



A Discussion Paper on Day-Ahead Mechanisms

August 10, 2007

Public

Table of Contents

Introduction	3
Section 1 – Ontario’s Industry Context Regarding Day-Ahead Initiatives.....	5
Section 2 – Approaching Opportunities and Challenges for the Energy Markets	8
Section 3 - Description of Alternatives for Improved Day-Ahead Mechanisms	13
Base Case – Efficient Unit Commitment	15
Option 1 – HOEP Forecast	20
Option 2 – Voluntary Energy Forward Market.....	22
Option 3 – DAM with Unconstrained Price and Quantity	24
Appendix A.....	34
Appendix A – Attachment	39
Appendix B	45
Appendix C	47
Appendix D.....	55

Introduction

The IESO's 2007 Business Plan states,

“At the core of the IESO's Business Plan is the implementation of a set of progressive (market) enhancements. The first key enhancement continues to be the development of a DAM”.

Accordingly, IESO staff has been discussing the merits of various possible day-ahead designs and features with numerous stakeholders, to better understand how such mechanisms might benefit their businesses, their sectors and the industry as a whole. In this document, the IESO is reporting back to the industry what it has learned from these discussions, what it believes are some opportunities that exist to advance the market's day-ahead features, and how it intends to proceed from this point onward.

This report is divided into three sections. The first section provides Ontario's current market and industry context in which day-ahead designs must operate. The second section summarizes the major IESO findings from the stakeholder discussions – some of the recurring themes – by summarizing the current problems or future opportunities that could be addressed through enhanced day-ahead features of the IESO-administered market. As well, the section includes some conditions that participants felt a day-ahead design must satisfy – for example, “keep it simple”. In addition to the points in this section, a summary of stakeholder feedback has been provided as Appendix C. Lastly, section three provides a brief description of alternative day-ahead designs that could address the problems, take advantage of the opportunities, and meet the conditions, each to varying degrees.

The IESO intends to explore the alternative designs with stakeholders in greater depth throughout the fall. The revised stakeholder plan, including the complete schedule is attached as Appendix D. The goal of these discussions is to try and reach a consensus on the appropriate high-level design of day-ahead improvements to the IESO-administered market that should be pursued. The recommended design will be provided to the IESO Board, with a request that they approve IESO staff and stakeholders proceeding with a detailed design phase in 2008. Consensus would be ideal, but absent consensus, IESO management will make a recommendation to its Board based on the feedback it has received and its best judgement of the appropriate course of action.

The recommendation will be accompanied by a high-level Cost-Benefit Analysis (CBA) that will assess both the likely costs and benefits to individual participant classes and to the economic efficiency for the Province as a whole. The CBA will draw heavily from the stakeholders' own analyses and inputs to the IESO on the costs and benefits they foresee. A framework for the CBA is attached as Appendix A. The recommendation will also be evaluated against additional criteria listed in Appendix B, which represent generally accepted sound market design principles. Finally, the recommendation will also be evaluated on how it might impact further market or industry evolution initiatives, including the OPA's “innovative strategies to encourage and facilitate the competitive market-based responses and options for meeting overall system needs”, as per Ontario Regulation 424/04. Specifically, the recommendation will provide

the Board with an analysis of potential impacts on the liquidity of forward contracting and the development of forward exchanges, on the OPA's exploration of the load-serving entity (LSE) concept, and on the IESO's continuing investigation of efficiency impacts of locational prices for electricity in Ontario.

The design phase description that will accompany the recommendation to the IESO Board will include a schedule that lays out any applicable milestone dates for major deliverables such as the resolution of any outstanding design features, the approval of the required market rules, the systems designs and specifications, and the business process designs. In each instance, the CBA will be reviewed, potentially incorporating greater detail, to ensure that the analysis remains sound. This design phase schedule will also clearly illustrate for stakeholders at what point the IESO would be considering subsequent work to be under a capital project.

Section 1 – Ontario’s Industry Context Regarding Day-Ahead Initiatives

Advancing the design of the day-ahead features of the IESO-administered market has been a recurrent theme in market design discussions. A rudimentary day-ahead energy forward market was included in the original set of market rules passed to the IMO by Minister Wilson, Minister of Energy, Science and Technology, on April 15, 1999, but was never pursued. In 2003/2004, the IESO and several stakeholders invested significant effort in designing a comprehensive and sophisticated DAM that contained numerous features to provide flexibility and address specific risks for participants. However, the resulting complexity and high implementation costs eroded the initial support from stakeholders. In 2005 and 2006, following a particularly difficult period of operation over the summer of 2005 that was partly attributed to the unreliability of real-time-only electricity imports, the IESO and participants designed and implemented the reliability-based Day-Ahead Commitment Process (DACP), which is where the current market design stands.

In discussions with stakeholders, some continue to question why the IESO is investigating a day-ahead market. They wondered if it was a DAM for the sake of a DAM, or if it was perhaps to align Ontario’s market with those of the neighbouring U.S. jurisdictions. What problems are we trying to solve was a recurring question. Identifying the problems and assessing the opportunities through a shift to day-ahead business depends on an understanding of the current environment and the changes the industry will be undergoing. The description of the current environment is provided here and a discussion of the coming changes is provided in section 2.

The DACP is a process that was specifically designed to address reliability concerns in the most expedient manner possible. Impressively, the industry mobilized to create and implement the DACP over an 8-month period, in time to be available for summertime operation in 2006 – a very significant achievement. As one could imagine, this new process, while effective in that the IESO has the ability to provide day-ahead financial guarantees to both importers and domestic generators as necessary to address reliability needs, is not particularly efficient. First, under the DACP design resources are scheduled for the next day based on minimizing the costs in each hour based on incremental energy costs, and the IESO is only to influence unit commitment decisions if necessary to address reliable operation. This is in contrast to the day-ahead design in all regions of the Northeastern U.S. (New York, New England, PJM, Midwest ISO), where the day-ahead schedule is optimized across the day with full costing (multi-part bidding) to ensure that generators are only started if they are needed and efficient relative to all other supply alternatives such as other generators and import opportunities. Secondly, the DACP is not a market and does not permit any participants to secure a day ahead price, and so participants must wait for real-time prices to know what they will be paying or be paid. And thirdly, the DACP is often a poor predictor of real-time operations, as it does not consider export volumes, causing both the dispatch advisories that inform generators of their likely production levels for the next day, and the price calculations from DACP to be unreliable predictors of real-time results. So, as of today, consumers and other participants do not have a reliable forecast of next-day prices that is publicly available to them. Day-ahead dispatch advisories are not sufficient for generators to plan their operations. And there is no economic coordination of generator start-up schedules. Most of the problems and opportunities discussed in this report flow from this current reality. They are all the more

relevant given the significant changes that are approaching as a result of generator retirements or refurbishments, continuing increases in contributions from renewable resources, and the significant future dependence on demand response and conservation. This review of day-ahead mechanisms provides an opportunity to address these opportunities and concerns.

There are two factors that make development of a day-ahead market in Ontario challenging.

The first factor is related to the uniform price for electricity in Ontario – a mismatch between the incentives created through uniform energy prices and the dispatch that the IESO requires of generators and some consumers to recognize the limitations on the transmission system. In real time, the commercial impacts of this mismatch are addressed through congestion management settlement credits (CMSC) that result in dispatchable participants receiving constrained-on or constrained-off payments when they are asked by the IESO to operate in a manner that differs from their price-based preference. CMSC payments are critical components of our uniform-price market design as they remove impediments that would otherwise exist to forward contracting between generators and consumers. Without CMSC payments, the dispatchable generator that struck a contract to sell a specific volume to a consumer would be exposed to significant risks of not being able to generate the agreed-upon volume but still being responsible for delivery to the consumer, thereby having to purchase the missing production from the spot market. By receiving CMSC payments, the generator receives revenues sufficient to cover the replacement cost for the missing volume. In terms of impacts on forward contracting, CMSC payments are analogous to Transmission Rights contracts in a locational pricing model. With this level of protection, it would seem that the real-time CMSC payments should be sufficient to address the risks of the generator entering a day-ahead financial position, and that Ontario's current uniform price model should not be a barrier to developing a day-ahead market that creates financial obligations based on the unconstrained day-ahead perspective. However, the 2004 DAM initiative included significant complexity to address this possible risk, and hence this issue will require further analysis before it can be definitively answered. This analysis will be discussed with stakeholders in the weeks to come. Also, when discussing the uniform price methodology, some recognition must be given to the potential for future change. As discussed with both SAC and Market Pricing Working Group, the IESO is continuing to improve our ability to analyse the economic efficiency differences between the uniform pricing model and pricing models that better reflect transmission congestion. While this work is proceeding at a measured pace, the possibility of future change leads to a preference for a least-regrets approach and reinforces the preference for lower-cost, lower-complexity alternatives in the short term.

The second factor is related to the impacts of OPA contracts, the OPG rebate and the Global Adjustment. There are a significant number of contractual and regulatory commitments that both generators and consumers (via the OPA) are currently locked into and that flow through to real time – about 80% of supply is currently settled under contract or regulated rates against HOEP with the financial differences being passed to consumers via the Global Adjustment or OPG Rebate. For the majority of baseload producers, fixed price contracts or regulated rates have resulted in the operators of these facilities being indifferent to market prices. These fixed prices result in a large amount of baseload supply being made available to consumers at known and constant prices, thereby dampening the volatility of their bills. It

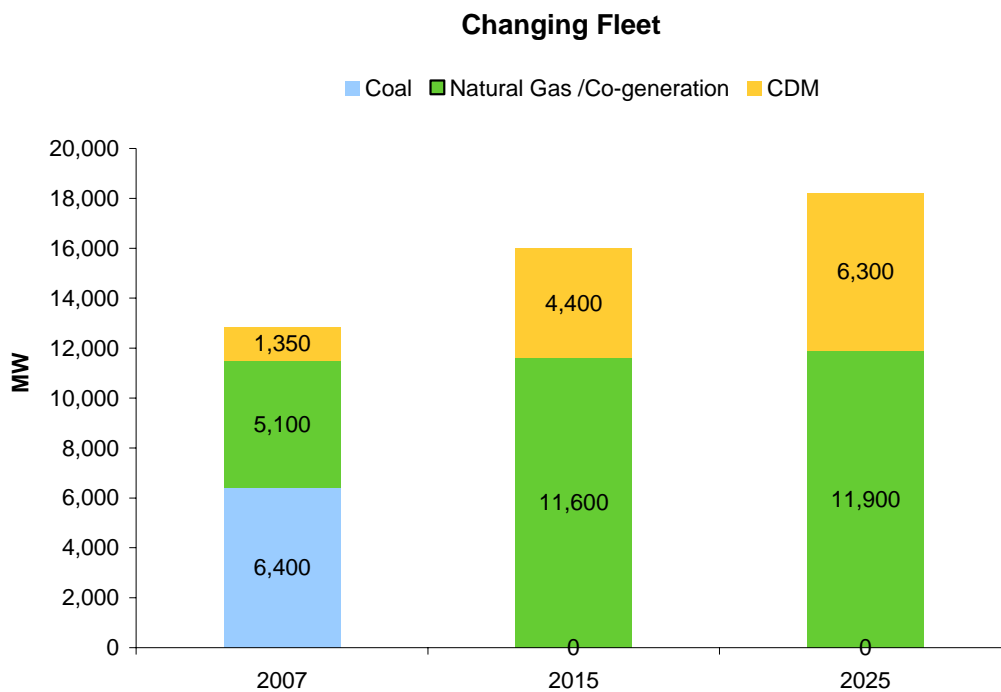
also could cause the operators of such generators to have little or no interest in market signals, including day-ahead hedges against HOEP. Consumers are currently hedged to a large extent through the Global Adjustment/OPG rebate, and have no active risk management decisions being made to address their remaining price risks. Alternatives to this latter concern about the lack of forward risk management for consumers are currently being explored by the OPA through their consultation on load serving entities (LSEs), but at the current time there are few Ontario participants on either side of the market who are motivated to address real-time price volatility. In other jurisdictions with functioning day-ahead markets, the day-ahead prices are typically the prices against which forward contracts clear. With forward contracts having cleared the day ahead, both producers and consumers are able to take on day-ahead market commitments that serve to anchor the next-day's physical operation and provide assurances to the ISO that the system will be operated in the most efficient and reliable manner possible. In Ontario's context, any financial commitments based on unconstrained prices and volumes would be less effective at anchoring the next day's operation, however, the results would still be critical to create the best possible picture of tomorrow's operation, thereby permitting the IESO to perform an effective 24-hour optimization to drive efficiency, and create the best dispatch advisories possible for use by generators in planning their next day's operations. While many of the OPA supply contracts contain provisions to address the creation of a day-ahead market, the transition of all current contracts and regulated settlements to a day-ahead basis would be complex.

For any day-ahead mechanism to be successful, its design must recognize the two factors of uniform price and impacts of OPA contracts. The IESO has attempted to do this in the work presented here. However, the full effect of these factors must be further explored through broad stakeholder review and discussions on specific issues. It is through the discussions over the coming weeks that the eventual course for day-ahead enhancements to the IESO-administered markets will be charted.

Section 2 – Approaching Opportunities and Challenges for the Energy Markets

As we look to the future, the Ontario generation supply mix is undergoing tremendous change. With 85% of current generation due to retire by 2025 coupled with growth in demand, Ontario will be making significant changes to our supply mix.

The figure below contrasts Ontario's current supply with the supply for coal, natural gas and conservation/demand management anticipated by the most current Ontario Power Authority planning documents. These changes will bring a new mix of operating characteristics and a variety of challenges and opportunities.



Approximate values

Conservation and Demand Response

Conservation and Demand Response are important parts of Ontario's strategy to replace generation that would otherwise have to be built. The OPA long term supply plan calls for an additional 430 MW by 2010 and 1,637 MW by 2025. Conservation refers to reduced consumption through conservation measures such as increasing air conditioner set points. Demand Response is also important in managing the balance between supply and demand and involves shifting consumption to off peak periods, particularly when there are strains on the system such as during heat waves. For example, running dishwashers in off peak hours will flatten the peak and reduce the need for peak load generation.

The IPSP (Integrated Power Supply Plan) targets represent a challenge to Ontario and the energy markets. Consumers need access to appropriate information to drive appropriate conservation and demand response decisions. The installation of time of use meters (smart meters) in Ontario will provide retail customers with the opportunity for time of use billing. This will pass on savings from demand response programs back to consumers.

However, even customers who currently have time of use meters and pay real-time prices face challenges in responding to price signals. The current real-time price is only available after the end of the hour. Consumers must decide on their response based on their expectation of price rather than on an actual price for the upcoming period. The IESO does not currently publish a price forecast as such for consumers to use for decision making. The inputs to the pre-dispatch runs are different than those to the real-time process so as to create an output that signals to producers and importers about the operation needed to reliably operate the system in the coming hours. The pre-dispatch prices were not designed to be estimates of real-time prices and in fact do not provide such a forecast.

Demand response and conservation should be improved by providing consumers with accurate price signals in advance and in particular a day in advance so that decisions can be made with certainty.

Distributed Generation

Distributed Generation is expected to increase in the future. It has been identified by the OPA in their supply plan as a type of conservation and demand response, and is identified in IPSP discussion papers as an important contributor to meeting future needs. It is typically thought to include smaller generation sources such as standby or emergency power, combined heat and power (CHP), and small-scale renewable energy (photovoltaic, wind and biomass), but can more broadly include any generation that is and is either connected to the distribution system or located within a customer's facility. As such, distributed generation is unlikely to be registered in the IESO-administered market and dispatched by the IESO.

This form of generation often has a contract to operate during certain hours, but is free to operate when economic in additional hours. Without an accurate price forecast, it is very difficult for these generators to decide when it is appropriate to run outside their contract hours. This uncertainty can lead to inefficiencies - times where it would have been more economic to utilize their energy than an alternative

such as an import however without accurate information; the distributed generator will have difficulty identifying these opportunities.

Since such generators are not dispatched by the IESO and therefore would not receive dispatch advisories or any cost guarantees, better day-ahead price information could play a key role in providing the signals needed to operate these facilities economically.

Changing Supply Mix – Unit Commitment and Natural Gas/Electricity Coordination

The changing supply mix includes an increase in supply from gas fired generation. This generation will largely replace the current coal fired generation. Comparing the two technologies, typically gas fired generation has more limited maneuvering ability than coal generation does. In particular, minimum outputs are a higher percentage of total output. While a 500 MW coal unit may have a minimum output of 100 MW, a 500 MW gas fired unit could have a minimum output of 300 MW. The higher minimum makes the decision to commit a gas unit (commit = synchronize to the grid and bring to minimum output) much more significant. Not only is the financial implication larger, but it means the unit must be allowed to operate at least at its minimum output level. With larger minimums, start ups must be carefully planned to ensure there is sufficient demand to consume the output from the unit. This means added complexity in scheduling generation to follow changes in demand.

The IESO is confident that we can maintain reliability while accommodating these unit characteristics however, there is an issue of efficiency. There are significant unit commitment costs associated with these high minimum outputs and the current Day-ahead Commitment Process does not undertake a full economic assessment of the start up costs. Instead, the DACP only looks at incremental energy offered rather than total cost when deciding which units to commit. With the current fleet, this shortcoming of the DACP results in inefficiencies on the order of only several million per year, however as the size of the gas fleet grows, so too will the cost of this inefficient commitment process.

Other jurisdictions with energy markets that manage a large gas fuelled fleet employ a day-ahead market mechanism to optimize their commitments.

Beyond the unit commitment issue, gas fired generation creates challenges for fuel management. Coal-fired generation can carry large supplies of fuel on site. Gas generators obtain their fuel in real-time and in competition with other consumers. With uncertainty in fuel requirements, this creates challenges for the gas generator which include:

- Most gas trading activity is done day-ahead.
- Real time gas trading does happen but there is usually a significant price premium for gas purchased day at hand compared to day-ahead.
- Gas delivery is also scheduled with the pipeline owners day-ahead.
- The “gas day” for planning/scheduling purposes is from 10am to 10am, which does not match the electricity industry, which uses a calendar day.

While it is possible for gas generators to alter delivery of gas in the day at hand, it involves higher fuel costs as both increasing and decreasing fuel supply from the day-ahead projection involves costs. This places business risk on a gas generator if they have uncertainty day-ahead as to their real time operating level. This business risk must be reflected in energy offers as higher marginal costs. With a clearing price market, these higher costs affect all energy when gas is setting the price in Ontario.

The current real-time market does not provide gas generators with any guarantee beyond their minimum output level established during the day in advance time frame. Advisories of real-time quantities produced in the day-ahead time frame are only indicative and are not sufficiently accurate to mitigate the risk associated with gas purchasing and scheduling. The inaccuracies have many sources, but one key source is the lack of exports in the DACP. On many days in the past year exports have represented 2,000 MW or more of additional demand in every hour of real-time. This creates a large gap between DACP advisories and real-time schedules. These inaccuracies in the current day-ahead projections make it difficult of gas generators to minimize their marginal costs.

The contracts signed between the Ontario Power Authority and gas generators were created recognizing the inefficiencies of scheduling gas generation in real-time. Because it was assumed efficiencies could be gained through a DAM, these contracts contained provisions that allow for deeming calculations to be based on day-ahead prices if the IESO creates a DAM. This could result in lower overall cost to consumers, reflecting a lower level of gas purchasing and scheduling risk for these contracted generators.

These contracts include recognition of when gas generators contracted with the OPA are “deemed” to be operating. This deeming uses the contracted heat rate, the hourly price of energy in Ontario and the cost of gas on the gas market to determine when a gas generator “should” be operating and earning revenue. This deemed revenue is considered when calculating any guarantee payments required under the contract.

With a real-time only market, the gas generators must anticipate which hours they will be deemed to operate when deciding on their operating strategy. With the imperfect information from the current DACP process, this introduces additional business risk on the gas generator which can impact their cost structure. As mentioned earlier, day-ahead advisories are not an accurate indication of real-time output.

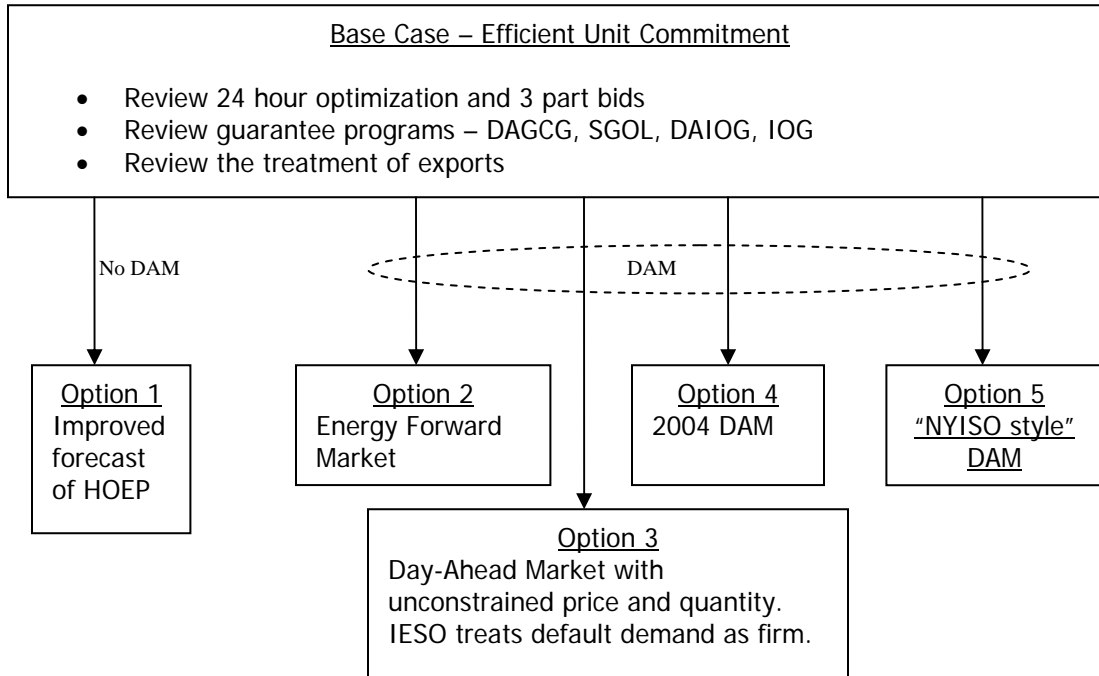
In summary:

1. The management of committing gas units with large unit minimums and associated start up costs presents a challenge to meet changing demand in the most cost efficient manner.
2. Additional costs involved in scheduling gas in real-time compared to a day- ahead time frame can impact marginal costs for gas generators

These challenges have been addressed in other jurisdictions through day-ahead scheduling provisions and day-ahead markets, and will be examined in these day-ahead discussions for both today's operation and in preparation for the increasing contribution by gas-fired generators to Ontario's supply mix.

Section 3 - Description of Alternatives for Improved Day-Ahead Mechanisms

The diagram below depicts the spectrum of day-ahead mechanism alternatives:



The previous effort on DAM in 2003/4 (Option 4 above) involved a design that minimized risks and potential gaming opportunities for participants with complicated day-ahead congestion settlement rules. Since that time, the IESO implemented the Day-Ahead Commitment Process and in that process addressed several complex interactions between DACP guarantees and the existing real-time congestion payments. Some of these interactions were unforeseen, were complex to analyse, and required last-minute settlement rule changes to address. Given that experience, the IESO believes significant effort would be required to ensure that the possibility of unintended interactions between day-ahead and real-time congestion settlement rules had been addressed, and it could in fact represent a significant challenge to a DAM design such as Option 4. However, this option was explored in great detail in 2004, and in fact draft market rule amendments were written at that time to enable the implementation of that DAM design. Hence, if it is determined that other simpler designs are not effective, then a solid starting-point exists for continuing to pursue Option 4 if the expected benefits are thought to be worthwhile. However, at this time, the IESO does not intend to explore Option 4 further, and will instead concentrate on simpler, less-costly designs.

At this point in the evolution of Ontario’s market, there is insufficient support for a shift from the current uniform pricing model to a locational-based pricing model (the basis for Option 5 above). The Ontario government recently examined a regional pricing model and concluded that it would not be pursued at this time. This may not rule out some form of future pricing model that accounts for transmission

congestion, and the IESO is taking steps to improve its ability to assess the efficiency implications of such a model in the future. In the mean time, the IESO is concentrating on exploring DAM designs that are simpler and less costly alternatives, and will assess the extent to which such designs impact on any future flexibility on possible pricing models that would lead to a DAM such as Option 5.

Two DAM models will be described below. Each model is assumed to be used in conjunction with a day-ahead commitment process to ensure reliability in the most efficient manner possible. One model (Option 2) is the voluntary energy forward market that was envisioned by the Market Design Committee in 1999 but never implemented; and the other (Option 3) is a DAM that uses the existing unconstrained algorithm and in which the IESO would forecast demand for all default consumers (retail), effectively moving the majority of consumers to a day-ahead price.

There is also an option presented that involves the IESO providing a day-ahead forecast of HOEP. This option is included because some stakeholders have indicated that they would not be likely to participate in a DAM, but an improved HOEP forecast would allow them to better plan their next day's production.

A description of Options one through three is included below.

Base Case – Efficient Unit Commitment

Whether or not the IESO proceeds with more comprehensive day-ahead mechanisms, the efficiency and effectiveness of the unit-commitment process in Ontario must be examined. After over a year of experience with the day-ahead commitment process (DACP), it is appropriate to examine the costs and benefits of the associated procedures and guarantees. It is worth investigating if modifications to existing protocols can deliver equivalent reliability in a more efficient manner, especially in light of the operating characteristics of gas-fired generators, which represent a growing component in the Ontario fuel mix. The following reviews will form the “base case” for any other day-ahead market evolution. Any more comprehensive approaches will be assumed to include:

1. A review of current guarantees in the day-ahead commitment process and real-time market,
2. A review of the scheduling protocols for the day-ahead commitment process (DACP), giving consideration to 24 hour optimization and 3 part bidding
3. A review of the current treatment of exports in the DACP

Review of the Day-Ahead Commitment Process

Review of Guarantees

As the market has evolved, the IESO has introduced guarantees to ensure the adequacy of supply to Ontario. Further evolution such as changes to the day-ahead commitment process, requires a comprehensive review of these guarantees to ensure that any market design changes would not adversely impact the intent or relevance of the guarantees. As a point of reference, the following describes the guarantees currently in use at the IESO.

Day-Ahead and Real-Time Inter-tie Offer Guarantees

Inter-tie Offer Guarantee (IOG) payments were introduced as a reliability measure to help ensure an adequate supply of energy in Ontario. They provide a “hold whole” mechanism that assures importers that their transaction will not receive a payment that is lower than their offer price in real-time. The IOG is available in both the day-ahead commitment process and real-time market.

Day-Ahead Generator Cost Guarantees

This guarantee lets eligible generators committed in the Day-Ahead Commitment Process recover certain costs called ‘combined guaranteed costs’. Combined guaranteed costs are fuel and incremental operations and maintenance costs incurred to achieve synchronization, to ramp output to minimum loading point, and then to run the generator for the minimum generation block run-time. The guarantee applies when these costs are not recovered through other market revenues. Participation is voluntary. The intent of the guarantee is to encourage generators that are required for reliability reasons to start their units even at times when the prospects for earning profits are poor. Under the program, generators

receive at least the cost associated with start-up and minimum run. The Ontario market benefits through the assurance that sufficient generation is committed to meet the next day's expected demand.

Spare Generation On Line (SGOL)

The SGOL program offers a guarantee of start-up costs and minimum run-time costs to eligible generators in the real-time market. This guarantee is offered in recognition of the fact that some fossil generators need to begin their start-up operations well before they know if their offers will be economic and scheduled in the real-time market. The intent of this guarantee, which is very similar to DAGCG, is to increase the availability of spare generation during off-peak and shoulder periods which helps to further increase grid reliability.

These guarantees will have to be reviewed pending the option chosen and report back on any suggested changes that would enhance their efficiency.

24 Hour Optimization and Three Part Bidding

Description:

Under the current DACP, generator commitments are based on the results of a day-ahead pre-dispatch run. Generators are scheduled to economically meet forecast load on an hourly basis. Each hour of the dispatch day is considered separately. The lowest cost solution for each hour is determined, independent of the remaining hours of the dispatch day.

Generators submit single-part offers for incremental energy only. Generators are expected to reflect their commitment costs in these incremental energy offers. This approach can pose a challenge to generators, as start-up and minimum load costs cannot be included in the energy offer without knowing how many hours the generator will run for. To encourage generators to offer capacity day-ahead and to increase the likelihood that generation selected day-ahead will be available in real-time, the market provides a day-ahead generator cost guarantee. This guarantee ensures that generators designated by the IESO in its DACP will recover costs associated with start-up and minimum load operation for a minimum time. Generators that fail to recover start-up and minimum run costs through real-time revenues are eligible to receive a top-up payment. The payment is based on costs incurred to meet the day-ahead guaranteed schedule, less any market revenues that were earned. Payments are funded through uplifts to consumers, with costs being submitted by generators after-the-fact. These commitment costs are not considered by the IESO's pre-dispatch algorithm when unit commitments are made. By scheduling resources based on single-part, energy-only offers, and then paying uplifts based on a measure of generator costs that includes start-up and minimum load costs, the IESO's hourly optimization does not reflect the complete cost that is ultimately borne by Ontario consumers.

Implementation of three-part bidding within the DACP would allow the IESO to consider the total cost associated with generator offers: start-up, minimum load, and minimum generation block run-time. By

including these costs when determining day-ahead schedules and commitments, the IESO's algorithm could produce a solution that is more reflective of costs that will be incurred in real-time.

With 24 hour optimization, a least-cost solution is produced for the entire day, rather than for 24 individual hours. Multi-part bidding is essential to perform this assessment, as it allows for the dispatch algorithm to recognize the costs associated with generator starts, minimum run-times, and other hour-to-hour constraints such as ramping limitations. For example, a generator that appears economic in a single hour may in fact be a more expensive choice due to a minimum run-time that lasts several hours. Constraining this unit on for hours when it would otherwise be uneconomic may produce a higher-cost result for the day. In contrast, it may be beneficial to schedule a different (higher energy offer) resource for the single hour, avoiding the cost of the unit's minimum run. The present pre-dispatch algorithm does not make this assessment.

Opportunity:

Three-part bidding with 24 hour optimization would allow for an algorithm that would co-optimize energy and operating reserve over a 24-hour period rather than on an hourly basis. An optimized solution would be produced using offers and bids submitted for energy and operating reserve.

Three-part bids (or offers) would enable generators to more accurately reflect the cost of unit commitment, as well as the incremental cost of providing energy. The three parts of the offers would include start-up costs, the cost to maintain a minimum loading point for a minimum time, as well as incremental energy.

Three-part bidding with 24 hour optimization could be used as part of a day-ahead market design, or as an enhancement to the day-ahead commitment process (DACP) in use today. However, if it is incorporated into DACP only, then the practicality of optimizing unit commitment to meet a demand that does not include significant export volumes will have to be addressed.

What are the benefits of 24 hour optimization and three part bidding?

- ***Improved Market Efficiencies***

With 24 hour optimization, the daily commitment decisions would be based on calculating the benefit of all offered units to the system on the basis of their total net value to the system while meeting the load forecast reliably (including imports and exports), while taking account of transmission constraints (i.e. the DACP commitment would be based on a constrained model, although prices would be determined in an unconstrained pass). Whether it is cost-effective to secure an import or use dispatchable load versus start up a generator and make it available for dispatch depends on the prices and scheduled quantities over the multiple hours and services for which the generator is committed, not on the prices in any single hour or for any single service. With implementation of 24 hour optimization, the relative costs of energy limited resources, non-quick start generation, dispatchable loads, other generation facilities or imports are considered over

the entire day. The optimal solution is the one that maximizes the economic gain¹ from trade across all hours using all generator costs (including cost guarantees) while meeting the load forecast reliably through a security commitment analysis. The implementation of 24 hour optimization would therefore result in more efficient (i.e. lower cost) commitment of units compared to hourly optimization and a reduction in uplift costs (which are borne by consumers). With knowledge of total costs (energy and associated start-up costs) dispatch efficiency is improved. As well, price signals more reflective of market conditions should result.

While three-part bidding and 24 hour optimization will allow a generator to submit offers that more closely reflect its actual cost structure, this will only occur and lead to desired improvements in efficiency if generators have an incentive to submit offers that reflect their costs.

- ***Improved Operational Stability***

With 24 hour optimization, resources are scheduled recognizing requirements over the day. The multi-hour view may reduce the number of start/stop sequences that units are exposed to, which could result in less wear and tear on the units, and an increase in overall unit availability.

- ***Improved Market Transparency during Unit Commitment***

“When making multiple hour commitment decisions, knowing guaranteed costs upfront fosters equitable treatment to all offers, allows an expression of underlying economics and preferences of the offers and encourages competition amongst all sources of generation, imports and dispatchable loads. In an environment of centralized unit commitment with co-optimization of energy and reserves, three-part bidding is desirable because it enables generators to express all components of their costs (start-up, no-load, and energy) directly.”²

As well, the need for manual intervention to meet non-quick start generation multi-hour restrictions not recognized in the current hourly pre-dispatch day-ahead commitment process will be eliminated promoting transparency in dispatch decisions.

Reviewing the Treatment of Exports in the DACP

Stakeholders consistently note that Ontario’s day-ahead price signals have significant room for improvement. Often, day-ahead price signals, including the prices from the day-ahead commitment process (DACP), are not reflective of market conditions expected in real-time. There are several systematic differences that contribute to this disconnect. Specific to DACP, a significant factor is the exclusion of exports. Considering Ontario demand and not market demand contributes to DACP and

¹ Defined in the Market Rules as: “Maximising the economic gain from trade will determine quantities and prices that “clear the market,” in the sense that, given the market-clearing prices and the *dispatch data*, no *market participant* would be economically better off (in terms of the *dispatch data* it submitted itself) producing or withdrawing more or less than the market-clearing quantity of any physical service.”

² United States of America before the Federal Energy Regulatory Commission, New England Power Pool) Docket No. ER00-2016-000 Affidavit of Peter Cramton April 13, 2000.

real-time pricing differences. An accurate picture of day-ahead market demand would improve day-ahead price signals.

The day-ahead commitment process is intended to reliably meet Ontario forecast demand and reserve requirements. Export transactions do not serve Ontario demand. Therefore, one might question the need to include exports in a reliability based day-ahead process such as DACP. However, excluding export transactions can result in the commitment of fewer resources than what is actually needed in real-time to most efficiently meet both Ontario demand and real-time scheduled exports. During the initial implementation of DACP, some market participants indicated a preference to consider exports and thus market demand in the day-ahead commitment process. Others suggested that there was not a sufficient reliability rationale for this.

While it appears unlikely to IESO staff that the inclusion of exports in DACP is feasible, a review of DACP enables further discussion of this topic at this time.

Option 1 – HOEP Forecast

While the IESO currently publishes the results of our pre-dispatch process, including prices, this was never intended as an accurate forecast of real-time price (HOEP). These pre-dispatch results are intended to signal evolving market conditions as the real-time dispatch hour approaches. Prices associated with the DACP's pre-dispatch of record do not forecast day-ahead price, but are utilized when making day-ahead commitments of generators and imports. There are several differences between the calculations of real-time prices and pre-dispatch prices. The main differences are:

- the treatments of import and export transactions – The real-time price is calculated every five minutes and uses only the offer/bid prices of suppliers/consumers that can change output/consumption in that timeframe. Imports and exports, which are arranged ahead of time and fixed for the hour, cannot be changed in a five minute timeframe. Therefore, those offers and bids are unable to set price in the real-time price calculation – although their scheduled quantities are a part of the demand to be met by the market
- demand used for the calculations – There are two differences between the demand used in the pre-dispatch and the real-time price calculations. Absolute errors in total forecast and the use of hourly peak versus average for the forecast hour both prevent convergence of pre-dispatch and real-time prices.

Recent market surveillance panel reports have highlighted the persistent gap between pre-dispatch price and real-time HOEP. The pre-dispatch price is not an accurate predictor of real-time HOEP. “Inaccurate or unreliable pre-dispatch prices can lead to inefficient production decisions and can cause real-time scheduling inefficiencies.”³ This concern of the MSP has also been expressed by some members of the stakeholder community who have told us that they could make use of a better forecast of HOEP to properly plan their production for the next day.

A day-ahead market, with the expected convergence of day-ahead and real-time prices, should provide a more accurate forecast of HOEP. However, if a DAM is not implemented at this time, it may be prudent to investigate methods to provide a forecast of HOEP.

There are mixed views on whether the IESO should be forecasting prices in the market it operates. This will be a subject of discussion in the coming weeks. However, in that the pre-dispatch results are viewed by many as such a forecast, the IESO's initial position is that providing what most would consider as “an improved forecast” would be an improvement. As is true with the current pre-dispatch price calculations, any use of forecast prices by participants would be at their own risk, as risks of contingencies or changing demand forecasts would still exist.

³ Market Surveillance Panel Report November 2005 – April 2006, Ontario Energy Board

HOEP Forecasting Methods

One forecasting method would be to use another run of the day-ahead pre-dispatch algorithm that accounts for some of the known influences that prevent price convergence between the current pre-dispatch run price and the real-time price. This would include adjustments such as:

- some forecast of real-time intertie transactions
- treating intertie transaction volumes as non dispatchable (price taking)
- adjustment of Ontario demand to more closely follow the demand seen by the real-time price setting algorithm.

Another method would make use of a separate price forecasting model based upon econometrics, which would make use of the information available to pre-dispatch, as well as historical trends and other factors. This model or extra pre-dispatch would be run once some time during the day-ahead and the resulting price forecast published.

Combinations of the two approaches are also possible. In any event, the forecast would be produced using a pre-defined algorithm using defined inputs rather than being performed or significantly influenced by the judgement of an IESO staff member.

Option 2 – Voluntary Energy Forward Market

Some stakeholders have indicated that Ontario's real-time-only market does not promote forward trading. This leads to a market that lacks liquidity, limiting long-term arrangements and risk management options for some market participants. In the absence of a more comprehensive physical DAM, these concerns could be addressed through an Energy Forward Market, which would operate separately from the existing pre-dispatch process as well as the DACP process. Basic features could include:

- Simple financial market - supply offers and demand bids
- Voluntary participation
- No constraints of any kind
- No tie to the physical market
- One price, no intertie zones or operating reserves prices

Such a market could resemble the IESO's Energy Forward Market (EFM) that currently exists in the Market Rules but has never been implemented, or a market run by another entity.

An energy forward market is described in Chapter 8 of the Market Rules. It is a clearing-price auction, for each hour of the next day. Suppliers cleared in the EFM are paid the difference between the EFM price and the HOEP, multiplied by their cleared quantity, for each hour. Consumers cleared in the EFM pay the difference between the EFM price and the HOEP, multiplied by their cleared quantity, for each hour. The settlement equation for a particular EFM participant in a particular hour is shown here:

$$\text{NFMSC} = \text{FMQS} \times (\text{FMP} - \text{HOEP})$$

Where:

NFMSC = net forward market settlement credit

FMQS = energy forward market quantity cleared (positive for supply, negative for demand)

FMP = energy forward market price

There are no physical limitations considered by the EFM as it is a purely financial market. Offers and bids into the EFM have no connection to actual facilities. Also, the EFM offers and bids are submitted separately from offers and bids for pre-dispatch (DACP), so a facility owner or intertie trader can provide different inputs to the EFM and DACP.

While the EFM is already included in the Market Rules and would be fairly easy to activate, further analysis of this option would be required to ensure that it would be of value. The IESO's current discussions have led us to question the value of this sort of voluntary market. Participants in such a voluntary market would be entering the market with their own expectations of a reasonable price, and are therefore likely to be engaged participants. Such participants already have opportunities to trade

day-ahead via broker-facilitated over-the-counter markets and through third-party exchange platforms. Hence, the added value of a voluntary EFM would have to be explored.

An issue that would need to be explored with this model relates to prudential requirements, which may be at least partially duplicated, i.e. collateral required to be supplied to both the real-time market and to the EFM. It may be possible for there to be some coordination between the real-time market and the EFM to reduce/eliminate this duplication.

An entity other than the IESO could operate an EFM-style market for electricity in Ontario. This opportunity has always existed, and to date such a model has not flourished. It may be possible for the IESO to encourage this model by adopting rules that would facilitate cleared positions from a third-party EFM to be submitted to the IESO, and allow these positions to be netted against the real-time market. This possibility would have to be examined further if it is thought to provide value.

Option 3 – DAM with Unconstrained Price and Quantity

Introduction

The key feature of this model is that it would create a day-ahead market that would provide day-ahead price and quantity commitments to all participants, and it would provide improved dispatch advisories to dispatchable participants. This model proposes to accomplish this without introducing locational pricing or complex day-ahead congestion (CMSC) calculations. The day-ahead price and quantity would be from the unconstrained algorithm, with the IESO forecasting default demand (for all consumers not actively participating in the DAM), ensuring that the consumption side is well represented in the DAM.

This DAM would provide advance price signals to better enable demand response and embedded or distributed generation. The settlement of this design for participants with physical assets operating in real-time would be much like a financial EFM coupled with a DACP process. Gas generators would be able to secure gas and transportation based on the improved dispatch advisories and possibly on the deemed operating pattern being based on the day-ahead financial results. In total, the improved day-ahead price and operational certainty would provide opportunities to many participants for more efficient decisions, which should reflect themselves in overall savings to consumers.

One of the significant challenges listed in Section 1 of this report referred to the difficulty of creating an effective day-ahead market with a lack of active consumer representation given the industry structure in Ontario. This DAM option would address this issue in the near term by the IESO forecasting demand, and provide an opportunity for the market to transition over time to a model that would encourage greater buy-side participation in the market.

The following sections describe the proposed DAM design in more detail. Several DAM settlement examples are also included in the last section.

High-Level Description

The DAM (Day-Ahead Market) would use a constrained and unconstrained run similar to the current real-time market. The unconstrained run would be used one day in advance of operation to produce marginal market prices with co-optimization of energy and reserve in the absence of internal transmission constraints. The constrained run would also be run a day in advance to ensure that reliability needs will be satisfied in an efficient manner, and would produce physical schedules for energy and OR using co optimization that would be used for day-ahead commitment purposes. The market would produce hourly results for all hours of the next day. Timing regarding the closing of the bid/offer window and the availability of DAM results would have to be determined.

Importers, exporters, and speculators (often referred to as virtual traders in other markets), would all be able to participate in the DAM and would be able to set prices in the DAM.

Two-Settlement System

The two-settlement system for this market design is based upon a comparison between day-ahead unconstrained schedule and a real time quantity that is actually produced or consumed. Participants who are assigned a day-ahead position would be settled for their day-ahead unconstrained quantity at the day-ahead price. If they consume (or produce) that quantity in real time, they will have only paid (or be paid) based on the day-ahead price. Differences between the day-ahead unconstrained quantity and the actual energy consumed (or delivered) in the real-time market would be settled at the real-time price.

The current CMSC process would continue. Real-time constraint payments will keep participants whole to their real-time unconstrained position, eliminating the effect of real-time constraints (see examples). However, day-ahead CMSC payments would not be developed.

24 Hour Optimization

This DAM design would include 3 part bidding and 24 hour optimization to arrive at schedules (unit commitment decisions, import/export scheduling and potentially the timing of use of energy-limited resources), thereby significantly improving the efficiency of the DAM over the current DACP. The constrained run of the DAM would utilize all bids and offers, including imports and exports but excluding any virtual bids or offers, to produce advisories of the expected real time dispatch levels. For many, these advisory schedules would differ from the schedules produced by the unconstrained DAM algorithm, and are not financial positions or guarantees, but are expected to be good representations of actual physical operation, and hence of sufficient quality to help suppliers, dispatchable loads and exporters plan their next day's operation.

Including 24 hour optimization and three part offers from non-quick start generators would allow the IESO to make generator commitment decisions much more efficiently than is possible today. The total as-offered costs of committing a resource for its minimum run time and quantity would be considered in the commitment decision. These total costs would be weighed against other options which may have a higher single-part offer cost but when considered over a several hour period are in fact more economical. The scheduling of energy limited resources can also be optimized more effectively than today by using a multi-hour optimization, however there would be no obligation on the part of energy-limited resource owners to make use of this feature.

Production Cost Guarantees

The DAM will include production cost guarantees for resources that are committed to at least their minimum generation levels in the constrained run of the DAM. The guarantees would be similar in nature to those offered in the New York market, but modified to recognize Ontario's single price design. The details of how production cost guarantees will be calculated have not yet been determined, but several design questions will need to be addressed:

- Separate day-ahead and real-time guarantees?
- Day-ahead guarantee based on revenue from DAM only?
- Day-ahead guarantee based on revenue from DA and RT markets?

Consumer Participation

Currently, approximately 45% of the consumers pay a regulated price set by the OEB (RPP) that is fixed for six months at a time, with an accumulating variance so that over the longer term the cost to RPP consumers reflects the long-term average of real-time prices. A further 35% of the market does pay the real-time price that is passed-through to them by their LDC (Local Distribution Company) and do not typically interact with the IESO. For consumers in either of these groups to participate directly in any DAM, they would have to become IESO market participants.

This DAM option would move these consumers from the real-time price to the day-ahead price by creating a “default customer pool” for which the IESO would forecast demand. RPP would be based on the expected DAM prices instead of real-time prices and LDCs would pass through to their large embedded consumers the DAM prices instead of real-time prices. The large embedded customers would have the option of becoming IESO market participants. This would allow them to bid into the IESO markets, either DAM or real-time and therefore remove themselves from this default customer pool.

Wholesale consumers, and exporters, which represent over 20% of consumption, would be able to bid their load directly into the DAM. Under this DAM option, wholesale load would be assumed to be participants in the DAM. This includes the option of bidding out of day-ahead prices and consuming entirely at real-time prices. The market design would also allow wholesale load the option to be part of the default customer pool, consuming at day-ahead prices without the need to bid a specific quantity in the DAM.

By including a forecast of the default demand, these Ontario consumers are committed to a day-ahead price. The default customer pool would also be charged or credited through an uplift whenever the default pool real-time consumption varies from the IESO forecast. The net result is that all consumers would know their price for electricity for tomorrow, which would hopefully heighten awareness of consumers’ options and provide a greater potential for demand response.

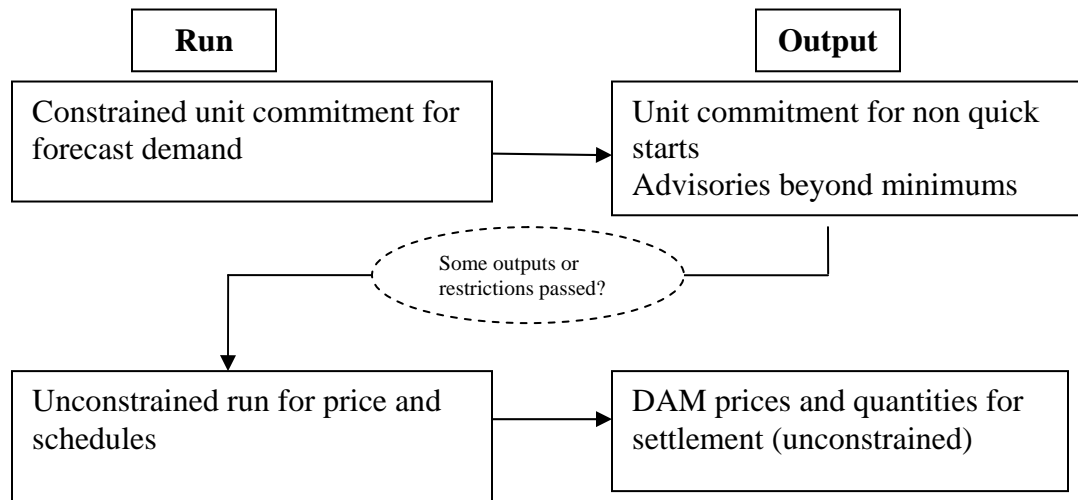
This migration to day-ahead prices should be an improvement over the current reliance on ex-post real-time prices. It is also a structure that would accommodate and benefit from any movement towards development of LSEs (load-serving entities). If LSEs were created for some portion of the default customers, the LSE would then act on behalf of those consumers and the IESO would no longer forecast their consumption. Eventually, the entire default pool could be taken over by LSEs, introducing commercially-motivated entities whose interests are sensitive to the impacts of real-time consumption through the two-settlement system would create the efficient financial drivers for the development of economic demand response programs. These drivers are currently missing in Ontario and as a result, are being compensated for by programs from the Ontario Power Authority.

Multi-Step Process

As mentioned above, the IESO would provide a forecast for default customers, and would also know what load quantities were bid by active DAM participants. There will however be load in the day-ahead forecast beyond these default and bidding customers. The IESO will continue to forecast total system needs, and will use this in the constrained runs to provide assurance that total system demand will be met the next day. However, the unit commitment costs incurred for the different groups of consumers could differ – there may be costs from committing additional non-quick start units, and providing an associated production cost guarantee for consumption that is not being included in the unconstrained pricing run. The details of how these costs are apportioned amongst the consumers are not yet determined. One possibility would be to only charge such additional costs to those consumers that had the ability to participate in the DAM but chose not to. While this may remove some cross subsidies between consumers and produce some added incentive for participation in the DAM that may not justify the increased design complexity required. This will have to be examined further.

An important objective of the DAM is to produce day-ahead schedules, unit commitments and advisories that are both achievable and as close to the expected real time results as possible given the constraints on the market design. There are some possible design features that could improve the alignment between the constrained and unconstrained DAM runs that will be examined in the coming weeks. Three options are described here:

1. Perform the day-ahead commitment run (constrained) prior to the unconstrained price/schedule run. The constrained run would first commit sufficient generation to reflect the forecast requirements for the next day. Any non-quick start generator committed through this process would be seen as a must run generator in the unconstrained run at their unit minimums.
2. Perform the day-ahead commitment run (constrained) prior to the unconstrained price/schedule run. Any non-quick start generator that is not committed through this process would be unavailable to the unconstrained run. This is similar to what happens in the real-time unconstrained run, where non-quick start generators are only included if they are synchronized to the system (breaker is closed).
3. Day-ahead commitment run and unconstrained price/schedule run are independent of each other.



Forecast Error

Demand forecast error in the day-ahead time frame can lead to a new potential cost or revenue related to the two settlement process that will need to be uplifted. Depending on the direction of the forecast error (high or low) and the difference between the day-ahead and real time prices, the two-settlement process could result in an accumulated revenue or expense associated with the day-ahead position taken for default consumers. Any variance, positive or negative, would have to be accounted for as uplift and applied to the default consumers. Wholesale consumers and exporters could avoid this uplift by taking their own day-ahead position. For RPP customers the uplift would, like energy charges, be transferred to the OPA managed RPP variance account.

Virtual Participation

Virtual positions are positions in the day-ahead market that are not tied to a physical meter or real-time intertie schedule. Their day-ahead positions are simply netted against real time prices using the two settlement system. Virtual participation allows participants to manage risks, while also driving price convergence between the day-ahead and real-time markets. Any systematic discrepancy between the day-ahead price and the real time price will represent an arbitrage potential that will be taken advantage of by the virtual participants and will drive price convergence. For example a market participant might buy virtual energy in the DAM if prices in the real-time market are expected to be higher. Conversely, one might sell virtual energy in the DAM if real-time market prices are expected to be lower.

Since virtual transactions only involve quantities transacted day-ahead, they have no impact on real-time system reliability. Virtual transactions allow more participants to actively participate in the IESO-administered markets, which will increase liquidity in the DAM. A more liquid market will tend to reduce price volatility and help bring DAM and real-time market prices closer together. This convergence of prices over time provides participants with a reliable price indicator to help make operational decisions and a stable forward price index for other markets.

The DAM interface could encourage liquidity in the forward market by being designed to allow third-party forward exchanges to close their remaining open positions directly into the IESO administered DAM as virtual participants. A potential advantage of acting as virtual participant over the use of the physical bilateral system is that the exchange would not need to supply balanced pairs of transactions between sellers and buyers. The issue of prudential requirements for the exchange would have to be worked through as part of the detailed design.

Demand Forecast

The demand forecast used day-ahead would be a crucial piece of this option. Currently the IESO demand forecast is used in the pre-dispatch and DACP process. This leads to unit commitments and associated guarantees and impacts the real-time price of energy in Ontario. In this option, the day-ahead price would be largely impacted by the quality of the IESO day-ahead forecast. One of the drivers for this option is to stimulate increased demand response. Until Load Serving Entities are created and bid on behalf of their customers, the IESO demand forecast would be critical. Currently the single largest variable in predicting demand a day in advance is the quality of the weather forecast. However, if the quantity of responsive demand increased, this would create a new variable for the IESO in forecasting demand a day in advance. It may become necessary for the IESO to predict default consumers response to price in the energy market in order to make an accurate demand forecast.

OPA and Government Contracts

Normally when a well-functioning day-ahead market exists, forward contracts are structured to settle based on the day-ahead price. As stated earlier, there are many centrally-held contracts and regulations in Ontario and each type will have to be examined in terms of the practicality and advisability of moving settlement to day-ahead prices. Generally, this model would benefit from, and may even require day-ahead contract clearing, as it would then free-up suppliers to be the counter-party to the consumers' day-ahead financial positions. With the IESO forecasting default demand and including that quantity in the unconstrained dispatch, there would need to be significant demand-side participation, requiring a corresponding supply-side activity.

The "CES style" contracts have provision in them to allow a change to the deeming methodology such that it would be based on DAM results if a DAM is implemented by the IESO. Many holders of these contracts have stated that they expect to be better able to manage their business if a DAM is implemented and this contract change occurs. The efficiency improvements in this mode of operation could lead to lower overall cost to consumers.

The practicality and potential implications of day-ahead clearing of fixed price, variable quantity contracts that the most baseload suppliers in Ontario operate under will have to be explored.

In all cases, further analysis will be required to ensure that inappropriate risks or incentives for the holders of existing contracts have not been created by the introduction of this DAM.

Examples of the Two Settlement System

A few examples of constrained on and off generator situations are included here. This is not a complete list of possible scenarios. Many more examples will need to be reviewed to determine if any inappropriate risks or opportunities exist.

The basic settlement formulas for a generator are:

Financial settlement = $(QD \times PD) - (QD \times PRT)$

Real-time settlement = $PRT \times DQSI$

Resulting Net Energy Settlement = $(QD \times PD) + PRT (DQSI - QD)$

CMSC = $(PRT - Offer) \times (QRT - DQSI)$

Where:

Day-Ahead Market

Unconstrained run results in day-ahead price and quantity:

PD = Day-ahead Unconstrained price

QD = Day-ahead Unconstrained quantity

Day-ahead constrained run results in:

DACP = Start-up schedule, min run, start-up costs, non-binding quantity

Real-time Market

Unconstrained run results in real-time price and quantity:

PRT = Unconstrained price

QRT = Unconstrained quantity

Real Time Constrained run results in:

DQSI = Dispatch quantity supplied

Example 1 - Generator constrained off, price constant between day-ahead and real-time runs:

DA and RT Offer = \$15

PD = \$50

QD = 100 MW

PRT = \$ 50

QRT = 100 MW

DQSI = 0 MW

$$\begin{aligned}
\text{Energy Settlement} &= (QD \times PD) + PRT (DQSI - QD) \\
&= (100 \text{ MW} \times \$50) + \$50(0\text{MW} - 100\text{MW}) \\
&= \$5,000 - \$5,000 \\
&= \$0 \\
\text{CMSC} &= [(PRT - \text{Offer}) \times (QRT - DQSI)] \\
&= [(\$50 - \$15) \times (100 \text{ MW} - 0 \text{ MW})] \\
&= \$3,500 \\
\text{Total Settlement} &= \text{Energy Settlement} + \text{CMSC} \\
&= \$0 + \$3,500 \\
&= \$3,500
\end{aligned}$$

Summary:

The generator is paid revenue based on a combination of day-ahead unconstrained quantity and real-time constrained (dispatch) quantity. Under this method the constrained off generator earns the same revenue as the current real-time only market. CMSC calculation accounts for the operating profit not earned relative to the RT unconstrained schedule

Example 2 - Generator constrained on, price constant between day-ahead and real-time runs:

$$\begin{aligned}
\text{DA and RT Offer} &= \$55 \\
\text{PD} &= \$50 \\
\text{QD} &= 0 \text{ MW} \\
\text{PRT} &= \$ 50 \\
\text{QRT} &= 0 \text{ MW} \\
\text{DQSI} &= 100 \text{ MW}
\end{aligned}$$

$$\begin{aligned}
\text{Energy Settlement} &= (QD \times PD) + PRT (DQSI - QD) \\
&= (0 \text{ MW} \times \$50) + \$50(100\text{MW} - 0\text{MW}) \\
&= 0 + \$5,000 \\
&= \$5,000 \\
\text{CMSC} &= [(PRT - \text{Offer}) \times (QRT - DQSI)] \\
&= [(\$50 - \$55) \times (0 \text{ MW} - 100 \text{ MW})] \\
&= \$500 \\
\text{Total Settlement} &= \text{Energy Settlement} + \text{CMSC} \\
&= \$5000 + \$500 \\
&= \$5,500
\end{aligned}$$

Summary:

The generator does not have a day-ahead position and is paid only for the real-time energy produced at the real-time price, as well as a CMSC credit for being constrained on. Under this method the constrained on generator earns the same revenue as in the current real-time only market.

Example 3 - Generator constrained off, price increases between day-ahead and real-time runs:

DA and RT Offer = \$15

PD = \$50

QD = 100 MW

PRT = \$ 55

QRT = 100 MW

DQSI = 0 MW

$$\begin{aligned}\text{Energy Settlement} &= (QD \times PD) + PRT (DQSI - QD) \\ &= (100 \text{ MW} \times \$50) + \$55(0\text{MW} - 100\text{MW}) \\ &= \$5,000 - \$5,500 \\ &= - \$500 \text{ (charge)}\end{aligned}$$

$$\begin{aligned}\text{CMSC} &= [(PRT - \text{Offer}) \times (QRT - DQSI)] \\ &= [(\$55 - \$15) \times (100 \text{ MW} - 0 \text{ MW})] \\ &= \$4,000\end{aligned}$$

$$\begin{aligned}\text{Total Settlement} &= \text{Energy Settlement} + \text{CMSC} \\ &= - \$500 + \$4000 \\ &= \$3,500\end{aligned}$$

Summary:

The energy settlement has charged the generator to replace the energy that it didn't produce by buying it from the market at the higher RT price. The CMSC calculation accounts for the operating profit not earned relative to the RT unconstrained schedule and RT price. The total settlement is less revenue than the current real-time only market would have provided.

Example 4 - Generator constrained off, price decreases between day-ahead and real-time runs:

DA and RT Offer = \$15

PD = \$50

QD = 100 MW

PRT = \$ 45

QRT = 100 MW

DQSI = 0 MW

$$\begin{aligned}\text{Energy Settlement} &= (QD \times PD) + PRT (DQSI - QD) \\ &= (100 \text{ MW} \times \$50) + \$45(0\text{MW} - 100\text{MW}) \\ &= \$5,000 - \$4,500 \\ &= \$500\end{aligned}$$

$$\begin{aligned}\text{CMSC} &= [(PRT - \text{Offer}) \times (QRT - DQSI)] \\ &= [(\$45 - \$15) \times (100 \text{ MW} - 0 \text{ MW})] \\ &= \$3,000\end{aligned}$$

$$\begin{aligned}\text{Total Settlement} &= \text{Energy Settlement} + \text{CMSC} \\ &= \$3000 + \$500 \\ &= \$3,500\end{aligned}$$

Summary:

The energy settlement has paid the generator to replace the energy that it didn't produce by buying it from the market at the lower RT price. The CMSC calculation accounts for the operating profit not earned relative to the RT unconstrained schedule and RT price. The total settlement is more revenue than the current real-time only market would have provided.

A Framework for the Application of a Cost-Benefit Analysis to Proposed Day-Ahead Mechanisms

Question and Answers

The IESO intends to apply cost-benefit analysis techniques in its evaluation of the various possible day-ahead designs and features. The following Q's&A's are intended to provide stakeholders with a better understanding of the cost-benefit analysis framework and how the IESO intends to apply it in the DAM stakeholder and decision making processes.

Q. What is cost benefit analysis (CBA)?

A. Cost-benefit analysis is a decision standard that is commonly used by policymakers to assist in determining whether a policy or project should be implemented. Governments and regulators in Canada and other countries make use of CBA to choose among policy options or at least to assist their policy decisions. Examples of government bodies that use CBA are the Ontario Energy Board⁴, the Canadian Competition Bureau, the U.S. Environmental Protection Agency, and the government of the UK.⁵

Q. How is CBA typically conducted?

A. In general terms, CBA involves first evaluating both the costs and benefits to individuals of a proposed project or policy (such as the implementation of a DAM) and then deciding whether the change should be implemented according to a particular decision rule that compares costs and benefits.

More specifically, CBA consists of the following stages of analysis:

- (i) A projection or forecast of how a policy change will affect individuals, both at the time of the change and for some time period into the future. This includes a projection of how individuals are likely to respond to the policy change, and how the aggregated responses of all individuals will affect the key market variable such as prices, levels of consumption and levels of production. CBA monetizes the effects of a policy change on individuals in order to facilitate comparisons with the status quo or with other policy options. The monetization of the effects on individuals can involve a wide range of tools and methods and, depending on the project, can require highly specialized skills and expertise. One particular method

⁴ Ontario Energy Board, "Development of Filing Requirements for Transmission Infrastructure Investment (EB-2005-0470)", Staff Discussion Paper for Technical Advisory Team.

⁵ See "Overview of Cost-Benefit Analysis and its Applications in Public Policy Decisions," by Michael Trebilcock, Adonis Yatchew, and Andy Baziliauskas. (Add cite to our web so readers can find the paper)

commonly applied is the concepts of consumer and producer surplus.⁶ If an individual is made worse off by the policy change, the individual's losses are treated as a cost of the change. If an individual is made better off by a policy change the individual's gains are treated as a benefit of the policy change. Costs incurred and benefits realized into the future are made comparable by calculating their present value.

- (ii) The present value cost and benefits of all individuals affected by the policy change are then aggregated into total present value costs and benefits. The present value of the total benefits is compared to the present value of the total costs. The comparison also requires consideration of non-market costs related to the policy change – specifically the cost incurred by any individual of implementing the policy change. The comparison of costs and benefits inform the ultimate decision to proceed with the policy change.

Q. Does a project have to benefit all individuals to pass a CBA decision rule?

- A. No. CBA recommends policy changes that provide an overall net benefit to the province as a whole. The welfare impacts of the policy change on different classes of individuals may factor in the decision later, particularly if there are programs or mechanisms available that can be used to facilitate or ease the transition for those individuals made worse off by the policy change.

Changes in policy or regulation almost always create both 'winners' and 'losers'. If the decision criterion for approving policy change is that no individual is to be made worse off, such a decision criterion is likely to prevent the implementation of many projects that most people agree would clearly be socially desirable.⁷

A less restrictive decision rule and the one that forms the basis of modern CBA, is the Kaldor-Hicks criterion. This criterion is usually stated as requiring that a change be approved if the winners from the change could hypothetically compensate the losers and still be better off. More accurately, the change is approved if the gains to 'winners' exceed the losses to 'losers', such that the change creates benefits that are sufficiently large to offset the losses. This criterion does not require that losers are actually compensated to accept a change; it only requires that the overall gains are such that "winners" could theoretically provide compensatory transfers to other parties to make them at least as well off as before while themselves remaining better off than under the status quo.

⁶ The consumer surplus accruing to a consumer from the consumption of X units of a good is the difference between the maximum amount that the consumer would pay for the X units and the amount that the consumer actually pays. Consumer surplus can be measured using information from consumer's demand curve; it is measured as the area under the demand curve but above the price. Producer surplus is measured in an analogous manner, but using supply curves rather than demand curves. A supply curve shows the prices at which producers are willing to supply various units of output. The area above the supply curve but below the price is the producers' surplus. When the introduction of regulation changes the price received by producers or paid by consumers, the effect (either a cost or a benefit, depending on whether price decreases or increases) is measured as the change in producers' surplus or consumers' surplus.

⁷ This is essentially the Pareto criterion. A change is said to be a Pareto improvement if at least one individual is made better off by the change and no one is made worse off.

The Kaldor-Hicks criterion forms the basis of modern CBA. If winners gain enough from a project to compensate the losers while remaining better off, we can say that gains exceed losses. In other words, if the present value of the total benefits exceeds the present value of the total cost plus any implementation costs, the policy change is said to satisfy the Kaldor-Hicks criterion.

Q. What is the relationship between CBA and efficiency concepts?

- A. CBA recommends policy changes that are economically efficient. In other words, a policy change has positive net benefits to the province as a whole (satisfies the Kaldor-Hicks criterion) if it improves economic efficiency.

There are three broad concepts that are commonly used by economists to evaluate whether an outcome is efficient, namely allocative efficiency, productive efficiency, and dynamic efficiency. In order for a policy change to satisfy the Kaldor-Hicks criterion within a CBA, it must lead to an enhancement in the allocative, productive and/or dynamic efficiency of the market.

- Productive efficiency is defined as using the least amount of resources to produce a given good or service. In other words, output is being produced at the lowest possible unit cost. A process that uses more of any input – labour, capital, or land – than the minimum needed to produce the given level of output suffers from productive inefficiency.
- Allocative efficiency is the market condition whereby resources are allocated in a way that maximizes the net benefit attained through their use. A market will be allocatively efficient if:
 - (i) Output is produced by the lowest cost producers; and
 - (ii) Output is consumed by those most willing to pay for it and only when its value to the consumer is at least as great as the incremental cost of its production.
- Dynamic efficiency relates to efficient technology choice and timely and efficient capacity investment decisions both on the supply side and the demand side of the industry. Dynamic efficiency deals with the evolution of a more efficient mix of resources for the market over time.

Q. What is the IESO's purpose for applying CBA in the evaluation of the various possible day-ahead designs and features?

- A. Before the IESO recommends proceeding with the implementation of a particular day-ahead design and or features, it wants to establish that there is a sound business case for doing so. CBA will provide an input into this assessment. In particular, the IESO wants to ensure that the implementation of a day-ahead mechanism will bring positive benefits to the Province as a whole and that these benefits will exceed the cost of creating and implementing the mechanism.

Q. Does the IESO plan to complete a detailed CBA before it seeks the IESO Board's approval to proceed with a detailed design phase of a particular option in 2008?

A. The IESO expects to complete a high level CBA of each of the proposed day-ahead design options by the end of 2007. The high-level CBA will allow a ranking of the likely net benefits (cost) of each of the proposed options and will provide guidance as to which of the proposed options, if any, to recommend for detailed design and subsequent implementation. A more detailed CBA of the preferred option will be completed by the time that the IESO seeks final approval for implementing the preferred option.

As discussed above, in a standard CBA, a policy change will have a positive net benefit for the province as a whole if it leads to improvements in allocative, productive or dynamic efficiency. Therefore, as a first step towards conducting a CBA for the different day-ahead options, the IESO intends to focus its study towards understanding and to the extent possible, quantifying how each of the day-ahead options could enhance industry efficiency. Sources for potential improved efficiencies via day-ahead mechanisms include:

- Reduced generation cost (productive efficiency)
- Input cost savings at the individual consumer level (productive efficiency)
- More efficient levels of consumption or production (allocative efficiency)
- Reduced transactions cost due to reduced operational and consumption uncertainty (productive efficiency)
- Reduced existing barriers for long-term investment in generation or demand management technologies (dynamic efficiencies)

Through experience gained from other electricity markets and through its discussions with stakeholders, the IESO has identified five main areas in which improved day-ahead market mechanisms could provide benefits to either suppliers or consumers of electricity in the province and hence contribute towards improved industry efficiency. These include:

- Improved opportunities for demand response
- Enhanced efficiency through efficient use of embedded generation
- Enhanced unit commitment efficiency
- Reduced transaction costs through improved coordination of natural gas/electricity operations
- Reduced cost of forward contracting

Through the fall, the IESO proposes to focus its study of the efficiency benefits of day-ahead market mechanisms on these five key areas. The IESO will also consider other main areas for potential efficiency gains or efficiency losses as identified by stakeholders. Attachment A to this document provides a more detailed description of the potential efficiency benefits attributable to each of these five areas and possible areas of study for estimating these benefits. The outcome of

these studies will provide the basis for the high-level CBA to be completed by the end of the fall. Not all of the proposed day-ahead options are expected to achieve each of the five benefits listed above. Consideration will be given as to which of the identified five benefits of day-ahead mechanism improvements each of the proposed options are likely to achieve.

Q. Does the IESO have all the data or information required to carryout the proposed analysis?

A. No. The IESO will rely heavily on stakeholders for information, data and analysis of how each of the proposed day-ahead options will affect their operations. In this regard, the IESO intends to solicit the assistance of knowledgeable individuals representing the various participant classes. It is hoped that these individuals will assist the IESO staff over the fall by:

- (i) providing advice on study methodologies (i.e., what to measure and how to measure it),
- (ii) providing individual firm level data or information where available or need to carry-out the analysis, and
- (iii) conducting firm level analysis of potential efficiency gains.

Additionally, the IESO may consider contracting consulting expertise if required.

The IESO intends to establish stakeholder/IESO staff working teams in early September for each of the five identified areas.

Attachment A

1. Improved Opportunities for demand response

Description: A day-ahead market mechanism that provides a price forecast one day in advance of the real-time spot prices would enable large industrial and commercial consumers to better plan their next day's consumption. The demand for electricity is more elastic one day prior to consumption than it is on the day of consumption. As noted in a recent study for the NYISO, "the demand curve in real time ... is steeper than the one for the day-ahead market."⁸ The elasticities are different because a customer that is participating in a day-ahead market and is provided with a day-ahead price notification has more time to make necessary adjustments to minimize the effect of a reduction in electricity usage compared to a customer that is informed of price only a few hours in advance of real-time. The types of adjustments a consumer can make are to shift consumption from high priced hours to lower priced hours, or to find alternative ways to produce its products, e.g. using alternative inputs or processes, that use less electricity.

The ability to lock into a day-ahead price will also provide large industrial and commercial consumers with another mechanism to hedge their real-time consumption and price risk. This will reduce transactions cost associated with managing price risk.

Furthermore, providing small commercial customers and residential customers with a day-ahead price notification or locking these consumers into day-ahead prices will facilitate increased demand response. Currently, a major impediment to the development of demand response is the lack or inaccessibility of advance price signals that would enable these customers to plan their daily consumption patterns in advance of real-time. As more of these customers are equipped with smart meters, more of the province's consumers will have the ability to respond to market prices.

Primary Efficiency Impacts

- Input cost savings at the individual consumer level (productive efficiency).
- More efficient levels of consumption or production (allocative efficiency).
- Capital cost savings due to reduced need for peaking generation (dynamic efficiency).

Secondary Impacts

Improved day-ahead demand response may provide other benefits within the Ontario electricity industry. These include:

- Reduced price volatility.
- Improved system reliability.

⁸ "How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSEERDA 2002 PRL Program Performance", Neenan Associates and CERTS (January 2003).

- Reduced need for resource adequacy mechanism and protections such as price caps or reliance on IESO control actions which would promote more efficient long-term investment via market signals.
- Reduced environmental emissions.
- Mitigation against potential market power concerns.

Areas for potential efficiency analysis

- Simulation and sensitivity analysis of possible production cost savings resulting from a changing load shape.
 - The increased demand response will lead to a change in the province's load shape. Using Ontario market data/information and elasticity estimates from other jurisdictions with electricity markets, the IESO would determine different load shapes that could evolve as a result of the day-ahead market. Market simulations could then be used to estimate the change in the production costs associated with meeting these load shapes.
 - To the extent that demand response reduces system peak demand, estimates of the avoided investment costs could be computed.

2. Enhanced efficiency through efficient use of embedded generation

Description: The number of embedded generators is likely to grow over the next ten years. These generators generally operate under fixed price contracts that induce the generators to operate in specified hours, typically peak demand hours. In these hours, the embedded generator's operation is not influenced by the real-time price; the generator responds only to the compensation provided by the contract. However, in those hours when the embedded generator is not compensated under the contract, the generator has an opportunity to earn additional revenues. If the generator injects electricity into the grid, the generator is paid the real-time price (HOEP) for the amount of electricity produced.

As a result of a volatile real-time price, it is a challenge for these generators to predict which hours the real-time prices will provide revenues above the avoided operating cost of the unit, i.e., when it is profitable to operate. If the embedded generator operates when prices are too low, it risks losing money. Often, the cost to the embedded generator of monitoring or forecasting real-time prices is too high so the generator does not commit resources to this activity - often when it would otherwise be efficient to do so. A day-ahead option that provides a day-ahead price forecast and possibly a day-ahead price and quantity commitment would reduce the risk of the embedded generator (reduce the cost of monitoring or forecasting prices) and may induce the generator to operate in the real-time market when its avoidable operating costs are lower than the real-time price (and hence lower than the operating cost of the marginal generators).

Primary Efficiency Impacts

- Reduced generation cost (productive efficiency).
- Reduced transactions cost due to reduced operational and consumption uncertainty (productive efficiency).

Secondary Impacts

- Provides environmental benefits when embedded generators with less environmentally harmful productions replace generation with more harmful environmental productions.
- Reduces price volatility.
- Improves system reliability.
- Reduces need for resource adequacy mechanism and protections such as price caps or reliance on IESO control actions which would promote more efficient long-term investment via market signals.

Areas for potential efficiency analysis

- Simulation and sensitivity analysis of possible production cost savings resulting from increased production of embedded generation.
 - This analysis would involve an estimation of the potential supply response function of existing and future embedded generators operating at market prices as a result of the day-ahead market. The supply response function would then be incorporated in market simulations to estimate the change in the overall electricity production costs.

3. Enhanced unit commitment efficiency

Description: Currently, generators with minimum loading points greater than 0 MW and minimum run times greater than one hour are eligible for a commitment guarantee in the Day-Ahead Commitment Process (DACP). The Generation Cost Guarantee (GCG) removes the financial risk associated with the day-ahead commitment by compensating generators who do not recover their commitment costs (start-up costs, speed no load costs and O&M) through real-time market revenues. Generators are eligible for the GCG if they are scheduled in the DACP for the length of their minimum run time. The GCG applies only to the minimum loading point quantity. Furthermore, a second unit commitment program called the Spare-Generation On-line program (SGOL) offers non-quick start generators with a second opportunity to minimize their commitment risk. If these generators are scheduled in any of the 3 hour to 1 hour ahead pre-dispatch runs, they are eligible to receive a cost recovery payment for start-up cost and speed-no-load costs for the minimum run time. Unlike the DACP, the unit does not have to be scheduled for the entire period of its minimum run time or even its minimum loading point.

For both of these programs, generators do not submit 3-part offers including offers for their variable energy cost, start-up cost, speed-no-load costs. Therefore, the DACP does not minimize the total cost of meeting load including these fixed operating costs. Instead, the program selects the units for commitment based on energy offers only where offers are reflective of marginal cost. This process likely results in an over commitment of generation and lost efficiencies: the total cost of meeting the load, including start-up and speed-no-load costs is higher than it would be if there were three part bids and optimization over all operating cost parameters. These costs appear in the market as higher uplift costs. Furthermore, since generators' start-up cost, speed-no-load costs and minimum run times are not

included in the optimization and hence do not influence generators' scheduling, generators are not influenced by competitive forces to minimize these costs when possible.

A day-ahead market mechanism with 3-part offers and optimization of all operating costs would improve the efficiency of dispatch and lower the current uplift charges. It would also provide additional competitive discipline with respect to ensuring that most economic units are committed.

Primary Efficiency Impacts

- Reduced generation cost (productive efficiency).

Secondary Impacts

- Reduced need for adequacy mechanism and promotes more efficient long-term investment.

Areas for potential efficiency analysis

- Currently, the IESO does not have a market simulation tool that can be used to estimate the potential cost savings from 24-hour optimization with 3-part bids. Efforts would have to be made to modify the existing tools to permit such analysis; however it is not clear that such a simulation tool could be developed within the time frame outlined in the stakeholder plan. Short of this, the IESO proposes to identify select days where over-commitment of units likely occurred under the current DACP. Using data for bids and offers on these days as well as submitted start-up, speed no load and minimum run-time data as part of the DACP and SGOL programs, the IESO would determine different daily scheduling outcomes. These outcomes would then be used to estimate the potential cost savings that could have occurred with 24-hour optimization and 3-part bids.

4. Reduced transaction costs through improved coordination of natural gas/electricity operations

Description: Currently, gas-fired generators are required to determine how much gas to purchase based on their own assessment of their expected dispatch. To the extent that they overestimate their dispatch, they will buy too much gas and likely incur losses reselling the gas in the intra-day gas market. Conversely, if they underestimate their dispatch, they will potentially be required to buy gas at much higher prices in the intra-day gas market. The transactions costs associated with these forecasting errors are reflected in the offer prices of gas-fired generators and ultimately in the cost of power to consumers.

If a day-ahead mechanism provides gas-fired generators with day-ahead schedules that are a better indication of each unit's real-time dispatch than the generator's own forecast of its dispatch, gas-fired generators will be able to better coordinate their gas purchases with their actual dispatch. This would reduce the overall cost of meeting demand. The day-ahead financial schedules produced by a day-ahead market provide a potentially valuable source of information for gas-fired generators in purchasing gas because the schedules are financially binding and available prior to the real-time dispatch. It is important that the day-ahead schedules be financially binding because the financially binding status

provides the hedge for suppliers when they incur costs in the day-ahead time frame based on these schedules.

Primary Efficiency Impacts

- Reduced generation cost (productive efficiency).
- Reduced transactions cost due to reduced operational and consumption uncertainty (productive efficiency).

Secondary Impacts

- Improved system reliability.

Areas for potential efficiency analysis

- Analyze the accuracy of the scheduling information currently provided by gas-fired generators through the DACP and postulate how this information could be improved through the different day-ahead options. With key stakeholder assistance, estimate how these improvements would
i) reduce gas-fired generators' transactions costs for managing the gas-electricity coordination and
ii) affect gas-fired generators' offers in both the day-ahead and real-time markets.

5. Reducing the cost of forward contracting

Description: The price at which suppliers will offer forward contracts to consumers is determined in part by the expected cost to the supplier of covering the obligation to supply that power. The cost to each supplier of covering such an obligation is not simply the cost of operating that supplier's plant to cover the contract, but also reflects that supplier's ability to purchase power from the real-time market to cover the supply obligation. During days or hours in which the real-time price is lower than the supplier's generating cost, the supplier will prefer to meet its obligation by buying from the spot market. During days or hours in which the spot price is high than the supplier's generating cost, the supplier will prefer to meet its obligation by selling its output into the real-time market. The forward contract price will therefore reflect these revenue opportunities and hence the forward contract price is influenced by expected future spot prices.

There are real-time operation risks that a supplier must also incorporate into its forward price. If the real-time price is volatile, the generator, particularly those that require some advance warning to start, may miss an opportunity to operate when the real-time price is greater than its operating cost. Additionally, the risk of an outage must be factored into the forward contract price.

Day-ahead markets with financial commitments provide suppliers with an additional opportunity to hedge against these real-time operation risks. In particular, day-ahead markets with unit commitments enable generators to cover their forward contracts at minimum cost by settling their forward contracts against day-ahead prices and bidding their resources into the day-ahead market at cost. With this

contract structure, the resource owner can be assured that its resource will be committed to generate during any period in which the owner can cover its contract at lower cost by operating the resource than by purchasing power in the day-ahead market. The implementation of day-ahead market mechanisms would therefore reduce some of the risk and hence transactions cost of forward contracting. This should further reduce the spread between forward contract prices and expected future real-time prices. Furthermore, the reduced cost of forward contracting should increase the amount of suppliers willing to offer longer term forward contracts (increased forward contracting liquidity).

Primary Efficiency Impacts

- Reduced transactions cost due to reduced operational and consumption uncertainty (productive efficiency).
- Reduced existing barriers for long-term investment in generation or demand management technologies (dynamic efficiencies).

Secondary Impacts

- Reduced need for adequacy mechanism and promotes more efficient long-term investment.

Areas for potential efficiency analysis

- To be discussed with key stakeholders.

Improved Day-Ahead Mechanisms – Decision Criteria

Central to a decision to proceed with any day-ahead mechanisms will be a cost benefit analysis (CBA), which will be conducted consistent with the description in the CBA Framework document. However, there will always be some aspects of the analysis that cannot be quantified and therefore other criteria will impact on the decision making process. The extent to which these additional criteria impact on the decision will involve judgement. The IESO will provide stakeholders an explanation of how the criteria have influenced the decision.

The IESO proposes to consider the following criteria in making decisions regarding improved day-ahead mechanisms.

Allocative Efficiency

Allocative efficiency refers to maximizing the efficiency of the resources currently available to the market. Allocative efficiency is maximized when power is being provided to those most willing to pay the lowest cost. If the cost of producing the energy exceeds the value placed on the energy by those consuming it, efficiency is reduced. Allocative efficiency is achieved through appropriate real-time dispatch, through response to prices by both consumers and generators, through bids and offers by dispatchable participants, including importers and exporters, and through maintenance scheduling decisions. In principle, allocative efficiency considerations will be captured within the CBA.

Dynamic Efficiency

The market design should help signal investment in efficient technology choices in a timely manner. Day ahead mechanisms can aid dynamic efficiency by encouraging liquidity in forward contracting. Further, increases in allocative efficiency such as the encouragement of day-ahead demand response could alleviate the need to build peaking generation for extreme electricity demands.

Fairness

The market design must provide equal, non-discriminatory access to the market, and equal and non-discriminatory treatment for all participants.

Reliability

The market design must enable the reliable operation of the IESO-controlled grid, and should do so by providing transparent signals and incentives to consumers and producers that result in appropriate responses in all timeframes. Specifically, day-ahead mechanisms must ensure that actions can be taken by both the IESO and market participants that will result in the system being adequately prepared for next day's operation with those actions being driven by participant interests to the maximum extent possible.

Transparency

The market design must be understood by participants. Participants should be able to infer system conditions from market signals, be able to predict market signals for a given set of system conditions, and be able to respond to those signals.

Robustness

At the most basic level, robustness means the market design should be sufficiently comprehensive so as to ensure that only extraordinary circumstances can upset the functioning of the market in the short and long term. The market design must meet the needs of today, and should not inhibit future market initiatives. Specifically, day-ahead mechanisms should be assessed on the extent to which they either encourage or inhibit any of:

- liquidity of forward contracting and the possible development of forward exchange trading,
- the possible development of load serving entities, and
- the examination of the efficiency implications of locational pricing.

Stakeholder Feedback

Summary of Feedback Process

The goal of the day-ahead market stakeholder plan is to help the IESO in identifying and understanding stakeholder needs and wants in the context of individual stakeholder's businesses. Stakeholder feedback was gathered using a 3-step approach. Stakeholders had an opportunity to provide comments through a questionnaire, a group session, and individual meetings.

Questionnaires were distributed in January, 2007. Although questions were tailored to consumers, generators, or intertie traders, participants were encouraged to answer additional questionnaires if desired. Questionnaires featured open-ended questions, allowing for stakeholders to insert comments as required. A meeting with stakeholders was held in April, as an opportunity for participants to review and discuss the feedback. Based on these discussions, a summary of stakeholder feedback to date was published.

Stakeholder feedback provided the IESO a starting point for a series of meetings with a cross-section of individual stakeholders and small groups of stakeholders. In an effort to understand their business needs as they might relate to a day-ahead market in Ontario, the IESO included stakeholders that aren't directly connected to the IESO controlled grid and traditionally aren't as active in IESO stakeholder processes.

Feedback from stakeholders led the IESO to focus on problems and opportunities within the current market construct. Stakeholders widely accept that problems and opportunities should be identified, allowing for analysis of possible options without narrowing options to a particular day-ahead design.

Summary of Consumer Feedback

This section summarizes the comments we received from consumers through the survey, group stakeholder session and several small focus group style meetings held with consumers.

Current Construct

Consumer's participating in the stakeholder process shared a wide range of views regarding the development of a possible day-ahead market, with energy-intensive businesses generally showing a greater interest in exploring the costs and benefits of a DAM.

Consumers consistently noted that any proposal must pass a cost-benefit analysis, with consideration for the "whole cost" of electricity, including uplifts and regulatory costs. Consumers agree that the market should seek to find greater efficiencies, and are generally willing to accept some short-term price impacts for long-term gain. There is a general acceptance for the IESO's incremental approach to market evolution, but consumers would like to understand the desired "end state" or vision.

Many consumers note that electricity is not their core business, and is but one of many costs that they must manage in a competitive environment. Often, commercial consumers do not have very much flexibility in their consumption pattern. Businesses that do not actively participate in the wholesale electricity market have generally focused on conservation as a means to manage energy costs. Some consumers question the additional benefits a day-ahead market would bring, given the hedges provided by the Global Adjustment and OPG Rebate.

Some consumers expressed a frustration at the perceived inaccuracy of pre-dispatch price signals. These consumers seek price certainty, which would allow for better operational planning and flexibility.

Future Day-Ahead Mechanism(s)

Consumers consistently agree that any evolution must drive economic growth and investment certainty.

Consumers accept that some change may be necessary, but desire a solution that is neither costly nor time consuming. A simple approach is generally considered to be the most desirable. Any day-ahead mechanism must not detract from other consumer-focused initiatives, such as demand response. Some consumers note that the ability to avoid high prices would not produce the same financial benefits to them as demand response payments.

Many consumers seek ways to minimize the environmental impact of their various businesses. There is a willingness to alter consumption patterns in response to an emergency or to assist with air quality issues. With this in mind, there is an interest in exploring the possible environmental benefits of a day-ahead market, whether it impacts conservation or leads to the development of cleaner sources of energy.

Consumer Questionnaires: Summary of Responses

Most respondents to the consumers' survey were neither in favour of nor against the commencement of work on a day-ahead market (DAM) in Ontario. Consumers noted that it is mainly those with significant flexibility to reschedule energy-intensive operations that would benefit from a day-ahead price. Consumers with less flexibility and/or less energy intensive operations (the majority of survey respondents) are unlikely to change their consumption patterns significantly as a result of the ability to lock in a price day-ahead or a more accurate day-ahead price. While generally indifferent to the establishment of a DAM, there were a few caveats documented in the survey responses if work on a DAM went ahead.

First the benefits of DAM implementation must clearly outweigh the costs. If the design and implementation of a DAM will conclusively result in net benefits to the Market overall, and the DAM costs and risks are reasonable then consumers are prepared to support the initiative.

Secondly, DAM implementation should support other initiatives currently underway. The survey results did reflect a belief that a day-ahead price might facilitate some "next day" demand response planning particularly by consumers that are typically limited in their actions in real time. Therefore, any DAM design must fit together with demand response and smart metering programs and enhance opportunities under these programs.

Summary of Generator Feedback

This section summarizes the comments we received from generators through the survey, group stakeholder session and several small focus group style meetings held with generators.

Current Construct

Generators generally agree that the present construct is not a desirable end-state. The market should continue to evolve, based on experience to date, and in preparation for future needs.

Generators suggest that the IESO must identify problems that require solutions. Generators accept the IESO's incremental approach to market evolution, but feel that evolution should proceed with a planned end state in mind. Most generators agree that "doing nothing" is not an acceptable option.

Members of the generator community agree that the IESO must continue to address real-time issues. The IESO should continue to investigate improvements to the pre-dispatch, with a goal of better alignment with the real-time market. Generators agree that dispatch issues and demand forecasting remain priorities. Day-ahead market evolution must not detract from these initiatives.

Generators consistently comment that the unconstrained market is fundamentally flawed. This causes some concern that a DAM might be built on a poor foundation. "A DAM based on unconstrained pricing may unintentionally prevent future evolution."

There is a consensus among generators that public policy in Ontario prevents real progress in market evolution. The hedges provided through the Global Adjustment and OPG rebate prevent consumers from understanding the current situation or from realizing the costs or benefits of proposed changes. For the market to deliver the intended benefits, some volatility is desirable.

Future Day-Ahead Mechanism(s)

Most generators agree that the current day-ahead commitment process is an incomplete solution. In particular, gas-fired generators desire a day-ahead commitment that is more reflective of real-time operations. Gas generators cite the need for efficient fuel procurement as a challenge under the current system. Newer facilities, which often have an OPA contract, express a concern that the "deeming" of imputed revenues in the real-time market presents a challenge. A day-ahead market that allows OPA contracts to be moved to the day-ahead timeframe, would result in more predictable and cost-effective operation of gas generators. Any changes to day-ahead mechanisms (including DACP) must take into account the possible impacts on OPA contracted supply.

While day-ahead schedules may be desirable for many generators, operators of energy-limited resources require a day-ahead construct that will allow them to manage their real-time output.

Generators note that the current market lacks buyers. Possible development of Load Serving Entities could address this. For loads to fully participate and manage risk in the electricity market, some kind of day-ahead market is essential.

Generator Questionnaires: Summary of Responses

Responses from the generator community generally support the development of a day-ahead market (DAM) in Ontario. The following attributes were consistently rated by generators as being important in the development of a DAM, in order of preference:

1. Gaining some level of operational certainty by having greater confidence in the amount of energy to be produced the next day.
2. Gaining some level of operational certainty by receiving a commitment for start-up or shut-down time.
3. Day-ahead results that are available in a timely manner to aid in fuel management or fuel procurement.
4. Having a day-ahead energy price that can help manage business risks.

To a lesser degree, generators rated the ability to hedge against the volatility of the real-time price as important.

Summary of Generator Comments associated with important attributes

Gaining some level of operational certainty by having greater confidence in the amount of energy to be produced the next day:

- Any DAM design must provide the certainty that operation according to the day-ahead schedule will result in receipt of market revenues no less than offer costs, including start-up, minimum load, etc.
- It is important for a generator to understand the hours of operation and pricing associated with each hour. This will lead to more accurate fuel procurement, which will allow for more aggressive energy offers. Lower risks, lower fuel costs, and increased operating efficiency will provide broad benefits to consumers.
- Although IESO pre-dispatch price signals have been improving, they continue to be an unreliable mechanism for planning of operations. Most large thermal generating stations are slow-start in nature and require several hours to reach minimum load. Operating decisions and plans must be made for these dispatchable generators many hours prior to expected operation and, when based on inaccurate price forecasts, can lead to inefficiencies. When market conditions change during real-time operation, generators are often faced with operating plans which no longer make economic sense but may not easily be changed. This ultimately increases costs to both generators and consumers.
- CES contract imputed revenues must be consistent with the operating schedule determined in the DAM.
- The rights of self-scheduling generators must be preserved under any day-ahead market design. Participation must therefore be voluntary.

Gaining some level of operational certainty by receiving a commitment for start-up or shut-down time:

- A DAM will provide better price signals to allow generators to plan their start-up and shut-down activities more consistent with the needs of the system, resulting in overall cost efficiencies that can benefit both generators and consumers.

Day-ahead results that are available in a timely manner to aid in fuel management or fuel procurement:

- Natural gas procurement and nomination processes are generally done on a day-ahead basis. The quantity of gas needed as well as transportation and storage services to be used must be planned and nominated by mid-day of the day-ahead.
- If DAM timing was aligned with the timing for the gas nomination process, gas management costs could be minimized. This improved efficiency would ultimately show up in lower prices to consumers.
- Awareness of the “gas day” and gas market timetables are very important in determining appropriate day-ahead electricity processes. The Natural Gas and Electricity Interface Review (NGEIR) has resulted in some significant accommodation in the gas transportation and nomination processes to reflect electricity system needs. Convergence is now needed from the electricity perspective.
- It is preferable to have day-ahead electricity schedules in time for all gas commodity transactions. Consideration should therefore be given to using the “gas day” as a basis for the electricity DAM. It is recognised that it will be difficult to fully reflect the gas market timetable, and that this is not the norm in North-East US ISO markets.

Having a day-ahead energy price that can help manage business risks:

- As discussed, many OPA contracts provide that if a DAM is developed in Ontario, the “deeming” of market revenues would be done based on the results of the DAM. This would allow a generator to effectively align their “deemed” operation with their physical operation and significantly reduce the risk associated with these protocols. This would reduce costs to the generator which would ultimately show up as lower costs to consumers.

Summary of Trader Feedback

This section summarizes the comments we received from Intertie Traders through the survey, group stakeholder session and several small focus group style meetings held with traders.

Current Construct

Intertie traders express frustration with the current Ontario market design. The real-time-only market is seen as an incomplete solution. Traders link many of the shortcomings of the real-time market to the absence of a day-ahead market. In particular, traders feel that pre-dispatch price signals are inconsistent due to the lack of a DAM. The Day-Ahead Commitment Process (DACP) is seen as a contributing factor. By excluding exports in the DACP, it is argued that current day-ahead price signals are of little value.

Traders indicate that forward trading is inhibited by the lack of a DAM in Ontario. This leads to poor liquidity, limiting long-term arrangements and risk management options that could benefit Ontario consumers.

Traders agree that there is a lack of volatility in Ontario's real-time market. The hedge provided by the Global Adjustment and OPG Rebate add to this, and may undermine public policy goals of energy conservation, and efficient scheduling of energy.

Future Day-Ahead Mechanism(s)

Traders express support for market evolution in general. A day-ahead market is seen as part of a complete solution, enabling Ontario to realise the full benefits of competition. If a comprehensive DAM is not feasible, changes should be considered to enhance the efficiency and transparency of the existing market. The addition of exports to the DACP is seen as an important step in producing a valid day-ahead price signal. Multi-part bidding, with 24 hour optimization is also seen as an important element of any day-ahead mechanism.

Intertie Trader Questionnaires: Summary of Responses

Responses from Intertie Traders and Marketers supported the development of a day-ahead market (DAM) in Ontario.

Timing

Traders were asked to comment on the importance of timing of an Ontario day-ahead market relative to the availability of results from day-ahead markets in neighbouring jurisdictions.

Traders consistently commented that DAM timing should be coordinated with neighbouring markets. Some responses suggested that an Ontario DAM should also coordinate with natural gas markets. Traders indicated that coordinated timing would lead to reduced transaction failures, and create a level playing field with other markets. Consistency with other markets would provide traders with additional options to manage risks, leading to more aggressive energy offers in the Ontario market. Some

responses suggested that an Ontario DAM should close after neighbouring markets, further reducing transaction failures.

DAM relative to Day-Ahead Commitment Process (DACP)

Traders were asked to comment on whether a day-ahead market would facilitate efficient trade between jurisdictions beyond what is occurring under the DACP.

Traders commented that by allowing for a bi-directional market, a DAM would be preferable to the DACP. By including exports, a DAM would improve the quality of pre-dispatch prices and schedules. This increased certainty would lead to increased participation. One trader noted that other day-ahead markets experience participation rates approaching 90%, versus approximately 3% for the DACP.

General Comments

Traders noted that the DACP should be viewed as a temporary solution, and not a substitute for a functioning day-ahead market. In addition, traders suggest that a DAM would facilitate load participation, and encourage the development of a retail market. Active load participation would have reliability and pricing benefits for the whole market.

Appendix D

Stakeholder Engagement Plan SE-21

Day-Ahead Market Evolution



May 3 August 10th revision: The schedule has been updated in section III to include specific dates for stakeholder meetings in September and November. There is no change to the overall timeline. Also, this section has been updated to outline the creation of technical support groups on specific aspects of potential day-ahead mechanisms. Additional time is needed for individual stakeholder meetings and as a result the publication of a draft proposal is now being scheduled for mid August instead of the previously planned June 1, 2007 date.

I. Introduction and Background

This stakeholder engagement plan defines the process the IESO will use to obtain stakeholder input on the design of a Day-Ahead Market (DAM) for Ontario. The outcome of this plan will be heavily influenced by day-ahead market requirements and benefits identified by stakeholders, and therefore could fall within a wide range of possible outcomes - from as comprehensive a recommendation as the implementation of a full-featured DAM to as basic a recommendation as to retain or enhance the existing Day-Ahead Commitment Process. The recommendation will also be influenced by an analysis of the current industry environment, and the viability and sustainability of any proposed day-ahead initiatives. The objective of this stakeholder plan is to provide stakeholders with the opportunity to input to the high-level design of an appropriate Day-Ahead Market or other day-ahead mechanisms for Ontario. That input will be provided to the Stakeholder Advisory Committee in the course of seeking their advice, prior to IESO Board decisions on this initiative. Any subsequent implementation phase would follow design approval, and is not the subject of this plan.

Day-Ahead Market for Ontario

The IESO operates a real-time market for energy and operating reserves in which electricity prices are determined every five minutes. With the energy price being calculated so frequently, it can be subject to significant variability as the supply/demand conditions change from interval to interval. This variability makes it difficult for both consumers and producers to factor the price of electricity into their plans. Management of these risks is made all the more complex due to the fact no transparent forecast of real-time price currently exists. All market calculations prior to real time (i.e. pre-dispatch runs) are performed with an hourly granularity and therefore consider imports and exports when calculating price and therefore do not specifically replicate the real-time process. In today's Ontario market, import and export bids and offers cannot be changed in the five-minute timeframe and are therefore ignored in the real-time price calculation – although their scheduled quantities do establish the demand to be met by the market.

Real-time markets are generally expected to be volatile in nature, reflecting the ups and downs of balancing supply and demand within the constraints of the transmission system. Ideally, consumers or producers should only be exposed to the real-time price if, a) events have unfolded in such a way as to cause the real-time market to adjust to their change in output or consumption, or b) they can voluntarily change their production or consumption with very short notice. Most consumers and producers are

expected to protect themselves from the volatile prices by a combination of contracting forward, locking in prices in a day-ahead market, or planning their consumption or production for the next day based on day-ahead price signals.

The Day-Ahead Commitment Process (DACP)

In June 2006, the IESO implemented a Day-Ahead Commitment Process (DACP). The DACP was designed to increase the reliability of imports and the availability of generators by offering guarantees for those scheduled a day in advance. While the DACP does provide reliability benefits, it does not serve the purposes of a day-ahead market. The DACP only offers financial guarantees to suppliers with the goal of improving reliability of the real-time market. The DACP has improved the quality of the pre-dispatch results somewhat, however it does not produce a quality day-ahead price signal, and it does not provide any opportunity for consumers to lock into a price for the next day. DACP guarantees are not likely to be as effective at assuring supply in real time as is providing participants with a day-ahead financial position, which a day-ahead market would do. A day-ahead financial position would expose producers to real-time buy-outs for under-delivery or real-time rewards for over-delivery. It would expose consumers to real-time rewards for under-consumption and real-time charges for excess consumption and would encourage real-time performance that is “correct” for the prevailing real-time market conditions. Finally, the lack of transparent day-ahead prices means that the DACP does little to improve the day-ahead signals needed for further demand response development or the operation of embedded, non-dispatchable generation. Several modifications and additions to the DACP can be contemplated to improve both the effectiveness of, and the efficiencies gained from the DACP process, and these will be considered both within the context of a day-ahead market and as possible stand-alone initiatives.

Developing a Day-Ahead Market in Ontario

A DAM would enable participants to lock into a price one day in advance of real-time energy delivery if they so desire. This would provide more certainty to suppliers and consumers, allowing them to react to price by leveraging added flexibility they may have a day in advance that is just not possible to take advantage of in real time. The added certainty and flexibility will improve the overall efficiency of the market and should have a commensurate impact on price; but the benefits go beyond improved efficiency and include improved reliability. A more reliable day-ahead price signal enables consumers to decrease peak consumption by avoiding high-price hours, encourages embedded generation to be available to operate during those same high-priced hours, and enables dispatchable generators to better manage their operations. The analysis of the benefits of day-ahead prices must take into account the current Ontario industry context in which the Global Adjustment significantly insulates consumers from real-time prices.

The availability of day-ahead prices can potentially facilitate additional demand response in the near future, given Ontario’s Smart Meter initiative which by 2010 will see all of Ontario’s consumption measured by interval meters. With hourly energy billing made possible by smart meters, and with consumers potentially having hourly prices for the next day from a day-ahead market outcome, consumers could adjust their consumption patterns to reduce energy costs.

Many possible designs exist for a DAM, and many features can be incorporated into a day-ahead market or day-ahead commitment process. In a comprehensive market design, the day-ahead market would produce physical schedules for supply of energy. In some day-ahead market designs, schedules are based on an optimization across the entire day, taking generator start-up costs and any energy limitations into account. Enhancements to the DACP with twenty-four hour optimization would allow the system operator to ensure demand is met in the most efficient manner possible, which can provide both reliability and efficiency gains. Improvements to day-ahead commitment such as those mentioned here will be examined in light of the coming additions to Ontario's generation fleet with several new natural gas-fired generators currently under construction in Ontario.

The day-ahead design that will be recommended to the IESO Board must address these issues and answer several key questions. Some of these questions are outlined in the attached addendum.

II. Stakeholder Engagement Plan Overview

This stakeholder engagement plan addresses only the development of a high-level design of the appropriate day-ahead mechanisms and, upon finalization and approval of a design, stakeholder input would be solicited on a stakeholder engagement plan for the implementation phase.

III. Design Phase: Day-Ahead Market Stakeholder Engagement Plan

Goal

To provide stakeholders with the opportunity to provide advice on the design of enhanced day-ahead processes, with a target date of the Fall of 2007 for a high-level design recommendation to the IESO Board.

Objectives

To provide all stakeholders with the opportunity to review and provide input on the design of enhanced day-ahead processes for the IESO-administered market.

Stakeholder Engagement Approach and Methods

The stakeholder engagement approach for the design phase will involve written submissions by stakeholders, face-to-face dialogue, as well as public postings of information and proposals. The implementation of the stakeholder engagement process will be in accordance with the IESO's approved [stakeholder engagement principles](#).

The stakeholder engagement methods to be employed will be a combination of written surveys, individual meetings with stakeholders, stakeholder sessions, web-based postings providing all stakeholders the opportunity for comment, and discussions with the Stakeholder Advisory Committee.

The stakeholder plan will be subject to review and update as the process evolves and stakeholder comments are incorporated.

Development of Stakeholder Needs and Wants

The first step in the stakeholder process will be to determine stakeholder needs and wants from day-ahead arrangements. All stakeholders will be invited to respond to specific questions from the IESO that have been designed to aid both the stakeholders and the IESO to understand how day-ahead mechanisms would be used in their specific business. One-on-one follow-up meetings will be held with a cross-section of stakeholders to clarify stakeholder goals and expectations. The feedback will be summarized in a manner that would ensure confidentiality of respondents, and would be published in combination with information gathered from other sources such as consultants and other ISOs.

Stakeholder Sessions

The IESO will organize meetings to discuss stakeholder's comments and significant issues regarding a day-ahead market and to present and discuss the IESO's day-ahead proposal. There will be meetings with individuals, small groups, and sectors such as consumers, generators, and traders, so that their specific issues can be addressed, as well as open sessions where stakeholders can gain from understanding each others' diverse perspectives.

There will also be technical support groups formed to discuss particular aspects of the potential improvements to day-ahead mechanisms in greater detail. Some examples of subjects that these technical support groups will address are: prudentials, production cost guarantees, and quantification of benefits for the CBA. These groups will allow stakeholders to better understand these aspects of the potential design and to work closely with the IESO on these designs. Once formed, these groups will determine their preferred method for communicating ideas amongst the group – face-to-face meetings, teleconferences, email.

Materials for all meetings will be publicly posted and available to all stakeholders.

Web-Based Postings

Web-based postings provide all stakeholders with a lower-cost alternative to keep up-to-date with the process and to provide input as desired.

Stakeholder Advisory Committee to the Board and Executive

The Stakeholder Advisory Committee will be asked to review and consider the proposed high-level day-ahead market or process design, providing all stakeholder sectors the opportunity to express their views and positions directly to the IESO Board of Directors in advance of any final approvals.

Decision Making Steps and Schedule of Activities

Stakeholder Engagement Schedule – Design Phase	
Activity	Target Date
1. Post and communicate draft day-ahead market stakeholder plan.	Completed September 19, 2006
2. Input from Stakeholder Advisory Committee and other stakeholders on stakeholder engagement plan. Comments posted at: http://www.ieso.ca/imoweb/consult/consult_se21.asp	Completed October 2, 2006
3. Post revised stakeholder plan.	Completed January 8, 2007
4. Post and email survey to determine stakeholder needs and wants.	Completed January 25 2007
5. Deadline for survey responses on stakeholder needs and wants.	Completed February , 2007
6. Conduct individual meetings with stakeholders as necessary to clarify survey responses.	January and February, 2007
7. Post summary of survey responses with opportunity for stakeholders to provide additional information.	Completed late March, 2007
8. Stakeholders meeting to discuss stakeholder's comments and significant issues regarding a day-ahead market for Ontario.	Completed April 11, 2007
9. IESO staff to incorporate feedback received and develop initial day-ahead proposal(s). Additional ad-hoc meetings will be held with stakeholders during this period as appropriate.	April – July 2007
10. Management update to Stakeholder Advisory Committee	June 6
11. Posting of IESO staff's draft day-ahead proposal(s). At this stage, the proposal will may involve more than one option for a day-ahead mechanism.	Mid-August <u>10</u> , 2007
12. Present the options proposal(s) to Advisory Committee (for information purposes).	August 22, 2007
13. Meeting of the Consumers Forum to discuss the day-ahead mechanism options with particular attention to those aspects directly affecting consumers. Stakeholder meetings and open stakeholder sessions to present and solicit comments on the proposal(s), as it evolves throughout this period.	August– October <u>September</u> <u>13</u> , 2007
14. Stakeholder meeting to discuss the day-ahead mechanism options.	<u>September 20, 2007</u>

Stakeholder Engagement Schedule – Design Phase	
Activity	Target Date
15. Stakeholder meeting to discuss aspects of the day-ahead mechanism options that affect dispatchable market participants in greater detail.	September 21, 2007
14 .16. Deadline for written stakeholder feedback on proposal.	October 26 12, 2007
15 .17. IESO publishes IESO management’s proposal based on stakeholder feedback, along with rationale.	November 5 21, 2007
18. Stakeholder meeting to gather input on the IESO management proposal.	November 12, 2007
19. Publishing date for Stakeholder Advisory Committee materials.	November 21, 2007
16 .20. Stakeholder Advisory Committee meeting to gather input and advice for the IESO Board of Directors on the IESO management proposal.	December 5, 2007
17 .21. Present IESO management’s proposal to IESO Board for consideration including how stakeholder input was used.	December, 2007
18 .22. Posting of rationale for Board decisions	

Process Evaluation

Stakeholders will be provided the opportunity to provide feedback on the effectiveness of the process in achieving the stated objectives.

Participant Funding

Consistent with IESO Board and OEB approvals, funding in the amount of \$50,000 has been earmarked for a participant funding pilot project. IESO management will be proposing to the IESO Board that the pilot be conducted in respect of this stakeholder engagement plan, with the funding being focussed on the Consumer (primarily the smaller industrial, commercial and residential consumers) and Environmental sectors. The guidelines being proposed by management will encourage the effective co-ordination of those interests in providing input on this initiative.

IV. Implementation Phase: Day-Ahead Market Stakeholder Engagement Plan

Scope for implementation phase:

The subsequent implementation phase will address market rule changes, procedure changes, and system requirements and implementation planning.

The details of the implementation stakeholder plan will be developed once the design proposal is known.

Addendum

Questions to be addressed during the Design of a Day-Ahead Market

1. Will Ontario Continue with Unconstrained Pricing or Move to a Pricing Methodology that Better Reflects the Physical Constraints of the Power System?

The question of how real-time prices will be calculated is fundamental to the design of the DAM. Today's unconstrained pricing ignores the impact of transmission physical constraints within Ontario when setting price, whereas constrained pricing takes physical constraints into account when establishing prices. Significant complications arose in the comprehensive DAM design of 2004 by assuming unconstrained prices in both the day-ahead and real-time markets. System constraints anticipated a day in advance can differ from those that actually materialize in real-time, causing potentially significant differences in schedules for participants. To account for this, the previous design included congestion management settlement credits (CMSC) to be rationalized between day-ahead and real-time, leading to a complex settlement process which added significantly to costs, complexities, and would have further reduced the transparency of the market price signals. Based upon our previous DAM design experience and our subsequent experiences with the complexities of coordinating CMSC in the real-time market with the guarantees offered in the DACP, using unconstrained prices in a DAM with day-ahead physical scheduling going forward would present a major challenge. If unconstrained pricing is to continue in the long run in Ontario, then a simpler DAM design must be explored, which will probably represent a lower level of assurances to dispatchable resources than was offered in the previous comprehensive DAM design.

Recently, the IESO started a study to examine the implications of various locational pricing scenarios for Ontario. This activity is being addressed under a separate stakeholder plan, [SE-25 - Locational Pricing](#). The study results will be coordinated with the discussion on the design of the day-ahead market.

2. Should the DAM Include Physical Schedules?

It is possible to create a purely financial DAM that does not produce physical schedules and unit commitment. In such a DAM design, it would be up to the resource owners to anticipate real-time conditions such as transmission availability and demand forecasts, and decide how those conditions would likely affect their real-time dispatch for their particular portfolio of resources. Armed with that information, they would then need to decide how best to participate in the financial DAM. They would then develop their real-time offers to result in real-time dispatch that factors in their DAM positions. With suppliers carrying this level of risk between day-ahead expectations and actual operation, such a model would likely result in lower participation, as suppliers would be unlikely to offer their entire capability into the day-ahead market.

A pure financial DAM alone is likely to be thinly traded, which might prove to be of relatively low value for either increasing efficiency or reliability. The pure financial market would likely bring only limited reliability benefits leaving the IESO with the same reliability concerns that existed prior to the development of the DACP. In such a scenario, there would likely be a continued need for some version of the existing DACP.

If physical schedules are to be incorporated into the design, then a 24-hour optimization algorithm similar to that used in neighbouring day-ahead markets may prove to be beneficial. While the day-ahead commitment process (DACP) provides some of the reliability improvements of a DAM, it does not use 24-hour optimization. Twenty-four hour optimization permits generators to provide more detailed offers, including start-up costs, minimum generation levels and minimum run-times. The IESO would then combine this extra information with the knowledge of the load forecast for the next day, and with participant information about the energy available from energy-limited resources to best ensure reliability and to also create the most efficient coordination of resources across the entire day. This would provide generators with greater certainty about their operation, including start-up and shut-down times, and a high likelihood of when the energy-limited generators would be operated. Both the reliability and the efficiency benefits of 24-hour optimization will be addressed.

3. How is the Consumer Represented in the DAM?

The majority of Ontario's electricity consumers are served by the retail sector. Of that, much of this retail load is covered under the regulated price plan and don't need to manage real-time price volatility through a DAM. Even of the 50,000+ retail consumers paying real-time energy prices, few are likely to participate in a DAM as they are generally unable to dedicate day-to-day attention to electricity purchasing. Entities are needed to purchase on behalf of these consumers in the day-ahead.

There are options for ensuring sufficient buyers. The option that is most commonly used in other jurisdictions is to create load serving entities, (LSEs) to represent retail consumers. LSEs typically act on behalf of customers in a dual role; that of managing forward price risks, and if necessary, that of contracting for sufficient supply going forward to ensure adequate future supply. LSEs in other jurisdictions have strong incentives to participate in the day-ahead market, thereby increasing the liquidity in that market.

The DAM design does not specifically hinge on how, or if LSE responsibilities are carried out, although the effectiveness of any design may. A DAM that has low participation relative to the total demand for electricity in the province will be less effective at emulating the physical operation, leading to operational drivers that will be weaker and less certain. Further, if only a small proportion of the consumers have interest in forward commitments, including DAM positions, then Ontario will continue to be reliant on the real-time price. If LSEs are slow to materialize, then until they do materialize, it is possible that an entity such as the IESO could be called upon to forecast and nominate default load into the day-ahead market. However, it must be remembered that whomever forecasts demand and/or purchases day-ahead would be taking a financial position relative to real-time. With this position there is associated risk. Any design that included a central role for representing consumers in the market would have to deal with the financial gains or losses associated with this risk.

4. How Should the Day-Ahead Price and the Real-Time Price Relate to Each Other?

Day-ahead markets in the electricity industry classically perform a similar function to that of bilateral agreements, in that at their conclusion, they represent both buyers and sellers holding a financial position relative to the actual real-time market prices. This day-ahead/real-time linkage has commonly been referred to as a “two settlement system”. The first settlement is based on the day-ahead prices and volumes, and the second settlement is to adjust for differences in real-time.

This linkage to real time creates the financial drivers for participants’ real-time actions. The strength of the drivers is directly related to how closely the real-time conditions align with those expected in the day-ahead timeframe. When real-time conditions and day-ahead perspectives align, then the prices should be similar and the implications of changes in performance relative to day-ahead positions would be small. However, when the differences are large, then the prices can be substantially different, thereby providing strong drivers for participants to conform with their day-ahead commitments, and even to take additional actions that will allow them to take advantage of the real-time opportunities.

In this classical “two settlement system”, strong linkages between day-ahead pricing and real-time pricing emerge, even if there are systemic differences between how the two prices are calculated. This price convergence is often accomplished as a result of arbitrage of day-ahead to real-time energy price differences. The entities carrying out this role in the market are commonly referred to as virtual participants.

In Ontario’s electricity market, like those of the other Northeast American markets, we currently have a systemic difference between the processes for calculating real-time prices and those used to calculate pre-dispatch prices. The difference results from the way import and export transactions are treated in the two calculations. The real-time price is calculated every five minutes and uses only the offer/bid prices of suppliers/consumers that can change output/consumption in that timeframe. However, imports and exports are arranged prior to the hour of operation, and are arranged for a static quantity throughout the hour. In a five-minute timeframe, import and export bids and offers cannot be changed and are therefore ignored in the real-time price calculation – although their scheduled quantities establish the demand to be met by the market. In contrast to the real-time market, the DAM is expected to use an hourly resolution for establishing day-ahead prices, in which all hourly offers/bids would be considered in establishing the day-ahead hourly clearing prices. This systemic difference must be recognized and addressed in the day-ahead market design. It can be accepted as part of the design, relying on virtual participants to drive the convergence between the two markets, or it can be explicitly addressed through day-ahead or real-time price calculations. The issue of the role of intertie transactions in establishing the real-time prices is currently being discussed by the IESO and stakeholders. For more information, see Stakeholder Engagement Plan SE-18. This issue could significantly increase the scope of the DAM design, with corresponding impacts on timeline and costs.

Background on the Previous Day-Ahead Market Activities

During 2003 and 2004, the IESO conducted an extensive consultation program with stakeholders to guide the development of a recommended approach to a day-ahead market. A day-ahead market working group was established and numerous stakeholder meetings and web-based initiatives ensued.

A number of alternative designs were studied and the group proceeded with a design that attempted to address all of the objectives initially developed with the DAM working group. The comprehensive DAM was designed to address a wide range of stakeholder needs and wants through a single integrated solution, which had a high degree of complexity. With the introduction of Bill 100 in 2004, market participants and other stakeholders began to question whether it was the right time to proceed with the recommended DAM design. In December 2004, after review and discussion, the IMO Board directed the IESO to consider other potentially viable alternatives and identify the costs and benefits associated with each identified alternative. The background on the comprehensive DAM can be found at:

http://www.ieso.ca/imoweb/consult/mep_dam.asp

In Spring 2005, the IESO began stakeholder consultation on day-ahead needs and priorities to develop alternative solutions and recommendations. In August, the IESO proposed three possible alternative models for a DAM. Any work on these very preliminary alternatives ceased shortly thereafter, as the operational events of the summer of 2005 underscored the immediate challenges in providing a reliable supply of electricity. The background on day-ahead needs and priorities can be found at:

http://www.ieso.ca/imoweb/consult/consult_dam.asp. The tight demand/supply conditions during 2005 resulted in 12 days of public appeals, three separate occasions when the IESO implemented five percent voltage reductions, and numerous other occasions where emergency control actions were taken to preserve the reliability of the power system. Analysis of the events clearly identified import failures as a significant contributor to the problems, and cited the lack of day-ahead transaction scheduling as a major shortcoming. Given the significant impact of the summer events, the IESO moved forward with a stakeholder engagement plan to design a day-ahead commitment process (DACP). The plan was to identify, design, and implement measures to enhance the reliability of the power system in advance of the summer of 2006. The background on the day-ahead commitment process design can be found at:

http://www.ieso.ca/imoweb/consult/consult_isr.asp The DACP was implemented under a separate stakeholder initiative that can be found at: http://www.ieso.ca/imoweb/consult/consult_se16.asp. The DACP started operation, on schedule, prior to the summer, 2006.