

# Market Effectiveness Assessment

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## Executive Summary

This report is an assessment of the potential for efficient operations of the restructured wholesale electricity markets in Ontario. We analyze the market rules outlined by the Market Design Committee and further developed by the Independent Market Operator (IMO) Technical Panel, and also discuss the provisions of the Market Power Mitigation Agreement embodied within the licenses issued by the Ontario Energy Board (OEB) to Ontario Power Generation (OPG) and other market participants. We believe that the market rules contain many well-conceived provisions consistent with the efficient operations of an integrated grid for electrical service; however, the rules fall short in several key aspects. In addition, as presently structured, the Market Power Mitigation Agreement is likely to fail in promoting a competitive market. We recommend the inclusion of a few essential market elements and a more aggressive mitigation of OPG's dominant position.

The restructuring of Ontario's power industry is following a unique path. The transition to a competitive industry structure will not occur until *after* a competitive market framework is put in place. All of Ontario Hydro's generating capacity was transferred to OPG, which remains at arms-length from its sole shareholder, the provincial government of Ontario. The fear that low competitive prices would be insufficient to recover the debt held by Ontario Hydro at the time of restructuring provided justification for allowing OPG to remain whole. OPG currently controls approximately 90% of the operable capacity within Ontario. In order to assess the effectiveness of the proposed market structure we must first determine the perspective from which OPG should be viewed. The perspective that is most consistent with competitive markets is that OPG acts as a dominant profit maximizing entity that operates within the market rules to make as much money as possible. This is also the safest perspective from which to evaluate market power mitigation.

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If OPG is to be given incentives to act efficiently, markets must be designed effectively. In this report we recognize several key weaknesses in the design and make recommendations for rectifying them.

◆ **Weakness 1: Single settlement of the energy market**

The single-settlement system creates strong incentives to manipulate the spot price and reschedule. Since generators are free to change their schedules up to four hours in advance of dispatch, and can change their schedules with some restrictions up to two hours in advance of dispatch, there is no incentive to provide accurate information in the day-ahead scheduling process. Because OPG has such a dominant position, its ability to withhold needed information about its planned production and pricing seriously impairs the ability of other participants to accurately forecast spot market conditions, and successfully compete in the spot market. The proposed day-ahead financial forward market does not address the credibility of OPG's scheduling information.

• **Recommendation: Institute a multi-settlement system**

In a multi-settlement system, day-ahead bids are used for both scheduling and settling day-ahead transactions. The financial commitment made day-ahead limits a dominant player's incentive to adjust its schedules.

• **Recommendation: Allow small participants to adjust their schedules after OPG's schedule is set**

If small participants cannot anticipate OPG's schedule adjustments then they will not be able to plan their operating schedules effectively, and OPG's dominance will be reinforced. If small participants are forced to fully commit to their offers 2 hours before operations, then OPG should be required to fully commit to its offers 3 hours before operations.

◆ **Weakness 2: Uniform pricing of domestic energy**

In a congested system, injections and withdrawals at different points in the network impose different costs or benefits on the system. Efficiency requires that the prices parties face reflect these differences. If one party's interaction with the system creates transmission congestion, then it should pay the added costs of adjusting others' generation; if another's interaction reduces transmission congestion, then it should reap the benefit of the reduced costs of adjustment. Bid manipulation is encouraged by "constrained on/off" payments made to resources that are dispatched out of merit order to relieve congestion. Uniform energy pricing

does not send appropriate price signals to incent efficient investment in generation or transmission capacity.

- **Recommendation: Institute Locational Marginal Pricing (LMP)**

With LMP, a different price for energy is calculated at each node. These location-specific prices reflect the marginal cost of an additional MWh of energy at each node, taking into account all costs and benefits of the additional energy on the system. The Market Design Committee recommended implementation of LMP after the market opening. We stress the importance of this recommendation.

- **Recommendation: Eliminate “constrained off” payments**

Constrained off payments are made because there is a perception that if a generator makes an offer below the clearing price and is not dispatched due to transmission congestion then that generator must be compensated for the operating profit that it is forced to forgo. This reasoning is flawed; the perceived foregone operating profit is merely a byproduct of inefficient uniform pricing.

- ◆ **Weakness 3: Coordination problems with neighboring control systems**

Trade between markets in different regions presents a difficult problem. A transaction that is treated as an export by one system operator must be treated as an import by another. If the protocols used to schedule and price this transaction are inconsistent then a significant coordination problem arises. It is important that markets interact seamlessly in order to achieve economic efficiency.

- **Recommendation: Work with other jurisdictions to create consistent market protocols**

Consistency must be established regarding price caps, scheduling time frames, and definition of pricing zones. The New York ISO should be convinced to define Ontario as two pricing zones to match the disparate prices that are likely to arise at the Frontenac and Queenston interconnections when LMP is established.

- **Recommendation: Collect congestion rents only once**

The IMO and New York ISO both claim the right to assess congestion rents for the use of constrained interties between the markets. If congestion rents are paid twice, then trade will be discouraged and market efficiency will be diminished. This issue can be resolved

through an agreement between the markets to collect rents on imports only, or to collect rents on exports only.

◆ **Weakness 4: Insufficient mitigation of OPG's dominant position**

The Market Power Mitigation Agreement consists of a rebate provision, decontrol requirements, and various regulations governing the behavior of OPG and other market participants. In this report, we conclude that the measures taken to control OPG are necessary, but do not go far enough. If OPG chooses to, it will be able to manipulate the market to its advantage.

• **Recommendation: Eliminate the Price Spike Adjustment of the Rebate Provision**

The Price Spike Adjustment reduces OPG's incentive to bring generating units back online after an outage, and unwisely shifts the risk of outages from OPG to consumers.

• **Recommendation: Make sure that decontrol means divorce from incentives not just operations**

Decontrol actions will not be effective if OPG has incentive to make the assets involved profitable. Decontrol through short-term contracts should not be allowed, since OPG may have incentive to push up spot prices to gain favorable settlement when the contracts are renewed.

• **Recommendation: Encourage demand to respond to prices**

OPG will be less willing to push up prices if it knows that its sales will drop in response. The market rules wisely allow wholesale costs to be passed through to end consumers, although in some cases these costs may be shifted away from the parties that initiate them. More can be done to make the demand-side respond to prices.

• **Recommendation: Consider forcing OPG to divest**

A firm that controls 90% of a market will have a great deal of influence over operations and prices in that market. This is what economists refer to as market power. When a firm has market power, the actions that make that firm most profitable often are inconsistent with the actions that make that firm an efficient provider for consumers. Profit motives align with efficiency motives only when markets are well-designed and there are many players in the market. We are skeptical of the likelihood that the benefits of competitive markets will arise with a single dominant seller.

• **Recommendation: Consider forcing OPG to sign long-term contracts**

Long-term contracts can reduce the amount of OPG's output that clears at the spot price, and can therefore eliminate OPG's incentive to manipulate the spot market. Ontario can

learn from Alberta in this regard. Like Ontario, Alberta avoided forced divestiture. Unlike Ontario, Alberta sold the bidding and operating control of the existing generation as long-term power purchase agreements, lasting the life of the plants or twenty years. The current requirements for OPG to decontrol through contracts, divestiture or other means are not robust enough and will not take full effect for ten years.

## 1 Introduction

This report is an assessment of the potential for efficient operations of the restructured wholesale electricity markets in Ontario. We will analyze the market rules outlined by the Market Design Committee and further developed by the Independent Market Operator (IMO) Technical Panel, and will also discuss the provisions of the Market Power Mitigation Agreement embodied within the licenses issued by the Ontario Energy Board (OEB) to Ontario Power Generation (OPG) and other market participants.<sup>2</sup> We believe that the market rules contain many well-conceived provisions consistent with the efficient operations of an integrated grid for electrical service, however the rules fall short of optimality in regard to several key aspects. In addition, as presently structured, the Market Power Mitigation Agreement is likely to fall short of promoting a functionally competitive market. We recommend the inclusion of a few essential market elements and a more aggressive mitigation of OPG's dominant position.

The goal of efficiency demands that the production of electricity is done at least possible cost and that those who value electricity the most are able to consume it. There are many challenges in the development of efficient electricity markets. As in all electricity markets, consideration must be given to the unpredictable variability of demands and supplies over time, the non-storable nature of the product, the use of multiple technologies with varying cost structures and physical capabilities, environmental and siting restrictions, and the dependence on a reliable transmission system, which demonstrates substantial externalities due to loop flows. The experience in other areas around the world demonstrates that we cannot simply leave it up to the invisible hand of "the market" to overcome these challenges. Improperly designed markets can and have failed. Where appropriate, will look to the experiences in Alberta, California, New England, New York, PJM (Pennsylvania, New Jersey and Maryland), and elsewhere, for lessons that they can offer Ontario.

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<sup>2</sup> We rely on Issue 6.0 of Market Rules for the Ontario Electricity Market, February 26, 2001. The rules are available electronically at [www.iemo.com](http://www.iemo.com). The Market Power Mitigation Agreement was originally a single document, but is now effective through stipulations included in various market participants' licenses. A summary of the Market Power Mitigation Agreement is available at [www.opg.com](http://www.opg.com).

It is important that markets be designed effectively before they become operational. Once a market design is implemented participants will find ways to profit from flawed aspects of the design, and will have incentive to ensure that those aspects remain in place. Revision of markets can be tedious and unproductive because of the existence of those who wish to maintain the status quo. The system of market governance should be flexible enough to allow for changes that must be implemented, but the best way to implement an efficient market is to implement it efficiently from the start. If improvements to the market structure must be delayed until after the market's start day, these improvements should be well planned out and ready to implement without excessive debate and lobbying by interested parties.

Our analysis will draw on economics and game theory and will emphasize the strategic behavior of participants. We feel that it is important to design markets by assuming that suppliers have the objective of profit maximization, and will work within the market rules to achieve this as effectively as possible. Suppliers should not be expected to always act in the best interest of consumers. This is true for the proposed market of Ontario, even though the sole shareholder of OPG is the provincial government. Overbearing control of OPG will lead to inefficient operations, and create political risk, which is extremely hard to hedge. Any market design that leads to efficiency when participants act in their best interests will be most effective. In Ontario, additional issues are necessarily considered, however, because of the aforementioned overbearing dominance of OPG.

We begin in Section 2 by reviewing the status of restructuring in Ontario, discussing the properties of efficient market rules, and providing an overview of the proposed IMO-managed markets rules. Sections 3-5 discuss three major issues that the rules must address: the settlement system, transmission congestion, and interactions with neighboring markets. Section 6 considers the likely impact of various environmental policies. Section 7 analyzes the current structure of the industry, and gives our opinion of the ability of the Market Power Mitigation Agreement to promote a functionally competitive market. Section 8 discusses potential capacity markets. Section 9 considers retail pricing and the potential for demand-side response. Section 10 concludes with a recap of our perspective and our basic recommendations.

## **2 Background**

### ***2.1 The breakup of Ontario Hydro***

In January 1998, the Market Design Committee was formed to develop an implementation plan for the restructuring of Ontario's electricity industry. The committee's efforts resulted in the

passage of the Energy Competition Act (Bill 35) in October of 1998. This act included the Electricity Act, which set up the legislative framework for restructuring of the industry, and the Ontario Energy Board Act, which gave OEB the authority to issue licenses pertaining to the generation, transmission, distribution, and retail of electricity. Restructuring has resulted in the formation of separate entities which each control an aspect of the regulated service that Ontario Hydro had previously supplied. The Independent Electricity Market Operator (IMO) was formed from the Central Market Operations group of Ontario Hydro to run the market, OPG received all of Ontario Hydro's generation assets, and Ontario Hydro's wire business, including the transmission system and distribution to over a quarter of the province's retail customer, is now operated by HydroOne. Both OPG and HydroOne now operate at arm's length from their sole shareholder, the provincial government of Ontario.

In light of OPG's dominant position (it currently controls about 90% of the market), it was considered necessary for controlling steps to be taken before markets could be opened to competition and unregulated wholesale pricing. Negotiations by the former Ontario Hydro, the Market Design Committee, the Ministry of Energy, Science and Technology, and the Ministry of Finance resulted in the Market Power Mitigation Agreement. This agreement was approved by the Market Design Committee, was endorsed by the provincial government, and is now part of the license conditions governing OPG and other market participants. The agreement is characterized by a rebate provision, various decontrol requirements, and several other regulations, which will be described and discussed in Section 6.

Open access to Ontario's power market was originally expected to begin in November 2000, but it has been determined that more time is needed to ensure a smooth transition. It is now expected that markets will be opened in May 2002.

## **2.2 *Properties of efficient market rules***

It will be useful to discuss the properties of market rules that promote efficient trading before providing an overview of the market design in Ontario.

### **◆ Do the rules send the right price signals?**

The pricing rules are critical in assessing efficiency in markets. Prices provide the incentives that influence behavior. In order for participants to realize full gains from trade, prices should reflect the marginal costs of suppliers and the marginal values of demanders.

◆ **Do the rules minimize opportunities for gaming?**

Gaming arises from several sources. Incorrect price signals give bidders a direct incentive to act in a way contrary to efficiency. Market power enables large bidders to distort prices in their favor. Non-binding bids, unpenalized scheduling changes, and weak monitoring and enforcement of compliance, encourage misrepresentation.

◆ **Do the rules enable markets to be contested?**

Contestable markets discipline incumbents via the threat of entry. To the extent that entry is swift and costless, incumbents are unable to exercise market power. Efficient rules encourage entry. Simple and transparent rules are often best since they tend to minimize the cost of participation. It is also important for rules to encourage the creation of liquid markets. A liquid market gives small participants and potential entrants a stable and predictable place to sell their output.

◆ **Are the rules neutral with respect to bilateral transactions?**

Efficient rules let the bidders decide how best to participate in the market. Bilateral transactions are neither encouraged nor discouraged. Innovative and customized long-term contracts can enable realization of mutual advantages that are not priced explicitly in the general markets.

◆ **Are the rules consistent with those of neighboring jurisdictions?**

In order for full efficiency to be realized, trade must occur seamlessly, not just within a market, but also between markets. Coordination of inter-market trade is particularly difficult in electricity markets because of limited transfer ability and the real-time nature of the product. Consistency of market protocols is crucial and needs to be addressed.

We use these criteria as guides in our examination of Ontario's market structure.

### **2.3 Overview of the IMO's markets**

The IMO has developed a simultaneously optimized real-time market for energy and operating reserves. There is no separate market for transmission; physical transmission rights are procured through the energy market. A day-ahead financial market for energy, and various forms of capacity markets are being considered for implementation after the markets are opened. The IMO also oversees procurement markets for ancillary services and must run contracts.

Generators and dispatchable loads that wish to be considered for dispatch must submit hourly dispatch data between 6 am and 11 am of the day before operations (the predispach day). This data includes offers (from generators) or bids (from loads) that specify up to 20 price-quantity pairs for energy and up to 5 pairs for each class of operating reserve. Energy bids and offers must be below the Maximum Market Clearing Price (MMCP), and operating reserve offers must be below the Maximum Operating Reserve Price (MORP). Ramp up and down rates, specifying how quickly a participant can change its dispatch level, may be submitted for 5 ranges of output, and a single ramp rate is specified for use in activation of operating reserves. A maximum amount of energy available from a resource over the course of the day may be specified for use in the determination of the predispach schedule.

By noon of the predispach day, the IMO uses bid data, load forecasts, and various system constraints to determine the predispach schedule. Participants' designated schedules are revealed privately, and system-wide load, price, and other related data are revealed publicly. Prices determined at the time of predispach scheduling are for informational purposes only. The determination and communication of schedules are updated as need be. Bids and offers can be adjusted without limit until 4 hours before operations, and can be adjusted within specified limits up until 2 hours before operations. Any adjustment to a participant's bids or offers within 2 hours of operations will be subject to IMO discretion. The IMO considers participant's most recent bids and offers to determine the real-time dispatch.

The algorithm used to determine schedules and dispatch uses linear programming (LP) rules to maximize gains from trade subject to satisfying load, operating reserves, and various transmission and operations constraints. Unlike the scheduling algorithm, which considers import and export bids subject to intertie constraints, the dispatch algorithm considers imports and exports as fixed over the course of the hour.<sup>3</sup> The coordination involved in scheduling imports and exports is discussed in section 5.

To derive a uniform price of energy within Ontario, the algorithm is run subject to an "unconstrained" model of the grid, ignoring internal transmission constraints. The unconstrained model simultaneously determines energy and operating reserves prices based on the shadow prices obtained from the LP optimization. If internal transmission constraints cause the dispatch of the constrained model to differ from the dispatch of the unconstrained model then "constrained

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<sup>3</sup> Deviations from external transaction schedules are accounted for by adjusting the value of load that the algorithm must satisfy.

on” output that is dispatched despite having an offer above the clearing price is paid its bid, whereas “constrained off” output that bids below the clearing price but fails to be dispatched is paid the difference between the clearing price and its bid. If intertie constraints are binding during predispach scheduling then external congestion rents are defined as the difference between the projected clearing price in Ontario and the highest accepted bid in the external zone affected by the constraint. The cost of managing transmission congestion is distributed evenly across all loads as an uplift payment. Congestion pricing is discussed in more detail in section 4.

### **3 Settlement structure and scheduling procedures**

A basic choice in any energy market is the settlement system. The market design described above can be characterized as a single-settlement system. The markets in New York and PJM currently use multi-settlement systems, and New England is in the process of implementing a multi-settlement system. In this section we describe the differences between the settlement systems, relate why a single-settlement system is not sufficient, and argue that the day ahead energy forward market, which is being considered for implementation sometime after the markets open, does not constitute the basis of a multi-settlement system.

#### **3.1 *Single-settlement vs. multi-settlement***

In a single-settlement system, day-ahead bids are used for scheduling, but prices are determined ex post based on real-time dispatch. In a multi-settlement system, day-ahead bids are used for both scheduling and settling day-ahead transactions. Scheduling in a multi-settlement system typically involves multiple steps. Units that make offers in the day-ahead market are scheduled to meet load bid in the day-ahead market subject to reserve requirements and system constraints. All units scheduled in this step make a financial commitment to serve load at the day-ahead price determined by the shadow price of the LP optimization. Additional units may be scheduled based on their day-ahead offers if the energy that clears in the day-ahead market falls short of load forecasts. Some multi-settlement systems, such as the one operated by NYISO, include additional rounds of scheduling and financial commitment in hour-ahead markets based on adjusted bids and offers. Bid and offer adjustments are typically allowed up to an hour before real time, and the system operator dispatches the system according to the most recent bids. Only deviations from day-ahead (or hour-ahead) schedules are settled at the real time price.

Ontario’s single-settlement system may appear simpler than a multi-settlement system because it involves just a single set of hourly prices, and does not require the IMO to keep track of when a unit was scheduled for settlement purposes. However, this simplicity is deceptive. The

difficulty with the single ex post settlement is that much is riding on the ex post prices, since all earlier commitments and transactions are settled at the prices established in real time. After the day-ahead schedule is formed, bidders have an incentive to make adjustments to influence the spot price in a favorable direction. Since the spot price is used for all trades, the incentive for manipulation may be large.<sup>4</sup> For instance, the IMO may schedule 95% of transactions day-ahead, but all transactions are settled at prices that reflect heavily the 5% traded in the real-time market. Bidders can take advantage of short-term inelasticities in the supply schedule to reap excess profits. Knowing how to do this is complex, and can be exploited best by large bidders with sufficient scale to make the efforts worthwhile, e.g. OPG. The added complexity and risk tends to discourage entry and participation by small bidders whose net revenue might be whipsawed by price volatility in the real-time market.

This gaming can be mitigated by financial penalties for failures to perform as scheduled. But then the question is: How to set the penalties? Some flexibility is needed because of uncertainties in demand and supply. Setting the penalties too high leads to inefficient responses to this uncertainty, and setting the penalties too low leads to excessive gaming. The reliance on penalties is highly inefficient and problematic in its workings. A penalty system will be subject to continual pressure (as in Alberta) for modifications and exceptions. Compliance has been shown to be a problem in Victoria, where a supplier can and does curtail generation by claiming an operating problem.

In a multi-settlement system, deviations from the day-ahead schedule are properly priced and regulatory penalties for non-performance are not necessary. If a generator fails to deliver as scheduled, then generation from higher up the stack will be dispatched, pushing up the spot price. The deviating generator pays a penalty equal to the difference between the spot price and the day-ahead price times the quantity the generator failed to deliver. Essentially the generator fulfils the obligation that it made day-ahead by buying energy out of the real time market. Day-ahead bids and resulting schedules are credible because they are financially binding. Deviations from the day-ahead schedule affect the spot price, but the spot price is used only to price these deviations. Hence, in a multi-settlement system the incentive to manipulate the spot price is not magnified as it is in a single-settlement system.

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<sup>4</sup> The rebate provision of the Market Power Mitigation Agreement may make the spot price irrelevant for a significant portion of OPG's transactions. However, in Section 7 we will argue that OPG will still have incentive to see high spot prices. It should also be recognized that the market is designed to outlive the Market Power Mitigation Agreement, and therefore should be robust to the unregulated application of market power by OPG or any other participant.

A difficulty with the multi-settlement system is that it involves multiple prices for energy. One might think that energy at a particular time (and place) should have one price. However, this is not correct. The price should be determined at the time resources are committed. Hence, if there are two commitment points (day-ahead based on forecasts and real-time based on events), then there should be two prices, one a forward price for early commitments and a second that recognizes the effects of contingencies.

The multi-settlement system has an additional benefit in that it reduces risk for participants, since they can lock in the day-ahead prices. The energy forward market that the IMO has considered for implementation at some time after the opening of the market also has potential for providing this benefit, but as structured, will not provide the complete benefit of a multi-settlement system. The proposed energy forward market is a purely financial market, which is independent of the scheduling process. One day in advance of operations the IMO will collect bids and offers, aggregate supply and demand, find a market clearing price, and accept offers below the clearing price and bids above the clearing price. As in a multi-settlement system, a financial commitment is made when a bid or offer is accepted, but in the proposed market the bids that determine this commitment are completely independent from the scheduling process. Separate bids will be used for the predispatch scheduling, and no financially binding prices will be derived from them. The incentive and opportunity for generators to manipulate the spot price by adjusting bids after units are scheduled is in no way altered by the existence of the proposed energy forward market. If a generator wishes to manipulate the spot price, as described above, it can simply choose not to participate in the optional energy forward market, and therefore will not be assessed the penalty for unexpectedly withdrawing capacity that it would have incurred if it had made a forward commitment.

The proposed energy forward market is also flawed because it does not use the scheduling software to clear the market, as is done in New York, PJM and the proposed market in New England. The purpose of the energy forward market is to allow participants to hedge their transactions. To achieve this the day-ahead market should anticipate the physical operations of the system as accurately as possible.

### **3.2 Centralized commitment versus self-scheduling of resources**

An attractive feature of the IMO's rules for scheduling and dispatch is their simplicity. Many other markets are needlessly complicated in order to fit the paradigm that existed before restructuring. Ideally, market rules should provide a framework around which trading and

physical operations can be organized. Market rules should be flexible enough to allow participants to trade and operate as they see fit. This flexibility should be achieved as simply as possible. Simplicity minimizes gaming opportunities, limits transactions costs and allows small participants to participate in the market as effectively as their larger rivals.

Markets are often needlessly complicated by special exceptions in the rules regarding bilateral contracts and self-scheduling of generating units. Participants often feel that they need to maintain complete control of their resources and are skeptical of letting a system operator determine the timing of the dispatch of their units. It is common for market makers to give in to this sentiment by giving participants who trade bilaterally the option of submitting a schedule of their units' operation rather than an economic offer to be considered in the energy market. The scheduling of resources out of the energy market is then done to meet the residual load that is not covered by bilateral transactions. We feel that these self-scheduling provisions add little to the market framework and needlessly complicate the process.

Special treatment of self-scheduled resources with regard to transmission congestion and uplift cost burden can lead to a drop in the liquidity of the spot market and an increase in the spot price volatility. Large participants may have an advantage in finding partners for bilateral transactions and may use this advantage to keep small players and potential entrants out of the bilateral market. The existence of a stable and liquid spot market will give small participants a place to market their output, and will enhance efficiency by encouraging entry.

In the Ontario market design, all resources are scheduled and dispatched through the centralized pool. The market design recognizes bilateral contracts as a transfer of settlement obligations, but does not allow these contracts to needlessly complicate physical operations. If participants want to make sure that their units are scheduled and dispatched at a specific time they can achieve this by submitting an energy offer of negative MMCP (the lowest possible offer). By doing so, the participant can essentially self-schedule its units within the framework provided by the market design.

Moreover, an appealing feature of a centralized pool is that bilateral contracts, such as contracts for differences, can be written that do not force a supplier to operate according to a predetermined schedule. A supplier can buy out of the pool to fulfill its contractual obligations if its energy would be relatively expensive to produce, and the supplier can sell uncontracted output into the pool if the market price is high enough to make it profitable. The centralized output decisions made in real time by the IMO will be more efficient than inflexible production

decisions made according to rigid contractual obligations. The lack of self-scheduling provisions should in no way be seen as a discouragement of bilateral trading; it should be seen as an encouragement of efficient bilateral trades that use the centralized pool to their advantage.<sup>5</sup>

Participants are placing a great deal of trust in the IMO when they give it the authority to determine the dispatch schedule of all generating units. This trust will only be justified if the IMO operates the system effectively, and consistently applies the rules that it establishes. In other markets, such as New England, self-scheduling ability gives participants a way around the ISO's centralized control when they feel that the ISO cannot be trusted to appropriately dispatch the system. In some sense, self-scheduling provides a remedy for a generator that believes that its units are not being scheduled appropriately. By taking away the self-scheduling option, the IMO increases the importance of consistency in its application of the market rules.

Some optimized pools allow generators to specify unit characteristics beyond their offers and ramp times in order to influence the scheduling and dispatch process to their advantage. In New England for example, units are allowed to submit a minimum run time. If a unit is scheduled, it will be scheduled for at least the duration of its minimum run time even if it has energy bids above the clearing price in some hours in this duration. In hours when the unit is scheduled out of merit, the unit is paid uplift equal to the amount between its bid and the clearing price. These uplift payments have become a significant problem in New England. Generators have incentive to submit a long minimum run time and wildly fluctuating energy prices. By doing so, the unit is scheduled on the merit of its low bids and is paid uplift in the hours when its bids are high. New England is in the process of redesigning this feature of the markets.

Ontario is wise to avoid these uplift payments and the gaming opportunities that come with them. However, the flexibility that generators need to be able to plan their operations without the submission of detailed unit characteristics is better provided by a multi-settlement system than a single-settlement system. If a generator finds that its unit is not scheduled in an hour when intertemporal costs dictate it, then the generator can get the unit scheduled by adjusting its offer after the scheduling period. A generator's ability to adjust offers to optimize its intertemporal cost structure is dependent on the accuracy and credibility of schedules set day ahead. As discussed above, this credibility and accuracy is greater in a multi-settlement system than in a single

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<sup>5</sup> The status of existing long-term contracts needs to be addressed by the IMO. Whenever possible, these contracts should be converted into financial contracts that fit into the market framework.

settlement system. Given that there is complete freedom to change offers and bids up until four hours before operations, it is unclear whether any party has sufficient incentive to make its day-ahead submissions meaningful. In the similar single settlement system of Alberta, generators have incentive to delay commitments in order to gain an advantage over competitors.

This is a particular concern in the context of OPG's dominance. OPG can effectively internalize the scheduling process, and thereby avoid giving any other party any useful information. If small participants cannot anticipate OPG's schedule adjustments then they will not be able to plan their operating schedules effectively, and OPG's dominance will be reinforced.

The restrictions on schedule adjustments in the hours before operations limit OPG's ability to delay commitment, but they also limit small player's ability to adjust in response to OPG. We feel that in light of OPG's overwhelming informational advantage, consideration should be given to allowing small participants more flexibility than OPG in the timing of their adjustments if a single settlement system is maintained. If small participants are forced to fully commit to their offers 2 hours before operations, then OPG should be forced to fully commit to its offers 3 hours before operations. The extra hour given to small participants will give the IMO time to come up with an accurate schedule after OPG's final commitment, and give small participants time to adjust to this schedule. A distinction between OPG and other participants should also be made with regard to the deadline currently set four hours ahead of operations.

## **4 Congestion pricing**

A key issue in market design is how to handle transmission congestion. Ideally, there will be excess transmission capacity, and congestion will be important only in exceptional circumstances. In this case, there will be just one liquid and competitive electricity market, and energy prices will vary by time but not by place. Many believe that this will be the case within Ontario where the core of the system is considered to be robust.<sup>6</sup> Historically, transmission congestion has only been a significant issue on the interties that enable imports and exports. However, it is important to plan for significant congestion, including internal congestion, in the event that transmission congestion becomes more of an issue after restructuring. Indeed, there is reason to believe that transmission congestion *will* become more of an issue after restructuring. In a market, suppliers will operate to maximize profits. Supplier profits may be enhanced by exploiting transmission

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<sup>6</sup> Links from the North and the Northwest of the province have been subject to significant congestion and marginal losses.

congestion to create a local monopoly. For example, a supplier with multiple units may offer them in such a way as to force a unit with a higher bid on line when it otherwise would not be dispatched. Hence, the fact that transmission congestion was not a problem in the past does not mean that it can be ignored in the future when suppliers face market incentives.

#### **4.1 Uniform uplift**

When the markets open, the IMO plans to use a uniform uplift charge to cover the costs of alleviating congestion. Uniform uplift works as follows. When transmission constraints are violated, units are selected out of merit order to solve the security-constrained problem at least cost. These “constrained on” units are paid their offers, rather than the lower clearing price for energy or the higher clearing price for the marginal cost of adjustments invoked to eliminate congestion. Units with offers below the clearing price, which are “constrained off” because their output would exacerbate transmission congestion, are paid the difference between the clearing price and their offers to make up for the operating profit that they forego due to congestion.<sup>7</sup> The cost of these extra payments is recovered through a uniform uplift charge that all loads pay on a proportionate basis. Intertie congestion is dealt with separately, and will be addressed in Section 5.

The uniform uplift approach is simple—all loads pay the same energy price. However, it does not send the correct market signals to demanders *or* suppliers. In a congested system, injections and withdrawals at different points in the network impose different costs or benefits on the system. Efficiency requires that the prices parties face reflect these differences. If one party’s interaction with the system creates transmission congestion, then it should pay the added costs of adjusting others’ generation; if another’s interaction reduces transmission congestion, then it should reap the benefit of the reduced costs of adjustment.

The uniform uplift approach is vulnerable to bid manipulation. A supplier will submit a high bid in situations where it is likely it will be constrained on, and so receive its bid, rather than the clearing price, whereas a supplier that anticipates that it will not be dispatched due to congestion will submit a low bid to maximize its “constrained off” payment. Other offers may be adjusted to increase the chances that constrained-on and/or constrained-off payments will be made. This distorts the energy market. The market monitoring rules that limit the situations in which a bidder

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<sup>7</sup> Constrained on/off payments are subject to surveillance and possible mitigation as described in Section 7.

is paid its bid mitigates the distortion and will be discussed in Section 7. However, these administrative rules are ad hoc and inflexible. A market-based response to the problem is better.

Any time bids and offers are manipulated, the efficiency of the market is endangered. Since the IMO's optimization algorithms minimize the cost of production as submitted in participants offers, the least cost dispatch will be implemented only if generator's offers reflect actual costs of production. Manipulation can result in relatively cheap resources being priced out of the market, and relatively expensive resources taking their place.

## **4.2 Locational Marginal Pricing**

The Market Design Committee recommended that uniform pricing be replaced by system-wide Locational Marginal Pricing (LMP) at the wholesale level eighteen months after markets open, and at the retail level 36 months after markets open. The IMO has not explicitly adopted this time frame, but it is expected that consideration of locational pricing will commence one year after the markets open. LMP has already been adopted by PJM and New York, and will soon be adopted by New England. With LMP, a different price for energy is calculated at each node. These location-specific prices reflect the marginal cost of an additional MWh of energy at each node, taking into account all costs and benefits of the additional energy on the system.

Correctly pricing congestion can have substantial benefits in constrained systems. Most importantly, it gives the ISO a market-based means of satisfying security constraints. Participants react to the location-specific prices in ways consistent with economically efficient dispatch subject to these constraints. The alternative is apt to be far less responsive or efficient.

As with all proposed market changes, the Locational Marginal Pricing system should be well planned out even before the markets open. After a market opens with an inefficient pricing system, there are those who learn to take advantage of the inefficiencies, and who gain an interest in seeing that the market structure remain unchanged. If possible, Locational Marginal Pricing should be a part of the market structure from the very beginning.

## **4.3 Constrained-off payments**

If the inferior system of uniform pricing is to be implemented, then it should be implemented in such a way to mimic the superior system of Locational Marginal Pricing as closely as possible. We suggest that the elimination of constrained-off payments will bring the uniform-pricing system closer to the ideal.

Constrained-on payments are sensible because the generation provided by a constrained-on unit provides an extra benefit to the system beyond the energy it provides through the alleviation of transmission congestion. In a nodal system, a constrained-on unit would be located at a high-priced node, and would be paid at least its offer.

Constrained-off payments are made because there is a perception that if a generator makes an offer below the clearing price and is not dispatched because of transmission congestion then that generator must be compensated for the operating profit that it is forced to forgo. This reasoning is flawed; the perceived foregone operating profit is merely a byproduct of inefficient uniform pricing. If the system was priced appropriately then the constrained-off generator would be located at a low-priced node, would not appear to be foregoing a deserved profit, and would not be entitled to any compensation. The output of the constrained-off generator would impose a cost on the system, and this cost must be considered when determining what compensation the generator is entitled to. Constrained-off payments are not paid in other uniformly priced markets, such as New England, and we believe that they should be eliminated in Ontario.<sup>8</sup>

#### **4.4 Incentives for new transmission capacity**

The incentives for new transmission capacity will play a critical role in determining the long run efficiency of the wholesale electricity market in Ontario. There typically is a strong conflict of interest between suppliers and demanders on this issue, as well as among suppliers. Transmission congestion creates congestion rents. The specifics of the grid and the market rules impact how those rents are distributed among participants. Inevitably some parties will benefit from the status quo, and will lobby hard against changes to the grid. This is especially true of transmission expansion that would increase the contestability of the market from imports, but also is significant with regard to external expansion. For the electricity market to be efficient, it is essential that such lobbying efforts prove unsuccessful. At a minimum, new capacity should be added whenever its cost can be covered by a reduction in future congestion costs.<sup>9</sup> Indeed, if there is a bias in these decisions it should be toward building excessive transmission capacity, since this capacity is essential in making the markets contestable.

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<sup>8</sup> Elimination of constrained-off payments will not be effective if generators are compensated according to their metered output as specified in the current settlement procedures. In order to ensure compliance, the IMO must not compensate units that run despite being constrained-off according to the dispatch instructions.

<sup>9</sup> In order for transmission capacity expansion to be most effective at reducing congestion costs, the externalities associated with loop flows must be carefully considered.

Resolving this issue is beyond the scope of this report. Transmission expansion is part of a larger policy agenda that is not directly governed by the market rules that we are addressing. However, some features of the market rules, such as the choice of uniform uplift versus locational pricing, can have an influence on the debate over transmission expansion. Locational pricing has the advantage that it makes the congestion costs transparent and therefore is likely to stimulate demand for new transmission capacity in the places where it is most needed, and to encourage siting of new generation capacity in locations enabling unconstrained exports. The importance of appropriate transmission expansion, to ensure reliability *and* economic efficiency, cannot be underestimated. It would be pointless to make a Herculean effort in fine-tuning the market rules if the goal of long run efficiency is undermined by poor transmission investment.

## **5 Interconnected market issues**

Trade between markets in different regions presents a difficult problem. A transaction that is treated as an export by one system operator must be treated as an import by another. If the protocols used to schedule and price this transaction are inconsistent then a significant coordination problem arises. It is important that markets interact seamlessly in order to achieve economic efficiency. In this section we identify some potential coordination problems, and analyze how well the Ontario market structure deals with them.

### **5.1 *Inter-regional trading***

Any participant who wishes to arrange a transaction into or out of Ontario must register a “border entity” in an external zone. The structure of the offers and bids made by these border entities is similar to the bids and offers made for domestic transactions. The challenge in scheduling inter-regional trades is that if a trade is scheduled in one market it must also be scheduled in the neighboring market. In order to achieve this coordination, it is necessary for market operators to have time to adjust their schedules in response to their neighbors. For this reason, import and export bids are not considered after the completion of the scheduling process initiated one hour before dispatch and the associated interjurisdictional coordination. Import and export transactions are considered firm after the hour-ahead scheduling process is complete.

Ontario’s market designers have wisely decided to avoid the problems of uniform pricing of import and export transactions. When an external constraint is binding, the market rules require that users of intertie capacity pay a congestion rental determined hour ahead as the difference between the clearing price for bids from that external zone and the projected Ontario clearing price. These congestion rents are fixed hour ahead and are not influenced by divergence of the

real-time energy price from the projected energy price. Financial Transmission Rights, which can be used by participants to hedge against transmission congestion, will be auctioned by the IMO.

For every MWh of electricity taken from the Ontario market, an exporter must pay the

- ◆ Ontario energy price (determined in real time)
- ◆ Congestion rent (determined at the time of scheduling)
- ◆ Uplift for operating reserve, transmission losses and congestion
- ◆ Ancillary services costs
- ◆ IMO fee
- ◆ \$1 export service charge.

Importers are not obliged to pay oncost or transmission service fees. Imports will be compensated according to the Ontario Energy Price less the congestion rental. Wheel through transactions pay for transmission service on the export portion of their transactions only.

Importers and exporters are eligible for constrained on/off payments for the alleviation of congestion constraints internal to Ontario at the time of hour-ahead scheduling. These payments are determined based on the clearing price of the external zone.

## **5.2 Why free trade?**

Ontario has traditionally been an exporter into the United States. While this balance has been altered somewhat recently due to the deactivation of two large Canadian nuclear units, there remains a fear that open access will encourage additional exports, which will cause a significant shift up the Canadian price curve. This may be a valid argument for limitations on trade if the goal of restructuring is to minimize rates in the short run. However, if the goal of restructuring is to maximize long run economic efficiency, as it should be, then free trade must be encouraged.

As in all markets where investment decisions are made by profit maximizing entities, prices in the United States and Canada will be equalized in the long run. With free trade, prices equalize because of efficient arbitrage between markets, and all gains from trade are captured. With restrictions on trade, price equalization comes about because of inefficient investment decisions. Limitations on Canadian generators' ability to profit from high prices in the US create adverse limitations on the incentive to build generation in Canada. Investors will not take advantage of the

natural resources available in Canada if they are forced to sell their product into a market where rates are held artificially low. Therefore trade should be encouraged, and any seams that form impediments to trade should be eliminated.

### **5.3 Competing commercial jurisdictions**

The essential problem of inter-regional trading is that commercial jurisdictions are not well defined with regard to the interties. Both Ontario and New York claim the right to allocate scarce intertie capacity among participants. To get a transaction scheduled a participant must have the schedule approved by both New York and Ontario. It is uncertain how the balance of power in the control of this scheduling process will be resolved. There is some chance that New York's scheduling protocol will effectively preempt Ontario's.

If congestion arises, then inter-regional traders will presumably have to pay congestion rents to both New York and Ontario. This excessively penalizes inter-regional trades and will discourage trades that could potentially be profit and efficiency enhancing. Importers and exporters should have to internalize the costs that they impose on the transmission network, but should not have to do it twice. Since the Ontario market is designed around importers providing competition for OPG, this is a particular concern. Anything that discourages outside participation bolsters OPG's dominant position. This issue can be resolved through an agreement between the markets to collect rents on imports only or to collect rents on exports only.

There is some evidence that intertie capacity between the ISOs of the Northeast US has not been utilized efficiently due to scheduling coordination problems.<sup>10</sup> Patton (2001) demonstrates that in many hours exports flowed from New York to an adjacent market (PJM or New England) with a lower price for that hour, whereas in many other hours imports came into New York from an adjacent market with a higher price for that hour. In one instance, power flowed from New York to New England, even though prices ended up more than US\$1000 in New York and less than US\$70 in New England. As long as control systems are optimized independently, arbitrage cannot be 100% effective, however there are things that can be done to help manage coordination problems.

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<sup>10</sup> Scheduling in the Northeast US is complicated by the need to procure Physical Transmission Rights for transactions in New England. Ontario has avoided this extra layer of complication by allocating transmission capacity based on the results of the energy market.

## **5.4 Market consistency**

In order for coordination to be successfully achieved, certain features of market operations must be consistent across markets. These features include

### **◆ Price caps**

The Maximum Market Clearing Price, which sets an upper bound on energy bids and prices in Ontario should be set at a level generally consistent with the caps imposed in adjacent jurisdictions. The present level of bid caps imposed throughout the Northeast US is US\$1000. It may be appropriate to allow for the difference between the nature of the Northeast US market caps (on bids), and the Ontario cap (on price).

### **◆ Scheduling time frame**

New York ISO adjusts schedules according to its hour-ahead market, and changes export schedules that others (particularly PJM) had considered firm. New York has recently adopted priority status for some day-ahead commitments, but additional coordination efforts need to be pursued.

### **◆ Definition of pricing zones**

An inconsistent pricing protocol will be implemented if zonal definitions differ between markets. New York currently sees Ontario as a single bidding zone even though the Frontenac and Queenston interconnections are geographically distinct. To be consistent with this classification the Ontario market design will probably recognize a single zone in New York. However, the transition to Locational Marginal Pricing would be smoother if two distinct zones were identified in New York to match the disparate Frontenac and Queenston prices that are likely to arise. Both the IMO and New York ISO should recognize the two distinct interconnections before the commencement of the Ontario market.

The IMO took steps to address these coordination problems in December of 1999, when it signed the Memorandum of Understanding that also includes the ISO's in New England, New York and PJM. Communication and data sharing is key to the success of the coordination effort, not just in day-to-day operations, but also in long-term planning and market design.

## **5.5 Asymmetric investment incentives**

A major weakness of the uniform pricing system is that it does not give new generation incentive to locate in areas that will tend to alleviate transmission congestion. The transition to a

Locational Marginal Pricing system will help to correct investment-siting incentives, but there still may be problems associated with asymmetric investment incentives across jurisdictions. These asymmetries may lead to intertie congestion and endangerment of an under-invested jurisdiction's internal security. Asymmetries may arise due to

◆ **Taxation**

The US has lower income and capital tax rates. The US system also allows for faster depreciation than the Canadian system. US exporters can be exempt from taxation if they do not maintain a permanent nexus in Canada.

◆ **The Canadian fair market access rule**

The fair market access rule is designed so that Canadians will not have to pay high prices for goods imported into Canada that could have been attained from domestic sources. The rule implies that if an exporter wants to sell power from Canada into the US it must make sure that Canadian utilities are aware of the sale and able to purchase equivalent energy at equivalent cost. Firms interested in building generation capacity in Canada must address how they plan to fulfill fair market access in the permitting process for export. The fair market access rule has not significantly disrupted trading of natural gas, but how it will affect electricity trading remains to be seen.<sup>11</sup>

◆ **Capacity markets (or lack thereof)**

The markets of the Northeast US include capacity markets. Such markets are designed and ready for implementation if the IMO sees fit, however they are not planned to begin when the markets open. In Section 8 we provide reasons why the IMO should not implement these markets, but nonetheless their absence may create a significant asymmetry.

◆ **Environmental policy**

Environmental policy will be addressed in Section 6. The recent reinvigoration of Ontario's environmental policy could potentially favor the siting of generation investment in the US over investment in Canada.

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<sup>11</sup> Stravos, R. "Electricity Reform in Canada: Powering Cross-Border Competition?" *Public Utilities Fortnightly*, May 15, 2000.

These factors suggest that investment in Ontario may be discouraged. However, there are other factors, such as its natural resources, that have made Ontario historically an energy exporter. We expect these factors to continue.

## **6 Environmental issues**

In response to public sentiment, Ontario regulators have recently significantly tightened environmental standards. NO<sub>x</sub> emissions from OPG's coal-burning plants will be cut by 53%, SO<sub>2</sub> emissions will be cut by 25%, and the Lakeview plant will be forced to stop burning coal entirely.<sup>12</sup> The emissions limits can be met by converting resources from coal to natural gas or oil, by cleaning up coal-fired emissions, or by purchasing emissions credits from industrial sources in Ontario or the United States. There is also some chance that Canadian compliance with international CO<sub>2</sub> limiting agreements, such as the Kyoto protocol, will put serious restrictions on the industry.

The costs of complying with these standards are prodigious. Unofficial estimates put the cost of converting the Lakeview plant at about \$500 million, and compliance costs at the five remaining coal-fired plants could reach \$1 billion.<sup>13</sup>

An issue that needs to be resolved is the treatment of imports with regard to Emission Performance Standards. Imports are subject to the same standards as domestic production. However, implementation of these standards is problematic due to difficulties in tracking and monitoring external sources. This issue needs to be resolved.

The California experience demonstrates that emissions trading programs can have significant spillover effects in the larger market. Until early 2000, NO<sub>x</sub> credits in the RTC trading program in the Los Angeles area were trading at low prices in the range of US\$1-2 per pound. In the Spring of 2000, traders began to realize that NO<sub>x</sub> limits would cause credits to be scarce and prices began to rise. Prices continued to rise through the summer and reached US\$35 per pound by late August. Since a typical generator in the Los Angeles area produces as much as one pound of NO<sub>x</sub> per MWh, this price increase must have played a major role in the escalation of California's electricity prices. The cost of an emissions credit represents a marginal cost of generating pollution, and will be included in the bid of a generator. This is true even if the generator does not have to buy credits to meet its limits. If the generator uses a credit to cover its own emissions, it is

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<sup>12</sup> *The Globe and Mail*, March 26, 2001.

<sup>13</sup> *The Globe and Mail*, March 27, 2001.

not able to sell that credit to another party and suffers a legitimate opportunity cost. Joskow and Kahn (2001) estimate that the RTC program raised the average marginal cost of generation in California by as much as US\$50/MWh last August.

This experience demonstrates that emissions limits for local pollutants, such as NO<sub>x</sub>, can be especially problematic. Since the limits are local, the emission market may be illiquid, especially if generation is highly concentrated in the local market. As a result, a generator requiring additional allowances may find that the allowances can be purchased only at a prohibitive price.

Emissions limits and associated trading programs are an important component of environmental protection. Increases in energy prices are by far the best way to encourage conservation, and should be a natural consequence of environmental policy. Attempts to soften the blow of environmental policy by fixing retail rates and essentially subsidizing the consumption of electricity out of general tax revenue, as was done in California, are counterproductive and lead to financial destabilization. Costs and benefits must be carefully weighed when environmental standards are determined, and consumers must be prepared to pay for environmental protection.

Environmental concerns also can play an important role in the permitting and siting of new generating facilities. No large generating units have come on-line in California in the past decade at least partly because of environmental concerns. It is important that appropriate costs are placed on those who produce pollutants, but that inflexible barriers to their operations are avoided. The contestability of the Ontario electricity market may serve as an important curb on the application of OPG's market power in the long run. If the pace of capital expansion is determined by regulatory concerns, not profit opportunity, then this curb disappears. We will return to this topic in Section 7.

## **7 Market power mitigation**

The restructuring of Ontario's power industry is following an unusual path. The transition to a competitive industry structure will not occur until *after* a competitive market framework is put in place. Initially, prices and output decisions will be determined by a market that is dominated by a single supplier. In this section we consider the extent of OPG's dominance, provide some perspective from which to view OPG, and analyze the Market Power Mitigation Agreement that regulators hope will police OPG's behavior.

## **7.1 Industry structure in Ontario**

OPG currently controls approximately 90% of the generating capacity within Ontario. Of the 27.4 GW of operable capacity controlled by OPG, 7.3 GW is hydraulic, 9.7 GW is thermal, and 8.7 GW is nuclear. OPG also owns over 5 GW of nuclear capacity that is non-operable due to the Nuclear Asset Optimization Program. The 2.1 GW Pickering A unit is due to return to service soon. An 18-year lease recently transferred control of the 3.1 GW Bruce A unit to Bruce Energy (a subsidiary of British Energy). The return to service of Bruce A is uncertain. The status of Pickering A and Bruce A will play a significant role in determining the adequacy of operable capacity in Ontario for years to come.

If markets open before the transfer of a significant portion of OPG's operable capacity, then the limited resources (1,660 MW) of Non-Utility Generators (NUGs) under contract to the Ontario Energy Finance Corp (OEFC) will provide OPG's main competition from within Ontario.<sup>14</sup> Enron has been subcontracted to administer all NUG contracts, and is currently in the process of taking over this responsibility from Hydro One. Negotiations to define the roles and responsibilities of NUGs are progressing slowly, so they are expected to be somewhat passive players at the time the markets first open.<sup>15</sup> Limited competition will also come from other utilities (approximately 400 MW), and 900 MW of industrial self-generation capacity will provide some demand response.

The primary source of competition for OPG will come from outside of Ontario. Interties have a current capacity of about 4 GW, including limited connections with Manitoba and Minnesota, and more significant connections with New York, Quebec and Michigan. Historically, these interties were primarily used for exports, but since the Nuclear Asset Optimization Program began imports have been more common. Hydro One is expanding the capacity available for imports from Quebec and Michigan, in accordance with the provisions of the Market Power Mitigation Agreement. The ability of outside generators to take advantage of arbitrage opportunities, thereby limiting OPG's ability to exercise its dominance, provided much of the justification for allowing OPG to remain whole, subject to the market power mitigation agreement, as markets open.

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<sup>14</sup> OEFC is owned and operated by the Ontario Finance Authority (OFA)

<sup>15</sup> Cary (2000), *Ontario Market Overview*

## **7.2 How should we view OPG?**

In order to assess if the steps taken to mitigate OPG's dominant position are sufficient, we must first determine the appropriate perspective from which OPG should be viewed. It will be useful to analyze the validity of several different potential perspectives.

◆ ***Perspective 1: Guardian of the consumer's interest because its sole shareholder is the province of Ontario***

Much of the hope for the success of the market has been justified by viewing OPG from this perspective. From our vantage point it is hard to observe the internal incentive structure that will govern the operations of OPG, and hard to predict if this perspective is valid. However, it seems strange to expect the benefits of competitive markets to arise when the dominant player in the market is actively controlled by the government. Businesses work best when they are free to operate as they see fit. Bureaucratic control is bound to result in internal inefficiencies. The government may have additional objectives such as debt recovery and tax relief that give it an interest to use OPG profitably.

◆ ***Perspective 2: Guardian of the consumer's interest because it is afraid of additional regulations that may be imposed on it by OEB***

There are many steps that regulators can take if OPG abuses its market power, including forced divestiture, and the imposition of restrictive price and bid caps, rebates and penalties. The relaxations of various provisions of the existing Market Power Mitigation Agreement are conditional on OPG's behavior. However, history shows us that market power abuse can be difficult to verify, and that punitive and corrective actions can be slow to take effect. Suppliers have been known to milk their market power before regulators can respond. Any market that relies on the threat of regulation to function properly is inherently unstable, and this political risk is extremely hard to hedge.

◆ ***Perspective 3: Profit maximizing entity that is led by the competitive forces of the North American marketplace***

This perspective is certainly not valid given the current industry structure. While external competitors should certainly be considered when defining a firm's market share, OPG's dominance of the Ontario marketplace is so great that competition across the interties with New York, Michigan and Quebec alone will be far from sufficient to keep its market power in check. The non-storability of power and difficulties associated with coordinating

transactions between markets limit participants' arbitrage ability. Even if interface capacity was unlimited (which it's not), OPG could find ways to profitably take advantage of these arbitrage limits.

◆ ***Perspective 4: Dominant profit maximizing entity that operates within the market rules to make as much money as possible***

We feel that this is the most appropriate perspective from which to view OPG when it comes to market design and market power mitigation. A well-designed market and licensing arrangement can align OPG's incentive to act profitably with its incentive to act efficiently. If market forces provide OPG with the incentive to act efficiently, then heavy-handed bureaucratic and regulatory control are not needed. In the remainder of this section we analyze the tool that regulators will use to shape OPG's incentives – the Market Power Mitigation Agreement.

### ***7.3 Market Power Mitigation Agreement***

The fear that low competitive prices would be insufficient to recover the \$38.1 billion debt held by Ontario Hydro at the time of restructuring provided justification for allowing OPG to remain whole. The Market Design Committee decided that allowing OPG to recover the debt within the confines of the Market Power Mitigation Agreement was preferable to assessing excessive debt recovery charges as part of the Non-Competitive Energy Charge. Thus, it is assumed that OPG will engage in behavior that gives it profits above the competitive benchmark, but that these profits will be held at a stable and appropriate level by the MPMA. The MPMA is characterized by direct procedural restrictions on OPG and other participant's behavior, a rebate provision, and various divestiture requirements.

#### ***7.3.1 Procedural regulation***

OPG is compelled to offer all of its available capacity into the operating reserve market at capped offer prices, and if necessary the IMO has the right to force OPG into cost-based operating reserve contracts. Forcing OPG to participate in the reserve markets indirectly forces OPG to offer all of its capacity into the energy market as well, but the price at which this energy is offered is limited only by the Maximum Market Clearing Price.

The idea that regulators can force OPG to offer its available capacity is premised on the assumption that regulators can observe if a generating unit is available or not. It is widely believed that, starting in the summer of 2000, generators in California strategically withheld

capacity to manipulate prices. However, no legally credible evidence has been put forth to verify that this is true. Even the most trained auditor visiting the site of a generation facility cannot observe if an outage is justified - only those who are familiar with the day-to-day operations of the facility can. The approval process for planned outages set forth in the market rules will give the IMO some limited control of outage coordination, but any attempt to compel OPG to offer its available capacity is undermined by OPG's ability to claim a forced outage. If OPG chooses to withhold capacity, either physically (by claiming a forced outage) or economically (by bidding its energy at the MMCP), it will be able to do so.

Limitations exist on the amount that OPG can import into Ontario. These limits are designed to ensure intertie capacity is available to competitors. The importance of these restrictions is very limited. If OPG chose to dominate imports it would have to do so economically. It is unclear how OPG could gain a profitable advantage from submitting excessively low import offers. OPG's market power is mitigated by the existence of *potential* competing importers regardless of if these importers are able to make offers under OPG's. It is likely that the import restrictions will not be binding, and therefore this may be a moot point. There are no restrictions on OPG's exports.

Constrained on/off payments are subject to market surveillance and possible corrective and punitive actions. When transmission constraints are binding, a generator's offer may be deemed unacceptable if it is sufficiently above the offers submitted by that generator over the past 90 days and it is sufficiently above the market clearing price. Penalties may be assessed if a participant's offer fails the screening tests.

The IMO's authority to review and mitigate OPG's offers is limited to the mitigation of local market power that arises due to transmission constraints. According to the summary of the agreement on OPG's webpage, the MPMA gives OPG "the explicit right to engage in unilateral actions to attempt to maintain hourly prices at levels that will result in the Average Price equaling the CAP [\$38/MWh], ... In the event that the Average Price exceeds the CAP, the sole remedy shall be payment of the rebate."

### **7.3.2 Rebate**

The rebate provision is the primary curb on OPG's market power in the short run. Although some (including OPG itself) refer to the rebate as a price cap, it is better characterized as a forward sale of the Contract Required Quantity (CRQ) to the IMO. The Contract Required Quantity was predetermined as an estimate of 90% of OPG's market sales into Ontario and is

composed of hourly output levels for each of OPG’s resources.<sup>16</sup> OPG is required to pay the rebate to the IMO whenever the average annual price (weighted by the hourly CRQs) exceeds \$38/MWh. The rebate will be distributed to all loads in proportion to their annual consumption. Algebraically the rebate can be expressed:

$$\begin{aligned} \text{Rebate} = & (\text{Average Price} - \$38) * \text{CRQ} - \text{Rebate Carry Forward Adjustment} \\ & - \text{Force Majeure Adjustment} - \text{Price Spike Adjustment} \end{aligned}$$

The Rebate Carry Forward Adjustment allows OPG to apply any amount that average price falls short of \$38/MWh to the next year’s rebate. The Force Majeure Adjustment protects OPG from the rebate if it is unable to meet the CRQ due to circumstances beyond its control. The Price Spike Adjustment also protects OPG from having to pay the rebate on output that it receives no revenue for. The Price Spike Adjustment is calculated in an hour when the market price exceeds \$125/MWh and OPG’s output falls short of that hour’s contribution to the Contract Required Quantity. In hours for which these conditions hold the Price Spike Adjustment can be expressed:

$$\begin{aligned} \text{Price Spike Adjustment} \\ = & (\text{Hourly Price} - \$125) * (\text{OPG's Hourly Required Quantity} - \text{OPG's Actual Output}) \end{aligned}$$

The annual Price Spike Adjustment equals the sum of all hourly Price Spike Adjustments.

Except for the adjustments, the rebate is essentially structured as a contract for differences. OPG has committed to selling the CRQ to the IMO at the predetermined price of \$38. OPG will be able to receive the market price for any amount of output that it sells in excess of the CRQ.

The rebate will have a large effect on OPG’s incentives, and is necessary to promote market efficiency. The rebate will limit the payoff that OPG receives from pushing prices above the competitive level, and therefore will help promote market efficiency. The lack of vesting contracts and restrictions against utilities signing bilateral forward contracts was a main reason why restructuring in California failed. Generators selling into California’s spot market had incentive to make spot prices as high as possible because they had no forward obligations.

However, there are several reasons to believe that, even with the rebate in place, OPG will benefit from high prices.

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<sup>16</sup> CRQ was estimated by assuming that OPG would act in a manner that would keep average prices at \$38/MWh. There is now some evidence that these estimates fall short of the 90% target.

- ◆ OPG receives the market price for output that it sells in excess of the CRQ. There is some evidence that the CRQ estimates actually fall short of their target of 90% of OPG's output. A significant portion of OPG's production may therefore benefit directly from high spot prices.
- ◆ Other producers beside OPG receive the market price. High prices may come back to help OPG if there is any sort of collusion.
- ◆ The settlement terms of long-term bilateral deals may be influenced by spot prices.
- ◆ The price at which OPG can sell its resources may be influenced by spot prices

There are also some reasons to believe that high prices may be detrimental to OPG beyond the fact that they will be rebated back to the IMO. Anti-competitive behavior may lead to an extension of the rebate provisions beyond the four-year horizon. High prices may also induce the construction of competing generating capacity within Ontario and may encourage the expansion of intertie transfer capability.<sup>17</sup> However, if the pace of siting of new capacity is determined by regulatory and environmental restrictions, and not by perceived profit opportunity, then the ability to earn a high divestiture price will outweigh this incentive softening effect of contestability.

### **7.3.3 Is the Price Spike Adjustment necessary?**

We are under the opinion that the Price Spike Adjustment serves no useful purpose and should be eliminated. In the Appendix we demonstrate algebraically that when the Price Spike Adjustment is in effect, the marginal revenue that OPG receives from increasing its output is only \$125. Thus, even if market prices are approaching \$1000/MWh, OPG will have limited incentive to bring generation back online after an outage. There is some possibility that operating costs will at some times exceed \$125, as they have recently in California, in which case OPG may not have economic incentive to offer its output at all.

The Price Spike Adjustment is premised on the misguided notion that OPG should not bear the risk of paying a large rebate on a production level that exceeds its actual output. Someone must bear the risk of capacity shortfalls and price spikes. If it is not OPG then it is consumers. It is more efficient for risk to be born by the party who has control over it, in this case, OPG. This also applies to the elements of the Force Majeure Adjustment that OPG can potentially control.

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<sup>17</sup> OPG may be incented to keep the market unstable, thereby diminishing other participants' incentive and ability to enter.

#### **7.3.4 Decontrol requirements**

The duration of the effectiveness of the rebate will be dependent on OPG's compliance with "decontrol" requirements. The specific actions that constitute acceptable decontrol are left up to the discretion of the OEB and are not spelled out in the MPMA, but it is believed that many arrangements will be acceptable, including asset sales, leases, swaps, and other types of contracts. Decontrol requirements are defined by categorizing all resources into two groups. Tier 1 capacity consists of hydro and nuclear resources. Tier 2 capacity includes everything else, including the intertie transfer capability and demand-side bidding. OPG is required to decontrol at least 4 GW of Tier 2 capacity so that it controls no more than 35% of Ontario's Tier 2 capacity within 42 months. Up to 1 GW of hydraulic capacity may be substituted for Tier 2 capacity. Within 10 years of market opening OPG is required to decontrol sufficiently many assets so that it controls no more than 35% of all capacity, and all other participants control less than 25% of the market.

Rebate provisions are scheduled to be effective for 48 months, but if the 10-year decontrol targets are met early then the rebate may be deactivated. If Tier 2 decontrol is delayed, the rebate may be extended beyond the fourth year. The effectiveness of the rebate will also be phased out as decontrol proceeds. The contribution of every generating unit to the Contract Required Quantity is defined, and the Contract Required Quantity will be reduced by 110% of this contribution when a generating unit is decontrolled.

The percentages listed in the decontrol requirements are somewhat deceptive. Because dispatchable load and intertie transfer capability are included as part of total Tier 2 capacity, it is possible for OPG to comply with the Tier 2 decontrol requirement while maintaining as much as 45% of the thermal capacity installed within Ontario. The 10-year decontrol requirement appears to make no exception for non-operable nuclear capacity, so it is conceivable that the lease of Bruce A will contribute to the requirement even if the unit does not return to service.

OPG has already begun the decontrol process. In addition to the lease of the Bruce A unit, OPG is currently looking to decontrol some of its thermal capacity, including the 1.2 GW Lakeview station and the 2 GW Lennox station. The decontrol of these plants was on hold while the government reviewed the environmental regulations governing coal-fired generation, but now appears ready to proceed. OPG has also announced plans to decontrol the 310 MW Thunder Bay Station, the 215 MW Atikokan station, and about 500 MW of hydroelectric capacity on the Mississagi River. According to OPG's president and CEO, Ron Osborne, "As a result of our decontrol initiatives and the non-OPG sources of electricity currently available, when the new

market opens, companies other than OPG will be capable of supplying more than half of the province's peak demand."<sup>18</sup>

OEB should be very careful to make sure that acceptable "decontrol" means that OPG is divorced not just from operational control, but also from the financial incentive to make a unit profitable. For example, if decontrol is done through some form of short-term contract, then OPG may still have strong incentive to push up prices so that contracts can be renewed at favorable rates. When an electrical system is stressed, the residual demand facing a large generator may be highly inelastic, and little reduction in output may be needed to push up prices. Therefore, even if OPG actively controls only a few GW of thermal capacity, it may have significant ability to influence prices.

Ontario can learn from Alberta in this regard. Like Ontario, Alberta avoided forced divestiture. Unlike Ontario, Alberta sold the bidding and operating control of the existing generation as long-term power purchase agreements, lasting the life of the plants or twenty years. In addition to the long duration, strict holding restrictions were put in place that prevent any one firm from having control over more than 25% of the capacity. Moreover, there are further restrictions that prevent the ownership of any sizable portion of the aggregate supply curve by a single firm.

The ability of a generator in Ontario to significantly influence prices with the control of only a few GW of thermal capacity makes us skeptical of the plan to allow the rebate to be deactivated before Tier 1 and Tier 2 decontrol are completed. If OPG was to divest only the required 4 GW of thermal capacity, it would still control about 16 GW of Tier 1 capacity and 6 GW of Tier 2 capacity, accounting for well more than one-half of the market.

To demonstrate the problems associated with this industry structure we consider the following example. Assume that there are two firms, firm A and firm B. Firm A owns two 400 MW thermal units and a large fleet of baseload units, whereas Firm B owns only two 400 MW thermal units. By withholding the output of one of its units, Firm B can increase the market price, but if it does so it will cut the amount of its output that benefits from that price increase in half. Firm A can also increase the market price by withholding the output of one of its units. However, unlike Firm B, the proportion of Firm A's output that benefits from a price increase is decreased only slightly by withholding the output of a single unit. Firm A's incentive to withhold output is

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<sup>18</sup> Remarks by Ron Osborne to the Empire Club, Toronto, Ontario

much greater than firm B's because withholding increases the profitability of Firm A's baseload units. It is important to consider not just the ability to push up prices (firms A and B have the same ability to push up prices using their thermal units), but also the incentive to push up prices (firm A has a much greater incentive to push up prices). OPG's incentive to push up prices will not go away until decontrol of both Tier 1 and Tier 2 capacity is achieved.

We have serious reservations whether the controls on OPG's market power will be sufficient. Even if OPG achieves the decontrol actions that it is currently pursuing, its share of the Ontario market will be higher than the share of any producer in any other electricity market in North America. We fear that the outcome in the short and medium-term will be energy prices that are politically negotiated, rather than true market prices determined by open and vigorous competition.

There is a sentiment in Ontario that, as long as the Pickering A nuclear unit is returned to service, generating capacity will be adequate, and therefore it will be possible to open the markets to competition. This faith in the ability of over-supply to produce an effective market also pervaded the debate over restructuring in California. The supply/demand balance quickly shifted in California, and the markets are no longer workably competitive. This is despite the fact that there are 5 major generators in California (compared to only one in Ontario). We should learn from the California experience that adequate capacity at the time that markets open does not ensure that the markets will be effective for very long.

One area where more can be done to mitigate market power is in establishing a price-responsive demand-side. This is a challenge in every market. California is the best example of the inherent instability of a market with a supply side with the ability to exercise market power facing an unresponsive demand. Developing a price-responsive demand-side now can help ensure that Ontario does not follow the same path as California. Demand and retail pricing will be discussed in more depth in Section 9.

## **8 Capacity markets**

The market rules provide a framework for the initiation of a capacity market, which may be implemented if the IMO decides that the existing market regime does not provide sufficient incentive for investment in generation. Indeed, as our analysis in Section 5 shows, we feel that there may be some reason to believe that investment incentives in Canada may lag behind investment incentive in the US. However, the capacity market design used in the Northeast US is fundamentally flawed, and other investment incentives can be used more effectively.

In principle, capacity markets are unnecessary in a competitive electricity market. Under competition, capacity is determined over the long term by the market in response to price expectations. If expectations are correct, then sufficient capacity is built so that the market prices just cover all costs including a risk-adjusted return on capital investments. If expectations are incorrect, then prices will be high, prompting additional investment in capacity, or low, prompting curtailed investment in capacity.

However, this did not deter the system operators of the Northeast United States from implementing capacity markets. The capacity markets are a holdover from the regulated setting, when capacity decisions were not made in response to price expectations.

The major flaw with capacity markets is that they make no distinction between valuable capacity and worthless capacity. Energy markets are run as uniform-price auctions because the power produced by all generators is essentially a homogeneous product. This cannot be said of capacity. At certain times, the capacity offered by a reliable baseload unit is much more valuable to the system than the capacity that is offered by an inefficient peaking unit. At other times, the capacity offered by a peaking unit with a quick startup time may be the most valued by the system. Uniform pricing of these different kinds of capacity creates inefficient investment incentives. Inefficient capacity with high operating costs may be able to limp along on capacity payments, and its presence may discourage the construction of more efficient and productive capacity.

Capacity costs should be recovered through prices in the energy and reserve markets, and not as part of an artificial market created by administrative regulations. The costs from having the capacity markets are increased complexity, and distortions in investment decisions.

## **9 Demand and the retail market**

The Ontario market design allows for competitive retailing, however, experience elsewhere shows that active retail markets can be slow in developing, and many end consumers will stick with the default Standard Supply Service (SSS). Due to metering limitations the rules pertaining to SSS distinguish between large customers and small customers.

Large metered customers who select Standard Supply Service will be charged the actual hourly price for all of their metered energy consumption. Large customers without interval meters will pay the Weighted Average Hourly System Price, which is calculated from the Net System Load Shape of the customer's distribution system.

The SSS code indicates that a Fixed Reference Price will be charged to small SSS customers who do not have interval meters. This Fixed Reference Price will be approved by OEB and will be periodically adjusted to be consistent with the Weighted Average Hourly System Price. Distributors will be able to maintain variance accounts of the difference between payments that they make for energy in the wholesale market and collections that they receive at the Fixed Reference Price. A customer will be allocated its share of the balance of its distributor's variance account if it leaves the distributor's service territory or switches from SSS to a competitive retailer. When a significant balance accrues in a distributor's variance account OEB may permit the distributor to eliminate the balance through "true-up" collections or distributions. The timing and manner of such true-up mechanisms will be determined by OEB. Distributors can choose to ignore the Fixed Reference Price billing method and pass the Weighted Average Hourly System Price directly on to customers as long as they offer an equal billing plan.

The pass through of wholesale prices to the retail level is the main feature of the Ontario market design that will ensure that the type of failure experienced in California is avoided. Someone must pay the wholesale costs of electricity at some time. Shifting costs to taxpayers or other parties, as in California, deprives the electricity market of essential price response. When consumers must bear the cost of the energy that they consume, conservation is encouraged, market power is reduced by the increase in demand elasticity, and the financial health of distributors and retailers is protected. We feel that the Ontario's basic framework linking retail prices to wholesale prices is encouraging, but there are some things that can be done to increase demand-side response.

We are skeptical of the wisdom and necessity of the Fixed Reference Price with true up system. If the Fixed Reference Price is set systematically below the Weighted Average Hourly System Price then variance accounts will grow, and consumer's will incur large true up payments to balance the accounts. Consumers will experience small monthly bills while variance accounts are growing and large monthly bills when the Fixed Reference Price is adjusted up and true up payments are added on. Therefore, consumer's monthly bills may potentially be destabilized by this system of pricing, rather than stabilized as intended. The true-up system has an additional drawback in that it delays the payment of spot prices, which will tend to dampen the incentive of consumers to respond to those prices.

The incentive of consumers to respond to spot prices is also dampened by OPG's rebate. The rebate will be allocated on the basis of annual energy consumption, so for every MWh consumed,

a customer claims a greater share of the rebate. The choice to allocate the rebate based on energy consumption is preferable to allocation based on a consumer's total energy bill. Allocation based on energy consumption effectively decreases the cost per MWh incurred by a customer by a constant throughout the year, whereas allocation based on total energy bill effectively scales the cost per MWh incurred by a customer down by a constant proportion.<sup>19</sup> The pass through of price spikes to end-users will be only marginally affected by energy-based allocation, and spot price dampening will occur only at a global level. Nonetheless, other rebate allocation methods, such as allocation based on customer class or historical consumption, or allocation through the tax system could eliminate spot price dampening entirely. As currently structured, the aforementioned MPMA shortcomings have the potential to combine negatively with the intent of retail pricing design in Ontario.

As in most electricity markets, there is opportunity for Ontario to extend the scope of real-time pricing by expanding the set of customers using hourly interval meters. Metering can be expensive, but these costs are justifiable given the enhancement of market efficiency that real-time pricing provides.

## 10 Conclusion

We have reviewed the proposed design of the Ontario electricity market. Our purpose was to answer the question whether the proposed rules facilitate an efficient wholesale electricity market. We conclude with a number of recommendations that we think would improve the market:

1. Ontario should implement a multi-settlement energy market, rather than the proposed forward energy market. The distinction is that in a true multi-settlement market, the day-ahead schedule and prices are tied to physical operations of the system. Hence, under multi-settlement the day-ahead financial commitment is based on the scheduled physical operation of the system.
2. Locational marginal pricing should be introduced as soon as is possible. This promotes efficiency by sending the right prices to both buyers and sellers in the wholesale market. In the interim, constrained-off payments should be eliminated. These payments are without economic justification.

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<sup>19</sup> Consumers will not know what these constants are ex ante.

3. Care should be taken in improving the interconnections with other markets. The seams should be managed to maximize coordination and minimize distortions across markets.
4. We are skeptical that the market power mitigation agreement will be successful in producing a competitive electricity market in the foreseeable future. OPG is simply too dominant. Further mitigation measures are needed. Moreover, Ontario, like most markets, has to do more to make the demand side respond to price, and arguably should be more aware of this general shortcoming given the dominance of OPG.
5. Capacity markets should not be introduced. They are an unnecessary holdover from the days of regulation.

Experience with deregulated electricity markets has been mixed. Success is enhanced to the extent that (1) the market is not highly concentrated, (2) both supply and demand respond to prices, and (3) entry costs are not too high. All three of these elements pose challenges in the Ontario market. If these challenges can be met, there is every reason to believe that the right price signals will be sent in the spot market. These price signals will provide the incentive for efficient long-term investment in generating capacity.

One important issue that we have not addressed is governance. Rule changes are inevitable under any system. Both short-term and long-term efficiency can be adversely affected by arduous governance procedures that lead to lengthy delays of necessary enhancements.

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## Appendix

The following notation and terminology is used to express the elements of the rebate and price spike adjustment in the Market Power Mitigation Agreement.

- AP*: Average Price – the weighted average of prices to which the price cap is compared in determining the rebate
- CRQ*: Contract Required Quantity – an annual total composed of hourly totals from all of OPG’s generating resources
- Q<sub>h</sub>*: Hourly Quantity – 90% of OPG’s estimated production in hour *h*. It is composed of the sum of the hourly generating unit quantities.
- P<sub>h</sub>*: Hourly Price – the unconstrained spot price in hour *h*.
- CAP*: Price Cap – the threshold compared the Average Price in the determination of the rebate. It is currently set at \$38/MWh
- PSA*: Price Spike Adjustment – the adjustment designed to protect OPG from having to refund price spikes for which it did not receive revenue because its output fell short of *CRQ*.

We will also use the notation, *AQ<sub>h</sub>*, to denote OPG’s actual quantity produced in hour *h*.

The rebate and its components are expressed algebraically as specified as

$$Rebate = (AP - CAP) * CRQ - \sum_{h=1}^{8760} PSA_h - other\ adjustments$$

$$AP = \frac{1}{CRQ} \sum_{h=1}^{8760} Q_h * P_h ,$$

$$CRQ = \sum_{h=1}^{8760} Q_h$$

$$PSA_h = (P_h - 125) * (Q_h - AQ_h) \text{ if } P_h > 125 \text{ and } AQ_h < Q_h$$

$$PSA_h = 0 \text{ if } P_h \leq 125 \text{ and } AQ_h \geq Q_h$$

Filling all of these expressions into the expression for the rebate gives

$$Rebate = \left( \frac{\sum_{h=1}^{8760} Q_h * P_h}{\sum_{h=1}^{8760} Q_h} - CAP \right) * \sum_{h=1}^{8760} Q_h - \sum_{h \text{ s.t. } PSA_h > 0} (P_h - 125) * (Q_h - AQ_h) ,$$

or equivalently

$$Rebate = \sum_{h \text{ s.t. } PSA_h=0} Q_h * P_h + \sum_{h \text{ s.t. } PSA_h>0} [(P_h - 125) * AQ_h + 125 * Q_h] - CAP * CRQ$$

The last term in this expression, the Price Cap multiplied by the Contract Required Quantity, can be thought of as a fixed payment made from the IMO to the OPG for the forward purchase of the CRQ. This payment is not influenced by OPG's daily operations, and therefore does not directly influence OPG's incentives to push up prices.

Now consider the contribution to annual profits attributable to OPG's production in an hour,  $H$ , when the Price Spike Adjustment is effective. We will denote this hourly operating profit as  $Profit_H$ , and will express it as OPG's operating profits in the spot market less the term from the above expression for the rebate that is effective only when  $PSA > 0$ .

$$Profit_H = AQ_H * P_H - operating\ costs - (P_H - 125) * AQ_H - 125 * Q_H, \text{ or}$$

$$Profit_H = 125 * (AQ_H - Q_H) - operating\ costs$$

This last expression demonstrates that in an hour when the Price Spike Adjustment is effective, if OPG increases its output by one MWh its revenue will increase by only \$125/MWh.