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Comments on the Evaluation of an Unconstrained Price Day-Ahead Market Compared to an Enhanced Day-Ahead Commitment Process

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September 3, 2008

I. OVERVIEW

In their comments, a number of Ontario market participants question whether the IESO has correctly compared the costs and benefits of the enhanced DACP relative to the UDAM. They have correctly observed that the enhanced DACP will not achieve all of the benefits realized in other jurisdictions from the implementation of day-ahead markets. Not all of the market participants' comments, however, recognize that the UDAM also would not achieve all of the benefits realized in other jurisdictions from the implementation of day-ahead markets because the realization of many of those benefits would require implementation of LMP-based day-ahead and real-time markets. The IESO's recommendation to investigate an enhanced DACP in part arose from a determination that important potential benefits of a day-ahead market with LMP cannot be realized within the single price UDAM design, even though it has the seemingly attractive feature of a day-ahead settlement. In the process of defining the UDAM, the IESO made a concentrated effort to specify rules that would enable the UDAM to achieve the benefits of day-ahead markets in other jurisdictions. After working through these rules in some detail, the IESO determined that the single-price market design would not only preclude realization within a UDAM of the benefits seen in LMP-based day-ahead markets, but also that implementation of a UDAM based on the single-price design would create additional problems or give rise to additional consumer costs. These issues are discussed further in Section II.

Some Ontario market participants are also concerned that the IESO analysis of the UDAM option may have failed to take sufficient account of the pay-as-bid incentives associated with an enhanced DACP and that had the adverse impacts of these pay-as-bid incentives been better accounted for, implementation of a UDAM would have been evaluated more favorably relative to implementation of an enhanced DACP. Once again, this view confuses the potential benefits from the implementation of an LMP-based day-ahead market with the benefits achievable through a single-price UDAM. Because pay-as-bid incentives are intrinsic to the current Ontario single-price market design, implementation of a UDAM based on this single-price design would be unlikely to produce much improvement in bidding incentives relative to an enhanced DACP based on this same single-price market design. Hence, consideration of the effect of pay-as-bid incentives does not materially change the relative merits of implementing an UDAM or an enhanced DACP. These pay-as-bid incentives are discussed further in Section III.

II. UNCONSTRAINED PRICE DAY-AHEAD MARKET ALIGNMENT ISSUES

An important conclusion contributing to the IESO's recommendation to investigate an enhanced DACP was the determination that the retention of the unconstrained pricing system in the UDAM would make it impossible to achieve many of the intended benefits of a day-ahead market without incurring other costs. In particular, implementation of the UDAM could materially raise consumer costs due to misalignment of physical and financial schedules, the misalignment between consumer bids and the actual cost of serving load, and artificial risks/costs imposed on suppliers by financial obligations to deliver power that would be constrained off in real time.[1]

A. Misalignment of Physical and Financial Schedules

One of the potential benefits from implementation of a day-ahead market is the determination of financially binding day-ahead schedules, both for imports and internal generation. In LMP-based day-ahead markets, the day-ahead physical schedules are financially binding, providing traders with day-ahead financial certainty and, from a policy perspective, providing incentives for efficient day-ahead bidding and scheduling. The use of the single-price UDAM in Ontario, however, would result in a disconnect between financial and physical day-ahead schedules, and this disconnect would create financial risks and inefficiencies not present in other LMP-based day-ahead markets. Some of these risks and inefficiencies could be addressed with settlement work-arounds so as to produce a more efficient day-ahead schedule, but these work arounds would often entail a substantial cost that would be borne by Ontario consumers. Because it is based on unconstrained pricing, the UDAM simply would not provide the same benefits as an LMP-based day-ahead market.

A disconnect between physical and financial schedules would arise, for example, when imports or generation were scheduled in the constrained pass but not in the unconstrained pass of the UDAM. In this case, the imports or generation would receive day-ahead physical schedules, but would not receive matching day-ahead financial schedules. As a result, the imports and generation receiving only a constrained schedule would not have the intended financial incentives to be prepared to operate in real time, which is one of the important benefits from implementation of a day-ahead market. To address this issue, the IESO considered the possibility of blocking on in the unconstrained pass the minimum load blocks of generation scheduled in the constrained pass, thus ensuring that that the resources scheduled in the constrained pass had a day-ahead financial schedule for at least some of their output. A similar approach was considered for imports scheduled in the constrained pass. However, this approach to ensuring that needed generation and imports receive financial schedules would have had other undesirable effects in the UDAM.

Blocking on in the unconstrained pass the minimum load block of generation and imports scheduled in the constrained pass would further depress prices in the unconstrained pass below the actual cost of meeting load in unconstrained regions.[2]

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[1] These concerns were described in "Day-ahead Market Evolution Preliminary Assessment-Appendices," May 6, 2008.

[2] Blocking on the minimum load block of generation and imports scheduled in the constrained pass but not in the unconstrained pass would shift the unconstrained supply curve to the right, so that the unconstrained cost of serving load would occur at a lower price level, moving it even farther below the actual marginal cost of serving load in constrained regions.

Blocking on the minimum load block of generation and imports scheduled in the constrained pass but not in the unconstrained pass also would have detrimental impacts on the efficiency and cost of exports scheduled from Ontario. Under the single-price system in Ontario, exports are charged the unconstrained price, although the marginal cost of providing energy to serve those exports exceeds this price; consequently, exports are subsidized when the unconstrained price is lower than the constrained price, unless exports are limited by the interface constraint with the adjacent control area.[3] The subsidy is paid by load in the form of the uplift payment to the generators constrained on to provide energy for the scheduled exports. The additional depression of the unconstrained price that could result from blocking on in the unconstrained pass the minimum load blocks and imports scheduled in the constrained pass, as well as the counterflow provided by the blocked-on imports, would have the potential to increase the amount of subsidized exports scheduled from Ontario as well as the amount of the subsidy, thus imposing additional costs on Ontario consumers.

An additional concern is that if the minimum load blocks of resources scheduled in the constrained pass were blocked on in the unconstrained pass this could provide an additional incentive for generators to overstate the amount of capacity, included in their minimum load blocks, requiring additional rules to deter this behavior. This incentive would result from the difference in the treatment of a generator's minimum load block in comparison with capacity above this minimum that is also scheduled in the constrained pass.

B. Consumer Load Bidding

A second alignment issue hindering the achievement of the desired day-ahead incentives and efficiencies within the single-price UDAM market design is that there would be no way to incorporate day-ahead consumer load bidding and day-ahead financial schedules for loads. Under the single price UDAM market design it does not appear to be possible to make consumers financially responsible for the day-ahead purchase of power to meet their loads. In LMP markets consumers submit day-ahead bids to buy power at their location, and physical generation is committed based on the quantity of load that clears in the constrained day-ahead market given the consumer bids. The day-ahead prices that consumers pay are based on the constrained market clearing prices determined from their bids and entities that choose to bid less than their true willingness-to-pay for energy and fail to buy power in the day-ahead market may have to pay high real-time locational prices to meet their load in real time. Thus, consumers have an incentive to bid their true willingness-to-pay into the day-ahead market, and these bids can be used to determine the quantity of generation that is committed day-ahead.

In contrast, under the UDAM consumers would pay an unconstrained price for power, and their bids to buy power in the UDAM therefore would reflect their expectations of the unconstrained price that they would pay to serve their load, not their true willingness to pay for energy to meet their expected load. If a consumer's load bid did not clear in the day-ahead market, it would be charged the real-time unconstrained price for any consumption that was not scheduled in the UDAM. Under the UDAM a consumer would not bid to buy power at prices in

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[3] When the export constraint is binding, a separate price is determined for the export region under the single-price system.

excess of its expectation of the unconstrained price, even if its willingness-to-pay and the actual marginal cost of serving its load (the constrained locational price) were much higher. This design would have been unworkable. The bidding incentives that the single-price system provides to consumers would make it impossible to use consumer bids as the basis for committing generation day-ahead. If the IESO committed generation in the constrained pass based on bids submitted by consumers to buy power in the unconstrained pass, insufficient generation in constrained-up regions would be committed in the constrained pass to meet the higher level of load in those regions that would clear at the lower, unconstrained price. This lack of alignment led to the recognition that in order to make a day-ahead market based on unconstrained pricing workable, the commitment of generation in the constrained pass would need to be based on the IESO's load forecast rather than on consumers' bids, which reflect expectations of prices in the unconstrained pass. But this would tend to artificially depress real-time prices, requiring further work-arounds. A related consequence is that consumers would not receive day-ahead financial schedules, because the day-ahead commitment of generation would be based on a load forecast.

These difficulties with implementing meaningful consumer bidding within a single-price day-ahead market design, such as the UDAM, also affect the potential role of virtual bidding and trading. Like physical load bids, virtual bids would not be included in the constrained pass, because the commitment in the constrained pass would minimize the as-offered cost of meeting the IESO's forecast of the next day's load. Virtual bids would be included in the unconstrained pass and generally would serve to improve convergence between day-ahead unconstrained prices and real-time unconstrained prices, but they would have no impact on the unit commitment or physical generation schedules, which would be determined in the constrained pass.

Beyond these relatively straightforward impacts, the combination of virtual trades with an unconstrained pricing system, a combination not present in any other day-ahead market, might permit market participants to use combinations of virtual trades and import and export bids to magnify constrained-on and constrained-off payments and costs. This could occur because virtual trades would be present in the unconstrained pass but not the constrained pass, but import offers and export bids would be present in both the constrained and unconstrained passes. These issues could potentially be addressed through a set of rules applying to offsetting virtual and physical positions, analogous to the rules currently applied to offsetting imports and exports, but this is another instance in which the use of unconstrained pricing in the UDAM would raise issues (and potentially consumer costs) not present in LMP-based day-ahead markets.

C. Unconstrained Schedule Risks

A third alignment issue arising from the unconstrained pricing system is the potential for resources to receive day-ahead unconstrained schedules but no day-ahead constrained schedules. The design of the settlements to apply in this situation leads to conflicts between providing appropriate incentives for Ontario generators, external loads and external suppliers and avoiding inflated power costs for Ontario consumers. If resources receiving day-ahead unconstrained schedules but no constrained schedules were financially bound to their unconstrained schedules, they would be at risk for potentially large losses if the unconstrained price were high in real-time, and they were not able to operate. This could occur, for example, if the resource was off-line in real-time or did not purchase gas because it did not receive a day-ahead constrained schedule. Thus, generators that found themselves with day-ahead financial commitments (i.e., an unconstrained schedule) but no day-ahead constrained schedule might incur costs to make themselves available in real time so that they could cover their financial commitments. However, since these resources would, by assumption, not have day-ahead constrained schedules, it would generally not be economic for these resources to incur costs in order to be available in real-time (such as scheduling gas in the case of internal gas-fired generation, or scheduling exports from adjacent control areas in the case of import supply).

Under the UDAM it would be necessary to design settlements that would not incent resources to incur uneconomic costs to run in real-time, while also providing enough compensation that resources would remain willing to take the financial risk of bidding into the day-ahead market. Designing CMSC, IOG and PCG payments on the premise that all generation receiving unconstrained schedules but no constrained schedules should incur costs to be available to generate in real time would inflate consumers' costs. On the other hand, enforcing financial settlements for resources not receiving a day-ahead constrained schedule without making such adjustments to the design of the CMSC, IOG and PCG payments could discourage suppliers from even offering in the day-ahead market, as this would expose them to the risk of receiving a day-ahead unconstrained schedule but no day-ahead constrained schedule. In order to address these issues, the settlements under the UDAM would need to include payments to resources, and hence consumer costs, that would not occur under an LMP-based day-ahead market.

III. PAY-AS-BID INCENTIVES

While there will be pay-as-bid incentives under the enhanced DACP design, the principal pay-as-bid incentives exist in the current market and would continue under either the UDAM or the enhanced DACP, as they result from the single-price market design. It is not evident that there would be any material difference in these incentives between the UDAM design and the enhanced DACP. This is shown below by considering the pay-as-bid incentives for four categories of suppliers.

A. Fixed Revenue Resources

There would be no change in the pay-as-bid incentives for units with fixed prices and regulated contracts under either the UDAM or an enhanced DACP, in comparison with the current DACP. Moreover, these resources have little incentive to participate in a UDAM and would likely be modeled in a UDAM by the IESO based on the information available to the IESO, rather than based on the offers of the resource owners.

B. Constrained-On Generation

Any generator that typically has constrained schedules that exceed its unconstrained schedules has pay-as-bid incentives in the current DACP, and would also have pay-as-bid incentives in a UDAM, and in an enhanced DACP. One limitation of the current DACP, which would be addressed by either the UDAM or an improved DACP, is that it does not consider minimum load or start-up costs in its day-ahead scheduling decisions. Implementation of either an enhanced DACP or the UDAM is expected to produce lower cost day-ahead schedules than the current market design, without regard to pay-as-bid incentives.

Under either an enhanced DACP or the UDAM, constrained-on generators would have an incentive to offer supply at prices just below the expected constrained price in the day-ahead market or the day-ahead commitment process. Under the enhanced DACP the resources would be paid the higher of their day-ahead bids or the real-time price. This would also be the case under the UDAM, given the assumption that these resources clear in the constrained pass but not in the unconstrained pass and thus would have no day-ahead financial schedule.

C. Constrained-Off Generation

Any generation that typically has an unconstrained schedule that exceeds its constrained schedule lacks pay-as-bid incentives in the current DACP, and would also lack such incentives in the UDAM or in an enhanced DACP. The reason for the lack of pay-as-bid incentives under an enhanced DACP is that since such units would by definition be constrained down, with lower constrained schedules than unconstrained schedules, they would be paid the real-time price for their output in a market based on an improved DACP and would also receive constrained-off payments based on their offer price and the real-time price. Under the UDAM, these resources would receive the day-ahead price for capacity that cleared day-ahead and would also receive a constrained-off payment.[4]

For these resources, however, the implementation of a UDAM with the resulting additional day-ahead unconstrained schedule gives rise to situations requiring settlement rules that would exacerbate the excess costs imposed on Ontario consumers by the unconstrained pricing system, as discussed in Section II.C above, entailing even higher payments to generation that this not needed to meet Ontario load. So in this case, rather than the UDAM benefiting market efficiency and reducing consumer costs, the UDAM would likely reduce efficiency and raise consumer costs.

D. Generation with Constrained Schedule Equal to Unconstrained Schedule

Thus, the only generation that potentially has increased pay-as-bid incentives under a enhanced DACP in comparison with the UDAM is generation that has the same schedule in the constrained and unconstrained pass. For generation located in the constrained-up region, this requires that the resource's offer prices be low enough to clear in the unconstrained pass and for

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[4] These resources could have an incentive under either the UDAM or the enhanced DACP to increase their constrained-off payments by lowering their bids for the capacity that is constrained off, but not for the capacity that is included in the constrained schedule. However, it is unlikely that they would have pay-as-bid incentives under either market design. A unit could be scheduled for a few megawatts of output in the constrained pass of the UDAM and receive a PCG payment if its total as-offered cost for its day-ahead constrained schedule were less than its revenues for its day-ahead constrained schedule. If it were not in the constrained pass at all, it would not get any guarantee, but as long as some of its output were economic, it would get a PCG payment. However, it is not clear that a resource could get an unconstrained schedule in excess of its constrained schedule and get a non-zero constrained schedule if the start-up and minimum load costs were high enough to raise the cost of the constrained output above the unconstrained price.

generation located in the constrained-down region this requires that the resource's offer prices be low enough to clear in the constrained pass.

Even in these cases, while there are circumstances in which a generator may have a greater incentive to increase its offer price to affect the amounts it is paid under the enhanced DACP than it would under the UDAM, there are other circumstances where the reverse would be true, which we describe below. As a result, it is not clear whether the enhanced DACP or the UDAM would more frequently provide generators with pay-as-bid incentives. The answer could be different for different generators, and it could be different for the same generator at different points in time.

First, consider generators which, if their day-ahead offers reflected their day-ahead costs, would expect to receive day-ahead revenue in the UDAM considerably exceeding their day-ahead costs. The UDAM would provide such generators with more of an incentive to submit day-ahead offers that reflect their actual day-ahead costs than would the enhanced DACP. The reason for this is that the potential gain from increasing day-ahead offer prices would be larger under the enhanced DACP than under the UDAM. Under the UDAM, if such a generator increased its day-ahead offer above the day-ahead price and were scheduled to operate anyway, its day-ahead revenue would reflect its day-ahead offer. In contrast, under the enhanced DACP, if such a generator increased its day-ahead offer to that same level and were scheduled to operate anyway, its day-ahead offer would merely establish a minimum revenue level. If real-time prices happened to exceed its day-ahead offer, it would be paid the real-time price. Meanwhile, the risks associated with increasing the day-ahead offer would be similar, regardless of whether there were a UDAM or an enhanced DACP: in either case, if the day-ahead offer were too high, the generator would not be committed, and would forego the margins it otherwise would have earned. Since the potential revenues resulting from increasing day-ahead offers are higher under the enhanced DACP than under the UDAM, while the costs of employing such a strategy are the same in either case, it is more likely that such generators would increase their day-ahead offers above their actual day-ahead costs if an enhanced DACP were implemented than if a UDAM were implemented. (Example 1 in the Appendix illustrates these incentives in more detail.)

But it is also important to consider generators which, if their day-ahead offers reflected their day-ahead costs, would only expect to receive day-ahead revenue in the UDAM that slightly exceeds their day-ahead costs. In this case, the risks associated with a generator increasing its day-ahead offer would no longer be similar, regardless of whether there were a UDAM or an enhanced DACP. The margins that the generator would forgo if the UDAM were in place and it was not committed would, by assumption, be small. Alternatively, if the enhanced DACP were in place and there were no day-ahead financial commitment, this generator would be paid at least its day-ahead costs if its offer reflected those costs, and might receive considerably more if real-time prices were higher than expected. Consequently, such generators would have more to lose as a result of increasing their offers if the enhanced DACP were used than if the UDAM were used, so they would be more likely to submit day-ahead offers that exceed their actual day-ahead costs if the UDAM were implemented than if the enhanced DACP were implemented**.** (Example 2 in the Appendix illustrates these incentives in more detail.)

E. Conclusions

Overall, because most of the pay-as-bid incentives in the DACP design arise from the unconstrained pricing system, most of these incentives would exist in the UDAM as well.

APPENDIX:

ILLUSTRATIONS OF PAY-AS-BID INCENTIVES FOR MARGINAL GENERATION

A. Assumptions

The examples below illustrate pay-as-bid incentives for marginal generation in a UDAM as compared to those incentives in an enhanced DACP. In order to focus exclusively on the impact that using the UDAM or the enhanced DACP has on those incentives, the examples make the following assumptions:

1. The expected real-time price is equal to the day-ahead price. This assumption is needed because generators will prefer not to have a day-ahead settlement if the expected real-time price exceeds the day-ahead price but, conversely, will prefer to have a day-ahead settlement if the expected real-time price is less than the day-ahead price

2. The generator in the examples can only be in one of two operational states: Either it does not run, or it runs at a particular output level. This permits us to focus on the bidding incentives affecting the single day-ahead offer the generator makes for its output.

3. The day-ahead price is known in advance, permitting us to focus on the implications of variability in real-time prices on bidding incentives given expectations of day-ahead prices.

4. The generator's real-time costs are well below day-ahead costs, so that generators committed a day ahead are dispatched in real time.

5. In the UDAM, the generator's day-ahead unconstrained schedule (DAUS) is assumed to be equal to the day-ahead constrained schedule (DACS), so that the generator receives a full day-ahead financial commitment for its DACS.

B. Example 1: Case Where Pay-as-Bid Incentives Under an Enhanced DACP Are Greater Than Those Under the UDAM

Example 1 is based on the following assumptions:

- The generator's actual day-ahead cost of producing energy at the assumed output level is $40/MWh.

- The day-ahead price will be $49/MWh.

- The real-time price will be:

    - $54/MWh with a probability of 50 percent.

- $44/MWh with a probability of 50 percent.

Therefore, the expected real-time price is equal to the day-ahead price.

A generator owner's decision as to whether it should increase its offer is likely to reflect the trade-off between the potential that it will increase its revenue as a result of increasing its offer and the potential that it will not be scheduled at all as a result of increasing its offer. For each potential offer that a generator can make, we can calculate a breakeven probability, which is the probability that makes the margins it expects to earn if it submits that offer equal to the margins it would earn if its offer simply reflected its costs. The lower the breakeven probability for a given offer, the greater the incentive that generator has to submit that offer instead of offering its cost.

To illustrate how breakeven probabilities are calculated, consider the margins that a generator would realize under the UDAM if its offer reflects its $40/MWh cost, and the margins it would realize if it submits a $50/MWh offer. If this generator's offer reflects its cost, it would be scheduled in the UDAM, and it would realize a margin of $49 – $40 = $9/MWh on its capacity. If it increases its offer to $50/MWh, and it is still scheduled, it will receive the $49/MWh day-ahead price plus another $1/MWh, so it will realize a margin of $10/MWh. Therefore, if p is the breakeven percentage, then the margin this generator expects to receive if it increases its offer to $50/MWh is 10p$/MWh. By setting this margin equal to the $9/MWh margin this generator earns if its offer reflects its cost, we find that $p = 0.9$. Therefore, if there is a 90 percent chance that this generator will continue to be scheduled, even though it has increased its day-ahead offer to $50/MWh, it is just as well off if it submits a $50/MWh offer as it is if its offer reflects its actual costs. If the likelihood that this generator will continue to be scheduled if it submits a $50/MWh offer is greater than 90 percent, then the generator will be better off on average if it submits the $50/MWh offer.

Next, consider the calculation of the breakeven probability associated with a $50/MWh offer when there is no day-ahead settlement, as under the enhanced DACP. In State 1, the real-time price is $54/MWh, so the generator would simply realize a margin of $54 – $40 = $14/MWh, regardless of it offered its $40/MWh cost or increased its offer to $50/MWh. In State 2, the real-time price is $44/MWh, so the generator only realizes a margin of $44 – $40 = $4/MWh if its offer was $40/MWh. But if its offer was $50/MWh, it receives a $6/MWh PCG payment in addition to the $44/MWh real-time energy payment, so its total margin is $10/MWh. Therefore, it earns an expected margin of 50% × $14 + 50% × $4 = $9/MWh if its offer is $40/MWh, and 50% × $14 + 50% × $10 = $12/MWh if its offer is $50/MWh, so the breakeven probability is 9/12, or 75 percent. If there is a 75 percent chance that this generator will continue to be scheduled, even though it has increased its day-ahead offer to $50/MWh, it is just as well off if it increases its day-ahead offer to $50/MWh as if it submits a day-ahead offer that reflects its actual costs.

For a $50/MWh offer, the breakeven probability is lower for the enhanced DACP than for the UDAM. If the likelihood that the generator will continue to be scheduled if it submits a $50/MWh offer is between 75 percent and 90 percent, it would be better off if it submitted the $50/MWh offer if the enhanced DACP is being used, but it would be better off submitting an offer that reflects its actual costs if the UDAM is in place. Therefore, for this particular offer, and for the generator in this particular example, the pay-as-bid incentives are stronger under the enhanced DACP than under the UDAM.

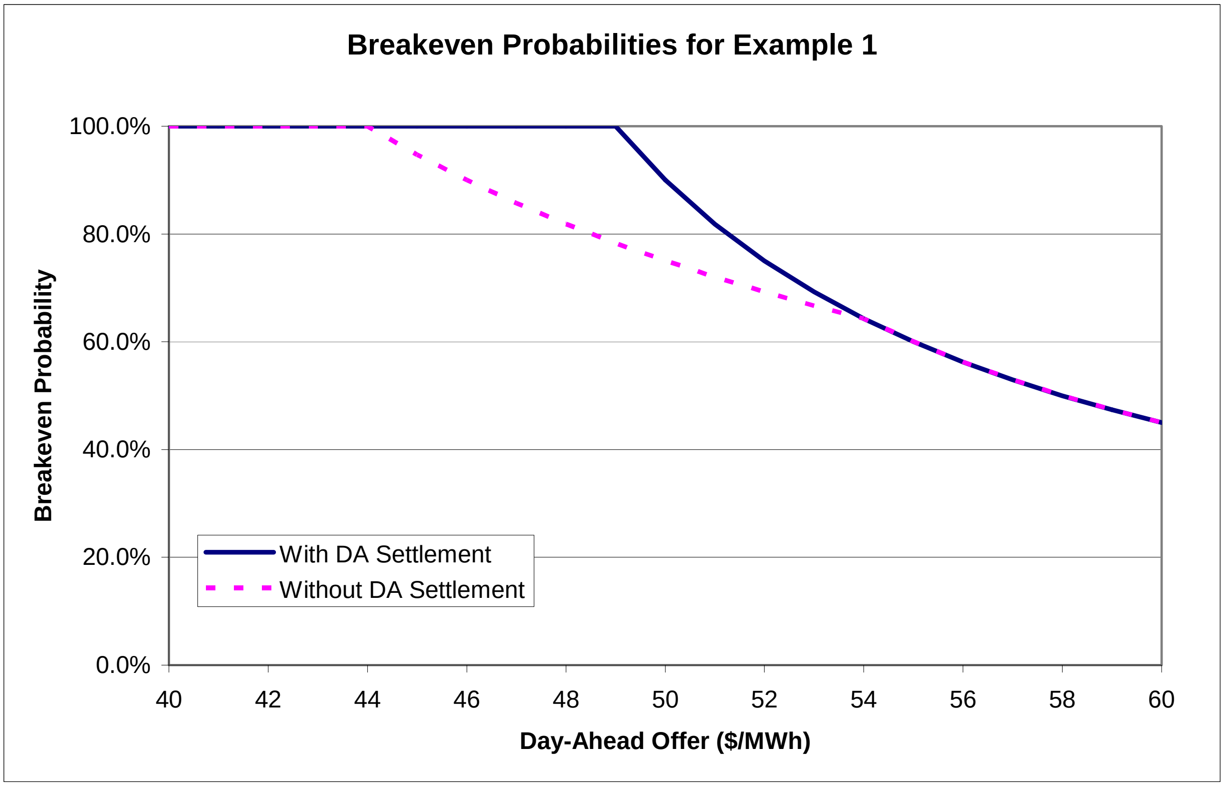
The graph below shows the breakeven probabilities corresponding to each possible offer for the generator in this example, under both the UDAM and the enhanced DACP. As it shows:

1. Increasing the offer to a level that is less than the real-time price of energy in State 2, $44/MWh, would not have any effect on the revenue the generator would receive. Therefore, the breakeven probability is 100 percent under whether there is a day-ahead settlement or not, since these offer increases would not increase the generator's revenues under either system.

2. For day-ahead offers between the real-time price of energy in State 1, $44/MWh and the day-ahead price, $49/MWh, the breakeven probability is below 100 percent when there is no day-ahead settlement. In those cases, submitting an increased day-ahead offer may increase the margins the generator earns in State 2, when the real-time price is only $44/MWh, because the generator would be eligible for a PCG payment in those cases if its offer was above the real-time price. But the breakeven probability remains 100 percent if there is a day-ahead settlement, since increasing the day-ahead offer will have no effect on the day-ahead PCG unless the offer exceeds the day-ahead price.

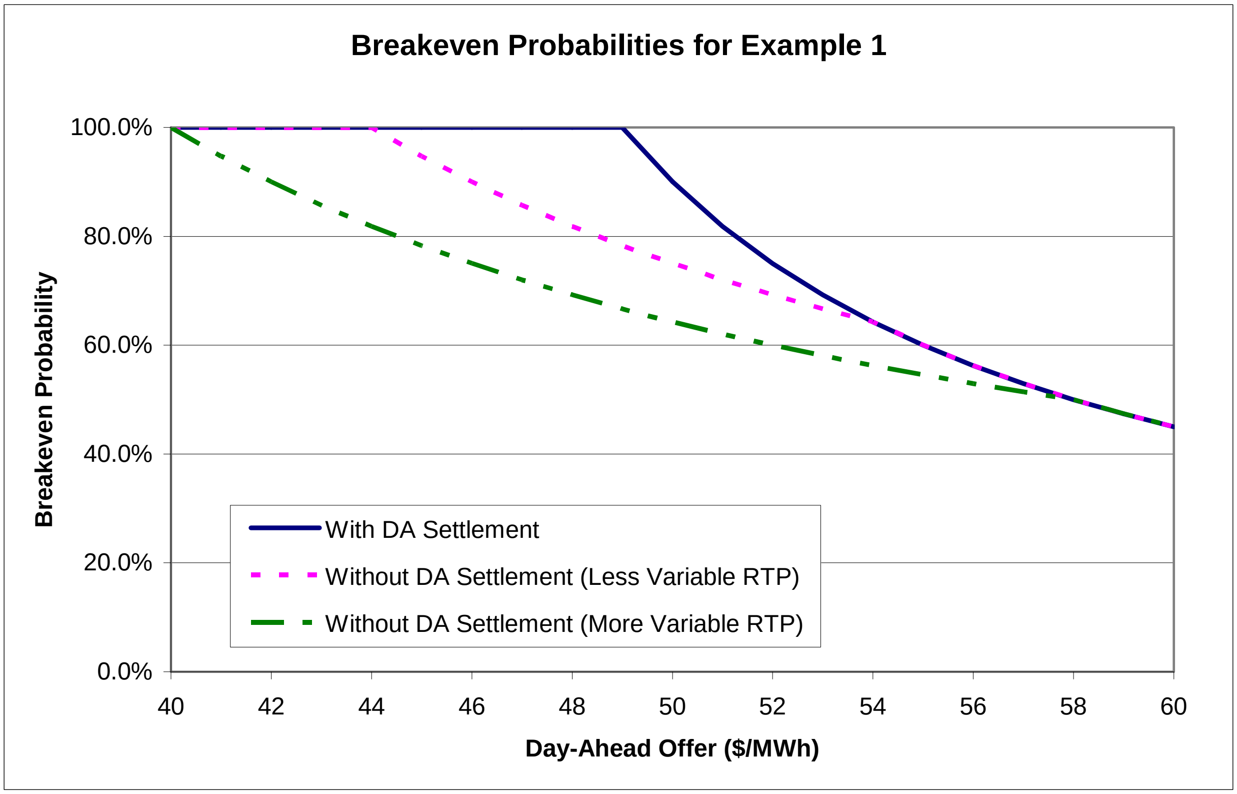
3. For day-ahead offers between $49/MWh and the real-time price of energy in State 1, $54/MWh, the breakeven probability is less than 100 percent both if there is a day-ahead settlement and if there is not a day-ahead settlement, but it is lower if there is not a day-ahead settlement. That is because if the generator is committed and there is no day-ahead settlement, the generator still benefits from high real-time prices in State 1, while it still realizes the same margins in State 2 that it would earned if there was a day-ahead settlement. Therefore, the margins the generator expects to realize if it submits one of these offers are higher than the margins it realizes if there is a day-ahead settlement. (Above, we showed that if the generator submitted a day-ahead offer of $50/MWh and was nevertheless committed, it would earn margins of 50% × $14 + 50% × $10 = $12/MWh on average if there was no day-ahead settlement, but it would only earn margins of $10/MWh if there was a day-ahead settlement.) Since the potential rewards from increasing the offer are higher for this generator if there is not a day-ahead settlement, the breakeven probability is lower if there is not a day-ahead settlement.

4. For day-ahead offers above $54/MWh, the breakeven probabilities are the same, since the generator would receive its day-ahead offer if it is committed a day ahead, regardless of whether there was a day-ahead settlement.



Since the breakeven probability if there is no day-ahead settlement is uniformly either less than or equal to the breakeven probability if there is a day-ahead settlement, the absence of a day-ahead settlement increases the likelihood in this example that a generator would find it profitable to submit a day-ahead offer that exceeds its cost.

Alternatively, assume that the real-time price in State 1 is $58/MWh and the real-time price in State 2 is $40/MWh. Then we obtain the following result:



Increased volatility in real-time prices reduces breakeven probabilities if there is no day-ahead settlement. This makes sense: The breakeven probability is lower when there was no day-ahead settlement than when there is a day-ahead settlement because generators can still be paid the high real-time prices in State 1 if there was day-ahead settlement. If the State 1 real-time price is even higher, the benefits of being able to receive that price increase, which decreases the breakeven probability associated with each potential day-ahead offer.

B. Example 2: Case Where Pay-as-Bid Incentives Under the UDAM Are Greater Than Those Under an Enhanced DACP

For Example 2, make the following assumptions:

- The generator's actual day-ahead cost of producing energy at the assumed output level is $40/MWh (as in Example 1).
- The day-ahead price will be $42/MWh.
- The real-time price will be:
  - $47/MWh with a probability of 50 percent.

- $37/MWh with a probability of 50 percent.

Therefore, the expected real-time price is still equal to the day-ahead price.

Compare the margins that a generator would realize under the UDAM if its offer reflects its $40/MWh cost to the margins it would realize if it submits a $50/MWh offer. If this generator's day-ahead offer simply reflects its day-ahead cost, it would receive the day-ahead price, thereby realizing a margin of $42 – $40 = $2/MWh. If it increases its offer to $45/MWh, and it is still scheduled, it will receive the $42/MWh day-ahead price plus another $3/MWh, for a total margin of $5/MWh. Therefore, the breakeven probability under the UDAM that is associated with a $45/MWh offer in this example is just 0.4, since 0.4 × $5/MWh = $2/MWh.

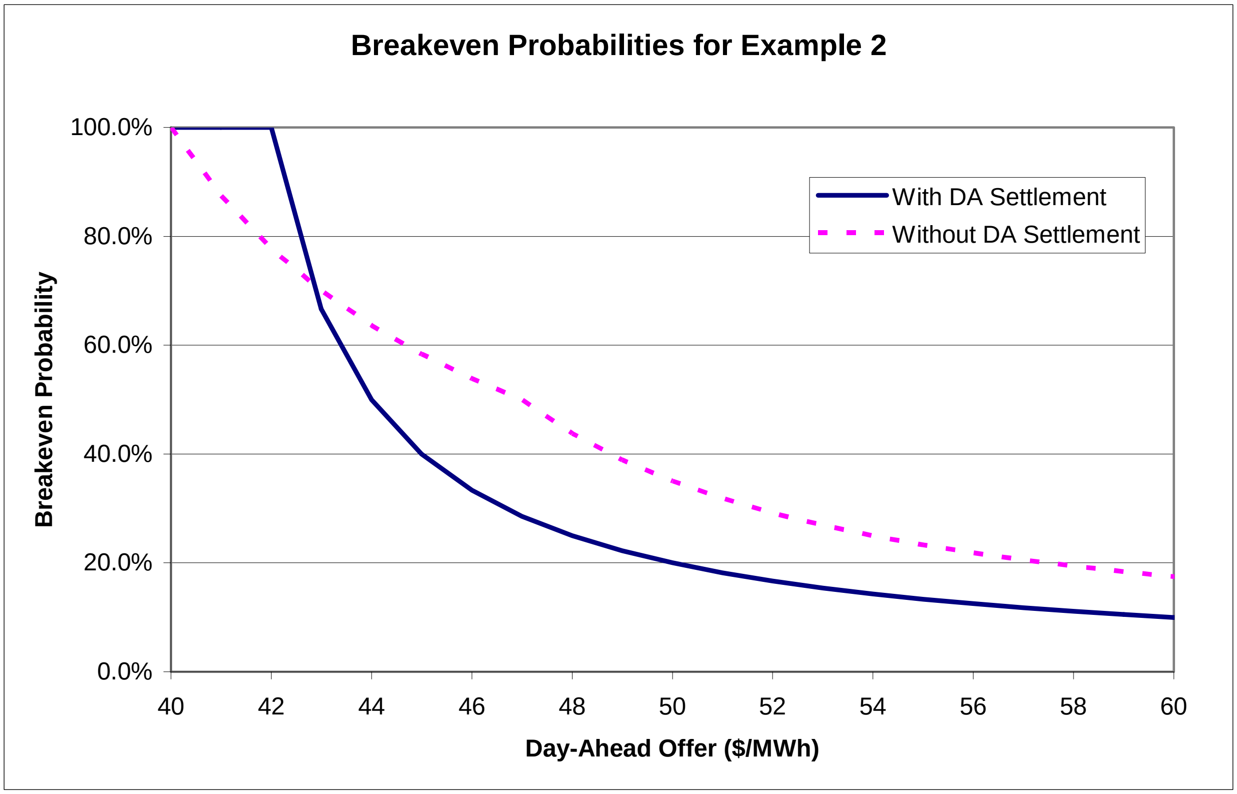
If there is no day-ahead settlement, the real-time price in State 1 is $47/MWh, so the generator would simply realize a margin of $47 – $40 = $7/MWh, regardless of it offered its $40/MWh cost or increased its offer to $45/MWh. In State 2, the real-time price is $37/MWh, so the generator receives a $3/MWh PCG payment, and realizes no margin, if its offer was $40/MWh; but it receives a $8/MWh PCG payment and realizes a margin of $5/MWh if its offer was $45/MWh. Therefore, its expected margin is 50% × $7 + 50% × $0 = $3.50/MWh if its day-ahead offer is $40/MWh, and 50% × $7 + 50% × $5 = $6/MWh if its day-ahead offer is $45/MWh. Therefore, in order to find the breakeven probability p under the enhanced DACP that is associated with a $45/MWh offer, we set $6p = 3.5$ and solve for p; $p = 3.5/6 = 0.583$. If there is a 58.3 percent chance that this generator will continue to be scheduled, even though it has increased its day-ahead offer to $45/MWh, it is just as well as off as if it had not increased its offer.

The breakeven probability in this example for a day-ahead offer of $45/MWh is higher when there is a day-ahead settlement than when there is not a day-ahead settlement. The graph below shows the breakeven probabilities corresponding to each possible offer for the generator in this example. As it shows:

1. For day-ahead offers below $42/MWh (the day-ahead price), the breakeven probability is below 100 percent when there is no day-ahead settlement, because submitting an increased day-ahead offer may increase the margins the generator earns in State 2. In contrast, the breakeven probability remains 100 percent if there is a day-ahead settlement, since increasing the day-ahead offer will have no effect on the day-ahead PCG unless the offer exceeds the day-ahead price.

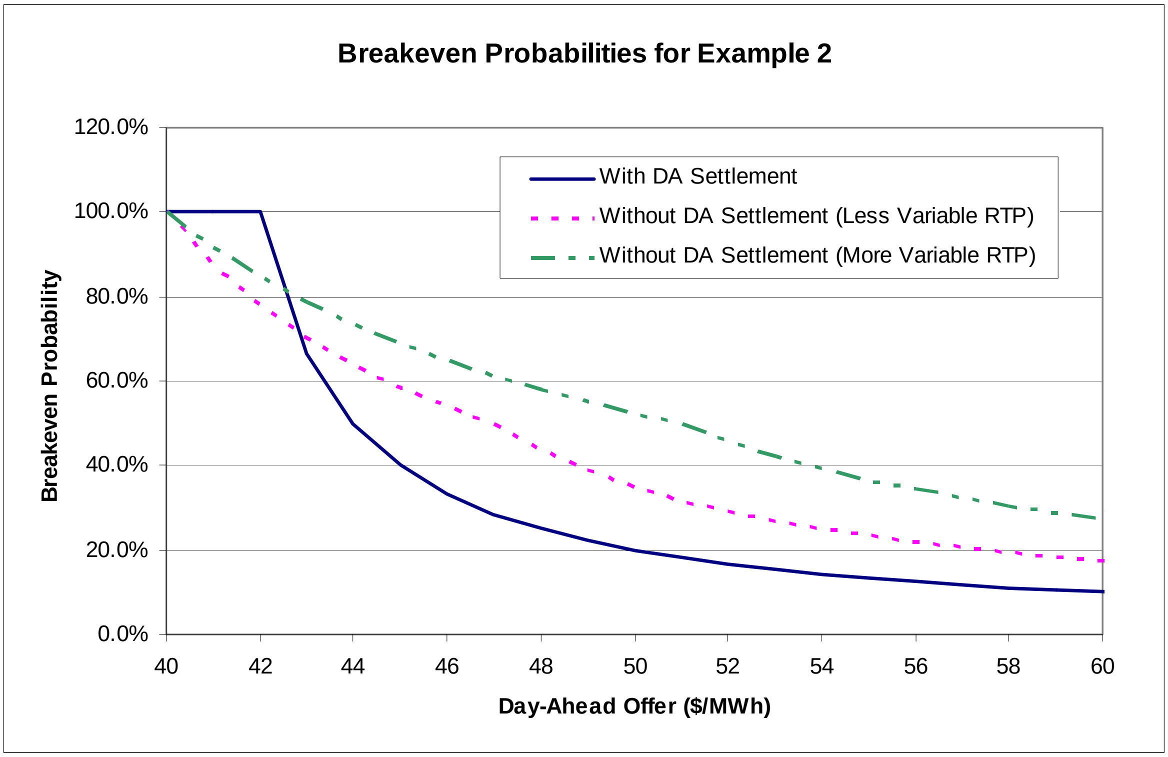
2. When day-ahead offers rise above the day-ahead price, the breakeven probability for the day-ahead settlement falls rapidly. For offers less than $42.80/MWh, the breakeven probability is still higher if there is a day-ahead settlement than if there is not a day-ahead settlement. But for offers above $42.80/MWh, the breakeven probability is lower if there is a day-ahead settlement than if there is not a day-ahead settlement. This result occurs because in this example, if their day-ahead offers reflect their actual costs, generators earn higher expected margins if there were no day-ahead settlement (50% × $7 + 50% × $0 = $3.50/MWh) than they earn if there is a day-ahead settlement ($2/MWh). Consequently, the disincentive to increase the day-ahead offer is less when there is a day-

ahead settlement than when there is not a day-ahead settlement, so the breakeven probability is lower when there is a day-ahead settlement.



Since the breakeven probability in this example if there is no day-ahead settlement is sometimes less than and sometimes more than the breakeven probability in this example if there is a day-ahead settlement, it is not possible to draw any general conclusions as to whether the generator in this example has more of an incentive to increase its day-ahead offer when there is or is not a day-ahead settlement. However, this certainly shows that it is *possible* that there would be more of an incentive for generators to inflate their offers if there is a day-ahead settlement than if there is not a day-ahead settlement.

Alternatively, assume that the real-time price in State 1 is \$51/MWh and the real-time price in State 2 is \$33/MWh. Then we obtain the following result:



Increased volatility in real-time prices increases breakeven probabilities if there is no day-ahead settlement. Again, this makes sense: The breakeven probability is lower when there is a day-ahead settlement than when there is no day-ahead settlement because the generator in this example realizes higher expected margins when its day-ahead offers reflected its costs if there was no day-ahead settlement. The increase in real-time volatility increases the State 1 real-time price, which in turn increases the expected margins that a generator earns when its day-ahead offers reflect its costs and there is no day-ahead settlement.