

9. The IESO customer consultation should correspond with and provide input into the OPA's review of its demand response program which is currently underway and the development of the next generation OPA/LDC Master Agreement on Conservation.

10. The OEB's Regulated Price Plan (including time-of-use prices), customer classifications and the structure of utility rates should be designed to provide signals that customers can rely upon to manage their electricity usage in light of system needs and costs.

11. The IESO should consider improving, amending, or replacing the two-schedule price setting system in order to improve scheduling, dispatch and pricing efficiency. The review should include:

- addressing Congestion Management Settlement Credits;
- reducing design complexity;
- improving compatibility with other markets; and
- potential for a day ahead market.

12. The IESO should review whether there are barriers to maximising potential benefits to Ontario from greater alignment with regional markets through intertie transactions. The scope and requirements of such a review would include identifying opportunities for electricity trade, identifying barriers and addressing feasible options for solutions. Such a review should include:

- more frequent scheduling of intertie transactions;
- potential to trade long-term capacity and/or operating reserve; and
- potential for load following and/or regulation services.

For more information about the
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