



Exploration of Enhancements to Dispatch Methodology and Processes (SE-61)

Issues and Problem Identification Paper

Introduction and Background

In Ontario, a real-time scheduling optimizer is used to determine dispatch instructions for dispatchable loads and generators. This paper deals only with generator dispatch. Dispatchable generators submit offers in real-time that reflect their price sensitivity. Generators can submit up to 20 different price/quantity pairs for the same facility for the same hour. The Dispatch Scheduling Optimizer (DSO)¹ uses these offers to determine prices and schedules. Under the current construct, the DSO is run every five minutes in real-time and dispatch instructions are sent indicating a facility's operating point at the end of the next 5-minute interval. The DSO will also consider a facility's ramp rate. Submitted ramp rates, up to 5, indicate how quickly a facility can change its operating point, and reflect its ability to move at different breakpoints. Ramp rates place limits on dispatch based on the number of MW's a unit can move in a minute. Instructions are only sent if there is a required change in output.

The DSO will optimize gain from trade by maximizing the benefits over five selected 'critical' intervals in an 11 interval (55-minute) study period. Dispatch instructions will be based on this 'multi-interval optimization' (MIO)², and affects the constrained dispatch schedule only.

As part of the MIO process, dispatch 'advisories' are issued every five minutes to dispatchable market participants. Dispatch advisories show anticipated dispatch targets and operating reserve schedules for the four selected advisory intervals in the MIO study period.

Unlike dispatchable generators, importers/exporters receive their real-time schedules in the hour ahead pre-dispatch. Projected schedules and prices are typically posted 45 to 30 minutes prior to the dispatch hour.

A generator is considered compliant with IESO dispatch instructions if its operating point is within $\pm 15\text{MW}$ (or $\pm 2\%$ of the total dispatch, whichever is greater) of the dispatch instruction³. To ease the burden of responding to numerous and sometime erratic dispatch, the IESO introduced compliance aggregation. With compliance aggregation, eligible participants can satisfy the dispatch instructions of two or more units by spreading the total megawatt (MW) requirement across the units. Some generators have interdependencies whereby one facility's response to a dispatch instruction can affect the ability of other facilities to efficiently meet their own dispatch instructions. Compliance with IESO dispatch instructions is measured against the aggregate performance rather than on a per unit basis.

The IESO also uses contracted ancillary services to dispatch generators. Regulation allows total system generation to match total system load minute-by-minute or even second-by-second as required on the electricity grid. This ancillary service is provided by generation units with automatic generation control (AGC) capability. Regulation is procured in sufficient quantities and at the appropriate locations to enable the IESO to meet its load following reliability obligations.

The IESO would like to maintain the reliability of Ontario's current resources and improve overall market efficiency by examining existing and potential dispatch issues. Dispatchable facilities have raised concerns about counter intuitive dispatch instructions and their impact on unit operating efficiencies.

¹ Details of the dispatch algorithm can be found in section 7.4 and App 7.5 of the Market Rules.

² Explanation of the MIO process is located in Quick Take 14: Multi Interval Optimization, available on the IESO public website at http://www.ieso.ca/imoweb/pubs/training/QT14_MIO.pdf.

³ Please refer to the Interpretation Bulletin [Compliance with Dispatch Instructions Issued to Dispatchable Generators](#) available on the Compliance pages of the IESO website.

Dispatch concerns have also been raised in the IESO's Operability Review of OPA's Integrated Power System Plan⁴. The review noted that in the absence of any further mitigation, dispatch volatility is unlikely to reduce from current levels. Dispatch volatility has also been discussed by the Market Surveillance Panel (MSP), most recently in the report issued January, 2008⁵. In order to maintain the availability of dispatchable resources the IESO and stakeholders must continue to address the impact of dispatch issues on flexible generation.

The IESO has held one-on-one discussions with Ontario generators to identify and understand the generator specific concerns. As a result of those discussions a set of dispatch issues were identified and are discussed in the next section of this paper.

This paper also defines four underlying problems contributing to generator dispatch issues. The process of isolating problems from the way they are expressed as dispatch issues is helpful for identifying multiple problems that may contribute to a single issue. Identifying specific problems will also assist in identifying specific solutions and setting realistic expectations for results.

Generator Identified Dispatch Issues

During 2008, the IESO held individual meetings with eight different Ontario dispatchable generators to identify and discuss the generator specific dispatch issues. The generation assets represent between 80% and 90% of installed Ontario generation capacity⁶ and in 2008 produced almost 90% of the electricity in the wholesale market. The technologies of the generation assets include:

- Nuclear
- Hydro-electric
- Fossil (coal, natural gas single and combined cycle, co-generation)
- Renewable

In these IESO-generator discussions, business details regarding specific dispatch issues and events were revealed. As a result, only an amalgamated summary of these discussions can be presented in this paper. However, the IESO-prepared notes from each meeting, from which this report has been developed, that were reviewed and confirmed by the applicable generator.

Generators identified many issues that can be grouped under two broad categories: erratic dispatch and dispatch schedule modelling. The generators also identified other more specific 'dispatch issues'. Each of these broad issues and the more specific issues are described below.

Erratic dispatch

Erratic dispatch describes situations where a generation unit receives dispatch instructions that require the unit to change the direction of its energy production for a short period of time.

⁴ The operability report is available on the IESO public website at http://www.ieso.ca/imoweb/pubs/ircp/IESO-Operability_Review_of_IPSP.pdf.

⁵ The MSP's discussion of dispatch issues can be found in the January 15, 2008 report at the following location: http://www.oeb.gov.on.ca/documents/msp/msp_report_20080115.pdf.

⁶ Installed capacity as of the end of 2008.

An example of erratic dispatch is when a generation unit receives a dispatch instruction to increase production for one interval, a dispatch instruction to reduce energy production in the next interval and a dispatch instruction to increase production in the third interval. The IESO has observed a series of dispatch instructions of this nature can frequently occur at the top of an hour as intertie transaction schedules are changed and new bids and offers for domestic dispatchable resources take effect. These dispatch instructions can also occur when demand is relatively flat, when one would expect that generation production would be comparably stable, because MIO positions units for forecasted demand.

Generators have also noted units at the same generation facility can receive contradictory dispatch instructions i.e. one unit is instructed to increase energy production while another unit is instructed to reduce energy production. The total output of both units remains essentially the same, but both units have had to change their energy production.

Sudden reversals in dispatch instruction are another example of erratic dispatch highlighted by facility operators. A generation unit receives a series of dispatch instructions to reduce energy production as demand drops off in the late evening and then receives a dispatch instruction to increase energy production for one interval and then dispatch instructions to continue reducing energy production in subsequent intervals.

Such erratic dispatch instructions require the generation unit to change its power production pattern on very short notice. Generators noted that:

- Being able to react to such erratic dispatch increases generation costs e.g. having auxiliary equipment available to handle the sudden changes in the dispatched energy production;
- Due to the inertial characteristics of generation units, these changes cannot always be met and can cause equipment stress and damage if they occur over a prolonged time.
- Responding to erratic dispatch may, over time, adversely impact the generation unit equipment to the point that there is reduced availability and ability to respond to power system reliability concerns.

Dispatch Scheduling Optimizer Modelling of Generation Units

Generators expressed the opinion that the IESO dispatch scheduling optimization (DSO) program does not adequately model the operating characteristics of the various generation technologies and configurations⁷. Generators identified the following examples of this inadequate modeling:

- For combined cycle generation, the DSO does not recognize the inter-dependencies between the gas turbine(s) and the steam turbine⁸;

⁷ Many of the bullets under DSO Modelling of Generation Units have been addressed in the past or are being addressed in discussions with SE-80 (http://www.ieso.ca/imoweb/consult/consult_se80.asp).

⁸ The Enhanced Day-Ahead Commitment (EDAC) process will model combined cycle generation facilities using a 'pseudo-unit' methodology. A description of this modelling can be found on the IESO public web site at the following location: http://www.ieso.ca/imoweb/pubs/consult/se21-edac/se21-edac-20081128-Pseudo_Units.pdf This modelling is expected to address the generator concerns in the day-ahead commitment process timeframe. The modelling of CCGT in real-time would remain as an issue.

- The numerous directional changes in dispatch instructions for large fossil-fired generation units would suggest the DSO does not recognize the cost of ramping or inertial characteristics of such units⁹;
- Generation unit start-up profiles and parameters under different conditions are not completely or accurately modelled;
- The temporal relationship among cascade hydroelectric generation units is not recognized within the DSO¹⁰.

This inadequate modeling results in the DSO sometimes issuing dispatch instructions that either cannot be physically met or result in inefficient operation of the generation units.

Inaccurate Dispatch Advisories

As part of the multi-interval optimization process for the real-time constrained scheduling, the DSO issues dispatch advisories to generation units. Dispatch advisories are issued every five minutes to dispatchable market participants only. The advisories are expected to allow the market participants to proactively manage the transition to potential new dispatch instructions.

Generators identified that these dispatch advisories are insufficiently accurate compared to the actual dispatch instructions subsequently issued and therefore the advisories cannot be the basis for generators to “proactively manage the transition to potential new dispatch instructions”.

Dispatch Errors

Dispatch errors are dispatch instructions to a generation unit that require the unit to operate in a manner incompatible with the capability of the unit. The IESO acknowledges that dispatch errors occur occasionally, and that these errors can occur when generation unit derate information is not input into the DSO in a timely or accurate manner. An observation was made that the 12 dispatch errors received by a generator over the course of one year represented less than 0.01% of the total dispatch instructions.

Reliance on non-AGC Resources to Manage Frequency

Automatic generation control (AGC) is a contracted ancillary service whereby the contracted generation units can respond to maintain system frequency within reliability standards. At times, the IESO, due to forecast error and non-compliance (inside and outside the deadbands), dispatches non-AGC generation units to change energy production in order to return AGC units to a neutral position, where the full up and down range of AGC is available. Generators noted that dispatches of this nature can cause sudden shifts in unit production, increasing generation operating costs and wear-and-tear, without commensurate compensation i.e. the generator offer prices, which form the basis for the compensation to the non-AGC resources, do not factor in the costs associated with these unanticipated dispatches. Generators have suggested that the IESO consider increasing the levels of contracted AGC.

⁹ It should be noted the issue of ramp costs has previously been discussed under SE-17, Price Calculation Methods – Impacts with 12 Times Ramp Rate. A summary of the ramp cost discussions can be found on the IESO public web site at the following location: http://www.ieso.ca/imoweb/consult/consult_se17.asp

¹⁰ The temporal relationship among cascade hydroelectric generation units has been addressed, to some extent, by the ‘compliance aggregation’. Further information on ‘compliance aggregation’ can be found on the IESO public web site at the following link: http://www.ieso.ca/imoweb/pubs/training/QT23_CompAgg.pdf

Insufficient Information Regarding Network Constraints provided to Market Participants

Generators note that network constraints can have a dramatic impact on the dispatch of their resources. Uncertainties regarding these constraints can make it more difficult for generators to plan their operations e.g. planning hydro-electric production to meet environmental regulation and IESO dispatch. These constraints can be transitional or long-lasting. Generators assert that the provision of more information regarding network constraints e.g. expected duration of the constraint, would assist them in planning their operations, meeting IESO dispatch instructions and meeting other regulatory requirements.

Two additional dispatch issues were raised by generators which are being addressed in separate initiatives. The concerns include the integration of gas-fired peaking generation and the lack of recovery of start-up costs for quick-start generation facilities. These issues will not be addressed in SE-61 and are mentioned here for completeness only.

Problem Identification

The IESO is committed to addressing material generator dispatch issues in ways that present an overall net benefit to the province of Ontario. To do so requires a clear problem definition that identifies the nature, source and materiality of the problem being addressed. In completing the problem definition, the IESO will isolate the inefficient market outcome (nature), what aspect of the market is inducing the inefficient outcome (source) and the impact on market participants (materiality). The range of dispatch issues raised by generators noted above suggests a number of underlying problems. The IESO has distilled generator issues into the following four problems.

Problem 1: Modelling

The optimal dispatch instruction should take into account the physical limitations of a dispatchable unit, but each instruction only accounts for the operating characteristics that are modelled in the DSO.

A dispatch instruction that can't be met by a dispatchable unit may be an inefficient market outcome if the total cost of the dispatch instruction and accompanying compensating action, such as AGC, operating reserve activation (ORA) or an out of market action, is greater than the cost of an alternative dispatch that could be met.

Consider the following example. A generating unit, following a period of steady operation, receives a series of dispatch instructions that make use of the unit's full ramp up capability followed by a series of dispatch instructions that make use of the unit's full ramp down capability. In this situation, the generator's actual energy production will lag the dispatch because the DSO does not model the unit's inertial characteristics. AGC would be required to maintain system balance. For the DSO to compute a dispatch that could be more easily followed, the limiting operating characteristics would need to be incorporated into the DSO model and accounted for during the optimization process.

Additional model complexity has its limitations. It is difficult to model all generator characteristics, and some of those that can be modelled have to be approximated. For example, a unit's ramp capability is modelled at five different break points as opposed to a continuous ramp curve. The approximate nature of the DSO model is accounted for in the 15MW compliance deadband. The IESO manages the deviation between the model and physical reality primarily with AGC and, when necessary, ORA or out of market

actions. An indication the dispatch instructions are failing to account for material operating characteristics would be the frequency use of compensating actions.

Computational constraints also limit the complexity of the model. The formulation of a dispatch solution must fit within the time constraints of a real time market. As greater detail is added to the model, performance limitations may prevent the development of a solution within the necessary time horizon.

This problem could be exacerbated with a changing resource mix. With the closure of coal fired facilities and increased amounts of variable generation, existing resources may be subject to different dispatch patterns as they occupy different positions within the energy stack, creating new dispatch issues. Alternatively, if resources are capable of responding to dispatch instructions but incur higher costs as a result of the new dispatch patterns, inefficient dispatch could still occur as described in Problem 2 below.

Problem 2: Cost Accounting

A set of dispatch instructions should reflect the lowest cost solution to meet demand, but a solution is not the lowest cost if all relevant costs are not accounted for during the optimization process.

If all relevant costs are not considered in issuing dispatch instructions then the DSO may dispatch in a more costly manner than otherwise needed. For example, some dispatchable generators have argued that the cost of ramp is not considered when the set of optimized dispatch instructions is formulated, which results in the overutilization of units. To illustrate this point, generators point to a set of dispatch instructions that occur during relatively flat periods of demand. In this case, the DSO is minimizing the total cost of production across all system constraints. Even small total market savings can result in a new set of dispatch instructions. However, generators argue that the total market savings are less than the costs they incur to move their units to a new base point. Even if generators recovered the cost of ramp through their offer price the dispatch would still be inefficient because the cost recovered is greater than the total market savings. Whereas, if the ramp cost was explicit and separate from offer prices, the total savings from a reduction in MCP would not warrant a change in dispatch because of the greater total costs associated with ramp.

If the relevant costs of all generators are not appropriately accounted for, then a dispatch could be a less than optimal mix of resources. Except for instances where the DSO dispatches to optimize for changes in system constraints, an explicit ramp cost is unlikely to reduce the number of dispatches but rather shift the dispatch instruction to the new lowest cost generator, i.e. the generator with the lowest total offer and ramp cost. In an efficient market, where the true marginal cost is accounted for, a generator should be indifferent to their dispatch. This is true whether a dispatch instruction is sent for a change in demand or to shuffle generators to allow for a lower cost mix of resources.

Problem 3: Forecast Error

A set of dispatch instructions should reflect the lowest cost solution to meet demand, but each solution is less than optimal because forecast error is not minimized.

If the DSO dispatch includes a forecast error, then an inefficient mix of resources was dispatched, which resulted in a higher cost than needed. A forecast error can lead to the dispatch of more resources than necessary (an over forecast) or the dispatch of fewer resources than necessary (an under forecast). In both cases, compensating actions are needed to keep the system in balance. Forecast methodologies can exacerbate the error inherent in any forecast. For example, the current forecast for non-dispatchable load (NDL) is sensitive to changes in dispatchable load (DL). Sudden changes in DL add volatility to the forecast for NDL, a counter intuitive result. Modifying the load forecast tool to eliminate the connection

between NDL and DL will reduce the error associated with forecasting NDL, a process currently under review at the IESO. In some cases, such as in demand forecasting, a level of deviation between forecast and actual is accepted. However, any improvement in forecast accuracy will minimize the deviation between forecast and actual and improve overall dispatch efficiency.

A future resource mix that includes more variable generation could exacerbate forecast errors. The IESO has been proactive in identifying new and improved forecasting methodologies related to variable generation. A recent initiative includes centralized wind forecasting¹¹. Whenever reliability is enhanced and where the benefits outweigh the costs, the IESO looks to improve forecast tools and methodologies.

Problem 4: Fixed One Hour Bid Window

A set of dispatch instructions should reflect the lowest cost solution to meet demand, but each solution is limited by the fixed one hour bid window that may prevent the optimal dispatch.

If a known mix of resources could theoretically meet demand at a lower cost than the dispatch but is limited by market design features, the dispatch may be inefficient. The source of inefficiency associated with the fixed one hour bid window has been well documented by the MSP¹². Such a design feature contributes to the large ramp up and down of domestic resources across the top of the hour to accommodate the hourly scheduling of imports and exports and the sudden entry of water resources during high priced hours. Practical reasons can impose design features that limit dispatch flexibility, such as the coordination needed with neighbouring jurisdictions for import and export scheduling as well as the net interchange schedule limit needed to maintain reliability on the IESO controlled grid. Regardless of the reason, the one hour bid window makes the market less responsive, and as a result, the MSP has identified instances of inefficiency across the top of the hour.

Next Steps

The IESO has issued this paper of categorized problems as a guide for the solution identification stage. For a solution to merit consideration, it must address one of the problems identified above. Stakeholders are welcome to submit comments on whether the problem statements are properly defined, however, unless significant disagreement is expressed the IESO will proceed with the solution identification stage. The objective of the solutions stage is to identify all plausible solutions to the defined problems. While a full range of possible solutions should be presented, those that are not feasible due to implementation costs (including the time required to implement), market structure, inter-jurisdictional integration complexities, or government policy constraints should be discounted or ruled out when appropriate. The IESO will issue a paper on all plausible solutions by November 27, 2009.

¹¹ For more details on centralized wind forecasting see SE-57 on the IESO website at http://www.ieso.ca/imoweb/consult/consult_se57.asp.

¹² Multiple MSP reports discuss the inefficiencies of import and export scheduling, including page 152 of the report released January 1, 2008, located at: http://www.oeb.gov.on.ca/documents/msp/msp_report_20080115.pdf.