Day-ahead Market Evolution Preliminary Assessment

Revised May 6, 2008

Table of Contents

List of Tables

1. Executive Summary

Changes in Ontario's electricity sector are on the horizon. Ontario's generation fleet is shifting away from coal through reduction and ultimate retirement in 2014 towards more natural gas, renewable and embedded generation. Growing focus on the environment, and the shift to greener solutions to meet Ontario's increasing electricity demand, has amplified the need to facilitate opportunities for demand response and utilization of Smart Meter technology.

In 2007, the IESO initiated a study to assess how our day-ahead planning mechanisms might be amended to support anticipated changes in Ontario's electricity sector. The assessment addressed both current and future challenges including how to most efficiently integrate and optimize Ontario's changing generation fleet (reduction and retirement of coal, more natural gas, renewable and embedded generation) and how to provide accurate price signals in advance of real-time to enable opportunities to better manage demand response and utilize Smart Meter technology. The merits of various possible day-ahead mechanisms have been studied and assessed under Stakeholder Engagement Plan 21 (SE-21). The goals[1] on entering into the study and assessment were threefold:

- **Enhanced unit commitment efficiency-** Establish if there are more efficient ways, in light of the changing supply mix, to commit resources to meet Ontario's energy needs in the day-ahead planning timeframe.

- **Provide more accurate day-ahead price signals and examine opportunities from day-ahead financial commitments -** Support the market but specifically demand response and embedded or distributed generation with more accurate day-ahead price signals. Present participants with an opportunity to manage real-time price and quantity risk by providing financial commitments day-ahead. Day-ahead financial commitment allows participants to lock in price and quantity day-ahead, reducing exposure to real-time volatility and provides hedging and risk mitigation opportunities. Both of these endeavors could create opportunities to facilitate operational efficiency for customers and suppliers.

- **Ensuring continued reliable system operations -** To ensure that the IESO day ahead planning mechanisms continue to support reliable operation of the grid with the changing supply mix expected to emerge in the next few years.

As the study progressed over the last year, the IESO reduced the range of options for consideration in its analysis of potential improvements to day-ahead market mechanisms to three options plus a baseline scenario. The baseline scenario provided the starting point against which the options were evaluated:

---

[1] Outlined at first stakeholder meeting April 11, 2007: http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20070411-DAM-Evolution.pdf and further detailed in August 2007 in Appendix A, Attachment A of the IESO publication A Discussion Paper on Day-Ahead Mechanisms: http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20070810_IESO_Staff_Report.pdf

- **Baseline Scenario** – Carrying on with the current wholesale market and DACP design, along with the continued publishing of the IESO day-ahead price forecast of real-time HOEP and a review of reliability cost guarantees

Options 1 and 2 focus on enhancing the current DACP, as follows:

- **Option 1:** An enhanced Day-Ahead Commitment Process (DACP) with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees, along with the continued publishing of the IESO day-ahead price forecast of real-time HOEP

- **Option 2:** An enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees and an Energy Forward Market (EFM)

Option 3 would establish a new Day-Ahead market under which participants would assume, and be financially responsible for, prices and quantities established day-ahead. It is anticipated that this new market would then establish the reference price for Ontario, with the current real-time market assuming a balancing role, while maintaining its dispatch function.

- **Option 3:** An unconstrained day-ahead market (UDAM). Like Options 1 and 2, the UDAM (Unconstrained Day-Ahead Market) would incorporate an enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees. Financial day-ahead positions would be derived from the IESO unconstrained algorithm.

The IESO used cost benefit analysis (CBA) techniques and consideration of additional non-quantifiable impacts to assess the relative merits of the options. The cost-benefit analysis included IESO and stakeholder costs and benefits measured through overall market efficiency impacts. The additional non-quantifiable factors analysis discusses impacts on relevant aspects of market and physical operation. Net effects on consumer bills were also considered.

The overall objective of the various analyses was to help identify day-ahead mechanism improvements that would result in net benefits to the province as a whole relative to the existing Day-Ahead Commitment Process (DACP). The outcome of our analyses is summarized in the table below.

CBA Analysis Outcome	Option 1	Option 2	Option 3
NPV (over 15 years)	$88.4M	$88.24M	$60.93M
Pay-back Post Implementation (# years)	2	2	3
Impact of Non-quantified	+ (shorter pay-back period)	++ (shorter pay-back period)	± (less likely to shorten pay-back)
Stakeholder Impact Analysis Outcome			
Year Post Implementation Bill Savings Realized	1	1	2
Rank	**2**	**1**	**3**

Following receipt and consideration of stakeholder comments, the IESO team responsible for this assessment will propose proceeding with one of the options or continuing with the Baseline Scenario. As set out in the final section of this report, the preliminary view of the study team is that Option 2 appears to offer a better overall set of amendments for addressing the efficiency, pricing and reliability goals on which this work has focused.

However stakeholder considerations are central to this assessment and before making any recommendation the study team welcomes the opportunity to consider stakeholder views, and in particular to understand any stakeholder concerns with the study results.

2. Report Layout

This report:

(i) Documents the results of the study and analysis;
(ii) Identifies the IESO's preliminary conclusions from the study and analysis; and
(iii) Provides the opportunity for stakeholders to review the study results and provide comments to the IESO.

This report is organized as follows:

Section 3 – Identification of day-ahead mechanism options considered and assessed,
Section 4 – Description of the cost-benefit analysis methodology, cost, benefit and net present value analysis,
Section 5 – Assessment of stakeholder impacts,
Section 6 – Additional factors considered,
Section 7 – Supporting rationale and request for stakeholder input.

A number of appendices that contain details regarding the study and analysis have been included in a separate document which is available at the following link:
http://www.ieso.ca/imoweb/consult/consult_se21.asp

3. Option Descriptions

When the IESO initiated this study, we identified several options for improved Day-Ahead Mechanism. These included:

- Enhancements to the current Day Ahead Commitment Process and guarantees
- Improved forecast of HOEP
- Energy Forward Market
- Unconstrained Day-Ahead Market with uniform price and quantities
- Day-Ahead Market as designed in 2004
- Day-Ahead Market with locational marginal pricing

In November 2007, the IESO eliminated the Day-Ahead Market designed from 2004 because it was judged too complex[2]; and the Day-Ahead Market with locational marginal pricing, as there is insufficient support in Ontario for a change to locational pricing[3].

At that same time the IESO recommended moving forward with the improved forecast of HOEP as a separate stakeholder initiative (SE-58). The stakeholder initiative is now complete and the IESO has announced that it will proceed with the publication of a day-ahead forecast of real-time HOEP[4] on a temporary basis pending a decision on a day-ahead mechanism. This leaves the IESO with three options for consideration in its analysis of potential improvements to day-ahead market mechanisms as well as the baseline scenario. The baseline scenario provided the starting point against which the options were evaluated:

- **Baseline Scenario** – Carrying on with the current wholesale market and DACP design, along with the continued publishing of the IESO day-ahead price forecast of real-time HOEP and a review of reliability cost guarantees

Options 1 and 2 focus on enhancing the current DACP, as follows:

---

[2] "A Discussion Paper on Day-Ahead Mechanisms", August 10, 2007, page 13; available on the IESO web site a the following location:
http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20070810_IESO_Staff_Report.pdf

[3] Ibid, pages 13-14.

[4] Refer to Stakeholder Engagement Plan SE-58 at the following location on the IESO web site:
http://www.ieso.ca/imoweb/consult/consult_se58.asp

- **Option 1:** An enhanced Day-Ahead Commitment Process (DACP) with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees, along with the continued publishing of the IESO day-ahead price forecast of real-time HOEP

- **Option 2:** An enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees and an Energy Forward Market (EFM)

Option 3 would establish a new Day-Ahead market under which participants would assume, and be financially responsible for, prices and quantities established day-ahead. It is anticipated that this new market would then establish the reference price for Ontario, with the current real-time market assuming a balancing role, while maintaining its dispatch function.

- **Option 3:** An unconstrained day-ahead market (UDAM). Like Options 1 and 2, the UDAM (Unconstrained Day-Ahead Market) would incorporate an enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees. Financial day-ahead positions would be derived from the IESO unconstrained algorithm.

A description of these options follows.

3.1 Option 1: Enhanced DACP and the Continued Publishing of the IESO Day-Ahead Forecast of HOEP

The DACP was introduced in 2006 as an initiative to address reliability needs for Ontario's power system. The DACP provides a day-ahead commitment process with financial reliability guarantees. It uses an hourly optimization process that commits internal generation resources and import transactions to meet Ontario forecasted peak demand. This optimization is based upon resources' incremental energy costs only, with no consideration of start up costs or unit minimum costs and levels. Export transactions are not considered. Resources committed through the DACP receive assurance from the market that the costs of starting up and operating their resources to their minimum levels will be compensated through day-ahead reliability guarantees if those costs are not recovered through other market revenues. The cost of these guarantees is recovered from market participants through uplift.

Option One considers modifications to the DACP to improve its efficiency.

The proposed revision to the DACP process would change to a 24 hour optimization rather than the present hourly process. This 24 hour optimization allows the algorithm to consider the entire 24 hour period as a whole rather than taking each hour independently. This gives the algorithm more flexibility and generally leads to a lower cost solution to meeting demand. Further, the revised DACP would include 3 part bidding, allowing participants to specify start up costs, the cost of operating at minimum output plus incremental energy cost above minimum levels. This would also include minimum run times and minimum generation levels.

Three part bidding allows participants to more accurately represent their operating costs, providing better information to the algorithm. With explicit information, the algorithm can solve for the lowest cost solution including all variables. For example, the algorithm could potentially commit a unit with slightly higher incremental energy costs but significantly lower start up costs in order to minimize the total cost of meeting demand.[5]

The revised DACP would also include an assessment of the current guarantees. The IESO would undertake a review of all day ahead and real-time reliability centered guarantees including production cost guarantees and import offer guarantees. In particular, the current Day-Ahead Generation Cost Guarantee (DA-GCG) associated with DACP will be reviewed. There is potential to create additional efficiencies by providing a guarantee for the entire advisory schedule rather than simply for unit minimums. Providing a guarantee for the full schedule will allow suppliers to more effectively plan their fuel supplies which should lead to improved efficiencies in real-time.

The IESO would also incorporate a multiple pass of the constrained algorithm as part of the enhanced DACP. The multiple pass approach currently under consideration uses three passes of the constrained algorithm. The first pass commits sufficient resources to meet the forecasted average demand for the hour. The second pass would then start with the commitments from the first pass and commit any additional resources required to meet the forecasted peak demand in the hour. The third pass and final pass would use all commitments from pass two to calculate hourly advisories based on forecasted average demand. The advisories from the third pass would be used for fuel planning purposes and would be the basis for any DA-GCG.

Finally, the revision to the DACP would include a review of the benefits of including some representation of exports into the DACP forecasted demand. This review would first focus on whether including exports into DACP demand would yield improved efficiencies for Ontario. If there are efficiencies to be gained, the IESO would then investigate how exports might be included in DACP, whether through allowing exports to bid with some export bid guarantee, an IESO estimate of expected exports or some other mechanism.

Publication of the day-ahead forecast of real-time HOEP would become a permanent feature of the IESO-administered markets.

Further details and discussion of the enhancements to the DACP and expected impacts can be found in the August 2007 IESO paper.[6]

The estimated timelines for review, design and implementation of the enhancements to the DACP is as follows:

---

[5] Refer to section 4.3.1 for the Cost Benefit Analysis which will document these efficiency gains.
[6] "A Discussion Paper on Day-Ahead Mechanisms" August 10, 2007, pages 15-19; available on IESO web site at following location:
http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20070810_IESO_Staff_Report.pdf

- Consideration and final design of enhancements, including market rules, in consultation with stakeholders July 2008 – December 2008
- IESO Board decision/approval to implement enhancements and approval of market rules – July 2008 - December 2008
- Procurement and testing, including market trials, of market systems – October 2008 - December 2009
- Enhancements in-service – Q1 2010

3.2 Option 2: Enhanced DACP and an Energy Forward Market

Option 2 involves the enhanced DACP described above, coupled with an IESO administered Energy Forward Market (EFM). Publication of the day-ahead forecast of real-time HOEP would continue on a temporary basis until such time that the IESO in consultation with stakeholders consider EFM pricing as an accurate forecast of real-time HOEP.

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 day-ahead market that includes financial commitments, these concerns could be addressed through an EFM (Energy Forward Market), which would operate separately from both the existing pre-dispatch process as well as from the DACP process.

In an EFM, participants are free to submit bids to buy and offers to sell energy for specific prices a day in advance of real-time. This would be a clearing based market and all bids to purchase above the clearing price and all offers to sell below the clearing price would clear at the single clearing price established where bids and offers converge. Day ahead financial positions would be settled for differences based upon real-time prices. 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. If for example, a participant buys 100 MWh at a day ahead clearing price of $45 and the real-time price comes in at $50, the participant would be credited the $5 price difference for each of the 100 MWh.

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.

When the Ontario market was created, it was always contemplated that there would be an EFM to supplement the real-time market. The current market rules include a section on an EFM in Chapter 8 outlining the operation of an EFM.

Since there is no tie between an EFM and the physical world of dispatch, it is possible for agencies other than the IESO to operate an EFM. In the six years since market opening there has not however been a

well established EFM by an external agency. As discussed in Section 4.2.1, the cost of the IESO opening and administering an EFM is relatively low – roughly $ 1 million. In addition, there are synergies for participants from having the IESO administer the EFM as they are already dealing with our settlement system and prudential system. An IESO administered EFM would avoid duplication of processes.
The estimated timelines for review, design and implementation of the enhancements to the DACP and introduction of an EFM is as follows:

- Consideration and final design of enhancements and EFM activation, including market rules, in consultation with stakeholders July 2008 – December 2008
- IESO Board decision/approval to implement enhancements and approval of market rules – July 2008 - December 2008
- Procurement and testing, including market trials, of market systems – October 2008 - December 2009
- Enhancements in-service – Q1 2010

3.3 Option 3: Unconstrained Day-Ahead Market

Like Option 2, Option 3 or the UDAM (Unconstrained Day-Ahead Market) builds from an enhanced DACP. In this case, financial positions day ahead are derived not from a pure financial market, but rather from the IESO unconstrained algorithm. This would mean adding a fourth pass to the 3 pass algorithm described for the revised DACP which would calculate unconstrained day ahead prices and quantities in the same way that they are calculated today.

An unconstrained day-ahead market would produce Ontario prices, plus prices for the import/export zones, respecting tie line limitations. This would also lead to the movement of the current Financial Transmission Rights Market to a day-ahead time frame based upon the UDAM prices.

Unlike the 2004 DAM design, the UDAM does not include CMSC (congestion payments) in the day-ahead time frame. CMSC is paid only in real-time.

The IESO has outlined Option 3 in more detail in numerous papers and presentations. In particular the April 2008 paper provides a great deal of detail on Option 3, including a discussion of outstanding design issues and challenges[7].

The estimated timelines for review design and implementation of the Baseline Scenario is as follows:

- Consideration and final design of UDAM, including market rules, in consultation with stakeholders July 2008 – February 2009
- IESO Board decision/approval to implement enhancements and approval of market rules – July 2008 – January 2009

[7] A status paper on day ahead mechanisms available at: http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20080411-UDAM-Design-Issues-and-Responses.pdf

- Procurement and testing, including market trials, of market systems – November 2008 - February 2010
- Enhancements in-service - Q3 2010

3.4 Baseline Scenario – Continue with price forecast and review guarantees

This is not a "do nothing" option; changes by the IESO would occur but to a much lesser degree than any of the other options under consideration. The baseline scenario means carrying on in the current wholesale market and DACP design. The interim day-ahead price forecast of real-time HOEP would become a permanent feature of the IESO-administered markets. The IESO would conduct a review of all existing reliability based guarantees, however within the current DACP process there likely would be limitations on the changes that could be made to the guarantees relative to other options under consideration. The risks inherent in the baseline scenario are included in the discussion of the baseline scenario in the cost benefit analysis outlined in section 4.1.1.

The estimated timelines for review, design and implementation of the UDAM is as follows:

- Consideration and design changes to guarantees, including market rules, in consultation with stakeholders July 2008 – February 2009
- IESO Board decision/approval to implement enhancements and approval of market rules – January 2009
- Enhancements in-service – Q2 2009

4. Cost Benefit Analysis

4.1 Methodological Approach and Basic Assumptions

Cost-Benefit Analysis (CBA) provides an analytic framework that facilitates a disciplined approach to assessing the net benefits (costs) of a proposed policy change such as the implementation of a day-ahead mechanism.[8] By quantifying all costs and benefits in monetary terms, and discounting, it is possible to determine the net benefits (costs) of an option in today's dollars. These net benefits (costs) can then be used to quantitatively rank alternative options, whether it is between a given option and the baseline scenario, or between competing options. The ranking of different options allows both the IESO and stakeholders to make informed recommendations.

[8] In preparing its assessment, the IESO has consulted the *Canadian Cost-Benefit Analysis Guide*: *Regulatory Proposals* (the CBA Guide) found at http://www.regulation.gc.ca/documents/gl-ld/analys/analys-eng.pdf. The *CBA Guide* is produced by the Treasury Board of Canada Secretariat for the use of federal departments and agencies as they perform cost-benefit analysis to support regulatory decisions. The guide incorporates the evolution of regulatory policy and developments in the analysis of the impacts of regulations in Canada and elsewhere over the past decade.

A standard CBA recommends changes that are economically efficient, while ignoring the effects of the change on wealth distribution.[9] In other words, a change has positive net benefits to the province as a whole if it improves economic efficiency. However, efficiency is typically not the sole criterion for public policy decision; analysis of who gains and who loses can be critical to the final decision.

In its assessment of the merits of each of the day-ahead options, the IESO follows the standard CBA approach for measuring the net benefit (cost) of each of the day-ahead options on the province as a whole.[10] However, stakeholder impacts, particularly the impact on the province's consumers would be considered and factored into the IESO's final recommendation to the Board.[11]

4.1.1 Baseline Scenario

One of the important concepts for defining the impacts of a proposed policy change in a CBA is to assess the incremental impact of the proposal relative to a baseline scenario, typically the status quo. In other words, to measure the impact—benefits and costs—that occur over and above what would have occurred in the absence of the proposal. This assures that the true contribution of the proposal is properly determined. Accordingly, when conducting our analysis of the impact of each of the day-ahead options, we conceptualize two scenarios: one that does not include the option (i.e., the baseline scenario) and one that does include the option (i.e., the "with options" scenario). The incremental costs and benefits of the option are measured relative to the baseline scenario.

Note that in a CBA, the baseline situation does not necessarily mean that nothing will happen to the current situation over time if the proposed policy were not implemented. The baseline scenario should consider changes to the industry (apart from those that would occur as a result of the implementation of the policy) that are reasonably likely to occur.

For its analysis, the IESO makes the following assumptions for defining a baseline scenario:

- The wholesale market continues as today. In particular, resources are dispatched based on offers and bids submitted to the IESO;
- The uniform "unconstrained" pricing model remains in place;
- The future generation and demand profile is consistent with the one that is projected by the OPA's Integrated Power System Plan (IPSP). This includes the government's commitment to reduce coal production with complete shutdown of the coal plants by the end of 2014;

---

[9] This is the outcome of the Kaldor-Hicks criterion. See "Overview of Cost-Benefit Analysis and its Applications in Public Policy Decisions," by Michael Trebilcock, Adonis Yatchew, and Andy Baziliauskas http://www.ieso.ca/imoweb/pubs/mear/CRA_Overview-of-Cost-Benefit-Analysis.pdf.

[10] This is also consistent with the April 2007, *Government of Canada, Cabinet Directive on Streamlining Regulation* for which a key requirement is that departments and agencies assess regulatory and non-regulatory options to maximize net benefits to society as a whole.

[11] Along with promoting economic efficiency for the sector, a key objective defined by the *Electricity Restructuring Act, 2004* is "to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service." The IESO must be mindful of this objective when reviewing market evolution initiatives.

- Regulations governing Ontario Power Generation's assets (Prescribed Assets and Non-Prescribed Assets) will continue;
- OPA contracts for new gas-fired generation assets will continue to use contracts similar to the Clean Energy Supply contracts which provide incentives for efficient dispatch but also provide monthly net revenue guarantees to cover those fixed cost and capital expenses not captured through the wholesale market revenues;
- IESO cost guarantees, such as the DACP "Generator Cost Guarantee" or Spare Generation on-line" guarantee will be reviewed for possible improvement.[12]
- IESO interim day-ahead forecast of real-time HOEP becomes a permanent feature of the IESO administered markets.

As with any assumption regarding the future path of the industry, there is inherent risk. In discussing the IESO's baseline scenario with stakeholders the following risks were identified.

- *Change in the government's commitment to the wholesale market*. There is always the potential that the government may decide that a return to some form of comprehensive regulation is preferred. However, with the growing decentralized ownership of the generation assets, even with a move to more regulation of the industry, there will still be a need for some decision rule for determining how and when the diverse assets should be dispatched. If the current algorithm continues to be used for dispatch, then many of the impacts discussed below (unit commitment efficiencies, and gas-fired generation efficiencies) could still be achievable, although the wealth transfer impacts would likely change. If the return to regulation would abandon the current dispatch algorithm, then the benefits attributable to the various options may be less certain.
- *Implementation of Locational-Marginal Pricing.*
- *Change in government policy regarding the regulation of OPG's assets.* The important aspect of this assumption for our analysis is that regulation governing OPG continue to have the same key objectives– to ensure the assets operate efficiently, mitigate the potential for the exercise of market power, and that revenues earned from the market, beyond an agreed upon "rate of return," are rebated to Ontario consumers. While regulations may change, if the objectives remain unchanged there is unlikely to be a major impact on our analysis.
- *Change in OPA policy towards contracting.*

How the IESO incorporates the consideration of these risks into its analysis is discussed in more detail below in the context of "pay-back" periods and discount rates.

[12] Note that the improvements do not include 24-hour optimization of fixed costs and minimum generation run-times. The improvements contemplated would be to address concerns related to the potential excess use of the programs as more and more non-quick start generation comes on-line.

4.1.2 Monetized, Quantified and non quantified Impacts

An aim of CBA is to quantify and monetize all incremental benefits and cost of a given proposal. However, some benefits/costs may be difficult to quantify and or monetize because of their nature, lack of data or scientific knowledge. While quantifying the benefits assists the decision makers in understanding the magnitude of the effects of the different options, some costs and benefits may be too difficult or costly to quantify in monetary terms. At the same time, some of these non quantifiable costs and benefits may be too important to ignore. Both quantified and non quantified impacts should be described and documented as part of a CBA in order to facilitate an informed decision.

Monetizing all of the potential efficiency gains attributable to each of the day-ahead options is a challenge. In its approach, the IESO has been guided by the principle of proportionality - the effort to do the cost-benefit analysis should be commensurate with the level of expected impacts. Through experience gained from other electricity markets and through its discussions with stakeholders, the IESO has focused its efforts to monetize three areas where improved day-ahead market mechanisms are most likely to provide material efficiency gains. These include:

- Improved opportunities for demand response;
- Enhanced unit commitment efficiency;
- Reduced transaction costs through improved coordination of natural gas/electricity operations.

Other areas of potential impacts are considered in the IESO's analysis. However, these impacts are not quantified and hence are considered qualitatively. In this report, the IESO provides its assessment of how these qualitative impacts influence the likely ranking of each of the options.

Finally, when estimating both the quantified costs and quantified benefits, the IESO has considered three different estimates: an expected value estimate, a high value estimate, and a low value estimate. The IESO will base its CBA on the expected value estimates as these reflect the mean value or likely value for each impact. The high value estimate and the low value estimate are presented to allow a consideration of the risks associated with each option. The IESO will also present a "worst case" scenario net present value calculation for each option to allow for the consideration of the high cost low benefit possibility. This is done to allow consideration of the options from the perspective of a "risk averse" decision maker.

4.1.3 Appropriate "Pay-Back" Period and Discount Rate

Discounting recognizes that the use of money has a value. A dollar today is worth more than a dollar in five years time. This concept is known as the time value of money. The time value of money means that cash inflows and outflows occurring in different time periods cannot simply be added together to determine the overall net cost or net benefit of a proposed policy change. It is necessary to remove the effect of the time value of money - that is discount back - to enable all values to be compared on an "apples with apples" basis, which is the present value. The process of discounting future financial cash flows (or economic costs and benefits) of a project is used to derive key decision indicators such as net present value (NPV).

Choosing a discount rate has been one of the most contentious and controversial aspects in the CBA of regulatory policies. In this context, the term discount rate refers to the time value of the costs and benefits from the viewpoint of society. And as noted in the Canadian CBA Guide, while it is similar to the concept of the private opportunity cost of capital used to discount a stream of net cash flows of an investment project, as a social rate, the implications can be more complex.

In choosing a discount rate for its assessment, the IESO has been guided by the *CBA Guide* and by private consultations with a Canadian CBA expert. First, the IESO uses the same discount rate across the impact period; a real rate of 7 percent.[13] The 7 percent rate was derived for the period 2007 based on the understanding that financing would come from three potential sources: new saving (use the rate of return on saving net of income taxes), displaced domestic investment (the gross rate of return required by domestic corporate borrowing) and foreign borrowing rates (adjusted for exchange rate risk).

Second, the IESO applies the same discount rate to both the stream of costs and benefits. To address the possibility that the stream of costs and benefits could have different levels of risk, the estimated yearly costs and benefits are transformed into certainty equivalents using a risk factor –one that can be different for costs and benefits -- that is specific to the nature of the risk.

Finally, the IESO conducts a rate sensitivity analysis, applying additional rates of 4% and 10%.

CBA analysis covers a discrete period of time, even though in practice the benefits of the project may continue for many years beyond the period of analysis. While, in theory, these long run benefits (and costs) should be included in the analysis, it can be problematic and in most cases impracticable to estimate them.
For its assessment, the IESO considers a pay-back period of 15 years when computing the net present value (NPV) of each option. However, the IESO reports on the cumulative NPV of each option in each year of the pay-back periods so that all stakeholders can see the NPV at a given point in the life of the option. For those who think that the types of risk regarding the baseline scenario described above would merit the use of a shorter pay-back period, the NPV for the shorter pay-back period will be available for their consideration.

4.2 Cost Analysis

In a CBA, "costs" are simply the monetary value of the resources used as a consequence of the implementation of the initiative or policy. The IESO identified two categories of cost for inclusion in the CBA:

(1) IESO implementation and Operation Maintenance & Administration (OM&A) costs; and

(2) Participants' implementation and OM&A costs.

[13] The benefits and costs in this report are estimated in current dollars or in real terms so that the reported values of benefits and costs over time that are due purely to inflation are removed.

4.2.1 IESO Costs

The IESO has conducted a review of the cost to implement and maintain each of the day-ahead mechanism options. A summary of these cost estimates are provided in this section. A more detailed description of the system procurement and IT development is provided in the Appendix found at the following link: http://www.ieso.ca/imoweb/consult/consult_se21.asp. This appendix builds on much of the information in the Procurement Scope for the Unconstrained Day-Ahead Market previously published in March 2008.[14]

None of the proposed options have been defined to a level of detail that would allow an IESO request for specific quotes from vendors. The cost estimates summarized below have been determined by reviewing and adjusting the detailed cost estimates prepared for the 2004 Day-Ahead Market (DAM) project. For those estimates, a detailed DAM design was made available to vendors, and the IESO received several vendor DAM cost estimates.

In developing the cost estimates for the day-ahead mechanism options, the IESO made the following assumptions:

- Compliance with IESO IT architecture, principles and management practices.
- Multiple vendors will be considered as possible suppliers of the day-ahead mechanism calculation engine.
- The acquisition of a network modeling tool will be required.
- The data related to start up and minimum generation prices will not initially be included in the offers but rather entered in the IESO databases manually and updated as required. Using the existing MIM function and database to support a day-ahead mechanism until the MIM interface and database are replaced in 2009 – 2010 will eliminate the need to acquire this function as a part of the day-ahead mechanism option. This assumption will also eliminate the need for a number of changes to other systems (VCRs).
- CRS (our current settlements system) will not be replaced. The existing CRS will be modified and functions will be added to support new day-ahead mechanism charge codes.
- No new tools are required by the Market Assessment and Compliance Department to support implementation of any option. Existing tools will be modified to support day-ahead mechanism implementation.
- The costs associated with the permanent price forecast or the introduction of an energy forward market are identified separately.

[14] Procurement Scope for the Unconstrained Day-Ahead Market can be found at the following link: http://www.ieso.ca/imoweb/pubs/consult/se21/se21-20080318-Procurement_Scope.pdf

- Systems will require upgrades in 7 years. Based or our experiences with other market systems, cost of these upgrades is estimated to be a third of the initial implementation cost.
- Contingency costs, representing 20% of the base cost estimates, is included to cover the potential for additional unforeseen contingencies of the estimated costs.

The cost estimates for each of the options are described below. These costs represent the expected value estimate of the costs. Detailed descriptions of each option are included in Section 2. Interest costs have been included for completeness but will be excluded from the net present value analysis as interest costs are implicitly included in the CBA discount rate. Furthermore, this is an estimate based on knowledge and expectation of the design and implementation today. Unknown issues related to either the design or implementation can not be identified nor estimated until project implementation is underway or completed. Therefore, the accuracy of these estimates could be incorrect within an error band of ± 30 percent. For the purposes of the CBA, the high estimate is computed as 30 percent above the expected value estimated while the low estimate is computed as 30 percent below the expected value estimate.[15]

Option 1:

An enhanced Day-Ahead Commitment Process (DACP) with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees, along with the continued publishing of the IESO price forecast. The initial estimated implementation cost for option 1 is $27 M. Including system upgrades after 7 years (a third of initial estimate - $8.1M) the total estimated cost over the assessment period is $35.1M. The four major cost components are:

- **Labour and associated cost:** $3.8M
  - Project management
  - Completing the high level design
  - Stakeholder tasks, education and training
  - System architecture and DSoW
  - Business design
  - Procedure development
  - Market design and rules
  - User acceptance testing
  - Market testing and launch
  - **Permanent price forecast model:** $0.5M

[15] As a point of clarity, the 20% project contingency relates to cost differences to estimates for known work, while the ± 30 percent error band relates to cost estimates for work that due to its unknown nature is not at all present in the current estimate.

- **System procurement and development:** $17M
    - DASO + NMM
    - CR VCR
    - Other VCRs and minor applications
    - Hardware

- **Interest** $1.1 M
- **Contingency** $4.6M
- **Upgrades – 7 year refresh of IT systems** $8.1 M

It is expected that to maintain Option 1 will require the use of 2 full-time staff and a third of an existing staff's time. The full cost of hiring new staff is $150, 000 per year. It is not clear whether the IESO will be required to hire additional staff or if it will use existing staff to perform the work. Using additional staff will require work that is currently being done by this staff to be foregone (i.e., there would be an opportunity cost). Under either staffing solution, the $150,000 annually per full time equivalent estimate is a reasonable approximation of the project staffing costs. The total expected OM&A ongoing costs for Option 1 is therefore $350,000 per year.

<u>Option 2:</u>

An enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees and an Energy Forward Market (EFM). The initial estimated implementation cost for Option 2 is $27.5M. Including system upgrades after 7 years (a third of initial cost estimates - $8.25M) the total estimated cost over the assessment period is $35.75M. The four major cost components are:

- **Labour and associated cost:** $3.8M
    - Project management
    - Completing the high level design
    - Stakeholder tasks, education and training
    - System architecture and DSoW
    - Business design
    - Procedure development
    - Market design and rules
    - User acceptance testing
    - Market testing and launch
- **System procurement and development:** $17M

- DASO + NMM
- CR VCR
- Other VCRs and minor applications
- Hardware
- Energy Forward Market VCRs and minor applications $1M

- **Interest** $1.1M
- **Contingency** $4.6M
- **Upgrades – 7 year refresh of IT systems** $8.25 M

It is expected that Option 2 will require the use of 2 full-time staff. Using the same rationale for estimated staffing costs from Option 1, the total expected OM&A ongoing costs for Option 2 is therefore $300,000 per year.

<u>Option 3:</u>

Development of an Unconstrained Day-Ahead Market (UDAM) with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees that would produce day-ahead hourly prices and schedules for the next day. The UDAM would produce financial commitments based on day-ahead unconstrained schedules, and a physical advisory based on day-ahead constrained schedules. The initial estimated cost for Option 3 is $39 M. Including system upgrades after 7 years (a third of initial cost estimate - $11.7M) the total estimated cost over the assessment period is $50.7M. The four major cost components are:

- **Labour and associated cost:** $7M
  - Project management
  - Completing the high level design
  - Stakeholder tasks, education and training
  - System architecture and DSoW
  - Business design
  - Procedure development
  - Market design and rules
  - User acceptance testing
  - Market testing and launch
- **System procurement and development:** $24M

    - DASO + NMM
    - CR VCR
    - Other VCRs and minor applications
    - Hardware
- **Interest** $1.5M
- **Contingency** $6.5M
- **Upgrades – 7 year refresh of IT systems** $11.7 M

It is expected that Option 3 will require the use of 4 full-time staff. Using the same rational for estimated staffing costs from Option 1, the total expected OM&A ongoing costs for Option 3 is therefore $600,000 per year.

Baseline Scenario:

Carrying on with the current wholesale market and DACP design, along with the continued publishing of the IESO day-ahead price forecast of real-time HOEP and review existing reliability cost guarantees The total estimated cost over the assessment period is $1M which is comprised of $.5M to permanently implement the price forecast model and $.5M estimate for labour and other VCRs and minor applications for guarantee changes. It is expected that the Baseline Scenario will require the use a third of an existing staff's time. Using the same rationale for estimated staffing costs from Option 1, the total OM&A ongoing cost for the Baseline Scenario is therefore $50,000 per year.

4.2.2 Participants' Cost

In March 2008, the IESO issued a survey to all dispatchable market participants and marketers requesting estimates of the implementation and on-going OM&A costs that they would incur for participation in either Option 1 or Option 3 (see Appendix found at the following link: http://www.ieso.ca/imoweb/consult/consult_se21.asp). We expect participant costs for Options 2 to be similar to those for Option 1. The IESO received survey responses from participants covering about 90% of the generation capacity and 80% of the dispatchable load capacity. No marketers returned completed surveys. One participant that operates a Non-Utility Generation (NUG) facility completed the survey.

Projections of the cost for those participants that did not complete a survey were made using the estimates received from other participants. The overall estimated costs to participants in the industry are summarized in Table 1.

Table 1: Total Participant Costs

Option	Cost	Expected Value	High Estimate	Low Estimate
Option 1 or Option 2	Implementation	$2.4M	$4.6M	$2.1M
	Annual OM&A	$0	$0	$0
Option 3	Implementation	$6.2M	$11.7M	$5.3M
	Annual OM&A	$1.4M	$2.5M	$1.2M

The following provides a brief explanation of some of the underlying assumptions and computations used to arrive at these estimates:

- Some participants provided a singe estimate to reflect their expected costs. Others provided both a high and low estimate. The IESO used the survey results to calculate three estimates of the potential costs: an expected value estimate; a high estimate; and a low estimate. For those participants that submitted a single cost estimate we calculated a high estimate by multiplying the single estimate by 1.5 and a low estimate by multiplying the single estimate by .85. For those participants that submitted a high and low estimate, we estimated the expected cost as the maximum of (high estimate/1.5, low estimate/0.85). The factors used to compute that high and low estimate were reflective of the other quotes submitted by participants.

- Some participant's submitted a cost estimate for Option 3 only. Some submitted cost estimates for each option. Based on the surveys received, we estimated that the cost of Option 1 and Option 2 is roughly 40 percent of the cost of Option 3. For those participants only submitting an estimate for Option 3, we computed an estimate for Option 1 and 2 by multiplying their Option 3 estimate by 40 percent.

- To extrapolate the cost for the 10 percent of generators that did not complete a survey we did the following. First, we computed the total cost estimate for those generators that completed the survey. We then computed the total generation capacity of these same generators. We then divided the total estimated cost by the total generation capacity to compute an average cost per MW of capacity for this set of generators. We then multiplied this average cost per MW times the capacity of those generators that did not complete the survey to project their costs under each option.

- We used the same approach as described above to extrapolate the cost of the 20 percent of dispatchable loads that did not complete a survey.

- Non-Utility Generators (NUGs) were assumed not to incur any implementation and ongoing cost for each of the options. However, the one NUG that completed the survey indicated that it may incur a one time training cost if Option 3 was implemented. We extrapolated this cost for all NUGs.

- Based on the surveys received we expect that there would not be any increase in the annual operating cost under Option 1 and Option 2. From a business process perspective, either option would operate similar to the DACP.

- Costs for marketers and for LDCs were not obtained through the survey. However, we expect that these costs are unlikely to be material and should be captured within the high cost estimate.

4.3 Benefit Analysis

Each of the proposed options is expected to produce benefits in the form of improved efficiencies. The IESO has attempted to identify all potential efficiency impacts that could be attributable to the implementation of each of the options. Some of these efficiencies have been quantified and monetized. The monetized benefits are discussed in section 4.3.1. Other impacts were more difficult to monetize or even quantify either due to the nature of the impact or the lack of data available to the IESO. Furthermore, other impacts were not expected to be material and hence were dealt with qualitatively in this report. The non quantified benefits and how they are accounted for in the net present value analysis are discussed in section 4.3.2.

4.3.1 Monetized Benefits

Unit Commitment Efficiencies

The IESO's analysis indicates that there are material efficiency gains that would be realized by improving the unit commitment process. Each of the day-ahead options provides for this opportunity. In particular, the IESO estimates that the introduction of three-part offers and 24-hour optimization of all operating costs would provide between $4 million and $5 million annually in improved efficiencies for the province.

Current Situation and Reasons for Potential Improvements

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 Day-Ahead Generation Cost Guarantee (DA-GCG) removes the financial risk associated with the day-ahead commitment by compensating generators who do not recover their commitment costs (i.e., start-up costs, speed-no-load costs and OM&A) through real-time market revenues. Generators are eligible for the DA-GCG if they are scheduled in the DACP for the length of their minimum run-time. The DA-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 three hour to one 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 in pre-dispatch for the entire period of its minimum run time or even its minimum loading point.

For both of these programs, generators do not submit three-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 energy offers are reflective of incremental or marginal cost. This process can at times result in an over-commitment of generation and lost efficiencies. In particular, 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 higher 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.

The current design of the DA-GCG and SGOL can create incentives for the generator to ensure that their units are committed, even when it is unlikely to be economic to run the facilities across the day. Under these programs, a generator can be virtually assured that it will be committed by offering its minimum load quantities at a very low price (even below its marginal cost) for the period of its minimum run time. When the unit is committed, it will be assured to at least recover the cost of running at minimum loading point for the minimum run time – it simply has to submit its fuel costs for running for this period after the fact and will be topped up for any cost short-falls. However, by ensuring that its unit is on-line, the generator can then be available to provide more output if prices run higher than expected. In short, there is very little risk to the generator from being committed even when it does not expect to be economic across the day,[16] but there is a positive "up-side" for being available in the event that prices rise beyond expected levels. While this potential problem has not materialized to any large extent today, as more non-quick start facilities enter the market as planned under the IPSP, there is a risk that this practice could become more pervasive, with considerable implications for the cost of operating the market. The implementation of any of the day-ahead options would remove these flaws of DA-GCG and SGOL programs and diminish the opportunities for the "strategic offers" of this nature. However, absent the adoption of one of the day-ahead options, the IESO would still review the commitment programs to reduce the incentives for such "strategic offers".

Method Used for Calculating Efficiency Gains:
It is anticipated that three-part offers and optimization of all operating costs over the entire day would improve the efficiency of dispatch and lower the total cost of dispatch. It would also provide additional competitive discipline with respect to ensuring that only the most economic units are committed. The

[16] There is an outage risk as these programs do not compensate a generator if it goes off-line prior to the end of their minimum run time.

Appendix found at the following link: http://www.ieso.ca/imoweb/consult/consult_se21.asp provides a detailed description of the IESO's methodology for calculating these efficiency gains. The following is a summary of the IESO's approach.

Step 1: Determine if DACP has over-committed any generation

To identify over-commitments by DACP, the average cost per MW for each generator committed is calculated and compared against the relevant shadow price for a generator's location. If the shadow price is less than the average cost per MW, the generator is deemed as over-committed. This is so because the shadow price represents the cost to serve the next MW of load at the location of the generator and if the average cost per MW for the generator exceeded its shadow price, it was not economic for that generator to be committed by DACP.

Step 2: Calculate the efficiency gains if the over-committed generator was replaced by other less expensive resources

The efficiency gain from avoiding overcommitted generation is in the form of using less expensive resources than the over-committed generator. This efficiency gain is calculated as the difference between the total cost of the generator that was over-committed and the total cost of replacing the output of this generator with output from generation that was unused but available (i.e., units that were on-line in real-time and that were not bottled due to transmission) or less expensive import offers that were not scheduled.

Estimated Efficiency Gains:

To estimate the potential efficiency gains that could be achieved with the implementation of either one of the day-ahead options, the above methodology was applied to the DACP results of 2007. The following is a summary of the findings of this analysis.

- For the year of 2007, there were a total of 94 days in which the current DACP process over-committed a unit. Over-commitment occurred the least during the summer months. On average, there were 5 days of over-commitment during each of the months from June to August. Whereas, for each of the other months, there was an average of 9 days of over-commitment.
- For the days when there was an over-commitment, the average amount of generation over-committed was about 1000 MWh per day or 100 MWh for 10 hours.
- The IESO estimated the cost savings (efficiencies gains) that could have been realized via three-part offers and 24-hour optimization of all operating cost during the 2007 period to be in excess of $6 million dollars.
- To project the cost savings for the 15 year period covered in the CBA, we assumed that supply sources would change as per the IPSP. We adjusted our 2007 resource mix and resource offers to reflect the cost structure of the future fleet, using different assumptions for heat rates for the projected gas generators and assumptions for start-up costs for these units. We then recalculate the occurrences of when there would likely be over-commitment and the cost of this over-commitment.

Using different assumptions regarding unit heat rates provides us with three estimates for efficiency gains, the expected value estimate and the high and low estimate.

- We estimate that with the phase-out of coal generation by 2014, the replacement costs for over-committed units would increase and thus reduce the overall efficiency gains. After 2015, the savings remain constant as the resource fleet also stabilizes. The table below summarizes the cost savings derived from unit commitment efficiencies for 2010 to 2022.

Table 2: Efficiency Gains from Improved Unit Commitment

Year	2010	2011	2012	2013	2014	2015	2016 to 2022
Expected Value	$5.0M	$4.9M	$4.5M	$4.5M	$4.5M	$4.3M	$4.3M
High Estimate	$5.3M	$5.2M	$4.9M	$4.9M	$4.9M	$4.8M	$4.8M
Low Estimate	$4.8M	$4.6M	$4.1M	$4.1M	$4.1M	$3.9M	$3.9M

Reduced Cost for Gas-Fired Generators

Analysis conducted for the IESO by Baden Energy Consulting Limited (BECL) indicates that providing greater certainty of dispatch a day-ahead for the electricity market will reduce the uncertainties and risks associated with natural gas procurement for gas-fired generation facilities. In particular, the implementation of any of the three day-ahead options would offer gas generators more predictability and a financial guarantee of their next day's gas needs. This would lead to efficiency gains in the form of reduced commodity costs and risk (hedge costs), reduced variable costs associated with injections to and withdrawals from storage, and reduced annual fixed costs for storage services. BECL estimates average annual efficiency gains between $7 million and $18 million; the amount of efficiency gains depends on the time in which the generator receives its commitment (either 11:00 am or 3:00pm) and the level of accuracy of the commitment provided.

Current Situation and Reasons for Potential Improvements

The natural gas consumption patterns for most industrial natural gas consumers are predictable, and for the most part, self-controllable. As a result, these consumers can order the appropriate amount of natural gas a day-ahead of actually needing it, with the hourly variation in actual consumption volumes and scheduled volumes being very minor. The predictability of their gas consumption patterns allows these customers considerable flexibility to schedule their next day gas needs at what they believe to be the best available price trading in the market that day. It also means that they can make appropriate arrangement with upstream pipelines, storage operators and distribution utilities to plan for the delivery and receipt of the required gas so as to minimize these additional costs. Finally, any minor variation between actual consumption and scheduled volumes can be managed with existing services and minimal cost.

In contrast, the hourly consumption patterns of gas-fired generators are less predictable. This is a product of the unpredictability of the electricity market and the electricity output of the gas-fired generation more specifically. Gas-fired generation is often the marginal generation unit in the electricity market which means that its electricity output can vary widely within an hour. Furthermore, variations in electricity demand or the unpredictable performance of other types of generation make it difficult for the gas-fired generator to predict a day in advance what will be its gas consumption requirements for the next day.

As a result, hourly and daily variations in actual consumption versus volumes scheduled on the gas-transmission systems for generators can be significant and may require supplemental pipeline services to manage the imbalances. For instance, gas generators run the risk of purchasing and scheduling gas supply a day ahead and then not being dispatched in real time, which would result in the generator's gas supply packing the pipeline. This can result in substantial penalties being assessed against the generator by the pipeline operator unless alternate markets for the gas can be found (such as storage), which could in turn lead to increased balancing costs for the generator. Conversely, if the generator does not nominate its gas supply ahead of time, (to avoid the risk of having too much gas), the generator runs the risk that the physical supply and pipeline transmission capacity may not be available when it is dispatched. Further if the gas is available and can be transported, the price could be at a significant premium versus normal day-ahead index pricing. These risks are heightened in the winter, especially on a cold winter day, and seasonally when storage levels are low.

The enhanced pipeline services, introduced following the Natural Gas Electricity Interface Review (NGEIR) undertaken by the Ontario Energy Board, do provide a generator with tools to better manage imbalances that will occur as the result of the unpredictability of the gas-fired generators' next day's consumption pattern but the enhanced services do not eliminate the underlying uncertainties. The unpredictability of the next day consumption pattern creates commodity cost risk, and requires the gas generator to incur additional transactions cost; it must purchase additional storage capacity and incur additional injection/withdrawal costs to manage the variability or forgo the opportunities to re-optimize its gas incremental/decremented gas needs within the electricity trading day.
The implementation of a UDAM would offer these gas generators more accurate signals of their real-time gas needs and a financial guarantee of their next day's electricity schedules. Increased certainty and financial guarantees would lead to cost saving for the generators and provide overall efficiency gains for the province as a whole.

Method Used for Calculating Efficiency Gains:
In September, 2007 the IESO contracted with BECL to analyze the implications of introducing day-ahead market mechanisms with improved financial guarantees for gas-fired generation facilities. In particular, BECL were asked to identify how the costs and risks associated with purchasing and scheduling natural gas to meet a dispatch schedule under the current market design would change with the implementation of improved day-ahead mechanisms. The approach adopted by BECL to analyze this issue and their conclusions are included in their report to the IESO (See Appendix found at the following link: http://www.ieso.ca/imoweb/consult/consult_se21.asp). The following represents a brief summary of their study methodology.

- BECL used the operating characteristics of a generic natural gas-fired generator to estimate the operating schedules of a potential gas-fired generator under a variety of market scenarios in two locations: one inside the Union franchise territory at a location west of the Dawn Hub (West Zone), the other inside the Enbridge franchise at a location where the generation facility could be connected to the TransCanada Pipeline Limited System via a dedicated pipeline owned and operated by Enbridge (Toronto Zone). BECL made certain assumptions regarding the time frame in which the generator purchased its gas and nominated gas delivery. Since the requirement to buy gas a day or two in advance of electricity production creates commodity cost risk for the generator, a "hedge cost" premium was estimated. The hedge cost was estimated as the expected value of the difference between the market value of the gas consumed and the actual purchase cost of the same gas. Certain assumptions regarding the need for storage and balancing services (NGIER services) were also made. The generic generator offered into the day-ahead (DACP or UDAM) or in real-time at its variable operating cost which of course depended on the price paid for gas and included the hedge cost estimate and the variable cost related to the NGIER services.
- **(Baseline Scenario)** BECL estimated the operating schedules for the generic generator for the baseline scenario. The baseline scenario assumed that the generic generator would buy and nominate its gas requirements, day-ahead, based on the level of financial commitment that it received from the DACP. Under the DACP, generators are committed only for their minimum run quantity and for their minimum run time. A DACP schedule was computed for each hour in 2007 using the relevant DACP shadow price for the location of the generic generator. Gas quantities and delivery nominations were determined based on the financial commitment received in the DACP. Real-time constrained dispatch schedules for each hour were then computed using the relevant real-time shadow price for the location of the generic generator. Based on both the DACP and real-time schedules derived from this process BECL re-evaluated the initial assumptions regarding the required NGEIR services and the hedge cost and if necessary adjusted the services required to ensure only the minimum amount of services were used. Based on the updated assumptions for NGEIR services, BECL then re-estimated the schedules for the generic generator. BECL iterated through this process until the minimum level of services were determined.
- **(UDAM Scenario)** BECL then computed similar outcomes for the generic generator under a UDAM. It computed the UDAM schedules for two different time frames: one for a UDAM that provided financial commitments by 11:00am (DAM1), another that provided financial commitments by 3:00pm (DAM2).[17] The UDAM schedules were computed using the unconstrained price produced in the DACP. Under a UDAM, the gas generator is eligible to receive a financial commitment beyond just its minimum run quantity and minimum run time. In this model it was assumed that the generic generator would buy and nominate gas deliveries for its entire day-ahead unconstrained schedule. As was done for the baseline scenario, the UDAM schedules were compared to the real-time constrained schedules for the generic generator and

[17] The timing of the UDAM closing influenced the timing at which natural gas could be purchased. Modeling different closing times captures the potential commodity risk faced by a gas-generator due to the different timing of the gas day and the electricity day and ultimately affected the hedge cost.

through the same iteration process used in the baseline scenario, the hedge cost and the optimum level of NGEIR services were computed for both locations.

- **(Proxy Price Scenario)** A third set of scenarios were then computed to approximate the outcomes that would occur under a more accurate UDAM schedule. To approximate the level of accuracy that could be achievable under a UDAM, BECL used the level of “convergence” achieved by the New York day-ahead market. In particular, BECL computed a *Proxy Price* for the UDAM. This price was computed so that the average absolute difference between the Proxy Price and the real-time shadow price matched the absolute average difference between the New York Zone A day-ahead prices and the New York Zone A real-time prices. BECL then re-ran their DAM1 and DAM2 scenarios (as discussed above) using the Proxy Price instead of the unconstrained price of the DACP. Once again, the same iterative process to compute the hedge cost and optimal levels of NGEIR services for both locations was followed.
- Finally, BECL compared the hedge cost and the cost to purchase the level of NGIER services under the baseline scenario to the same cost under each of the other scenarios (UDAM Scenario, and Proxy Price Scenario). The change in these costs represented the incremental efficiency gains attributable to each scenario. BECL then extrapolated the cost savings of the generic generator to the current fleet of gas generation facilities and the projected fleet of gas generation facilities until 2027 as projected under the IPSP. This provided an estimate of annual efficiency gains for each year until 2027.
- **(DACP Advisory Scenario)** After receiving the BECL initial analysis, the IESO asked that a forth scenario be run to measure the sensitivity around the assumption that the generic generator would buy and nominate its gas requirements, day-ahead based only on its financial commitment. This scenario could be used to adjust the expected efficiency gains to capture the potential that if in practice, a natural gas-fired generators purchased beyond the current DACP financial commitment. To conduct this analysis, BECL reran the model assuming that the generic generator purchased its next day’s gas requirements based on its current DACP advisory schedules. As was done in the previous scenarios, BECL than compared the hedge cost and the cost to purchase the level of NGIER services under the baseline scenario to the same cost under the DACP Advisory Scenario to estimate the potential efficiency gains. Once again, these estimates represent an adjustment to the previous result that accounts for a different starting assumption regarding the need for financial commitment.

Estimated Efficiency Gains:
The BECL analysis produced the following conclusions.

- The results of the baseline scenario were consistent with the operating experience of existing combined-cycle gas-fired generation in Ontario; predicted load factors were close to the actual load factors for these generators.
- Both UDAM Scenarios (DAM1 and DAM2) resulted in annual efficiency gains for the province as a whole. The annual efficiency gains for DAM1 ranged from $7.5 million to $14.3 million over the projected time period. The annual efficiency gains for DAM2, were slightly less; they ranged from $7 million to $11.5 million over the projected time period. The implication is that a UDAM with an earlier closing time is likely to reduce the hedge cost risk and lead to larger efficiency

gains. The efficiency gains in this scenario were derived by simply providing a financial commitment beyond unit minimum, leading to the need for less NGIER services as well as reduced start-up costs.

- Both Proxy Price Scenarios also resulted in annual efficiency gains. The annual efficiency gains for DAM1 ranged from $8.7 million to $17.9 million over the projected time period. The annual efficiency gains for DAM2, were slightly less; they ranged from $8.7 million to $13.7 million over the projected time period. The additional efficiencies for the Proxy Price scenario are a result of the improved convergence of prices day-ahead to real-time. In the Proxy Price scenario, the efficiencies were largely influenced by the reduction in injection and withdrawal from storage of a smaller total volume of gas.
- Finally, the DACP Advisory Scenario indicated that the estimates of the efficiency gains of the previous scenarios should be reduced by between $1.4 million to $3.2 million annually, if one believed that natural gas-fired generators do not require a financial guarantee to purchase gas and instead would purchase beyond the DACP financial commitment. The majority of the efficiency impacts were a result of the reduced hedge cost due to the greater volume purchased day ahead as per the advisory schedule versus purchasing only for the DACP financial commitment. There were essentially no efficiency gains attributable to a reduction in the other costs attributable to the difference between these two strategies.

For the purpose of the CBA, the IESO uses the efficiency gain estimates of the Proxy Price Scenario for DAM2, as its expected value estimates for the purpose of computing the net present value for each option. For the low value estimate the IESO uses efficiency gains for the UDAM Scenario of DAM2 less the adjustments estimated in the DACP Advisory Scenario. The IESO uses the efficiency gains for the Proxy Price Scenario of DAM1 as the high estimate.

Day Ahead Demand Response Efficiencies

The IESO retained the services of Dr Dean Mountain and Dr Ken Deal to address the following question: would a day-ahead market that provides more accurate day-ahead price signals and potential financial commitments of prices and consumption quantities, enable more price responsiveness of Ontario's consumers? Their study of the question involved two tasks: (i) a literature review on demand responsiveness in jurisdictions with and without day-ahead markets and an assessment of the likely impact of day-ahead markets on customer price responsiveness; and (ii) an estimate of the sensitivities of large Ontario customers to firm day- ahead prices as measured by elasticities based on survey research data. The outcome of this analysis provided the IESO with estimates of relevant Ontario demand elasticities.

Current Situation and Reasons for Potential Improvements

The IESO operates a real-time market in which electricity prices are determined in five minute intervals. Supply and demand conditions can change significantly from interval-to-interval and from hour-to-hour, causing real-time prices to vary significantly and often unexpectedly. Furthermore, consumers

learn of the real-time price changes as they happen, making it difficult for them to make efficient consumption decisions in response to these price changes. The volatility of the real-time prices and the lack of advance warning of these price changes create risk for consumers who seek to plan their operations. Many consumers require at least a one day notice to properly plan their operations.
The IESO publishes pre-dispatch results, including prices, which are intended to signal evolving market conditions as the real-time dispatch hour approaches. These prices are published day-ahead as early as 11:00am. The DACP also provides a "pre-dispatch of record" price at roughly 3:00pm day-ahead. If effective, these advance price signals could facilitate better consumption planning and lead to more efficient consumption decisions in the day-ahead time frame. However, the common industry view is that the current pre-dispatch price signal is not a "reliable" predictor of real-time prices.
A "reliable" forecast of the next day's real-time prices would enable consumers to better manage their next day's consumption and enable more efficient consumption decisions. Furthermore, the opportunity to "lock-in" to a firm price and quantity through a day-ahead financial commitment would provide a means for consumers to manage their price and quantity risk.

Overview of the DM Study
The Deal and Mountain (DM) study was conducted in two phases. The first phase entailed a thorough review of the literature on demand response in jurisdictions with and without day-ahead markets. The second phase of the study consisted of two stages. Stage 1 involved qualitative exploratory research designed and implemented as two focus group discussions with large industrial and large commercial customers. The outcomes of these discussions were used to design a specialized survey which was administered to approximately 400 large customers in Ontario, 42 of whom completed the survey. Stage 2 of the second phase consisted of a detailed econometric assessment of the price responsiveness of the large customers. The detailed report is found at the following link: http://www.ieso.ca/imoweb/consult/consult_se21.asp.

Phase 1 of DM study
The researchers conducted a thorough review of relevant studies on price responsiveness in jurisdictions with and without day-ahead markets. They also drew upon unpublished studies as well as their personal expertise in conducting similar studies in the New York and Texas electricity markets to provide a solid assessment of demand response potential in Ontario with the introduction of a day-ahead market. As the authors point out there is generally a paucity of research in that area:

> "*Ideally to assess the impact of a day-ahead market on demand responsiveness, one would want to conduct a panel data econometric analysis of a group of consumers before and after the implementation of a day-ahead market. From such a study, one could then estimate the incremental improvement in the price elasticity of consumers and this improved elasticity measure can be used to quantify the net incremental efficiency benefits of a DAM. To our knowledge, no such studies have ever been conducted."* [DM study page 6].

Based on their review, the researchers provided an expert opinion on the plausible range of elasticities that may be observed with the introduction of a day-ahead market in Ontario. The key findings of phase 1 of the report are:

1. For large industrial customers the review suggests an elasticity of substitution ranging from 0.035 to 0.24. For those with interruptible processes own-price elasticities could average -0.27.[18]
2. For large commercial customers in the government and education sectors, the elasticity of substitution could be between 0.20 and 0.40.

Phase 2 of DM Study

Phase 1 of the study provided preliminary elasticity estimates. In phase 2 the main objective was to quantify the elasticities of large customers[19]. In the first stage of phase 2, the researchers conducted two in-depth group discussions with consumers. The first group consisted of dispatchable consumers and the second group consisted of large non-dispatchable commercial customers. The results from these discussions provided a great deal of information that was used to design the specialized survey.
The survey exposed respondents to a series of prices and consumption decision scenarios. In phase 2 of stage 2, the researchers conducted a detailed econometric analysis of the survey response data. Various demand models were specified and tested to measure the price elasticities. In addition, the researchers analyzed the relationship between the level of accuracy of the day-ahead price forecast and the desire to lock-in consumption day-ahead. The key findings of the Phase 2 of the report are;

1. The more inaccurate the day-ahead price forecast, the more responsive customers are to day-ahead prices. With decreased forecast accuracy customers are more cautious and price sensitive in their attempts to avoid the risk of potential higher real-time volatility. On the other hand, with a more accurate day-ahead price forecast this risk concern dissipates.
2. The day-ahead elasticity of substitution between peak and off-peak consumption ranges between 0.307 and 0.388.
3. The day-ahead own-price peak elasticity ranges from -0.12 to -0.151
4. The day-ahead total impact own-price peak elasticity ranges from -0.20 to -0.23

Overall, the authors conclude that these elasticities, along with the other findings from this research, support the notion that a day-ahead market with improved day-ahead prices could have real efficiency benefits for large industrial, commercial and institutional customers in Ontario.
As part of SE-58, the IESO conducted a numerical study to assess the potential efficiency gains from providing an improved day-ahead price forecast.[20] This analysis estimated annual efficiency gains in the range of $200,000 to $2 million, depending on the assumed level of elasticity. The DM elasticity estimates suggest a level of price responsiveness of large Ontario consumers that is larger than the level assumed by the IESO in its SE-58 analysis, implying that the efficiency gains are likely to be on the upper range of the initial estimates.

---

[18] The own price elasticity, provides a measure of the degree to which consumers are willing to reduce consumption in a given hour in response to a price change. The elasticity of substitution provides a measure of the degree to which consumers are willing to switch the ratio of peak to off-peak electricity consumption across hours in a day or across a couple of days in response to off-peak to peak price changes.

[19] The focus on large customers stem from the results of previous research in other markets which show that most of the price responsive would likely come from a small group of large customers.

[20] The numerical study conducted for SE-58, Providing a Day-ahead Price Forecast of Real-time Price, can be found at http://www.ieso.ca/imoweb/pubs/consult/se58/se58-20080401-IESO_Position_Paper_Price_Forecast.pdf

4.3.2 Non quantified Impacts

Embedded Generation

The number of embedded generators is planned to grow significantly 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 (or if it has spare capacity beyond what it has been contracted for), 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.[21]

As a result of an unpredictable real-time price, it is a challenge for these generators to forecast 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 - missing opportunities to operate 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. This would provide additional operating efficiencies within the province as it would mean that more efficient generation would be induced to run ahead of less efficient generation; the province's energy requirements would be met but at a lower overall cost.

As part of the IESO's review of the merits for publishing a real-time price forecast stakeholders from the embedded generation community indicated the following.

- Those members who operate embedded generation for economic reasons are enthusiastic about the opportunity to gain more predictable pricing on a day-ahead basis. These members feel that there would be significant financial and operational benefit to having a known day ahead pricing structure. Embedded generators operating for base load steam/electrical generation see limited benefit to day ahead pricing.
- This type of forecast may also allow generators and Local Distribution Companies to better communicate with one another in ensuring that run times and switching can be configured to accept generation on expected high-price days ahead of time with more accuracy.

---

[21] There may be contractual arrangements that would allow sharing of these revenue opportunities. Nonetheless, the incentives to respond to HOEP should still exist.

Each of the options considered provide for the potential of improved price signals day ahead and hence it is expected that each option should realize additional efficiency benefits through improved operation of the provinces embedded generation. Only the UDAM would provide embedded generators with a financial guarantee. For the purpose of the CBA, the IESO treats this as a positive benefit, with the incremental benefit under a UDAM likely being larger (but not materially) than the benefit attributable to the other options. While not quantified, these benefits could be material depending on the size of the embedded generation fleet and the nature of the contracts of this fleet.

Import/Export Trade

Stakeholders indicated early on in our assessment a desire to have a day-ahead market as means to introduce more efficient levels of import/export trade, or better alignment with contiguous markets. The IESO contracted with LECG to analyze the implication of import/export trade under a UDAM. Their analysis which follows indicates it is unclear whether a UDAM would provide incremental benefits relative to the enhanced DACP or current market design.

Improved day-ahead unit commitment, scheduling and performance incentives have been one of the drivers for implementation of day-ahead markets in competitive energy markets such as those coordinated by PJM, the NYISO and the MISO. It was initially envisioned that the implementation of the UDAM would allow realization of substantial benefits arising from the scheduling of imports and exports in a day-ahead market, including:

- Improved convergence between day-ahead and real-time prices by including export schedules in the UDAM;
- More efficient responses to changes in market conditions by eliminating the many restrictions on offsetting imports and exports;
- Reductions in the cost to consumers of paying imports scheduled in the DACP the higher of their offer or the real-time price.

The possibility of these benefits was premised on the thought that the UDAM could achieve some or all of the same benefits as day-ahead markets that are based on LMP pricing. In LMP markets, however, there is no distinction between the price used to schedule and that used to settle import and export transactions. Imports and exports either clear or do not clear in the day-ahead market, and either clear or do not clear in the hour ahead pre-dispatch and settle at LMP prices aligned with these schedules, leading to efficient outcomes for schedules with external markets.

The day-ahead market under consideration for Ontario (UDAM), however, would be based on a single price, with separate constrained and unconstrained prices and schedules. As a result, imports and exports will receive both a constrained and unconstrained schedule in the day-ahead market, as well as a constrained and unconstrained schedule in the pre-dispatch, so that there are may additional scheduling scenarios in the UDAM, in which transactions clear in the constrained pass but not the unconstrained pass or vice versa, none of which have been addressed in other day-ahead markets.

Detailed analysis of imports and export scheduling and pricing rules within the context of a UDAM has shown that because of the separate constrained and unconstrained passes:

- There would continue to be a need for an import offer guarantee for imports scheduled in the constrained pass that did not receive a financial schedule.
- There would continue to be a potential for offsetting import and export transactions to magnify uplift costs.
- The treatment of day-ahead constrained import schedules in the real-time pre-dispatch unconstrained pass could result in increases in the cost to Ontario consumers of the export subsidy[22].
- The potential for import transactions to clear in one but not both passes of the UDAM has the potential to raise the cost of imports relative to an improved DACP.
- Rules designed to minimize the additional costs to consumers arising from the unconstrained pass could serve to deter needed imports in some circumstances.

The single price system for imports and exports often subsidizes exports in the current real-time market. An important criterion in developing the UDAM design was that it not magnify the cost to Ontario consumers of the current export subsidy nor increase the cost of imports scheduled in the constrained pass. While the IESO believes that it has been able to identify a general set of settlement rules that would permit implementation of the UDAM and avoid material increased costs to Ontario consumers either in payments for imports or the cost of the subsidy for exports, the resulting design also offers little prospect for cost reducing benefits for Ontario consumers from improved scheduling of imports and exports.

- Rules similar to the current rules regarding off-setting imports and exports would need to be retained and extended to transactions scheduled into the day-ahead market.
- The need to avoid magnifying the export subsidy would limit improvements designed to enable the UDAM price to provide an improved signal regarding real-time conditions.
- Even with changes to address the potential for cost increasing outcomes, it appears unclear whether the net impact of a UDAM would be to increase the net cost of imports and export subsidies, relative to the current design.

The key UDAM feature that gives rise to these difficulties is the existence of unconstrained pass schedules that differ from constrained pass schedules. While these unconstrained day-ahead financial schedules improve performance when they are consistent with the constrained schedules, they greatly complicate the market design. Given that the UDAM offers little prospect for cost reducing benefits for Ontario consumers from improved scheduling of imports and exports, the IESO does not attribute any potential additional benefits to Option 3.

---

[22] Export subsidy refers to different participant's scheduled import and export transactions that offset each other and result in no net flow of power, while requiring payments by Ontario consumers for the subsidized exports (the difference between the unconstrained price at which export power is purchased and the offer prices at which import power is sold back to Ontario). See Appendix found at the following link: http://www.ieso.ca/imoweb/consult/consult_se21.asp for a full discussion on export subsidy

Reliability

In June 2006, the IESO implemented a Day-Ahead Commitment Process (DACP). 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. The IESO is confident that we can maintain reliability under the current DACP. In our review of potential day-ahead improvements we have been focused more on finding options that could deliver equivalent reliability in a more efficient manner as the incremental reliability benefits relative the DACP would not be material.

That being said, to the extent that a day-ahead option improves operational stability and encourages additional consumer participation in the market, it will enhance 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. 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. Each of the different options provides, to the same degree more or less, these improvements; the difference between each option depends only on the level of price and scheduling accuracy that could be achieved. As a result, they should offer additional reliability benefits than what would be afforded under that status-quo.

The IESO does not expect that the reliability benefits would be material. Nor do they expect the benefits to be materially different across each option. For this reason, the IESO treats these benefits as having a positive but not material impact within its CBA assessment of each option.

Impact on Real-time dispatch

Some stakeholders raised a concern that a day-ahead option that provided generators with a financial guarantee day ahead could reduce the incentives for generators to efficiently follow demand in real-time. [23] The IESO agrees that design features of the UDAM or enhanced DACP can give resources reasons to submit offers or bids into the real-time market that do not reflect their actual real-time costs. To the extent that this could occur it could undermine some of the efficiencies that exist today creating negative benefits for each option when compared against the Baseline Scenario.

[23] See Ontario Power Generation's comments at http://www.theimo.com/imoweb/pubs/consult/se21/se21-20071012-Ontario_Power_Generation.pdf. In particular, OPG stated the concern as "If the CES contracted generation is converted to DAM deeming there may be a tendency for these resources to simply follow their DAM schedule in real-time. It is premature to conclude that this will occur but the final DAM design must provide incentives for the gas fired capacity new CCGTs to follow demand in real-time."

Production Cost Guarantee Design Risk

One critical issue pertains to the design of the production cost guarantee (PCG). The PCG is intended to ensure that the net revenue paid to resources committed and dispatched by the IESO is sufficient to cover their offers (or bids) to provide the services they were scheduled and/or dispatched to provide. If the net revenue that such a resource receives is less than the sum of its offers to provide the services it provided, it would receive a PCG payment to make up the difference.

The details of how the PCG payments are calculated can affect incentives for resources to submit offers or bids in the real-time market that reflect their real-time costs. PCG payments under each of these alternatives have not been fully defined, so there cannot be any assurance at this point that they would not also present some incentives for resources to modify their real-time offers or bids in attempts to preserve either PCG payments they would be due (in the case of the UDAM) or PCG payments they would expect to receive (in the case of the DACP enhancements) if their real-time operation reflected their day-ahead schedules. The IESO does not see this as having material negative impact on efficiency gains. The IESO is aware of this design risk but is confident that a PCG for each option can be designed to lessen this potential inefficiency or negative impact on benefits. The IESO does not see this as having material negative impact on efficiency gains of any of the options.

Second Settlement Risk for Constrained-Off Resources

The UDAM's financial commitment and two-settlement system could reduce efficiency of the real-time dispatch. Consequently, for the UDAM, we need to consider the risks that resources may assume as a result of having been scheduled to produce energy in the day-ahead market, and the impact that those risks would have on the offers in both the day-ahead and real-time markets.

In the UDAM, each resource that is scheduled in the unconstrained pass of the day-ahead market would receive the day-ahead unconstrained price for the amount of energy it is scheduled to produce in that pass. If a generator's real-time unconstrained schedule is not at least as large as its day-ahead unconstrained schedule, part or all of the loss it incurs as a result of being paid the day-ahead price and covering that obligation at the real-time price will not be offset by a CMSC payment. This potential may induce such generators to submit relatively low real-time offers in an attempt to increase their eligibility for CMSC payments and protecting themselves against such losses. In cases where they submit too low an offer and cause themselves to be dispatched to operate in real time, an inefficient outcome arises because the IESO's real-time dispatch was based on real-time offers that did not reflect actual real-time costs. The wrong generator is operating. This impact is expressed in the benefits analysis as a negative impact on the potential efficiency gains attributable to Option 3.

Alignment of constrained and unconstrained algorithms

Day-ahead markets, working within the context of a two-settlement system, are implemented to provide market-based financial incentives to market participants to operate according to their constrained day-ahead schedules or to make efficient changes to their operation in real-time based upon the results of the real-time market. The design of the financial settlements under a UDAM in Ontario would differ significantly from the day-ahead financial settlements implemented in other regions with a day-ahead market because of the use of unconstrained pricing in Ontario – two algorithms one for calculating the financial commitment and one calculating the schedules.

As the IESO has worked through the design of the UDAM unit commitment and scheduling algorithm and the related day-ahead financial settlements, many issues have arisen due to the differences between the constrained pass schedules and prices and the unconstrained pass schedules and prices that are central parts of the single unconstrained price UDAM. It is inevitable that the schedules resulting from the constrained and unconstrained unit commitment and scheduling runs would differ because transmission constraints are not represented in the unconstrained runs. Nevertheless, a goal has been to align the constrained and unconstrained schedules to the greatest extent possible, particularly with regard to the commitment of generating units and the schedules for imports and exports. Difficulties were expected in the context of an unconstrained price settlement system, and the development of the rules and protocols has reached the stage at which the IESO believes a workable system could be produced in the final design phase.

However, it has been challenging to design the scheduling algorithms for the UDAM to align the day-ahead constrained advisory schedules and unconstrained financial schedules so as to provide market participants with financial schedules that anticipate their expected real-time operation, or even that match the day-ahead unit commitment. Improvements in the day-ahead unit commitment will not lead to actual cost savings unless market participants have pricing incentives to follow their constrained unit commitment and schedules and, also, do not have incentives to distort the bid or offer information submitted to the IESO. Taking into account the probable lack of alignment, the settlement rules must address and mitigate this financial risk in order to prevent incentives leading to inefficient unit commitment and dispatch.

The work to date indicates that the UDAM scheduling and settlement rules are likely to be complicated, even with the simplification of limiting the CMSC to the real-time market.[24] We believe that the problems that we are seeing are intrinsic to the UDAM, because it results in day-ahead financial schedules that may be inconsistent with the constrained schedules. While it appears to be possible to create a system of schedules and settlements based on a single unconstrained price that will create incentives for market behavior consistent with the constrained unit commitment and advisory schedules, it also appears that these settlement rules will be more complex than expected. More importantly, it appears that the alignment of incentives would be achieved by imposing costs on consumers that would not be incurred within an enhanced DACP.

The IESO needed to address the matter of whether the additional benefits of a UDAM, in comparison with an improved DACP, justify the additional settlement complexity and costs. Working with LECG, we have examined whether the day-ahead financial settlements that are part of the UDAM are likely to provide net benefits relative to an improved DACP or, alternatively, whether new issues and difficulties could arise from attempting to implement a day-ahead market with a single unconstrained price UDAM.

---

[24] The UDAM limits CMSC to the real-time market in an effort to create a simpler system than that discussed in the 2004 DAM project, which included both a day-ahead and real-time CMSC.

LECG's detailed analysis can be found in the Appendix found at the following link: http://www.ieso.ca/imoweb/consult/consult_se21.asp.

While IESO remains confident that a workable system could be produced in the final design phase, it appears that this "incentive compatibility" can only be achieved in the UDAM settlements through considerable complexity and additional costs for consumers. As a result, there would be a negative impact on UDAM efficiency relative to any of the other options presented.

Integration of Regulated and OPA Contracts

One of the issues that the IESO indicated would have to be addressed in order to implement a UDAM was the integration of regulated and OPA contracts, as well as the NUG contracts into the day-ahead operations. As outlined in our April 11, 2008 Design paper, the IESO has determined that these contracts could be integrated. However, the integration may have implications for the costs and benefits attributable to the UDAM.

OPA's Clean Energy - (Clean Energy Supply, Combined Heat and Power Projects (CHP) or Natural Gas Simple Cycle/Combine Cycle Projects)
The IESO believes that OPA's Clean Energy Supply (CES), Combined Heat and Power Projects (CHP) or Natural Gas Simple Cycle/Combine Cycle Projects, including the Early Mover contracts, could be integrated into the UDAM effectively. The contracts already provide for the possible transfer of the contract deeming from the real-time to a day-ahead market administered by the IESO. While these contracts may require some renegotiation, this renegotiation is not likely to be a barrier to UDAM development or participation. The cost of this renegotiation should be considered as a cost to the UDAM option in the CBA.

That being said, the CES contracted generators have argued that the current real-time HOEP settlement mechanism for OPA contracts impose commitment risks and costs on these generators that likely raise the cost to OPA of contracting for incremental generation.[25] Switching the settlement of OPA contracts to a UDAM could benefit existing contract holders, but would also reduce future OPA contracting costs. The impact of this impact represents a positive benefit to the UDAM, although enhanced DACP may also realize these benefits. These cost savings may represent an efficiency benefit of a UDAM but also an efficiency benefit of the other two options. There may also be a reduction in the OPA contracting cost that could be realized and shared with Ontario consumers.

Other Contracts
Other contracts include the regulated contracts governing OPG's prescribed and non-prescribed assets, the Bruce Power contract with the OPA, the OPA's Renewable Energy Supply (RES), and the non-utility generators' contracts. These contracts essentially provide a fixed payment for output delivered in real-time. The owners of these contracts therefore have little to no incentive to participate in a day-ahead

[25] Recall that Ontario Power Generation identified a potential offsetting impact attributable to converting to UDAM deeming for these contracts. See section on Impact on Real-Time Dispatch.

market as their revenue streams already have guarantees.[26] In contrast, the owners of these contracts have expressed a concern that there participation (if mandatory) in the day-ahead market would create additional financial risk to their operations. They have indicated a need to address this risk if their participation is required. This concern exists for the UDAM only; the same financial risk does not exist under Option 1 or Option 2. At the same time, the IESO believes that the integration of these contracts into the UDAM would be necessary in order to achieve a more efficient unit commitment and more accurate day-ahead scheduling.

Changes to the contracts or regulations could be implemented to result in such facilities being held harmless for any additional risks introduced through UDAM participation, and therefore indifferent to a requirement to participate in UDAM. Alternatively, it is possible to include design features in the UDAM to hold contracted or regulated facilities harmless from any additional risks from UDAM participation, rather than change their contracts or regulations. One possible design would be to have the IESO forecast the expected real-time output of such resources and take account of this expected output in determining prices and schedules in the day-ahead market. This approach would require a mechanism to address the financial consequences of the decision not to apply second settlement charges and credits associated with the schedules for these facilities (an uplift charge or credit to consumers). This is similar to the approach proposed for IESO forecasting of the "default demand pool" and would have corresponding uplift implications of forecast errors. Another approach would have the UDAM design include an offset calculation to remove the effects of the two-settlement system for these generators. This would make these generators indifferent to participating in the UDAM, and therefore would likely require that their UDAM participation be mandated. The two-settlement system offset calculation for these generators would be shared by all consumers via uplift (could be a charge or credit).

Regardless of the approach taken, it is expected that there would be renegotiation and possible additional design costs that would be incurred in order to integrate these contracts. Furthermore, once integrated, there could be a wealth transfer from generators to the default consumers.

In short, while the IESO thinks that solutions exist for integrating all contracts into a UDAM, there would be a cost for doing so. On the other hand, there may be some benefit attributable to the integration of the CES contracts in a UDAM. There are no incremental benefits of integrating the other contracts in the UDAM, apart from the fact that it would be necessary to do so in order to achieve the unit-commitment efficiencies and other efficiencies achieved through more accurate day-ahead prices and schedules. On balance, the IESO thinks that the integration of contracts represents a negative impact for Option 3, the UDAM, relative to the other two options.

[26] There may be some incentive for these generators to participate in a day-ahead market as a speculator to arbitrage expected price differences between day-ahead and real-time.

Hydro-electric risk

Owners of energy-limited hydroelectric facilities have indicated that a UDAM presents operational and financial risks that they do not face currently under the DACP.[27] The risk is due to the financial commitments that are made under a UDAM. The owners of these facilities would not face this risk under either Option 1 or Option 2 as these options do not provide financial commitments to quick start facilities. This added risk can impact the degree of day-ahead to real-time price and schedule convergence and the unit commitment process.

Under the DACP, energy-limited hydroelectric facilities face two types of risks in the day-ahead timeframe. First, there is uncertainty in the total quantity of water available the next day for electricity generation. Second, there is uncertainty regarding which hours to use the limited water to produce electricity. The farther away from real-time operations the greater are these uncertainties. These uncertainties can also vary depending on the time of the year. For example, in the summer when water is relatively scarce and when price volatility is more likely due to weather conditions and tighter supply conditions, there is the greatest level of uncertainty.

Currently, hydro facilities manage these uncertainties by adjusting their offers in the day-ahead timeframe up until 2-hours in advance of real-time dispatch. They do so in response to the changing water conditions and the changes in expected price levels. Under the DACP, they are able to do this without any financial commitment. However, under the UDAM, if these facilities offer energy in the UDAM they would take on a financial commitment on a quantity of energy that they would be uncertain could be delivered in real-time. In particular, they would face the risk that they would have less water in real-time than what they had forecast in the day-ahead and as a consequence, they would have to buy back their day ahead financial commitment at real-time prices. This would create a potential for a financial penalty that they do not have to mange today. To mitigate this risk, under a UDAM, they have indicated that they would offer only a portion of their next days expected energy into the UDAM, holding back on offering additional expected energy levels for real-time until after the UDAM offer window closes.

If followed, a general practice of offering only a portion of the next day's hydroelectric energy, as a risk mitigation strategy, from the UDAM could affect the accuracy of day-ahead to real-time price and schedule convergence in a UDAM.

Price/Scheduling Accuracy

One of the intended improvements of each of the day-ahead options is the increased accuracy or convergence of the day-ahead prices and schedules to the real-time prices and schedules. The level of improved convergence is a factor driving the potential efficiency gains attributable to each option.

---

[27] See Ontario Power Generation's comments at http://www.theimo.com/imoweb/pubs/consult/se21/se21-20071012-Ontario_Power_Generation.pdf

The IESO expects that each of the three options under review will improve the level of price and schedule convergence. However, it is difficult *a priori* to determine by how much each of the three options will improve convergence. Our analysis of the expected efficiency gains has postulated different levels of improvements. In this regard, we have attempted to quantify the potential efficiency gains that are likely to be realized through incremental improvements in price and schedule convergence.

That being said, the IESO has not quantified the relative improvement in convergence that could be attributable to each option – would Option 3 result in a higher level of convergence relative to the other options and if so, what would this mean in terms of the additional benefits attributable to each option? Based on the factors discussed below, the IESO believes that there is unlikely to be a material difference in the level of price and schedule convergence realizable under each option.

- The scheduling accuracy of both Option 1 and Option 2 would be affected by the ability to include exports in the optimization. Currently under the DACP, export volumes are not included in the optimization. This typically has the affect of understating the next day's supply requirements. If the enhancements to the DACP under Option 1 and Option 2 do not address this issue, then it could mean that there is a bias towards the under commitment of non-quick start resources or an understatement of the financial commitments that would be afforded to the gas-fired generators –the efficiency gains attributable to these areas would tend towards the lower estimates (this is discussed more below). That being said, under a more detailed design stage of each of these options, the IESO would consider the use of a "market demand" forecast in the enhanced DACP. This would include a forecast for both the Ontario demand and export demand. The accuracy of this forecast would drive the accuracy of the day-ahead scheduling with a more accurate forecast tending to achieve higher levels of efficiency.
- Unlike Options 1 and Options 2, the scheduling accuracy of the UDAM would be driven largely by market forces. Suppliers and buyers (and virtual participants) would have a larger role in influencing the market outcomes and hence the scheduling accuracy. Since these participants face financial consequences form their participation in the UDAM, we would expect that there would be a stronger tendency for day-ahead to real-time scheduling convergence – this is something that has been realized in other jurisdictions with day-ahead markets. However, as discussed above, there are a number of aspects of the Ontario market the UDAM design that could undermine the degree of convergence. The UDAM would be based on an unconstrained algorithm rather than the constrained algorithm used in other jurisdictions. The lack of alignment between the unconstrained schedules with the physical constrained schedules would reduce the level of convergence for the physical schedules and hence could diminish some of the efficiency benefits. Furthermore, Ontario has a large share of energy limited hydro-electric generation. And as discussed above, the potential for "conservative" offer strategies for the owners of these facilities could undermine the level of convergence of both the day ahead unconstrained and constrained schedules to the real-time constrained schedules.
- Under Option 1, price convergence would depend on the performance of the IESO forecast model. Under Option 2, price convergence would depend on the ability of the EFM to clear and

to clear effectively. Under Option 3, the degree of price convergence would depend on some of the scheduling issues discussed above. IESO analysis under the SE-58, Price Forecast of Real-time Prices, indicated that the IESO's price forecast model performed equally as well if not better than the day-ahead markets in New York and MISO at projecting real-time prices.

In short, there are factors working for and against each option in terms of their ability to realize improved day-ahead to real-time price and schedule convergence. As a result, the IESO does not expect there to be material differences between the different options.

Financial Commitments and Guarantees

Day-ahead financial commitment allows participants to lock in price and quantity day-ahead, reducing exposure to real-time volatility. Financial commitments or financial guarantees provide hedging and risk mitigation opportunities. This risk mitigation has value to participants depending on their risk preferences. The financial commitments and guarantees can also impact the size of the efficiency gains realizable under each option.

All options would offer improvements in the financial guarantees afforded to non-quick start generators relative to the current DACP. Option 2, through the EFM, would provide all participants with a further mechanism to hedge their real-time price and quantity risk. The UDAM would provide all participants with a financial commitment based on the unconstrained algorithm.

The improvements in financial guarantees to gas-generators is a key driver for realizing the efficiency gains attributable in the form of reduced variable, storage and hedging costs for these generators. These efficiency gains will be realized under each of the different options. The IESO has not quantified the benefits attributable to the additional financial commitments opportunities afforded other participants with the EFM under Option 2 or the unconstrained financial commitments under the Option 3 UDAM. These benefits depend on the risk preferences of these participants which is difficult to value. Although the study performed by Deal and Mountain did suggest that there would be value to consumer from having a firm day-ahead price.

With the EFM, there is a concern that it may be thinly traded and hence there would be only limited opportunity for participants to gain the financial commitments. Furthermore, some participants (typically generators) would prefer resource specific commitments (i.e., that reflect physical operations) which are not provided under an EFM. Nonetheless, if there is indeed value in the commitments to participant, this may lead to more trade and the concern over a thinly traded market may be unfounded.

Under a UDAM, the default load would be included in the algorithm via the IESO forecast. On the plus side relative to the EFM, this would assure that the market would clear and that there would be more financial commitments available. On the negative side, it would also mean that some participants, particularly default loads, would be provided a *de facto* mandatory financial commitment – one that some have indicated that they really don't want. Furthermore, the financial commitments under the unconstrained schedules would be resource specific. This is a positive relative to the EFM for some participants. However, as discussed above, there are design challenges associated with trying to achieve alignment of these commitments with the physical schedules that represent a cost of the UDAM option relative to the EFM.

Overall, the availability of additional financial commitments under Option 2 and Option 3 for hedging and risk management purposes provides a positive benefit to these options relative to Option 1 and the Baseline Scenario. The benefits are expected to be large under the UDAM but are subject to the caveats discussed above.

Summary of Non Quantified Impacts and Incorporation into CBA

Table 3 provides a summary of the non-quantified impacts for each of the three options. A plus sign (+) under a given option implies that there are likely additional benefits realizable through the implementation of the option relative to the Baseline Scenario. A negative sign (-) implies that that there are either additional costs or a negative impact on efficiency from the option relative to the Baseline Scenario. An NA implies that there are no incremental impacts relative to the Baseline Scenario.

Table 3 Summary of Non Quantified Impacts

Impact	Option 1	Option 2	Option 3
Embedded Generation	+	+	+
Reliability	+	+	+
Impact of Financial Commitment on Real-time Dispatch	-	-	-
Alignment of Constrained and Unconstrained Algorithms	NA	NA	-
Integration of Regulated Contracts	NA	NA	-
Price/Scheduling Accuracy	+	+	+
Financial Commitment	NA	+	+

Overall, the IESO believes that while not quantified, there are additional positive efficiency gains that would be realized from the implementation of Option 1 or Option 2 relative to the baseline scenario. The only possible negative impact attributable to these options relates to the potential impact of financial commitments on real-time dispatch. As mentioned above, the IESO does not expect this to be material. It also expects that the positive impacts of the other factors would outweigh this impact.

Furthermore, the IESO believes that the non-quantified benefits of Option 2 are likely larger than those of Option 1, since Option 2 offers the potential for additional financial commitments not afforded under Option 1.

Overall, the IESO believes that there may be additional efficiency gains that could be realized from the implementation of a UDAM. However, because of the concerns related to the alignment of the constrained and unconstrained algorithms and the concerns regarding the integration of the regulated contracts it is less certain of this outcome.

In the next section, the IESO compares the present value of the quantified benefits of each option to the present value of the quantified costs of each option to determine the quantified net present value of each option relative to the Baseline Scenario. If the quantified net present value of a particular option is negative, the size of the shortfall provides a metric for assessing just how material the non-quantified benefits would have to be in order to achieve a positive outcome. Similarly, if the quantified net present value of one option (i.e., Option 2) is less than another option (i.e., Option 1), the amount of the difference in net present value provides a metric for how material the additional non quantified benefits expected under Option 2 would have to be in order to achieve a higher ranking than Option 1.

4.4 Net Present Value Analysis

This section provides a comparison of the costs and benefits of each option to determine the net present value of each option relative to the Baseline Scenario. Tables 4 to 6 provide the outcome of this comparison for each option. The net present value estimates presented in these tables were computed for a period of 15 years using a discount rate of 7 percent.

The estimates of net present value were based on the following considerations:

- Costs and benefits were measured on an annual basis. Year 1 of the analysis covers the period of July 2008 to June 2009 to coincide with the start of the final design phase of each option. Each of the subsequent years, Year 2 through Year 15, also cover the period July through June;
- The implementation costs are allocated over the first two years. This is consistent with the estimate of the timeframe needed until the launch of each option. The costs were allocated based on the expectation of when they would be incurred –roughly 20 percent in the first year and 80 percent in the second year. The IESO estimated that participant costs would also be incurred across Year 1 and Year 2 according to this ratio;

- Interest costs were not included in the cost for the purpose of the CBA. Instead, the time value of these funds was captured through use of the discount rate;[28]
- As discussed in section 4.2.1, it is estimated that there would be a $ 1 million cost incurred under the Baseline Scenario. These would include the cost to permanently implement a price forecast and to improve the current guarantee programs. Under a CBA, the costs and benefits attributable to a particular option must be incremental to those of the Baseline Scenario. As a result, the estimated $ 1 million cost of the Baseline Scenario was subtracted from the cost of each option in Year 1 for the purpose of the CBA net present value calculations;
- Similarly, the IESO believes that most of the demand response efficiencies could be realized simply from the improved price forecast. Therefore, for the purpose of measuring the incremental quantitative benefits of each option relative to the Baseline Scenario, the IESO does not include these estimated efficiency gains in their net present value calculations. Of course, additional demand response benefits may be realized under Options 2 and 3 if these options produce more accurate price signals. Furthermore, the financial commitments available under Option 2 and Option 3 may also provide additional benefits to consumers. The additional benefits attributable to Option 2 and Option 3 are considered as part of the non-quantifiable benefits (discussed more below);
- Finally, as stated in Section 4.1.2, the net present value estimates were computed using the "expected value estimates" of the different costs and benefits. An analysis of the "worst case" scenario is presented later in this section.

Results of the Quantified NPV Analysis

Tables 4, 5 and 6 present the quantified net present value estimates for each of Option 1, 2 and 3. These estimates assume a discount rate of 7 percent. The estimates using a 4 percent and 10 percent rate are provided in tables 7 through 12.

The tables list the annual benefits and costs for each category of impact. The cumulative present value benefits and cumulative value costs are presented for each year of the life of the Option. This provides a comparison of how the present value of each of the benefits and the costs change from year to year. The final row of each table provides the cumulative net present value of the option.

Each of the Options results in a positive quantified net present value relative to the Baseline Scenario over a 15 year period. Furthermore, each Option achieves a positive net present value relative to the Baseline Scenario in a relatively short time frame. Option 1 and Option 2 achieve the break-even point sometime in Year 5, while Option 3 achieves the break-even point in Year 6. Each Option provides for a positive net present value in without considering the additional, non quantified benefits.

Based on the quantified net present value estimates, Option 1 ranks the highest. The net present value of Option 1 over the 15 Year period is $88.4 million or $12.59 million on an annualized basis. The net

[28] This was the process recommended under the *Canadian Cost-Benefit Analysis Guide*: *Regulatory Proposals* found at http://www.regulation.gc.ca/documents/gl-ld/analys/analys-eng.pdf.

present value of Option 2 is marginally lower than Option 1 with a net present value of $88.24 million or $12.56 on an annualized basis. Option 3 provides for the lowest net present value of the three options. The net present value of Option 3 is $60.93 million over the 15 year period or $8.67 million on an annualized basis.

Note that the results are not materially affected by the use of either a 4 percent or 10 percent discount rate. Under either discount rate, each of the Options achieves a positive net present value relative to the Baseline Scenario. Furthermore, all options achieve the break-even point in Year 4 through Year 6.

Consideration of the Non Quantified Impacts

As discussed in the previous section, the IESO believes that there are additional positive non quantified benefits realizable under Option 1 and Option 2 relative to the baseline scenario. Furthermore, the IESO believes that the UDAM may also provide additional benefits relative to the baseline scenario; however it is less certain of this outcome than it is for Option 1 and Option 2. Using the results of the quantified net present value analysis, the non quantified benefits of the Option 3 UDAM would have to be in excess of $27.5 million dollars over the 15 year period or roughly $4 million on an annualized basis to rank higher than the other options.

When comparing Option 2 with Option 1, the additional non quantified benefits expected to be realized under Option 2 would have to be in excess of $0.17 million over the 15 year life, or $30,000 on an annualized basis to rank higher than Option 1.

Additional Scenario Analysis

The IESO also computed the quantified net present value for other scenarios to capture the potential risk that the expected values were either too high or too low. Scenarios considered include: (i) low estimate cost vs. low estimate benefit; (ii) high estimate cost vs. high estimate benefit; (iii) low estimate cost vs. high estimate benefit; and (iv) high estimate cost and low estimate benefit. The analysis of each of the first three scenarios indicated essentially the same outcomes (directionally) as the analysis using the expected value case – all Options provided a positive quantified net present value over the option life. In this section, the IESO presents the results of the fourth scenario - high estimate cost and low estimate benefit scenario, or what the IESO would refer to as the worst case scenario. A 10 percent discount rate was used for this scenario. This is done to provide a sense of the robustness or resiliency of the NPV analysis to the extreme situation. The net present value estimates for each option under this scenario are presented in Table 13 through 15.

Under the worst case scenario, Option 1 and Option 2 realize a positive net present value relative to the Baseline Scenario over the 15 year life of the option. However, Option 1 does not achieve the break-even point until the 6th year. Option 2 achieves the break-even point briefly in Year 7. However, in Year 8, when system upgrades are required, the cumulative net present value becomes negative again and does not become positive until Year 9. Option 3, due the considerably higher cost, does not achieve a positive net present value relative to the Baseline Scenario over the 15 year life of the option.

Table 4: Net Present Value, Option 1, 7 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
BENEFITS																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	5.00
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	12.38
Cumulative PV Benefits	0.00	0.00	12.18	23.32	33.48	43.93	53.74	64.04	74.05	83.55	92.53	101.10	108.61	115.75	122.10	17.38
COST																
IESO																
Implementation Cost	4.65	20.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.36
O&M Cost	0.00	0.00	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.33
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.72
Participant																
Implementation Cost	0.48	1.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Cumulative PV Cost	5.13	25.85	26.11	26.36	26.59	26.80	27.00	32.68	32.85	33.02	33.17	33.31	33.44	33.57	33.69	4.80
Cumulative NPV	**(5.13)**	**(25.85)**	**(13.93)**	**(3.03)**	**6.90**	**17.13**	**26.74**	**31.36**	**41.20**	**50.54**	**59.37**	**67.79**	**75.16**	**82.18**	**88.41**	**12.59**

Table 5: Net Present Value, Option 2, 7 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
BENEFITS																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	5.00
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	12.38
Cumulative PV Benefits	0.00	0.00	12.18	23.32	33.48	43.93	53.74	64.04	74.05	83.55	92.53	101.10	108.61	115.75	122.10	17.38
COST																
IESO																
Implementation Cost	4.75	20.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.42
O&M Cost	0.00	0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.28
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.73
Participant																
Implementation Cost	0.48	1.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Cumulative PV Cost	5.23	26.32	26.54	26.75	26.94	27.11	27.28	33.02	33.17	33.30	33.43	33.55	33.66	33.77	33.86	4.82
Cumulative NPV	**(5.23)**	**(26.32)**	**(14.36)**	**(3.42)**	**6.55**	**16.82**	**26.46**	**31.01**	**40.88**	**50.25**	**59.10**	**67.55**	**74.95**	**81.98**	**88.24**	**12.56**

Table 6: Net Present Value, Option 3, 7 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
BENEFITS																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	5.00
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	12.38
Cumulative PV Benefits	0.00	0.00	12.18	23.32	33.48	43.93	53.74	64.04	74.05	83.55	92.53	101.10	108.61	115.75	122.10	17.38
COST																
IESO																
Implementation Cost	6.90	26.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.50
O&M Cost	0.00	0.00	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.61
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04
Participant																
Implementation Cost	1.24	4.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.84
O&M Cost	0.00	0.00	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.56
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16
Cumulative PV Cost	8.14	37.50	39.20	40.79	42.28	43.67	44.97	54.63	55.76	56.82	57.81	58.74	59.61	60.41	61.17	8.71
Cumulative NPV	**(8.14)**	**(37.50)**	**(27.02)**	**(17.47)**	**(8.79)**	**0.26**	**8.77**	**9.41**	**18.29**	**26.73**	**34.72**	**42.36**	**49.00**	**55.33**	**60.93**	**8.67**

Table 7: Net Present Value, Option 1, 10 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
Benefits																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.75
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	11.53
Cumulative PV Benefits	0.00	0.00	11.53	21.78	30.88	39.98	48.29	56.77	64.80	72.21	79.02	85.34	90.72	95.71	100.02	16.28
Cost																
IESO																
Implementation Cost	4.65	20.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.75
O&M Cost	0.00	0.00	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.32
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.68
Participant																
Implementation Cost	0.48	1.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.36
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Cumulative PV Cost	5.13	25.28	25.53	25.76	25.96	26.15	26.32	31.00	31.14	31.27	31.38	31.49	31.58	31.67	31.75	5.17
Cumulative NPV	**(5.13)**	**(25.28)**	**(14.01)**	**(3.98)**	**4.91**	**13.83**	**21.97**	**25.77**	**33.66**	**40.94**	**47.64**	**53.85**	**59.14**	**64.04**	**68.27**	**11.11**

Table 8: Net Present Value, Option 2, 10 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
Benefits																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.75
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	11.53
Cumulative PV Benefits	0.00	0.00	11.53	21.78	30.88	39.98	48.29	56.77	64.80	100.02	100.02	16.28	0.00	0.00	0.00	16.28
Cost																
IESO																
Implementation Cost	4.75	20.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.83
O&M Cost	0.00	0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.26
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.69
Participant																
Implementation Cost	0.48	1.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.36
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Cumulative PV Cost	5.23	25.75	25.95	26.14	26.31	26.47	26.61	31.34	31.46	31.56	31.66	31.75	31.83	31.90	31.97	5.20
Cumulative NPV	**(5.23)**	**(25.75)**	**(14.43)**	**(4.36)**	**4.56**	**13.51**	**21.68**	**25.43**	**33.34**	**40.64**	**47.36**	**53.59**	**58.90**	**63.81**	**68.05**	**11.08**

Table 9 Net Present Value, Option 3, 10 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
Benefits																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.75
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	11.53
Cumulative PV Benefits	0.00	0.00	11.53	21.78	30.88	39.98	48.29	56.77	64.80	72.21	79.02	85.34	90.72	95.71	100.02	16.28
Cost																
IESO																
Implementation Cost	6.90	26.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.04
O&M Cost	0.00	0.00	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.58
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.98
Participant																
Implementation Cost	1.24	4.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.94
O&M Cost	0.00	0.00	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.47
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16
Cumulative PV Cost	8.14	36.69	38.31	39.77	41.10	42.31	43.41	51.37	52.28	53.11	53.86	54.55	55.17	55.73	56.25	9.15
Cumulative NPV	**(8.14)**	**(36.69)**	**(26.78)**	**(17.99)**	**(10.23)**	**(2.34)**	**4.87**	**5.40**	**12.51**	**19.10**	**25.15**	**30.79**	**35.56**	**39.98**	**43.77**	**7.12**

Table 10: Net Present Value, Option 1, 4 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
Benefits																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	5.30
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	13.38
Cumulative PV Benefits	0.00	0.00	12.90	25.03	36.41	48.46	60.09	72.65	85.23	97.50	109.44	121.15	131.71	142.04	151.50	18.68
Cost																
IESO																
Implementation Cost	4.65	20.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.97
O&M Cost	0.00	0.00	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.36
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.76
Participant																
Implementation Cost	0.48	1.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.29
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07
Cumulative PV Cost	5.13	26.45	26.72	26.99	27.25	27.49	27.73	34.66	34.88	35.09	35.29	35.49	35.68	35.86	36.03	4.44
Cumulative NPV	**(5.13)**	**(26.45)**	**(13.83)**	**(1.96)**	**9.16**	**20.96**	**32.36**	**37.99**	**50.34**	**62.41**	**74.14**	**85.66**	**96.03**	**106.18**	**115.47**	**14.24**

Table 11: Net Present Value, Option 2, 4 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
Benefits																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	5.30
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	13.38
Cumulative PV Benefits	0.00	0.00	12.90	25.03	36.41	48.46	60.09	72.65	85.23	151.50	151.50	18.68	0.00	0.00	0.00	18.68
Cost																
IESO																
Implementation Cost	4.75	20.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.03
O&M Cost	0.00	0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.30
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77
Participant																
Implementation Cost	0.48	1.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.29
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07
Cumulative PV Cost	5.23	26.93	27.16	27.39	27.60	27.80	28.00	35.01	35.19	35.37	35.54	35.70	35.85	36.00	36.15	4.46
Cumulative NPV	**(5.23)**	**(26.93)**	**(14.27)**	**(2.36)**	**8.81**	**20.65**	**32.09**	**37.64**	**50.03**	**62.13**	**73.90**	**85.45**	**95.85**	**106.04**	**115.35**	**14.22**

Table 12: Net Present Value, Option 3, 4 percent Discount Rate ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
Benefits																
Unit Commitment	0.00	0.00	5.00	4.90	4.50	4.50	4.50	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	5.30
Gas Cost Savings	0.00	0.00	8.95	8.75	8.82	10.16	10.22	12.23	12.91	13.17	13.37	13.73	12.61	12.90	12.08	13.38
Cumulative PV Benefits	0.00	0.00	12.90	25.03	36.41	48.46	60.09	72.65	85.23	97.50	109.44	121.15	131.71	142.04	151.50	18.68
Cost																
IESO																
Implementation Cost	6.90	26.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.99
O&M Cost	0.00	0.00	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.65
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.10
Participant																
Implementation Cost	1.24	4.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.74
O&M Cost	0.00	0.00	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.40	1.66
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17
Cumulative PV Cost	8.14	38.34	40.14	41.88	43.55	45.15	46.69	58.48	59.90	61.27	62.59	63.85	65.07	66.24	67.37	8.31
Cumulative NPV	**(8.14)**	**(38.34)**	**(27.25)**	**(16.85)**	**(7.13)**	**3.31**	**13.40**	**14.18**	**25.33**	**36.23**	**46.85**	**57.29**	**66.64**	**75.80**	**84.13**	**10.37**

Table 13: Net Present Value, Option 1, "Worst Case Scenario" ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
Benefits																
Unit Commitment	0.00	0.00	4.80	4.60	4.10	4.10	4.10	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	4.37
Gas Cost Savings	0.00	0.00	5.68	5.66	5.67	6.75	6.75	7.26	7.28	7.31	7.22	7.26	7.13	7.17	7.07	6.93
Cumulative PV Benefits	0.00	0.00	8.66	16.37	23.04	29.78	35.90	41.63	46.84	51.60	55.88	59.79	63.31	66.51	69.40	11.29
Cost																
IESO																
Implementation Cost	6.05	26.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.88
O&M Cost	0.00	0.00	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.32
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.88
Participant																
Implementation Cost	0.92	3.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.69
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Cumulative PV Cost	6.97	34.24	34.49	34.72	34.92	35.11	35.28	41.20	41.34	41.47	41.59	41.69	41.79	41.87	41.95	6.83
Cumulative NPV	**(6.97)**	**(34.24)**	**(25.83)**	**(18.34)**	**(11.88)**	**(5.33)**	**0.63**	**0.43**	**5.50**	**10.12**	**14.30**	**18.10**	**21.52**	**24.64**	**27.45**	**4.47**

Table 14: Net Present Value, Option 2, "Worst Case Scenario" ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
Benefits																
Unit Commitment	0.00	0.00	4.80	4.60	4.10	4.10	4.10	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	4.37
Gas Cost Savings	0.00	0.00	5.68	5.66	5.67	6.75	6.75	7.26	7.28	7.31	7.22	7.26	7.13	7.17	7.07	6.93
Cumulative PV Benefits	0.00	0.00	8.66	16.37	23.04	29.78	35.90	41.63	46.84	69.40	69.40	11.29	0.00	0.00	0.00	11.29
Cost																
IESO																
Implementation Cost	6.18	26.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.98
O&M Cost	0.00	0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.26
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.90
Participant																
Implementation Cost	0.92	3.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.69
O&M Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08
Cumulative PV Cost	7.10	34.85	35.05	35.24	35.41	35.57	35.71	41.82	41.94	42.04	42.14	42.23	42.31	42.38	42.44	6.91
Cumulative NPV	**(7.10)**	**(34.85)**	**(26.39)**	**(18.87)**	**(12.37)**	**(5.79)**	**0.20**	**(0.19)**	**4.91**	**9.55**	**13.74**	**17.57**	**21.00**	**24.13**	**26.96**	**4.39**

Table 15: Net Present Value, Option 3, "Worst Case Scenario" ($ million)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Annualized Value
Benefits																
Unit Commitment	0.00	0.00	4.80	4.60	4.10	4.10	4.10	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90	4.37
Gas Cost Savings	0.00	0.00	5.68	5.66	5.67	6.75	6.75	7.26	7.28	7.31	7.22	7.26	7.13	7.17	7.07	6.93
Cumulative PV Benefits	0.00	0.00	8.66	16.37	23.04	29.78	35.90	41.63	46.84	51.60	55.88	59.79	63.31	66.51	69.40	11.29
Cost																
IESO																
Implementation Cost	8.97	34.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.55
O&M Cost	0.00	0.00	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.55	0.58
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.27
Participant																
Implementation Cost	2.34	9.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.77
O&M Cost	0.00	0.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.63
System Upgrade Cost	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20
Cumulative PV Cost	11.31	51.08	53.60	55.89	57.97	59.87	61.59	72.20	73.62	74.92	76.09	77.16	78.13	79.02	79.82	12.99
Cumulative NPV	**(11.31)**	**(51.08)**	**(44.94)**	**(39.52)**	**(34.93)**	**(30.09)**	**(25.68)**	**(30.57)**	**(26.78)**	**(23.32)**	**(20.21)**	**(17.37)**	**(14.83)**	**(12.50)**	**(10.42)**	**(1.70)**

5. Assessment of Stakeholder Impacts

In addition to the CBA, the IESO's overall assessment of the merits of each option includes an analysis of the distribution of the impacts of each option on various stakeholders (wealth transfer impacts). Stakeholder analysis attempts to allocate the net benefits or losses generated by each option. The output of the stakeholder analysis contains critical information for decision makers, as it indicates which groups would be the net beneficiaries and which groups would be the net losers and by how much.

5.1 IESO Stakeholder Impact Analysis

The IESO stakeholder impact analysis involves consideration of the effect of each option on (i) the Hourly Ontario Energy Price (HOEP), (ii) IESO uplifts and (iii) assignment of the IESO's implementation costs. The IESO has conducted an analysis of the likely impact on HOEP and uplifts under the same assumptions applied in the CBA.

While the stakeholder analysis considers the impacts on all stakeholders, we also determined the overall impact to the electricity bills of Ontario consumers. By combining the potential changes to HOEP and uplifts, and the assignment of IESO implementation costs, we estimated the consumers' electricity bill impacts for each of the options. Consumers could see a slight increase to their bill of less than 1 cent / MWh with Options 1 and 2 in the first year post implementation and an increase of about 1 cent / MWh for Option 3 for the first two years post implementation. Beyond the first few years post implementation for all options, consumers could then see a decrease of their electricity bill of up to 3 cents / MWh. The NPV of savings for consumers over the 15-year analysis period for Options 1 and 2 is $23M. For Option 3, the NPV savings is $13M.

Some dispatchable generation are paid the market clearing price for energy and uplifts. Others, such as NUGs and prescribed generation assets may be under various contracts and paid differently. Thus, we could not estimate the general overall impact on generator revenues except for the change in HOEP and total uplifts they would see as described in the follow sections.

Impacts on HOEP[29]

Implementation of any one of the options would affect the HOEP and in roughly the same magnitude. The IESO's analysis indicates a potential increase to HOEP prior to any global adjustment correction in the range of $0.01/MWh to $0.39/MWh. The change to HOEP is affected by two specific results from the implementation of one of the day-ahead options:

- improved unit commitment, and
- a reduction in the variable costs for gas-fired generation.

[29] The effects of global adjustment and export arbitrage were factored into the analysis of HOEP change.

As discussed in section 4.3.1, the current DACP selects units for commitment based on energy offers only. These energy offers are reflective of incremental or marginal cost. This process can at times results in an over-commitment of generation. In particular, 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 higher costs appear in the market as higher uplift costs. In addition, over-commitments also put downward pressure on the HOEP. Over-commitment in DACP affects HOEP because over-committed resources which otherwise would not have be economical are scheduled in real-time and placed at the bottom of the offer stack. Thus, there is downward pressure on HOEP as less expensive resources are pushed up the stack becoming marginal.

In contrast, as indicted in the BECL analysis, each of the day-ahead options would provide gas-generators with more accurate signals of their real-time gas needs and a financial guarantee of their next day's electricity schedules. This would allow them to realize variable cost savings. It is expected that these savings would be reflected in the generators offer prices and hence in the HOEP. As a result, there should be downward pressure on the HOEP.

The IESO conducted an analysis that considered the combined impacts of these factors on HOEP. The impact to HOEP is assessed for the period under consideration by the cost benefit analysis and factors in changes in supply and demand as projected in the IPSP[30]. A detailed description of the methodology and all the assumptions is presented in the Appendix found at the following link: http://www.ieso.ca/imoweb/consult/consult_se21.asp.

To recap, the IESO analysis indicates that the HOEP would be higher with the implementation of one of the day-ahead options relative to HOEP in the baseline scenario. The HOEP impact would range from a potential high of $0.39/MWh to a low of $0.01/MWh. The impact is expected to decline overtime as coal is phased out.

Of course a higher HOEP adversely impacts consumers and benefits generators. The presence of the OPG Rebate and Global Adjustment Mechanism mitigates a major share of the potential wealth transfers caused by higher HOEP. As indicated in the IESO's past analysis and analysis conducted by Navigant Consulting and the Market Surveillance Panel, roughly 80 percent of the supply for Ontario's consumption is under a fixed price contract or other contract that dampen the impacts of price changes. That is, for a $1/MWh increase in HOEP, the net consumer impact is effectively only an increase of $0.20/MWh. Using this as a guide, the effective net HOEP impact on consumers from the implementation of one of the day-ahead options is expected to be between $0.08/MWh and less than $0.01MWh.

[30] Considerations for the changing supply fleet were based on the IPSP, Exhibit D, Tab 2, Schedule 1, (http://www.powerauthority.on.ca/Storage/53/4863_D-2-1_Att_2_corrected_071019.pdf) and the demand forecast figures used in the analysis were based on the IPSP, Exhibit D, Tab 1 Schedule 1, (http://www.powerauthority.on.ca/Storage/53/4861_D-1-1_corrected_071019.pdf).

Impact on IESO Uplifts

While improved unit commitment would put upward pressure on the HOEP, it would also lead to a reduction in hourly uplifts through reduced DA-GCG payments. The IESO's analysis of unit commitment impacts indicates that the overall annual payment for DA-GCG would to decline by $6.7M to $6.9M annually. The reduced uplift charge represents a reduction in the payments made by consumers. Over the course of the CBA study period, this represents a savings of about $0.04MWh on consumers' electricity bill.

Assignment of the IESO's Implementation Costs

The IESO's cost to implement any of the options will be paid by Ontario consumers and exporters over the IESO's amortization schedule for capital projects. The IESO amortizes capital project costs associated with hardware over a 4-year period and other capital costs (such as labour, software systems) over a 7-year period based on consumption. At the end of each amortization period, there would be additional costs for upgrades estimated at 30% of the original total capital cost and again to be amortized over the same period. As an example, for a day-ahead option that is in service for 2010, the initial hardware costs would be amortized from 2010 to 2013. Then, there would be an upgrade to the hardware at 2014 costing 30% of the original cost. This upgrade cost would be amortized over 2014 to 2017. Similarly, software and labour costs would be amortized from 2010 to 2016. The software would be upgraded in 2017 at 30% of the original cost. The upgrade costs would be amortized over 2017 to 2023.

To approximate the charges over this period we used, (a) the annual energy consumption forecasts indicated in the IPSP, (b) the average annual energy exported, and (c) the total cost of each option to compute an annual charge for each year. Based on the IESO cost estimates detailed in section 4.3.1, the average annual costs of each of the options borne by Ontario consumers (the amounts that exporters would be charged have been subtracted) are tabulated below.

Table 16: Range of Average Annual Implementation Costs Paid by Consumers

	Average Annual Costs			
	Hardware	Hardware Upgrade	Software Systems and Labour	Software Systems Upgrade and Labour
Period of Amortization	2010-2013	2014-2017	2010-2016	2017-2023
Option 1	$0.12M-$0.15M	$0.04M-$0.05M	$3.4M-$4.4M	$1.0M-$1.3M
Option 2	$0.12M-$0.15M	$0.04M-$0.05M	$3.5M-$4.5M	$1.1M-$1.4M
Option 3	$0.23M-$0.30M	$0.07M-$0.09M	$5.0M-$6.4M	$1.5M-$2.0M

On a per MWh basis the above costs translate to a range of $0.01/MWh -$0.04/MWh charge to the consumers' electricity bill.

5.2 Net Impact to Ontario Consumers

The overall impact to Ontario consumers for the implementation of any one of the options is determined by combining the impacts on HOEP, IESO uplifts and IESO's implementation costs. Tables 17 to 19 summarize the expected overall costs to Ontario consumers for implementation of each of the options. For options 1 and 2, consumers would see an average of less than one cent per MWh increase to their electricity bill for year 3. From years 4 and beyond, consumers could expect to see an average decrease of about 3 cents per MWh for their total electricity costs as the impacts of HOEP and the annual recovery costs for implementation decrease below the total savings from uplift reduction. By year 15, the cumulative net present value of the savings to consumers total to about $23M. For option 3, consumers could expect to see a 1 cent per MWh increase to their electricity bill for years 3 and 4. After year 4, consumers could receive a decrease of 3 cents per MWh for their total electricity costs for the same reasons that the impacts to HOEP and the annual implementation costs to be recover decrease below the total savings from uplift reduction. The cumulative net present value of the savings to consumers from implementation of Option 3 amounts to about $13M.

Upper bounds on consumer impacts were also calculated by using the higher estimates of HOEP impacts and the higher cost estimates for each option. The dollar impacts for each option under this scenario are summarized in tables 20 to 22. Under this scenario, consumers would expect an overall increase to their electricity costs in the range of $0.01 to $0.06 per MWh through out the entire 15 year period. The cumulative net present value of these costs is over $40M for options 1 and 2, and about 53M for option 3 by year 15.

Table 17 Option 1 Expected Impact on Consumers' Electricity Bill

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Increase to HOEP ($/MWh)	0.00	0.00	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Increase to Energy Costs ($M)	0.00	0.00	(3.96)	(3.20)	(0.96)	(0.97)	(0.98)	(0.27)	(0.27)	(0.28)	(0.28)	(0.28)	(0.28)	(0.29)	(0.29)
Implementation Costs ($M)	0.00	0.00	(3.41)	(3.45)	(3.49)	(3.52)	(3.48)	(3.51)	(3.55)	(1.03)	(1.00)	(1.02)	(1.03)	(1.04)	(1.05)
Annual Uplift Savings ($M)	0.00	0.00	6.80	6.80	6.80	6.80	6.80	6.76	6.76	6.76	6.76	6.76	6.76	6.76	6.76
Net Cost / Saving ($M)	0.00	0.00	(0.57)	0.15	2.35	2.30	2.34	2.98	2.94	5.45	5.48	5.46	5.45	5.44	5.42
Cumulative Net Present Value ($M)	0.00	0.00	(0.50)	(0.37)	1.42	3.06	4.62	6.48	8.19	11.15	13.94	16.53	18.95	21.21	23.31
Net Impact on Electricity Bill per MWh	+0.00	+0.00	+0.00	-0.00	-0.01	-0.01	-0.01	-0.02	-0.02	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03

Table 18: Option 2 Expected Impact on Consumers' Electricity Bill

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Increase to HOEP ($/MWh)	0.00	0.00	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Increase to Energy Costs ($M)	0.00	0.00	(3.96)	(3.20)	(0.96)	(0.97)	(0.98)	(0.27)	(0.27)	(0.28)	(0.28)	(0.28)	(0.28)	(0.29)	(0.29)
Implementation Costs ($M)	0.00	0.00	(3.48)	(3.51)	(3.55)	(3.59)	(3.54)	(3.58)	(3.62)	(1.08)	(1.06)	(1.07)	(1.08)	(1.09)	(1.11)
Annual Uplift Savings ($M)	0.00	0.00	6.80	6.80	6.80	6.80	6.80	6.76	6.76	6.76	6.76	6.76	6.76	6.76	6.76
Net Cost / Saving ($M)	0.00	0.00	(0.63)	0.09	2.29	2.24	2.27	2.91	2.87	5.40	5.42	5.41	5.39	5.38	5.36
Cumulative Net Present Value ($M)	0.00	0.00	(0.55)	(0.48)	1.26	2.86	4.37	6.18	7.85	10.79	13.55	16.11	18.51	20.74	22.82
Net Impact on Electricity Bill per MWh	+0.00	+0.00	+0.00	-0.00	-0.01	-0.01	-0.01	-0.02	-0.02	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03

Table 19 Option 3 Expected Impact on Consumers' Electricity Bill

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Increase to HOEP ($/MWh)	0.00	0.00	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Increase to Energy Costs ($M)	0.00	0.00	(3.96)	(3.20)	(0.96)	(0.97)	(0.98)	(0.27)	(0.27)	(0.28)	(0.28)	(0.28)	(0.28)	(0.29)	(0.29)
Implementation Costs ($M)	0.00	0.00	(5.01)	(5.06)	(5.12)	(5.17)	(5.06)	(5.11)	(5.16)	(1.55)	(1.49)	(1.51)	(1.52)	(1.54)	(1.56)
Annual Uplift Savings ($M)	0.00	0.00	6.80	6.80	6.80	6.80	6.80	6.76	6.76	6.76	6.76	6.76	6.76	6.76	6.76
Net Cost / Saving ($M)	0.00	0.00	(2.17)	(1.46)	0.72	0.66	0.76	1.38	1.32	4.94	4.99	4.97	4.95	4.93	4.91
Cumulative Net Present Value ($M)	0.00	0.00	(1.89)	(3.08)	(2.53)	(2.06)	(1.56)	(0.70)	0.07	2.76	5.29	7.65	9.85	11.90	13.81
Net Impact on Electricity Bill per MWh	+0.00	+0.00	+0.01	+0.01	-0.00	-0.00	-0.00	-0.01	-0.01	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03

Table 20 Option 1 Upper Range of Impact on Consumer's Electricity Bill

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Increase to HOEP ($/MWh)	0.00	0.00	0.08	0.07	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Annual Increase to Energy Costs ($M)	0.00	0.00	(12.31)	(11.29)	(8.08)	(8.16)	(8.24)	(7.20)	(7.27)	(7.35)	(7.42)	(7.49)	(7.57)	(7.65)	(7.72)
Implementation Costs ($M)	0.00	0.00	(4.43)	(4.48)	(4.53)	(4.58)	(4.52)	(4.57)	(4.62)	(1.34)	(1.31)	(1.32)	(1.33)	(1.35)	(1.36)
Annual Uplift Savings ($M)	0.00	0.00	6.80	6.80	6.80	6.80	6.80	6.76	6.76	6.76	6.76	6.76	6.76	6.76	6.76
Net Cost / Saving ($M)	0.00	0.00	(9.94)	(8.97)	(5.81)	(5.94)	(5.96)	(5.01)	(5.13)	(1.93)	(1.97)	(2.06)	(2.14)	(2.23)	(2.33)
Cumulative Net Present Value ($M)	0.00	0.00	(8.68)	(16.01)	(20.44)	(24.67)	(28.64)	(31.76)	(34.75)	(35.79)	(36.79)	(37.77)	(38.72)	(39.65)	(40.55)
Net Impact on Electricity Bill per MWh	+0.00	+0.00	+0.06	+0.06	+0.04	+0.04	+0.04	+0.03	+0.03	+0.01	+0.01	+0.01	+0.01	+0.01	+0.01

Table 21 Option 2 Upper Range of Impact on Consumer's Electricity Bill

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Increase to HOEP ($/MWh)	0.00	0.00	0.08	0.07	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Annual Increase to Energy Costs ($M)	0.00	0.00	(12.31)	(11.29)	(8.08)	(8.16)	(8.24)	(7.20)	(7.27)	(7.35)	(7.42)	(7.49)	(7.57)	(7.65)	(7.72)
Implementation Costs ($M)	0.00	0.00	(4.52)	(4.57)	(4.62)	(4.67)	(4.61)	(4.65)	(4.70)	(1.41)	(1.38)	(1.39)	(1.41)	(1.42)	(1.44)
Annual Uplift Savings ($M)	0.00	0.00	6.80	6.80	6.80	6.80	6.80	6.76	6.76	6.76	6.76	6.76	6.76	6.76	6.76
Net Cost / Saving ($M)	0.00	0.00	(10.03)	(9.06)	(5.89)	(6.02)	(6.05)	(5.10)	(5.22)	(2.00)	(2.04)	(2.13)	(2.22)	(2.31)	(2.40)
Cumulative Net Present Value ($M)	0.00	0.00	(8.76)	(16.15)	(20.65)	(24.94)	(28.97)	(32.14)	(35.18)	(36.27)	(37.30)	(38.31)	(39.30)	(40.26)	(41.19)
Net Impact on Electricity Bill per MWh	+0.00	+0.00	+0.06	+0.06	+0.04	+0.04	+0.04	+0.03	+0.03	+0.01	+0.01	+0.01	+0.01	+0.01	+0.01

Table 22 Option 3 Upper Range of Impact on Consumer's Electricity Bill

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Increase to HOEP ($/MWh)	0.00	0.00	0.08	0.07	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Annual Increase to Energy Costs ($M)	0.00	0.00	(12.31)	(11.29)	(8.08)	(8.16)	(8.24)	(7.20)	(7.27)	(7.35)	(7.42)	(7.49)	(7.57)	(7.65)	(7.72)
Implementation Costs ($M)	0.00	0.00	(6.51)	(6.58)	(6.65)	(6.72)	(6.57)	(6.64)	(6.71)	(2.01)	(1.94)	(1.96)	(1.98)	(2.00)	(2.02)
Annual Uplift Savings ($M)	0.00	0.00	6.80	6.80	6.80	6.80	6.80	6.76	6.76	6.76	6.76	6.76	6.76	6.76	6.76
Net Cost / Saving ($M)	0.00	0.00	(12.02)	(11.07)	(7.93)	(8.08)	(8.01)	(7.09)	(7.23)	(2.60)	(2.60)	(2.69)	(2.79)	(2.89)	(2.99)
Cumulative Net Present Value ($M)	0.00	0.00	(10.49)	(19.53)	(25.58)	(31.34)	(36.68)	(41.09)	(45.30)	(46.71)	(48.03)	(49.31)	(50.55)	(51.75)	(52.91)
Net Impact on Electricity Bill per MWh	+0.00	+0.00	+0.08	+0.07	+0.05	+0.05	+0.05	+0.04	+0.04	+0.02	+0.02	+0.02	+0.02	+0.02	+0.02

6. Additional Factors Considered

Often in public policy matters, additional considerations beyond the results of a CBA may factor into any final decision or recommendation. The IESO considered two additional factors important for review in this regard. These are discussed below.

6.1 Re-contracting of Non-Utility Generation Contracts

The implementation of a UDAM (Option 3) could act as the catalyst to affect further positive change within the industry. For example, the introduction of UDAM could create opportunities to achieve a more efficient utilization of the provinces NUG plants. To the extent that the UDAM enables positive change that may not otherwise occur should be factored into any final decision regarding the merits of the different day-ahead options.

Current Situation and Reasons for Potential Improvements

At the risk of oversimplifying the complexity of the contracts, the following provides an outline of how a typical NUG contract works. The current contracts between the NUGS and Ontario Electricity Financing Corporation (OEFC) are settled against the real-time price (HOEP). OEFC pays the NUG owners a fixed price for each MW delivered in real-time market. The fixed price may depend on the hour of operation (of-peak and on-peak hours) and may depend on the number of hours that the unit operates.

The NUG operates in the wholesale market as a self-scheduling generator and effectively runs when it expects that the contract price exceeds its operating cost. The NUG operates without consideration of the prevailing market prices. As a result, it may at times operate ahead of another dispatchable generator, even though the NUG has a higher operating cost. This is inefficient since the province's energy needs could be satisfied more cheaply by not running the NUG and running the cheaper generator. Alternatively, at times it may not operate even though its operating cost is lower than other dispatchable generators that are operating. This too is inefficient.

Under the contract, when the NUG operates, OEFC receives the HOEP for each MW delivered. If the HOEP is greater than the NUGs contract price, OEFC receives additional revenue above what it is require to pay the NUG. When this occurs, the additional revenues are credited to the Global Adjustment account, thereby reducing some of the financial burden of the province's ratepayers. If however, the HOEP is less than the contract price, then OEFC provides the NUG with a "top-up" payment above what it receives though the HOEP. This "top-up" payment is then debited to the Global Adjustment, which adds to the financial burden of the province's ratepayers.

Creating a contract that encourages the NUG to operate more efficiently in the wholesale market could create an opportunity for both the NUG and OEFC to realize benefits. If the NUG were to operate only when its variable cost was less than the HOEP, OEFC would receive only positive additional revenues through the market (HOEP above the contract price case) and would avoid having to make "top-up" payments. Both OEFC and the NUGs could be made better off if they essentially share these efficiency savings.

That being said, because the current contracts typically provide the NUGs with the incentive to run when they are inefficient, they have the effect of putting downward pressure on the HOEP. Changes in the contract terms that would encourage more efficient operation of the NUGs, while achieving efficiency improvement, would put upward pressure on the HOEP that could cause the potential for ratepayers to be made worse off as a result. Ratepayers would only be made better off under the new arrangement if the contract savings that OEFC would realize offset any impacts from higher energy prices. This would be a concern for OEFC with any arrangements.

During its discussions with OEFC and certain NUG owners regarding the integration of these contracts into a UDAM, the IESO discussed the potential to transfer the settlement of these contracts from the real-time price (HOEP) to the day-ahead price. The objective of these discussions was to determine if by settling the contracts day-ahead but then exposing the NUG to the two-settlement process of a UDAM, there would be (i) opportunities to create incentives for the NUGS to operate more efficiently, and (ii) opportunities to make both the NUGS and OEFC (ratepayers) better off in the process – a "win-win" arrangement.

In short, while the details of an arrangement were not fully worked out, the IESO determined that certain contract arrangements could be devised to provide incentives for some NUGS, those that have some flexibility in dispatch, to operate more efficiently within the wholesale market. The NUGs could guarantee OEFC contract prices through the UDAM, simply by offering in the UDAM at a low price in the hours that are most profitable under the contract (offer in UDAM much like it does in real-time today as a self-scheduler). However, the NUG could then offer and operate in real-time in order to take advantage of opportunities through the two settlement process – essentially to buy from the real-time market to supply the OEFC contract quantity when the HOEP was less than its variable operating cost, and produce more than its OEFC contract quantity when the HOEP was higher than its variable operating cost. This would ensure that it would operate when it was efficient relative to the other dispatchable generators.

No further progress was made regarding potential sharing arrangements or other arrangements that would assure a "win-win" type arrangement. Hence, there is no assurance that agreement amongst certain NUG owners and the OEFC could be realized. Nonetheless, the UDAM could provide a potential for such a "win-win" contract.

Estimated Potential Efficiency Gains:
The IESO conducted a simulation exercise to estimate the potential magnitude of the efficiency gains that could be realized through improved operating incentives for NUGs via the UDAM. The analysis involved two of the larger NUG owners, covering the operations of 11 NUG resources – a total nameplate capacity of 770 MWs.

The NUG owners provided the IESO with data of the operating and cost characteristics of the resources. Using this data, the IESO made assumptions regarding the likely "offer strategy" for each of the plants. Essentially, it was assumed that the resources would be offered at their variable operating cost in real-time. This would mean that the resources would run in real-time (subject to certain minimum load and minimum run time conditions) when the real-time price were higher than their variable operating cost and would shut-down when the real-time price was below their operating cost. This strategy would allow the NUG to realize profit opportunities under the two-settlement process of the UDAM as described above. The IESO then ran a simulation of the real-time market, incorporating these offers for the NUG resources. The simulations were conducted for the year 2007.

The IESO simulations indicated that by providing these NUGs with the incentives to be dispatched according to their variable cost in real-time (i.e., via the settlement of the OEFC contracts in the UDAM), the province could realize potential efficiency improvements. Depending on the level of flexibility achievable from these resources, these efficiency gains could range from $3.8 million to upwards of $10 million per year. These efficiency gains would come in the form of reduced fuel cost for the province as a whole for meeting its energy demand. That being said, the reduced operation of these NUGs would put upward pressure on the HOEP. For the period simulated, the average HOEP would have been between $3.00/MWh to $5.00/MWh higher.

In short, a UDAM could be the catalyst to enabling contract changes with the NUGs that would realize efficiency gains. Further study of potential sharing arrangements would have to be considered to determine if a "win-win" contract arrangement could be realized. Given the uncertainty of realizing these "win-win" arrangements at this time, the IESO does not believe that there would be sufficient evidence to recommend a UDAM on the basis of achieving these efficiencies.

6.2 Enabling Other Market Evolution Issues

At the outset of our study, we indicated changes to the market design must meet the needs of today, but should not impede the achievement of future industry improvements. Therefore, as part of our assessment it is essential to consider the extent to which each day-ahead option either encourages or inhibits other possible improvements to the market or the industry. As a means to provide option comparison for impacts on future market development, the IESO limited their analysis against to the following broad-based market initiatives:

- implementation of locational marginal pricing (LMP)
- possible development of load serving entities (LSE)
- promotion of long-term resource adequacy mechanisms (RAM)
- encourage environmental goals
- real-time market improvements/changes

Enhancement of DACP and the UDAM option both include a multiple pass approach of the constrained algorithm. Based on the experiences of other electricity markets that have locational marginal pricing (LMP), a multiple pass approach of the constrained algorithm would be required for a functioning LMP market in Ontario. Therefore with the introduction of a multiple pass constrained algorithm, both DACP enhancement and UDAM supports implementation of LMP. However, the implementation of the fourth pass under the UDAM option which establishes the financial commitment should be regarded before implementation as an avoidable cost when comparing against other options and the extent to which it supports LMP. Financial commitments within a LMP market would be determined in the constrained pass and any financial expenditure to include the unconstrained algorithm would not further the future development of LMP implementation. Arguably most of the implementation the cost differences between DACP enhancement and UDAM of $12M represents the establishment of financial commitments from the unconstrained algorithm. The cost of implementation of the energy forward market under Option 2 is not considerrd an avoidable cost because this market could conceivably continue operation depending how LMP is introduced into Ontario just in real-time or within the context of a day-ahead market implementation.

Arguably, development of load serving entities (LSE) does not require any enhancement of day-ahead mechanisms. However, Option 2 & 3 that include financial commitment positively influences the development of LSE. LSE that would be responsible for procuring the power consumption requirements of consumers, need a mechanism to provide longer-term arrangements and risk management options. While a comprehensive day-ahead market is a more complete solution, a fully functioning EFM would also address these requirements.

Unit commitment enhancements through 24 hour optimization present a potential opportunity to consider environmental impacts over a longer outlook. The opportunity to optimize over a longer period enables the possibility of environmental program introduction that otherwise may not be possible in current individual 1 hour outlook presently available to the market.

Implementation of any the day-ahead mechanisms will have a positive influence on outstanding real-time pricing improvements requested by stakeholders. The market pricing working group currently has three issues on hold awaiting the outcome of the day-ahead mechanism study:

1. Forecast of Real-Time Price
2. Pre-Dispatch Price Uncertainty
3. Imports and Exports Setting Price

All the options under consideration provide market participants with a price forecast of what the HOEP is likely to be. Such forecasts might assist participants in the price discovery process and therefore, should support a timely completion of outstanding pricing issues 1 and 2. In the UDAM design both imports and exports can set price and as such the real-time issue of imports and exports setting real-time price might be less critical. Enhancement of DACP or Baseline Scenario would not negatively impact the path of this initiative. Generally speaking all the day-ahead mechanism enhancements under consideration support continued evolution initiatives of IESO administered markets.

Table 23 Enabling Market Evolutions

Options	Option 1	Option 2	Option 3	Baseline Scenario
LMP	Positive influence – introduction of multi-pass constrained	Positive influence – introduction of multi-pass constrained	Less positive influence - introduction of multi-pass constrained offset by impact of avoidable capital cost of financial commitment	Neutral
LSE	Neutral	Positive influence only if EFM clears	Positive influence	Neutral
RAM	Neutral	Neutral	Neutral	Neutral
Environmental	Positive influence	Positive influence	Positive influence	Neutral
RT Market	Positive influence	Positive influence	Positive influence	Positive influence

7. Supporting Rationale and Request for Stakeholder Input

As the IESO approaches a decision in respect of day-ahead mechanisms, the focus of the study team has been to pull together and document the various analyses that will provide the basis for our recommendation. From the outset of the study, the cost benefit analysis has been as central to that work. The aim of the CBA was to quantify and monetize the incremental benefits and costs of the options against the Baseline Scenario to the greatest practicable extent. Other aspects relevant to a decision but not amenable to quantification because of their nature or lack of available data, have been evaluated on a qualitative basis as to how they would influence the ranking of each of the options. These considerations, and other factors such as differences in customer costs between options, are also important in reaching a recommendation.

Each of the options considered result in a positive quantified NPV relative to the Baseline Scenario over a 15 year period. In fact, within three to four years post implementation, the NPV to that point (the annualized NPV) becomes positive for each option. With implementation in year 2, Option 1 and Option 2 achieve the break-even point sometime in Year 5, while Option 3 achieves the break-even point in Year 6.

Based on the CBA, the quantified NPV estimate for Option 1 ranks the highest with a NPV of $88.4 million (or $12.59M/yr). The NPV of Option 2 is marginally lower than Option 1 at $88.24 million (or $12.56M/yr). Option 3 provides for the lowest NPV of the three options at $60.93 million (or $8.67M/yr).

Moving to consideration of the qualitative analysis, the IESO day-ahead team believes that there are additional positive benefits for each option not realized in the NPV. But by using the results of the quantified NPV analysis, we can identify what value non quantified benefits must be worth to change the overall outcome of the CBA. For instance, the IESO calculates that non quantified benefits attributed to the UDAM would have to be valued at over $27.5 million dollars over the 15 year period (or $4 M/yr) to rank it higher than the other options. The IESO day-ahead team is not confident that the non-quantified benefits attributed to the UDAM would be material enough to meet this test. When comparing Option 2 with Option 1, the difference in the NPVs between the options is small – calculated at $0.17 million over the 15 year life of the Option (or $30,000M/yr). It seems reasonable that the introduction of the EFM for hedging and risk management purposes provides enough of a material positive benefit to exceed the required $30,000/yr so as to rank Option 2 higher than Option 1.

In its assessment of the merits of each of the day-ahead options, the IESO team also considered stakeholder impacts, particularly the impact on the overall electricity bills of Ontario consumers. In the initial year post implementation (year 3), essentially no change- less than one cent per megawatt hour – is anticipated for Options 1 and 2, with savings in all subsequent years. For Option 3, the increase in the initial year post implementation has been calculated at one cent per megawatt hour, with savings in all years commencing 2 years after implementation. Bill impacts reflect both anticipated HOEP changes and the effect of the Global Adjustment. Overall, the NPV of savings for consumers over the 15 year analysis period for the implementation of Options 1 and 2 is $23M. For Option 3, the NPV of the savings is $13M.

The IESO considers all of the options robust enough to meet the needs of today without inhibiting future market evolution initiatives. But the preliminary view of the IESO day-ahead team is that Option 2: an enhanced DACP with a 24-hour optimized unit commitment process, 3-part bids/offers, refined cost guarantees and an EFM offers a better overall set of amendments to our day-ahead planning mechanisms in support of anticipated changes in Ontario's electricity sector.

The IESO study team welcomes stakeholder views – and especially the rationale for those views - on both the overall assessment and the quantified and qualitative analyses.