Ontario Energy Board Commission de l’énergie de l’Ontario

Ontario

Market Surveillance Panel

# Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.

**Investigation No. 2010-2**
**February 2015**

PUBLIC VERSION

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# REPORT ON AN INVESTIGATION INTO POSSIBLE GAMING BEHAVIOUR RELATED TO CONGESTION MANAGEMENT SETTLEMENT CREDIT PAYMENTS BY ABITIBI-CONSOLIDATED COMPANY OF CANADA AND BOWATER CANADIAN FOREST PRODUCTS INC.

## 1. EXECUTIVE SUMMARY

This Report sets out the findings of the Market Surveillance Panel (the "Panel") in relation to an investigation into Congestion Management Settlement Credit ("CMSC") payments received by Bowater Canadian Forest Products Inc. ("Bowater") and Abitibi-Consolidated Company of Canada ("Abitibi") during the eight-month period from January 2010 to August 2010.[1] The companies were both ultimately owned by Abitibi Bowater Inc. (renamed Resolute Forest Products Inc. in 2011).

The Panel is mandated to monitor and investigate activities in the wholesale electricity market and the conduct of market participants, including in relation to inappropriate or anomalous market conduct. The conduct that is the subject of this investigation was noted by the Panel in one of its semi-annual Monitoring Reports, which discussed anomalous CMSC payments being made to two dispatchable loads located in Northern Ontario. Following receipt and publication of the Panel's Monitoring Report, the then Chair of the Ontario Energy Board ("OEB") requested that the Panel investigate the matter. At the same time, the Independent Electricity System Operator ("IESO") moved expeditiously to deal with two of the major sources of CMSC payments that had been made to Abitibi and Bowater and that are described in this Report.

As set out in greater detail below, the Panel's investigation considered a number of aspects of Bowater's and Abitibi's market conduct, including the submission of extremely high bid prices (both market participants), the submission bid quantities above the level of electricity that the facility was generally capable of consuming (Bowater) and frequent ramping (Abitibi). These kinds of behaviours can be used to obtain CMSC payments from the wholesale market in a manner and in amounts that go beyond what is intended by the wholesale market design and the

[1] Capitalized terms and abbreviations are listed and defined in the Glossary (Appendix A).

rules that govern the markets.[2] Where a market participant exploits a defect in the design, rules or procedures governing the wholesale electricity markets, and obtains a profit or benefit at the expense or disadvantage of the market, the Panel considers that to be gaming.

The Panel has concluded that both companies engaged in gaming. By their market conduct, they exploited certain market defects and, in so doing, received $20.4 million in CMSC payments during the eight-month period in question, and there was a corresponding disadvantage or expense to the market.[3] The documents and materials obtained by the Panel for the purposes of this investigation reveal that Bowater's and Abitibi's conduct was deliberate, and was understood by the companies to be inconsistent with the principles underlying the CMSC framework and as having the potential to be regarded as gaming.

### 1.1 CMSC Payments

To alleviate congestion resulting from transmission system constraints, the IESO must sometimes instruct a dispatchable load[4] to consume more or less energy than the load had bid to consume. When a load is "constrained off", it is being instructed to consume less energy than it desires even though the load's bid price is higher than the prevailing market price. When a load is "constrained on", it is being instructed to consume more energy than it desires at a time when the prevailing market price is higher than the load's bid price. In either case, the dispatchable load's operating profit would be assumed to be reduced.

CMSC payments are intended to compensate a load for the assumed reduction in operating profit caused by following such IESO dispatch instructions. Although the rationale for CMSC payments is clear, the rules and procedures governing the calculation of the payments are complex. The Panel identified various defects in the *Market Rules* and IESO procedures (as they

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[2] See section 6.3 for further detail regarding the origin, purpose and calculation of CMSC payments.

[3] The total CMSC payments made to the two companies over the eight-month period was over $22 million. $20.4 million is the amount that the Panel has found to have been received as a result of gaming.

[4] Bowater and Abitibi were registered as "dispatchable loads" in the wholesale electricity market. They submitted bids (the prices and quantities of electricity they were willing to purchase) into the market every hour and would be scheduled by the IESO as long as their bid prices were not lower than the market price. Dispatchable loads are required to adhere to IESO dispatch instructions sent every five minutes that indicate the amount of power they should consume.

existed at the relevant time) which Bowater and Abitibi exploited to obtain CMSC payments that were self-induced, rather than being caused by conditions on Ontario's power grid. "Self-induced" refers to the ability of a market participant to bring about an outcome (i.e., CMSC payment, ramp or dispatch instruction) through its own actions.

CMSC payments made by the IESO are recovered from market participants based on their respective withdrawals from the IESO-controlled grid through what is known as an "Uplift" charge. Ultimately, the cost of CMSC payments is borne by all electricity consumers.

### 1.2 Bowater's Conduct

Most of the CMSC payments received by Bowater were triggered in hours when its Thunder Bay pulp and paper mill was voluntarily reducing ("ramping down") or increasing ("ramping up") its power consumption. The CMSC payments received by Bowater during self-induced ramping hours far exceeded the cost of the electricity it consumed during those hours. As a result, it was effectively being paid, rather than paying, to consume the amount of electricity it wanted to consume during such hours.

The main behaviours that led to Bowater's substantial CMSC payments were:

- Submitting an extremely high bid price during the hours that Bowater chose to ramp its facility up or down.
- Submitting bid quantities above the level of electricity that its facility was generally capable of consuming.
- Timing the ramping down of its facility to increase the amount of CMSC payments.
- Submitting ramp rates that understated the rate at which its facility changed its electricity consumption, thereby increasing its CMSC payments.

Bowater received a total of $12.3 million in CMSC payments in the eight-month period in question. The Panel determined that the overwhelming majority of those payments – $11.0 million – was triggered by Bowater's gaming behaviour, which in turn increased Uplift charges for all wholesale customers by $0.12/MWh during that eight-month period. The $11.0 million in CMSC payments also served to effectively reduce Bowater's net cost for electricity at its Thunder Bay pulp and paper mill to an amount well below the net energy cost of other dispatchable wholesale customers.[5]

In summary, the Panel concluded that the four above-noted behaviours exploited market defects in the CMSC regime, were highly profitable to Bowater and disadvantaged the market participants who pay Uplift charges. These behaviours therefore constituted gaming.

### 1.3 Abitibi's Conduct

Abitibi received significant CMSC payments during hours when it was voluntarily ramping its Fort Frances pulp and paper mill up or down. The CMSC payments received by Abitibi during self-induced ramping hours far exceeded the cost of the electricity it consumed. As a result, it was effectively being paid, rather than paying, to consume the amount of electricity it wanted to consume during such hours.

The main behaviours engaged in by Abitibi that led to substantial constrained-off CMSC payments were:

- Submitting an extremely high bid price during the hours that Abitibi chose to ramp its facility up or down.
- Submitting ramp rates that understated the rate at which its facility changed its electricity consumption, thereby increasing its CMSC payments.
- Frequent ramping of the facility.

Between April and August 2010, Abitibi implemented an additional strategy to obtain constrained-on CMSC payments during certain hours. It submitted an extremely negative bid

[5] See Table 4-1 for the net energy cost for the Thunder Bay Facility and all other loads during the eight-month period in question.

price and then either was constrained on or consumed above the level of its dispatch instructions. A negative bid price should mean that a load is only willing to consume electricity if it is paid to do so. However, Abitibi intended to and did consume electricity during many of these hours. This behaviour relates to a market defect that had been publicly identified as such by the Panel and the IESO at the time, and that the IESO had announced would be the subject of *Market Rule* amendments.

Abitibi received a total of $9.7 million in net CMSC payments in the eight-month period in question. The Panel determined that the overwhelming majority of those payments – $9.4 million – were triggered by Abitibi's gaming behaviour, which in turn increased Uplift charges for all wholesale customers by $0.09/MWh during that eight-month period. The $9.4 million in CMSC payments also served to effectively reduce Abitibi's net cost for electricity at its Fort Frances pulp and paper mill to the point where Abitibi was in fact being paid to consume electricity.[6]

In summary, Abitibi engaged in three behaviours to exploit market defects in the constrained-off CMSC regime and two behaviours to exploit market defects in the constrained-on CMSC regime. These behaviours were highly profitable to Abitibi and disadvantaged the market participants who pay Uplift charges. These behaviours therefore constituted gaming.

## 1.4 Observations regarding Remedial Action and Review of Continuing CMSC Payments

### 1.4.1 Remedial Action

The Panel encourages the IESO to take whatever action may be open to it to recover the amounts paid to Bowater and Abitibi as a result of conduct that the Panel has found to constitute gaming behaviour.

The Panel's responsibilities include monitoring, investigations and reporting in respect of the wholesale market. The Panel's investigation reports may include recommendations, including

[6] See Table 4-1 for the net energy cost for the Fort Frances Facility and all other loads during the eight-month period in question.

recommendations regarding *Market Rule* amendments. However, the Panel does not have the legislative mandate to impose sanctions or remedies when it finds that gaming has occurred. While a compliance and enforcement regime exists in relation to breaches of the Market Rules, gaming does not necessarily constitute a breach of the *Market Rules*.

The IESO is currently engaging in stakeholder consultations regarding the introduction of a "general conduct rule" to the *Market Rules*. The Panel supports this initiative, and encourages the IESO to proceed expeditiously with its consultations and to ensure that any rule that it implements captures the conduct that is the subject of this investigation or similar kinds of conduct that have been discussed in other Panel reports.

### 1.4.2 Review of Continuing CMSC Payments

In late August 2010, the IESO used an Urgent Market Rule Amendment to suspend all CMSC payments to constrained-off dispatchable loads in light of the fact that significant CMSC payments had been made to two dispatchable loads which the IESO believed to be inconsistent with the intent of the CMSC regime. This foreclosed any further such payments to Bowater and Abitibi. After stakeholder consultations, the IESO went on to implement two amendments to the *Market Rules* in late 2010: one largely and permanently eliminated deviation-induced constrained-on CMSC payments and the other permanently eliminated constrained-off CMSC payments for self-induced ramping by dispatchable loads. These amendments dealt with two of the major sources of CMSC payments to Bowater and Abitibi that are the subject of this Report. However, dispatchable loads continue to receive CMSC payments. During 2011 to 2013, Bowater received approximately $1.7 million in CMSC payments, Abitibi received $2.4 million, and other dispatchable loads received $23.7 million. On December 10, 2012, Bowater generally stopped bidding as a dispatchable load, and on September 12, 2013 Abitibi did the same. Both market participants were therefore ineligible for CMSC payments. However, in 2013 CMSC payments to Abitibi (prior to September 12) and other dispatchable loads remained significant at $1.0 million and $13.3 million respectively.

The Panel considers that the continuing magnitude of CMSC payments under the current *Market Rules* is significant enough to warrant further review. The Panel therefore recommends:

a) *The IESO should review the CMSC payments being made to dispatchable loads since the November/December 2010 amendments to the Market Rules in order to determine whether there are significant amounts that continue to be unwarranted (i.e., paid as a result of market participant actions rather than to compensate for operating profit reductions arising from responding to dispatch instructions caused by Grid Conditions).*

b) *If necessary, the IESO should make further amendments to the Market Rules to eliminate unwarranted CMSC payments to dispatchable loads.*

## 1.5 Postscript

In accordance with section 7.2.2 of the Ontario Energy Board's By-law No. 3, the Panel provided a draft of this Report to the market participants on April 16, 2014, to provide them with an opportunity to discuss the findings with the Panel, to respond to the findings and to comment on matters of factual accuracy and confidentiality. The Panel offered to meet with the market participants, and identified the date by which any written response should be provided.

On May 15, 2014, Resolute FP Canada Inc. ("Resolute"), successor in interest to Abitibi and Bowater, requested that the Panel provide data used to support the Panel's findings before responding to those findings. On June 6, 2014, the Panel provided Resolute with a large amount of interval-by-interval data for each of the Thunder Bay and Fort Frances Facilities for the period covered by the Panel's investigation, being IESO data that the Panel used in its analysis. Resolute delivered a written response to the Panel's draft report on July 2, 2014. Resolute's July 2, 2014 response is reproduced in Appendix N, and the Panel's comments on that response are set out in Appendix O. Appendix O also describes subsequent correspondence exchanged between Resolute and the Panel, as well as an update on the status of the IESO's "general conduct rule" referred to in section 1.4.1 above.

In terms of confidentiality, as part of its July 2, 2014 response Resolute requested that the following be redacted from the public version of this Report: (i) numbers and figures such as bid numbers and operating costs; and (ii) the names of Resolute personnel. Although the Panel questions the commercially sensitive nature of the data referred to in (i) given the change in status of the two facilities at issue, the Panel nonetheless agreed to redact certain data as well as the names and titles of Resolute personnel. In accordance with section 7.5 of the Ontario Energy Board's By-law No. 3, both public and confidential versions of this Report have therefore been prepared, the former for public communication and the latter for transmittal to the Chair of the Ontario Energy Board and the CEO of the IESO. Appendix N as it appears in the public version of this Report was redacted by Resolute.

With the exception of this Postscript, Appendices N and O, and section 7.4.3 (which was modified by the Panel in light of Resolute's response), this Report is as at December 31, 2013.

## 2. INTRODUCTION

This Report contains the analysis and findings of the Market Surveillance Panel ("**MSP**", or the "**Panel**") in respect of an investigation (the "**Investigation**") into possible gaming of Congestion Management Settlement Credit ("**CMSC**") payments by dispatchable loads[7] operated by Abitibi-Consolidated Company of Canada ("**Abitibi**") and Bowater Canadian Forest Products Inc. ("**Bowater**") during the period January 2010 to August 2010 (the "**Relevant Period**"). Abitibi and Bowater are both subsidiaries of Abitibi Bowater Inc., and the issues relating to each participant are being dealt with in a single report because of overlaps in some of the time periods, personnel and behaviour related to both loads.

This Report begins by describing the market participants that are the subject of the Investigation (Section 3) and the CMSC payments they received (Section 4). It also summarizes the Panel's investigation framework and process as well as the applicable *Market Rules* and Independent Electricity System Operator ("**IESO**") procedures (Section 5), and other relevant aspects of the design of the Ontario wholesale market (Section 6). It then provides the Panel's analysis, findings and recommendations in respect of Bowater's (Section 7) and Abitibi's (Section 8) activities. The Report concludes with a recommendation relating to possible continuing unwarranted CMSC payments (Section 9).

With the exception of the Postscript that appears in section 1.5 of the Executive Summary and the section and Appendices noted at the end of that Postscript, the information set out in this Report is as at December 31, 2013.

[7] Dispatchable loads are large industrial users of electricity that receive instructions from the electricity system operator indicating the amount of electricity they should consume.

## 3. THE MARKET PARTICIPANTS AND DISPATCHABLE FACILITIES

The dispatchable loads that are the subject of this investigation were owned during the relevant period by subsidiaries of Abitibi Bowater Inc. ("**ABI**"), a Delaware registered corporation.[8] In 2009, ABI and its Canadian and U.S. subsidiaries entered into bankruptcy proceedings in Canada and the United States. ABI and its subsidiaries completed a reorganization and emerged from creditor protection under the *Companies' Creditors Arrangement Act* ("**CCAA**")[9] in Canada and under comparable US legislation on December 9, 2010.[10] ABI has been renamed Resolute Forest Products Inc.[11]

Although the two dispatchable facilities were under common ownership (see the corporate chart in Appendix B), they were owned by different subsidiaries and each was registered as a separate market participant with the IESO.

### 3.1 Bowater Canadian Forest Products Inc.

During the Relevant Period, Bowater owned and operated a pulp and paper mill in Thunder Bay, Ontario. Bowater was owned by AbitibiBowater Canada Inc., a TSX-listed corporation. AbitibiBowater Canada Inc. was owned by Bowater Canadian Holdings Incorporated, which was owned by Bowater Incorporated (a Delaware corporation), which was owned by ABI.[12]

Bowater's facility in Thunder Bay (the "**Thunder Bay Facility**") includes a thermo-mechanical pulpmill ("**TMP**") with two mainline refiners, a rejects refiner, auxiliaries, and a recycle mill. The Thunder Bay Facility produced commercial printing papers, newsprint and market pulp. It had a maximum dispatch capability of ● - ● MW and was one of the largest dispatchable loads in

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[8] See Abitibi Bowater Inc. Corporate Chart in Appendix B.

[9] *Companies' Creditors Arrangement Act, 1985 (Canada)*, as amended, online: http://laws-lois.justice.gc.ca/eng/acts/C-36/page-1.html

[10] Resolute Forest Products Inc., webpage, "About Us: Emergence", as at November 5, 2012, online: https://web.archive.org/web/20121105050415/http://www.resolutefp.com/emergence/.

[11] Resolute Forest Products Inc., webpage, "About Us: Legal Entity Name Changes", as at February 26, 2014, online: http://www.resolutefp.com/About_Us/Identity/

[12] Responses to RFI (defined in Section 5.4), A.1, p. 1.

Ontario. During the Relevant Period, Bowater held an Electricity Wholesaler Licence from the Ontario Energy Board ("**OEB**") which authorized it to buy and sell electricity through the IESO-administered markets.[13]

From July 2003 to August 2006, the Thunder Bay Facility operated as a dispatchable load. It elected to become non-dispatchable in September 2006. In 2009, as part of the CCAA process, Bowater idled its machines and reassessed its operations. It addressed labour, power and fibre cost issues, and also consulted with personnel at affiliated entities regarding opportunities to reduce power costs by generating CMSC payments as a dispatchable load.[14] The Thunder Bay Facility resumed operation of its Paper Machine 5 on December 17, 2009.[15] It became a dispatchable load again in the IESO-administered market on February 8, 2010.

### 3.2 Abitibi-Consolidated Company of Canada

During the Relevant Period, Abitibi[16] owned and operated a pulp and paper mill in Fort Frances, Ontario. Abitibi was owned by Abitibi-Consolidated Inc., which was owned by Abitibi Bowater Canada Inc. (18%), a Canadian corporation, and ABI (82%). Abitibi Bowater Canada Inc. was also ultimately owned by ABI.

Abitibi's facility in Fort Frances (the "**Fort Frances Facility**") includes three paper machines (two of which were active), one kraft mill, and a biomass and natural gas boiler/generator.[17] The facility produced commercial printing papers and market pulp. The load had a maximum dispatch capability of ● MW and the generator had a maximum dispatch capacity of ● MW.

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[13] Responses to RFI, A.4, p. 113; Electricity Wholesaler Licence EW-2005-0537 Bowater Canadian Forest Products Inc., available online at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/43273/view/DO_Bowater_licence_20060125.PDF.

[14] See, *e.g.*, email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], September 11, 2009. Responses to RFI, B.2.5.

[15] Responses to RFI, B.2, p.1.

[16] Abitibi-Consolidated Company of Canada was continued as Abibow Canada Inc. on December 10, 2010; Abibow Canada Inc. subsequently changed its name to Resolute FP Canada Inc..

[17] Responses to RFI, B.8.1.

During the Relevant Period, Abitibi held an Electricity Generation Licence from the OEB which authorized it to generate, sell and buy electricity through the IESO-administered markets.[18]

The Fort Frances Facility has operated as a dispatchable load since September 2004 and as a dispatchable generator since June 2007. During the CCAA restructuring, the Fort Frances Facility shut down one of the paper machines. At times, this resulted in changes to its operating pattern because of limited pulp storage capacity. On January 22, 2010, Fort Frances began to operate as an aggregated facility, meaning the load and generator could effectively bid or offer, and pay or be paid, for electricity as either a net load or net generator.[19] It typically operated as a net load (*i.e.* consumption exceeding on-site generation) and was charged for energy on the basis of its net metered consumption.

[18] Responses to RFI, A.4, p. 106; Electricity Generation Licence EG-2003-0204 Abitibi-Consolidated Company of Canada. The amended licence is available online at: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/384821/view/amd_licence_eg_resolute_20130228.PDF.

[19] Pursuant to Chapter 7, Section 2.3 of the *Market Rules*.

## 4. CMSC PAYMENTS TO BOWATER AND ABITIBI

Table 4-1 summarizes the CMSC payments received relative to the cost of purchasing electricity for each of the two facilities and all other loads in Ontario during the Relevant Period. CMSC payments reduced Bowater's average net electricity cost to $25.44/MWh, more than 60% less than the price being paid by other loads. Abitibi received approximately $2.5 million in net energy payments (*i.e.* its CMSC payments exceeded the energy, Uplift and Global Adjustment charges) and it was effectively being paid to consume energy at an average rate of $22.47/MWh.

***Table 4-1: Net Energy Cost per MWh for the Thunder Bay Facility, the Fort Frances Facility and All Other Loads January – August 2010 ($000, MWh and $/MWh)***

| Participant | Energy Charges ($000)* | CMSC ($000) ** | Net Energy Cost ($000) | Consumption (MWh) | Net Energy Cost Per MWh ($/MWh) |
|---|---|---|---|---|---|
| Bowater (Thunder Bay Facility)*** | 20,921 | 12,334 | 8,587 | 337,514 | **25.44** |
| Abitibi (Fort Frances Facility) | 7,176 | 9,694 | (2,518) | 112,034 | **(22.47)** |
| All Other Dispatchable Loads | 156,413 | 1,088 | 155,325 | 2,427,092 | **64.00** |
| Non-Dispatchable Loads | 5,946,423 | n/a | 5,946,423 | 88,709,646 | **67.03** |

* Includes Global Adjustment and Uplift charges.
** All amounts are net CMSC after clawback of charge type 105 (CMSC paid for the difference between the constrained and unconstrained schedule) and charge type 1050 (CMSC that should not be paid because it was the result of that registered facility's own equipment or operational limitations according to IESO Business Rules). Also excludes voluntary repayments. The clawback adjustments and the IESO Business Rules are described in Section 6.3.4 and Appendix H.
*** Bowater data excludes January 2010 as it only resumed being a dispatchable load in February 2010.

Table 4-2 summarizes the monthly CMSC payments made to the two facilities and to all other dispatchable loads during the Relevant Period. It also provides comparative data about the cost of electricity consumed (including Uplift and Global Adjustment charges). The CMSC amounts are net payments (*i.e.* gross CMSC less any clawbacks and voluntary repayments). Over the eight-month period the Thunder Bay Facility, which represented 10% of dispatchable load capacity in Ontario, received 53% of CMSC payments made to all Ontario dispatchable loads. The Fort Frances Facility, which represented 7% of dispatchable load capacity in Ontario, received 42% of such payments.

***Table 4-2: Energy Charges, CMSC Payments and Net Energy Cost for the Thunder Bay Facility, the Fort Frances Facility and All Other Dispatchable Loads January – August 2010 ($000)***

| Month (2010) | Bowater (Thunder Bay Facility) | | | Abitibi (Fort Frances Facility) | | | All Other Dispatchable Loads | | |
|---|---|---|---|---|---|---|---|---|---|
| | Energy Charges * | CMSC ** | Net Energy Cost | Energy Charges * | CMSC ** | Net Energy Cost | Energy Charges * | CMSC ** | Net Energy Cost |
| Jan | Not Dispatchable | | | 1,875 | 385 | 1,490 | 21,232 | 64 | 21,296 |
| Feb | 2,859 | 1,405 | 1,454 | 448 | 413 | 35 | 19,154 | 130 | 19,284 |
| Mar | 3,538 | 2,508 | 1,030 | 608 | 1,134 | (526) | 23,884 | 156 | 24,041 |
| Apr | 3,094 | 2,602 | 493 | 840 | 1,857 | (1,017) | 23,450 | 102 | 23,553 |
| May | 3,124 | 2,339 | 785 | 1,136 | 1,280 | (144) | 19,343 | 178 | 19,521 |
| Jun | 2,936 | 1,796 | 1,141 | 681 | 2,689 | (2,009) | 16,915 | 249 | 17,164 |
| Jul | 2,676 | 867 | 1,809 | 816 | 1,644 | (827) | 16,628 | 153 | 16,781 |
| Aug | 2,693 | 818 | 1,875 | 773 | 292 | 481 | 15,806 | 56 | 15,862 |
| **Total** | **$20,921** | **$12,334** | **$8,587** | **$7,176** | **$9,694** | **($2,518)** | **$156,413** | **$1,088** | **$157,501** |

* Includes Global Adjustment and Uplift charges.
** All amounts are net CMSC after clawback of charge type 105 (CMSC paid for the difference between the constrained and unconstrained schedule) and charge type 1050 (CMSC that should not be paid because it was the result of that registered facility's own equipment or operational limitations according to IESO Business Rules). Also excludes voluntary repayments. The clawback adjustments and the IESO Business Rules are described in Section 6.3.4 and Appendix H.

## 5. INVESTIGATION PROCESS AND FRAMEWORK

This section provides an overview of the MSP mandate in respect of market monitoring and gaming investigations, background on the events leading to the request for and commencement of the Investigation, the information gathered and the analytical framework used to assess gaming.

### 5.1 Market Surveillance Panel Mandate

The MSP is empowered under the *Electricity Act*, *1998* (the "**Act**"*)* to conduct investigations into any activity related to the IESO-administered markets or the conduct of a market participant.[20] The MSP, with the support of the IESO's Market Assessment Unit ("**MAU**"),[21] is also required by OEB By-Law #3 (the "**MSP By-Law**") to monitor activities related to the IESO-administered markets and the conduct of market participants with a view to identifying, among other matters:

- inappropriate or anomalous market conduct, including possible abuses of market power and gaming;
- design flaws and inefficiencies in the *Market Rules* and other rules and procedures of the IESO; and
- design flaws in the overall structure of the IESO-administered markets.[22]

The general process applicable to MSP investigations is set out in the MSP By-Law which provides, among other things, that:

- the Panel may initiate an investigation on its own, upon receipt of a complaint or at the request of the OEB Chair;[23]

[20] *Electricity Act***,** *1998* (Ontario), as amended, online: http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98e15_e.htm#BK95,s.37(1).
[21] The MAU provides support to the MSP pursuant to the Protocol Related to Market Surveillance Panel ("**Protocol**") between the IESO and the OEB, online: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_protocol.pdf. References in this report to investigative steps carried out by the Panel include investigative steps carried out by the MAU on behalf of the Panel.
[22] MSP By-Law, as amended, online: http://www.ontarioenergyboard.ca/oeb/_Documents/About%20the%20OEB/OEB_bylaw_3.pdf, s. 4.1.1.
[23] *Ibid,* s. 5.1.1.

- where the Panel commences an investigation, the Panel shall, upon determining that there is a *prima facie* case in respect of the conduct of a person that is the subject matter of the investigation, notify that person of the commencement of the investigation;[24]
- for the purpose of carrying out an investigation, the Panel has the power to examine and compel the production of any documents or other things, to summon and compel testimony, to conduct inspections, and to obtain warrants for search and seizure as authorized by the Act;[25] and
- upon completion of an investigation, the Panel shall prepare a written report on the matter investigated, the Panel's findings and its recommendations, if any. [26]

## 5.2 Background to Investigation

The Investigation arose as a result of market monitoring activities conducted by the MAU on behalf of the Panel during the spring and summer of 2010.

### 5.2.1 Initial Inquiries by the MAU

In May 2010, the MAU observed that large amounts of CMSC payments were being made to Bowater's Thunder Bay Facility and Abitibi's Fort Frances Facility. It appeared that anomalously high CMSC payments were arising as a result of facility-specific behaviours at both Facilities. The MAU briefed the Panel, and the Panel asked the MAU to examine the issues in greater detail.

On June 11, 2010, MAU staff contacted Bowater and Abitibi personnel to discuss the CMSC payments that the two Facilities were receiving. Bowater and Abitibi were subsequently provided with a summary which identified three high-level factors that, in the MAU's view, appeared to be contributing to the CMSC payments: (i) ramping actions; (ii) deviation from intended consumption in the market schedule resulting in "constrained-on" CMSC payments at the Fort Frances Facility; and (iii) deviation from intended consumption in the market schedule

[24] *Ibid,* s. 5.1.9.
[25] *Ibid,* s. 5.1.11.
[26] *Ibid,* ss. 5.1.13 and 7.2.

resulting in "constrained-off" payments.[27] During discussions with a representative of the Fort Frances and Thunder Bay Facilities in June 2010, the MAU also referenced information regarding the potential scope of gaming activity contained in the Panel's *Monitoring Document*: *Monitoring of Offers and Bids in the IESO-Administered Electricity Markets.*[28]

The MAU noted that the Thunder Bay Facility was often receiving upward of $80,000 in CMSC payments per day compared to the approximately $8,000 in CMSC payments per day it received in 2006 (when the facility had previously been dispatchable). It also indicated that Bowater's $●/MWh bid price was contributing to the very large CMSC payments (the relationship between bid price and CMSC payments is explained in Section 6.3.2). As it has done on various occasions in the past with market participants, the MAU requested on behalf of the IESO that Bowater consider a voluntary repayment of all CMSC payments associated with ramping (Bowater's ramping pattern is described in Section 7.2.2), and noted that a bid price of $●/MWh[29] would be similar to offer price changes that had been adopted by various generators who receive CMSC payments when they voluntarily chose to ramp down.[30] Bowater declined to repay any ramping CMSC payments[31], although it lowered its bid price from $●/MWh to $●/MWh during ramping periods on a go-forward basis.[32]

The MAU also noted the numerous instances of constrained-on CMSC payments at the Fort Frances Facility which appeared to be self-induced. The MAU requested that Abitibi consider a

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[27] Email from MAU to [Senior Abitibi Personnel #2] dated June 24, 2010. Responses to RFI, B.13.27.

[28] MSP, *Monitoring Document: Monitoring of Offers and Bids in the IESO-Administered Electricity Markets*, March 3, 2010, online: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Monitoring_Offers_Bids_Document_20100310.pdf, p. 44.

[29] Email from MAU to [Senior Abitibi Personnel #2], June 24, 2010. Responses to RFI, B.13.27.

[30] For further information about the relationship between CMSC payments and offer prices used by generators to signal an intention to ramp down, see MSP, *Monitoring Document: Generator Offer Prices Used to Signal an Intention to Come Offline*, August 19, 2011, online: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MonitoringDocument_GeneratorOfferPrices_20110819.pdf; and MSP, *Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2008 – October 2008*, online: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_200901.pdf, p. 213.

[31] Email from [Senior Abitibi Personnel #2] to MAU, June 25, 2010. Responses to RFI, B.13.27. See also email from [Senior Abitibi Personnel #2] to MAU, August 16, 2010. Responses to RFI, B.13.88

[32] Emails from [Senior Abitibi Personnel #2] to MAU, June 30, 2010. Responses to RFI, B.13.40.

voluntary repayment of ramping CMSC and constrained-on CMSC payments.[33] Abitibi has not repaid any ramping CMSC. However, it repaid the portion of constrained-on CMSC which arose as a result of consumption deviation between April 2010 and July 2010, which it calculated to be $1.825 million.[34]

### 5.2.2 MSP Winter 2010 Monitoring Report

On August 30, 2010, the MSP published its semi-annual Monitoring Report for the period from November 2009 to April 2010 (the "**Winter 2010 Monitoring Report**") which contained information about the anomalous CMSC payments made to two dispatchable loads located in Northwestern Ontario.[35] Bowater and Abitibi were not named in the Monitoring Report.

## 5.3 Request for an Investigation

Following receipt and publication of the Winter 2010 Monitoring Report, the then Chair of the OEB wrote to the then Chair of the MSP on September 3, 2010 and requested that the Panel investigate the circumstances that lead to the anomalous CMSC payments being made to two dispatchable loads.[36] The Panel commenced the Investigation in response to the OEB Chair's request and notified Bowater and Abitibi that a gaming investigation had been commenced.

## 5.4 Information Gathering

In carrying out its Investigation, the Panel obtained and considered extensive information from the IESO. This included statistical information related to prices, scheduled and actual consumption, settlement payments and other data.

The Panel also requested extensive information from Bowater and Abitibi. Information and materials were provided by Bowater and Abitibi in response to the Panel's requests for information (the "**Responses to RFI**") without the Panel having to use its statutory inspection or

[33] Email from MAU to [Senior Abitibi Personnel #2], June 24, 2010. Responses to RFI, B.13.27.

[34] Email from [Senior Abitibi Personnel #2] to MAU, August 17, 2010. Responses to RFI, B.13.163.

[35] MSP, *Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2009 – April 2010*, online: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20100830.pdf. p. 112.

[36] The request was made pursuant to MSP By-Law, s. 5.1.1(c).

other compulsory powers. Bowater and Abitibi represented that they had provided correct and complete responses to the Panel's information requests. The information provided by Bowater and Abitibi included:

- copies of emails between personnel at the companies and their affiliates[37] that pertained directly or indirectly to CMSC payments received during the Relevant Period;
- copies of communications and documents related to the development of bidding strategies in the wholesale electricity market and associated financial implications; and
- copies of documents related to operating strategies, including the determination of ramp rates and consumption patterns.

The Panel conducted detailed assessments of Bowater's and Abitibi's market conduct, their Responses to RFIs and relevant market outcomes. The assessments were based on the analytical framework used to assess gaming issues.

### 5.5 Framework for Gaming Investigations

This section outlines the framework applied by the Panel to assess whether the behaviours of a market participant constitute gaming.

The Panel's mandate includes investigations in relation to conduct that may constitute an abuse of market power or gaming. In the course of providing a framework for analyzing market power issues, the Panel has noted that gaming is a separate concept (which may or may not overlap with market power concerns) that encompasses, among others, market manipulation and conduct that involves the following four elements:

(i) a defect in the market design, poorly specified rules or procedures or a gap in the *Market Rules* or procedures (collectively referred to as a "market defect");

[37] See Appendix C for a list of selected Bowater, Abitibi and affiliated company personnel who prepared or received the communications and documents referenced in this Report.

(ii) exploitation of the market defect by the market participant;

(iii) profit or other benefit to the market participant; and

(iv) expense or disadvantage to the market.[38]

Sections 7 and 8 of this Report address each of these elements in respect of the conduct of Bowater at the Thunder Bay Facility and Abitibi at the Fort Frances Facility, respectively. Section 6 provides contextual information about relevant aspects of the wholesale market.

[38] See Market Surveillance Panel, *Report on an Investigation into Possible Gaming Behaviour Related to Infeasible Import Transactions by TransAlta Energy Marketing Corp. on the Manitoba-Ontario Intertie*, Investigation No. 2011-02, October 22, 2012, p. 7.

## 6. RELEVANT ASPECTS OF THE WHOLESALE MARKET DESIGN

This section provides an overview of how dispatchable loads participate in the Ontario wholesale electricity market, the "two schedule" market design and the associated CMSC payment regime.

The IESO administers the wholesale electricity markets in Ontario.[39] The IESO operates a real-time energy market, in which electricity demand and supply are balanced and instructions are issued to dispatchable generators and loads every five minutes as well as to intertie traders on an hourly basis. The IESO selects the most economic offers from generators and importers as well as bids from dispatchable loads and exporters in order to match the supply and consumption of electricity for each five-minute interval. The outputs of this process include dispatch quantities and the Market Clearing Price ("**MCP**"). The simple average of the 12 interval MCPs in an hour is the Hourly Ontario Energy Price ("**HOEP**").[40]

### 6.1 Dispatchable Loads

Most users of electricity (also known as loads), even those that are directly connected to the IESO-controlled grid, are not actively involved in the wholesale market (*i.e*. they do not submit bids to the IESO to buy electricity) and the IESO does not (except in emergency conditions) direct or control the amount of electricity they consume. These customers are referred to as non-dispatchable loads.

The *Market Rules* allow loads to become dispatchable and to submit bids in the wholesale market which indicate the quantity of electricity they wish to consume at particular price levels. To qualify as a dispatchable load, a facility must be capable of receiving and responding to dispatch instructions sent every five minutes by the IESO.[41] The IESO directs (dispatches) a

[39] See, *e.g.*, IESO, *Introduction to Ontario's Physical Markets: An IESO Marketplace Training Publication*, online: http://www.ieso.ca/imoweb/pubs/training/IntroOntarioPhysicalMarkets.pdf.

[40] See, *e.g.*, IESO, *Overview of the IESO-Administered Markets: An IESO Training Publication*, online: http://www.ieso.ca/imoweb/pubs/training/MarketsOverview.pdf.

[41] See, *e.g.*, IESO, *Quick Takes QT17: Dispatchable Loads*, online: http://www.ieso.ca/Documents/training/QT17_DispLoads.pdf. A dispatchable load is also eligible to provide operating reserve to the IESO's operating reserve market.

dispatchable load's energy consumption based on its bids, market supply and demand and conditions in the load's local area.

A dispatchable load may submit only one energy bid for each registered facility for any dispatch hour, but such a bid may contain "laminations" of up to 20 price-quantity pairs ("**P/Q Pairs**").[42] The price in each price-quantity pair cannot be greater than the Maximum Market Clearing Price ("**MMCP**") of $2,000/MWh, or lower than the negative MMCP (-$2,000/MWh).

If a load participating in the wholesale market bids at $1,999/MWh, it is treated as dispatchable by the IESO and will be scheduled at its desired consumption level (unless there is a need to dispatch it down/off in order to balance demand with supply after all other lower priced resources have been dispatched). However, if the load bids all or part of its consumption at the MMCP ($2,000/MWh) in any hour, that quantity is deemed by the IESO to be non-dispatchable in that hour (and therefore ineligible to be dispatched down).[43]

When market prices are negative, loads and exporters are paid to consume energy (instead of paying for their energy) and generators and importers are charged (instead of being paid) to supply energy. A bid at a negative price means the load is willing to consume energy only if it is paid to do so. For example, a bid of 20 MW at -$100/MWh indicates the load is willing to consume 20 MW only if the market price is less than (*i.e.*, more negative) or equal to -$100/MWh.

Dispatchable loads also submit ramp rates (in MW/minute) which indicate how quickly the load can change the amount of energy it is consuming. The IESO uses this information to determine

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[42] IESO, *Dispatchable Load Operating Guide*, online: http://www.ieso.ca/imoweb/pubs/training/DispLoadGuide.pdf.

[43] IESO, *Market Manual 4: Market Operations*, Part 4.2: Submission of Dispatch Data in the Real-Time Energy and Operating Reserve Markets, p. 10. For example, a bid may contain a first lamination of 20 MW for the MMCP of $2,000/MWh, indicating the load is non-dispatchable for 20 MW and wants to consume regardless of market price. The bid may also contain a second lamination of 50 MW at $500/MWh, indicating the load is willing to consume a total of 50 MW (*i.e.* an incremental 30 MW) so long as the market price is less than or equal to $500/MWh. At any price above $500/MWh, the load only wants to consume the first lamination of 20 MW.

dispatch instructions that a facility can physically follow. A dispatchable load can enter up to five ramp rates for the laminations comprising its energy bid for each hour.

### 6.2 The Two-Schedule Market Design

The real-time wholesale energy market is a uniform-price market in which suppliers (generators and importers) generally receive, and wholesale customers (including dispatchable and non-dispatchable loads as well as exporters) generally pay, a system-wide market price[44] for electricity irrespective of their location in Ontario.[45] The decision to adopt a uniform-price market, rather than a market in which prices vary by location, has resulted in a "two-schedule" system in order to deal with differences between the province-wide "market" (or "unconstrained") demand/supply and the physical capabilities of the system which results in the need for the IESO to "constrain" market participants in order to deal with localized demand/supply imbalances.

Under the two-schedule system, the IESO's dispatch algorithm is run in two modes for every five-minute interval of market operation:

- The "unconstrained mode" ignores most physical limitations of the transmission system inside Ontario. The outputs are settlement prices and "market schedules" (also referred to as "unconstrained schedules") that show the amount of energy that dispatchable facilities would have been prepared to inject or withdraw if there were no constraints on the system.

- The "constrained mode" considers all physical limitations of the grid including transmission constraints and transmission line losses ("**Grid Conditions**"). The outputs are the dispatch instructions that are issued by the IESO and "dispatch schedules" (also

[44] The price for generators and dispatchable loads is the MCP for each interval. Non-dispatchable loads pay the HOEP. Import and export transactions are also paid based on the HOEP, subject to adjustments related to localized intertie congestion.

[45] The description of the two-schedule system in this section and the following subsections is a simplified summary. For more detail, see IESO, *Introduction to Ontario's Physical Markets*, online: http://www.ieso.ca/imoweb/pubs/training/IntroOntarioPhysicalMarkets.pdf.

referred to as "constrained schedules") that show energy injections and withdrawals for dispatchable facilities that can actually happen within the physical constraints of the system.

A dispatchable resource is "constrained on" when the constrained schedule dispatches it to produce or consume more electricity than is indicated in the market schedule.  Conversely, a dispatchable resource is "constrained off" when the constrained schedule dispatches it to produce or consume less electricity than is indicated in the market schedule.

The main differences between unconstrained and constrained modes of the dispatch algorithm are summarized in Table 6-1 and are discussed in more detail in Appendix D (unconstrained schedule) and Appendix E (constrained schedule).

***Table 6-1: Differences between the Unconstrained and Constrained Modes of the IESO's Dispatch Algorithm***

| Attribute | Constrained Mode | Unconstrained Mode |
|---|---|---|
| Inputs – Prices and Quantities | Hourly bids and offers from dispatchable facilities, self-scheduling generator quantities, intermittent generation forecasts and a forecast of demand by non-dispatchable facilities. | Same as constrained mode. |
| Inputs – Transmission Constraints | Includes all transmission constraints and limitations within Ontario. | Ignores most transmission constraints within Ontario. |
| Inputs – Ramp Rates | Uses ramp rates submitted by market participants. | Uses ramp rates that are three times faster than the participant-submitted rates used in the constrained schedule (the "3x ramp rate multiplier"). |
| Outputs – Quantities | A constrained (or dispatch) schedule for each dispatchable participant that shows energy injections and withdrawals for a five-minute interval that can actually happen within the physical constraints of the transmission system and participant equipment.<br>The constrained schedule is the basis for the IESO's dispatch instructions to dispatchable facilities. | An unconstrained (or market) schedule for each dispatchable participant that shows the amount of energy the participant would be injecting/consuming in a five-minute interval given (a) its offer/bid, (b) ramp rates determined using the 3x ramp rate multiplier, and (c) the absence of transmission constraints on a province-wide basis. |
| Outputs – Prices | "**Nodal Prices**" for each injection or withdrawal node on the Ontario transmission system. These reflect the marginal cost of supplying an additional MW at that particular location on the grid, based on the offers/bids of market participants and constraints arising from Grid Conditions.<br>These prices are compared to the bid/offer prices submitted by participants to determine whether a dispatchable facility should be constrained on or constrained off. | Market Clearing Prices for each five-minute interval.<br><br>These MCPs (or the hourly average of them - HOEP) are used in the IESO's billing and settlement system. |
| Supply and Demand in Future Intervals | The constrained schedule for a five-minute interval is determined by considering offers, bids and Grid Conditions for the current interval and for the next several intervals. Multi-interval optimization provides a more efficient dispatch in the current and future intervals.<br>The starting point for each new interval is the actual production or consumption in the most recently completed interval. | The unconstrained mode considers only offers and bids for a single five-minute interval. It does not "look ahead" to offers and bids for upcoming intervals.<br><br>The starting point for each new interval is the unconstrained schedule for the most recently completed interval. |

### 6.3 Congestion Management Settlement Credits

CMSC payments are intended to compensate a dispatchable market participant when, based on the constrained schedule, the IESO instructs it to supply (dispatchable generator or importer) or consume (dispatchable load or exporter) electricity at an amount that is less profitable for the participant relative to the operating profit that would have been expected from generating or consuming at the level indicated for the participant in the market schedule.

#### 6.3.1 The Origin of CMSC Payments

CMSC payments arose from the decision to adopt a uniform-price market and the two-schedule system. The Market Design Committee, charged with designing Ontario's electricity market, proposed such payments to compensate dispatchable facilities for reductions in their operating profits that resulted from responding to system operator instructions to alter their output or consumption in order to relieve transmission constraints:

> A uniform "market" price (the price is actually administratively determined) implies a set of corresponding market quantities that each participant would sell or buy at that uniform market price. <u>However, transmission constraints may prevent participants from injecting or withdrawing those corresponding market quantities.</u> In order to relieve the actual constraints and remain within system security limits during dispatch, <u>the IMO [now IESO] may have to direct generators (and dispatchable loads) to produce (consume) more or less energy than they are willing to produce (consume) at the uniform price</u>, given the prices each participant has indicated in its bid or offer. To induce generators and loads to change their outputs or takes to the required levels, <u>a uniform pricing approach thus requires the IMO to compensate participants for any differences between the uniform price and their bids/offers whenever they are "constrained on" or "constrained off" in order to relieve transmission constraints</u>.[46] (emphasis added)

[46] Market Design Committee, *Final Report of the Market Design Committee: To the Honourable Jim Wilson, Minister of Energy, Science and Technology*, January 29, 1999, Volume 1, ch. 3, p. 8, online: http://www.ieso.ca/Documents/mdc/Reports/FinalReport/Volume-1.pdf.

### 6.3.2 Determination of CMSC Payments

The *Market Rules* established CMSC payments as compensation for reduced operating profits that result from responding to dispatch instructions to produce or consume at a level different than the market schedule:

> Dispatch instructions provided by the IESO to market participant 'k' will sometimes instruct k to deviate from its market schedule in ways that, based on market participant k's offers and bids, imply a change to market participant k's net operating profits relative to the operating profits implied by market participant k's market schedule. <u>When this occurs and market participant k responds to the IESO's dispatch instructions</u>, market participant k shall, subject to Appendix 7.6 of Chapter 7, <u>receive as compensation a settlement credit equal to the change in implied operating profits resulting from such response</u>, calculated in accordance with section 3.5.2.[47] (emphasis added)

6.3.2.1 <u>Formula for Calculation of CMSC</u>

As indicated in Table 6-2, the CMSC payment for a dispatchable load in any five-minute interval is effectively calculated as the difference between its bid price and the MCP, multiplied by the difference between its unconstrained schedule and constrained schedule (or in certain circumstances the load's actual consumption) quantities.[48]

***Table 6-2: Simplified CMSC Formulas***

| |
|---|
| Simplified Constrained-Off CMSC Formula: |
| Payment = [Bid Price – MCP] x [Unconstrained MW– Constrained MW] |
| Simplified Constrained-On CMSC Formula: |
| Payment = [MCP – Bid Price] x [Constrained MW – Unconstrained MW] |

[47] *Market Rules*, Chapter. 9, Section 3.5.1.

[48] A detailed explanation of the actual formulas is provided in Appendix F.

For constrained-off CMSC, as a dispatchable load's bid price increases, all else being equal, so too does the CMSC payment. Conversely, for constrained-on CMSC, as a dispatchable load's bid price decreases the CMSC increases. In both cases, as the difference between the quantities to be consumed in the constrained and unconstrained schedules grows so too does the CMSC payment. CMSC payments (or, in rare cases, negative amounts which must be repaid by the market participant) are determined for each five-minute interval (subject to certain "clawback" rules which are discussed below).

The IESO dispatches generators and loads based on the Nodal Price at each injection or withdrawal node on the Ontario transmission system. These Nodal Prices may differ from the MCP, sometimes dramatically. Depending on the relationship between the Nodal Price and a load's bid price, the IESO can instruct a load to consume more or less energy than the amount that appears in the load's market schedule. Even if a load's bid price is considered to be economic in the market schedule (*i.e.*, higher than the MCP), it will be required to curtail consumption when the Nodal Price at its withdrawal node is higher than its bid price. Similarly, it will be required to consume energy when its bid price exceeds the Nodal Price at its withdrawal node, even if it is uneconomic in the market schedule (*i.e.*, its bid price is lower than the MCP).

The CMSC payments that will be made to a load that is constrained off or constrained on by the IESO are illustrated in Table 6-3.

***Table 6-3: Illustration of CMSC Payments Arising from Differences in the Unconstrained and Constrained Modes of the IESO's Dispatch Algorithm***

| | Load Constrained Off | Load Constrained On |
|---|---|---|
| **Load's bid quantity** | 10 MW | 2 MW |
| **Load's bid price** | $100/MWh | -$900/MWh |
| **Market Clearing Price (MCP)** | $30/MWh | $30/MWh |
| **Nodal Price at load's withdrawal node** | $150/MWh | -$1000/MWh |
| **How many MWs would be scheduled based on the uniform, province-wide MCP?** | 10 MW (because $100 bid > $30 MCP) | 0 MW (because -$900 bid < $30 MCP) |
| **How many MWs will be included in the constrained schedule?** | 0 MW (because $100 bid < $150 Nodal Price) | 2 MW (because -$900 > -$1000 Nodal Price) |
| **CMSC Payment** | $700 ($100 bid - $30 MCP) x (10 MW - 0 MW) | $1860 ($30 MCP - (-$900 bid)) x (2 MW - 0 MW) [49] |

6.3.2.2 Relationship Between Marginal Benefit of Consumption and Operating Profits

The Marginal Benefit of Consumption is the incremental net revenue expected to result from increasing production by consuming an additional MW of electricity. "Net revenue" is the revenue expected to result from selling the additional output less variable costs of production (other than electricity). The change in operating profit is the incremental net revenue less the cost of electricity for the additional MW. A load normally would not be prepared to pay more for electricity than the Marginal Benefit of Consumption. If it did so, the cost of the extra MW would exceed the incremental net revenue from increasing output (*i.e.*, its operating profits would be reduced). The Marginal Benefit of Consumption may also be used to measure the lost net revenues (again, before considering electricity costs) when a load consumes one less MW of electricity. A load normally would not reduce its consumption if the Marginal Benefit of Consumption exceeded the price of electricity.

[49] However, because the dispatchable load is constrained on, it must also pay for the power it consumed at the MCP of $30/MWh. As a result, the net payment to the dispatchable load is $1,800.

While there is no Market Rule that requires a bid price submitted by a dispatchable load to reflect the load's Marginal Benefit of Consumption, the *Market Rules* relevant to CMSC assume that a bid price will reflect a dispatchable load's actual benefit of consumption:

> The dispatch scheduling and pricing process shall be a mathematical optimisation algorithm that will determine optimal schedules for each time period referred to in section 2.1.1, given the bids and offers submitted and applicable constraints on the use of the IESO-controlled grid. Marginal cost-based prices shall also be produced and, for such purpose, <u>offer prices shall be assumed to represent the actual costs of suppliers and bid prices shall be assumed to represent the actual benefits of consumption by dispatchable load facilities.</u>[50] (emphasis added)

In other words, the CMSC calculation assumes that the bid price submitted by a dispatchable load would reflect the load's Marginal Benefit of Consumption. The load's operating profit is assumed to be reduced whenever the load is directed by the IESO to consume less "cheap" power (MCP < load's bid price) than it otherwise would. Similarly, when market prices are "expensive" from the load's perspective (MCP > load's bid price), the load's operating profit is assumed to be reduced whenever the IESO requires the load to consume more than it otherwise would.

### 6.3.3 Self-Induced CMSC Payments

The Market Design Committee's Report and the *Market Rules* clearly indicate that three conditions should exist for a CMSC payment to be made:

(i) the reason for constrained-on or constrained-off dispatch instructions relates to Grid Conditions (*i.e.*, the IESO instructs a load to consume electricity in larger or smaller amounts than the economics of the load's bid would otherwise dictate in order to relieve transmission constraints and remain within system security limits);

[50] *Market Rules*, Appendix 7.5, Section 2.3.1.

(ii) the load would have consumed a different amount of energy absent the constrained-on or constrained-off dispatch instruction, and it earns lower operating profits by following the IESO's instruction; and

(iii) the amount of the CMSC payment should be limited to the amount necessary to provide compensation for operating profit reductions that are linked to the two foregoing conditions.

Although these conditions appear to be straightforward and sensible, the *Market Rules* and the IESO's settlement tools have been formulated in a manner which may allow CMSC payments to arise in other situations and may result in the market participant receiving payments that exceed compensation for reduced operating profits arising from responses to dispatch instructions caused by Grid Conditions.

In particular, a dispatchable load may be able to self-induce CMSC payments. "Self-induce" refers to the ability of the market participant to bring about the outcome, in this case the CMSC payment, through its own voluntary actions. The market participant can self-induce a CMSC payment by creating quantity differences between the unconstrained or constrained schedules either through its offer/bid submissions or its consumption behaviour. Actions that self-induce CMSC payments may or may not constitute gaming, depending on whether the market participant exploited a market defect, such as bidding above Marginal Benefit of Consumption during self-induced ramping hours, to its profit or benefit and to the expense or disadvantage of the market (see the analytical framework for gaming set out in Section 5.5). Both types of actions, self-inducing quantity differences and bidding at a price that does not reflect the Marginal Benefit of Consumption, are examined in relation to Bowater (see Section 7) and Abitibi (see Section 8).

### 6.3.4 Clawback of Certain CMSC Payments

CMSC payments are automatically determined by the IESO's settlement tools for every five-minute interval in which there are differences between the unconstrained and constrained schedules. The CMSC formulas do not distinguish between system-induced CMSC that arises from Grid Conditions and self-induced CMSC. However, in 2003 the *Market Rules* were amended to allow the IESO to either avoid making or completely recover self-induced constrained-off (but not constrained-on) CMSC payments from dispatchable loads under the following circumstances:

> A *registered market participant* for a *constrained off facility* is not entitled to a congestion management settlement credit determined in accordance with section 3.5.2 as the result of that registered *facility's* own equipment or operational limitations, if:
>
> > 3.5.1A.1 a *dispatchable load facility* does not fully or accurately respond to its *dispatch instructions*; or
> >
> > 3.5.1A.2 the ramping capability of a *dispatchable load facility*, as represented by the ramp rate set out in the *offers* or *bids*, is below the threshold for the *IESO* to modify *dispatch instructions* and thereby prevents changes to the *dispatch*;
>
> and then the *IESO* may withhold or recover such congestion management settlement credits . . . .[51]

The IESO initially relied on manual processes to identify self-induced CMSC payments that should be recovered. In 2007, the IESO introduced an automated approach to CMSC recovery, and documented the procedures used to calculate the amount of self-induced CMSC payments that may be clawed back under the *Market Rules*. Those procedures contain the four criteria (referred to as the "**Business Rules**") which are applied by the IESO to recover constrained-off CMSC payments from dispatchable loads (see Appendix H).[52]

The Business Rules have resulted in the clawback of a significant amount of self-induced constrained-off CMSC payments from dispatchable loads. During the Relevant Period, gross CMSC payments to all dispatchable loads in Ontario were $44.1 million, of which $19.1 million (43%) was clawed back under the Business Rules. If the Business Rules were perfectly effective, the net CMSC payments of $25 million should represent the amount required to

[51] *Market Rules*, Chapter 9, Section 3.5.1A, Issue 22.0.

[52] IESO, *Market Manual* 5, *Part 5.5: Physical Markets Settlement Statements* (Issue 38.0), s. 1.6.8.

compensate dispatchable loads for following IESO dispatch instructions in response to Grid Conditions. However, as will be seen in Sections 7 and 8 of this Report, the Business Rules do not operate so as to recover all constrained-off CMSC payments in excess of compensation for such operating profit reductions, particularly in situations involving self-induced ramping, deviations from dispatch instructions or bid prices that do not reflect the load's Marginal Benefit of Consumption. Moreover, they do not address constrained-on CMSC payments such as those arising from the negative-price bidding strategy used by Abitibi in certain hours (see Section 8.5).

# 7. BOWATER'S CONDUCT IN RESPECT OF THE THUNDER BAY FACILITY

This section contains the Panel's assessment of whether Bowater engaged in gaming in relation to CMSC payments made in respect of the Thunder Bay Facility. The introductory sections (Sections 7.1 and 7.2) describe the constrained-off CMSC payments received and Bowater's typical operating pattern for the Facility, including its bidding strategy and ramping pattern. The subsequent sections (Sections 7.3 to 7.6) consider the four elements of the gaming framework set out in Section 5.5, namely whether there were market defects which were exploited by Bowater to its profit or benefit and to the expense or disadvantage of the market. The Panel concludes (Section 7.7) that four of Bowater's behaviours constituted gaming.

## 7.1 CMSC Payments to Bowater

Between February and August 2010, Bowater received approximately $12.3 million in net CMSC payments (after clawbacks). All of the payments were for being constrained off. Although much of these CMSC payments were self-induced, as will be described in this section, the Business Rules only recovered a portion of such payments. Table 7-1 summarizes the CMSC payments to Bowater during the Relevant Period, including clawbacks.

***Table 7-1: Gross and Net CMSC Payments to Bowater for the Thunder Bay Facility February – August 2010 ($000)***

| Month | Gross Constrained-Off CMSC | Clawback of Constrained-off CMSC | Net Constrained-Off CMSC |
|---|---|---|---|
| **February** | 2,202 | 797 | 1,405 |
| **March** | 3,040 | 532 | 2,508 |
| **April** | 3,549 | 947 | 2,602 |
| **May** | 3,463 | 1,125 | 2,339 |
| **June** | 2,438 | 642 | 1,796 |
| **July** | 1,159 | 292 | 867 |
| **August** | 1,796 | 977 | 818 |
| **Total** | **$17,647** | **$5,312** | **$12,334** |

## 7.2 Typical Operating Pattern

The Thunder Bay Facility's energy consumption pattern in 2010 differed from historical patterns. Pursuant to a 2009 agreement with the Ontario Power Authority (OPA) which preceded the reopening of the Thunder Bay Facility (the "**DR2 Agreement**"),[53] Bowater agreed to reduce its energy consumption during "peak hours" when demand for energy was highest. Under the terms of the DR2 Agreement, Bowater agreed to curtail ● MW during its "On-Peak Contract Period" of 8:00 a.m. to 6:00 p.m. on weekdays.[54] Therefore, each weekday, the load was ramped down to a low level at or near 8:00 a.m., and ramped back up to a high level starting at or near 6:00 p.m. The DR2 Agreement did not apply to operations on the weekend.

### 7.2.1 Bidding Strategy

The Panel's review of Bowater's historical bid practices when it was dispatchable prior to September 2006 revealed that the use of a $●/MWh bid price had been limited to a small portion of the Thunder Bay Facility's load. Between November 2003 and July 2005, Bowater regularly submitted bids of $2,000/MWh (*i.e.* making the load non-dispatchable) or $●/MWh for up to ● MW of its total load, and submitted bid prices of between $●/MWh and $●/MWh for the balance of its load (during this time period the total load typically fluctuated between ● MW and ● MW). After July 2005 and before becoming non-dispatchable in September 2006, Bowater did not use bids of $●/MWh; instead it generally submitted bids between $●/MWh and $●/MWh during normal operations as well as when ramping up and ramping down (except for bids of $●/MWh at certain times).

Upon returning to the wholesale market as a dispatchable load, from February 2010 until June 2010, Bowater consistently submitted [an extremely high bid price]. Bowater submitted this bid price for all hours, including those hours when it signalled its intention to ramp by changing its bid quantity from one hour to the next. From July 2010 through August 2010, after discussions

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[53] *DR2 Contract between Bowater Canadian Forest Products Inc. and Ontario Power Authority*, October 21, 2009. Responses to RFI, B.12.2.

[54] *Ibid.*

with the MAU, Bowater generally maintained a bid price of $●/MWh during daytime operations, but used a bid price of $●/MWh during evening hours and when making changes to its quantity bids that signalled its intention to ramp up or down. The same bidding strategy was used on both weekdays and weekends.

### 7.2.2 Ramping Pattern

During weekdays in the Relevant Period, the Thunder Bay Facility normally ramped down to approximately ● MW by 8:00 a.m., and then ramped up to approximately ● MW usually starting at 6:00 p.m. The total morning and evening consumption change exceeded the ● MW commitment in the DR2 Agreement.

On weekends during the Relevant Period, the Thunder Bay Facility typically performed one ramp down and ramp up. Bowater indicated that these ramps were for the purpose of inventory management.[55]

To implement a ramp down (normally in Hour Ending ("HE") 7 on weekdays), Bowater decreased its quantity bid from the night-time level (● MW until May 12, 2010 and ● MW thereafter) to the day-time level of ● MW.

To implement a ramp up (normally in HE 19 on weekdays), Bowater increased its quantity bid from the day-time level of ● MW: first through a small step up to ● MW, followed by a change in the next hour from ● MW to the night-time level (● MW or ● MW).

During the Relevant Period, Bowater used ramp rates which ramped the Thunder Bay Facility up or down in three stages, as summarized in Table 7-2. The relationship between Bowater's ramp rates and the CMSC payments it received is discussed in Sections 7.4.4 and 7.4.5.

[55] Responses to RFI, B.13, p. 2.

***Table 7-2: Ramp Rates for the Thunder Bay Facility***
***February – August 2010***
***(MW and MW/min)***

| **RAMP DOWN** | | | **RAMP UP** | | |
|---|---|---|---|---|---|
| **Machine** | **MW Range** | **Ramp Rate** | **Machine** | **MW Range** | **Ramp Rate** |
| **First and Second Mainline Refiners** | ● (or ●) to ● | ● – ● MW/min | **Auxiliaries** | ● to ● | ● MW/min |
| **Rejects Refiner and Mainline Refiner Motors** | ● to ● | ● – ●MW/min | **Rejects Refiner and Mainline Refiner Motors** | ● to ● | ● – ● MW/min |
| **Auxiliaries** | ● to ● | ●MW/min | **First and Second Mainline Refiners** | ● to ● (or ●) | ● – ● MW/min |

Bowater utilized different ramp up sequences in 2010 than during its previous history as a dispatchable load.[56] In 2006, the rejects refiner was started 10-15 minutes prior to the hour, the first pair of mainline refiners was started on the hour, and the second pair of mainline refiners was loaded the following hour. The usual ramp-up profile in 2006,[57] in combination with the submitted ramp rates and bid prices, resulted in minimal CMSC payments (on the order of a few hundred dollars per ramp). In 2010, Bowater ramped its two mainline refiners and the rejects refiner in the same hour[58] with a typical ramp-up profile that triggered upwards of $20,000 in net CMSC payments per ramp up.

### 7.2.3 Constrained-off CMSC Payments During Ramping

As discussed in Section 6.3.4 and Appendix G, a dispatchable load can initiate ramping through a “self-induced dispatch” by changing the prices and/or quantities that it bids (*i.e.,* its P/Q Pairs). Both the market and the constrained schedules will change to allow the load to ramp to its desired new level of consumption. The changes to the load’s dispatch are caused by the ramping

[56] During ramp down Bowater utilized similar sequences in 2010 as it did in 2006. On ramp down, one pair of mainline refiners was shutdown followed 5 minutes later by the second mainline refiner and then the rejects refiner 10 minutes later. The auxiliary loads were shut down over the following 10-15 minute period, and the recycle plant was then started-up as quickly as possible. Responses to RFI, B.2, p. 4.

[57] Bid data in 2006 shows ramp ups were generally scheduled from ● MW to ● MW in one hour, and from ● MW to ● MW in the next hour.

[58] Responses to RFI, B.2, p. 4.

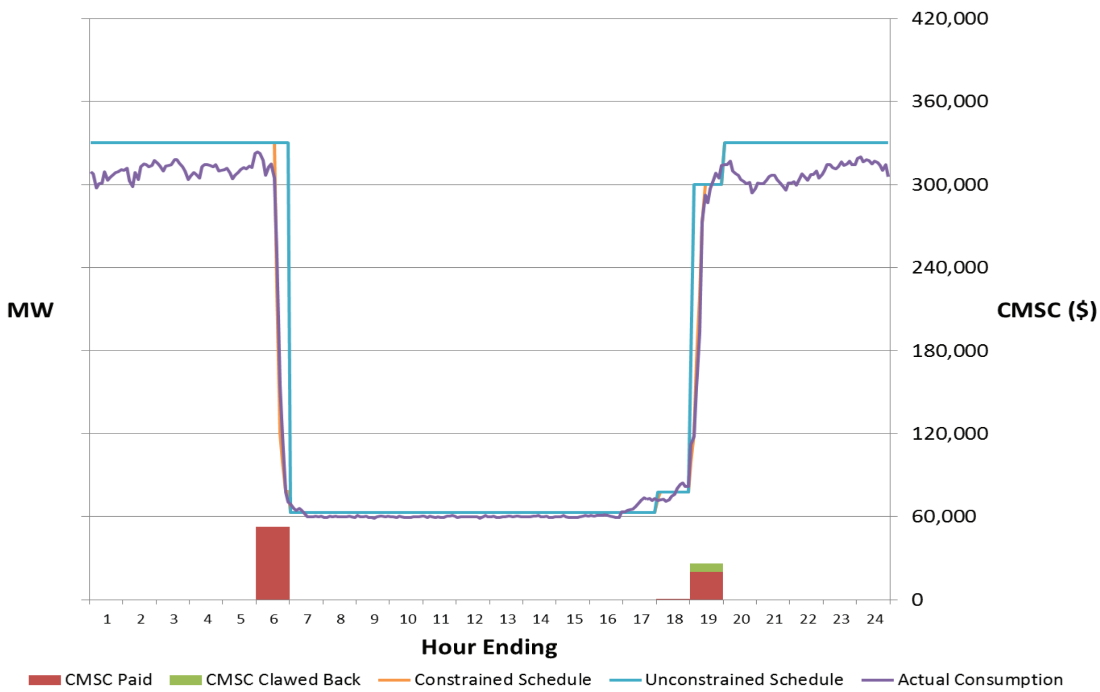
decision manifested in the bid of the dispatchable load, not by Grid Conditions. Nevertheless, CMSC payments will be made if the schedule quantities diverge as a result of a change in the price or quantity bid by the load. The resulting CMSC payments are self-induced.

During the Relevant Period, Bowater induced the desired changes in its energy consumption by changing its quantity bid between one hour ("**h**") and the following hour ("**h+1**"). Because the Thunder Bay Facility requires more than one five-minute interval to ramp to its new consumption level, the dispatches in the constrained schedule diverged from the market schedule.[59]

An illustration of ramping behaviour at the Thunder Bay Facility can be seen in the consumption pattern of Friday, May 14, 2010, when the facility earned over $73,000 in CMSC (net of clawbacks). Bowater bid $●/MWh in every hour and submitted the ramp rates noted previously in Table 7-2. The ramping of consumption, and the CMSC payments made during the ramping periods, are shown in Figure 7-1.

[59] During a ramp down at the Thunder Bay Facility, the constrained schedule will dispatch the Facility down (*i.e.* ramp) to its new consumption level by the end of hour h, while the market schedule will ramp the Facility down in the first interval of hour h+1. This is because the dispatch algorithm will not dispatch a facility in the constrained schedule above its maximum submitted quantity in hour h+1 or in a way that is inconsistent with the actual ramp rates of the facility, which is not the case in the unconstrained schedule. During a ramp up, the constrained schedule will normally dispatch a facility to begin ramping towards its new consumption level in the first interval of hour h+1, while the market schedule will begin ramping at the same time but using the 3x times ramp rate multiplier. (See Section 6.3 as well as Appendix D, Appendix E and Appendix G). In either case, the result is a discrepancy between the market and constrained schedules during the ramping period. This in turn triggers constrained-off CMSC payments because the quantity in the constrained schedule falls below the market schedule quantity during the ramp intervals.

***Figure 7-1: Sample Ramping Pattern and CMSC Payments for the Thunder Bay Facility May 14, 2010 (MW and $)***




7.2.3.1 <u>CMSC on Ramp Down</u>

To accommodate Bowater's morning change in bid quantity on May 14, 2010, the dispatch algorithm began to dispatch the Thunder Bay Facility down beginning in interval 8 of HE 6 using the submitted ramp-down rates. Accordingly, it was dispatched from ● MW to ● MW over five intervals. Throughout this period the Facility's market schedule remained at ● MW. To calculate CMSC, the IESO settlement tool took the quantity difference between (i) the market schedule and (ii) the greater of the constrained schedule and actual consumption quantities during each interval of the ramp period, and multiplied each quantity difference by (iii) the bid price less (iv) the MCP for the interval (which was in the vicinity of $35/MWh). In the result, over $50,000 in CMSC was paid in respect of this particular ramp down event.

Table 7-3 shows the total energy charges and CMSC payments to Bowater for each interval in HE 6 on May 14, 2010 when the Thunder Bay Facility was ramping down. The net CMSC payments ($52,908) were substantially larger than the energy charges ($5,155), such that Bowater was receiving nearly $48,000 while consuming the amount of energy it wanted to during its self-induced ramp down.

***Table 7-3: Energy Charges and CMSC Payments on a Typical Ramp Down of the Thunder Bay Facility May 14, 2010, HE 6 (MW, $/MWh and $)***

| Interval | Unconstrained Schedule (MW) | Constrained Schedule (MW) | Actual Consumption (MW) | Energy Charges* ($) | MCP ($/MWh) | Bid Price ($/MWh) | Net CMSC** ($) |
|---|---|---|---|---|---|---|---|
| 1 | ● | ● | ● | ● | 35.32 | ● | |
| 2 | ● | ● | ● | ● | 33.38 | ● | |
| 3 | ● | ● | ● | ● | 33.61 | ● | |
| 4 | ● | ● | ● | ● | 33.38 | ● | |
| 5 | ● | ● | ● | ● | 34.55 | ● | |
| 6 | ● | ● | ● | ● | 35.17 | ● | |
| 7 | ● | ● | ● | ● | 35.32 | ● | |
| 8 | ● | ● | ● | ● | 35.32 | ● | 4,376 |
| 9 | ● | ● | ● | ● | 35.33 | ● | 9,539 |
| 10 | ● | ● | ● | ● | 35.33 | ● | 11,538 |
| 11 | ● | ● | ● | ● | 35.37 | ● | 13,729 |
| 12 | ● | ● | ● | ● | 35.82 | ● | 13,726 |
| **Total** | | | | **$5,155** | | | **$52,908** |

* Includes Global Adjustment and Uplift charges.
** None of the Business Rules applied to claw back CMSC payments on the ramp down.

7.2.3.2 CMSC on Ramp Up

To accommodate Bowater's change in bid quantity for the evening of May 14, 2010, the dispatch algorithm dispatched the Thunder Bay Facility up beginning in interval 1 of HE 19 using the submitted ramp up rates. Accordingly, it was dispatched from ● MW to ● MW over five intervals. [60] The 3x ramp rate multiplier resulted in the market schedule moving to ● MW in interval one, and then to ● MW for the remaining intervals. To calculate CMSC, the IESO settlement tool took the quantity difference between (i) the market schedule and (ii) the greater

[60] The Facility was dispatched up from ● MW to ● MW in the next hour, HE 20. The staged ramp up corresponded to the staged increase in Bowater's submitted bid quantities.

of the constrained schedule and actual consumption quantities for each interval during the ramp period, and multiplied each quantity difference by (iii) the $●/MWh bid price less (iv) the MCP for the interval (which was approximately $33-35/MWh). In the result, over $20,000 in net CMSC payments were made in relation to this particular ramp up event.

Table 7-4 shows the total energy charges and CMSC payments to Bowater for each interval in HE 19 on May 14, 2010 when the Thunder Bay Facility was ramping up. The net CMSC payments ($20,075) were substantially larger than the energy charges ($5,132), such that Bowater was receiving nearly $15,000 while consuming the amount of energy it wanted to during its self-induced ramp up.

***Table 7-4: Energy Charges and CMSC Payments on a Typical Ramp Up of the Thunder Bay Facility May 14, 2010, HE 19 (MW, $/MWh and $)***

| Interval | Unconstrained Schedule (MW) | Constrained Schedule (MW) | Actual Consumption (MW) | Energy Charges* ($) | MCP ($/MWh) | Bid Price ($/MWh) | Net CMSC ** ($) |
|---|---|---|---|---|---|---|---|
| 1 | ● | ● | ● | ● | 35.33 | ● | 3,302 |
| 2 | ● | ● | ● | ● | 35.33 | ● | 9,818 |
| 3 | ● | ● | ● | ● | 35.35 | ● | 6,955 |
| 4 | ● | ● | ● | ● | 35.34 | ● | |
| 5 | ● | ● | ● | ● | 35.38 | ● | |
| 6 | ● | ● | ● | ● | 35.37 | ● | |
| 7 | ● | ● | ● | ● | 35.34 | ● | |
| 8 | ● | ● | ● | ● | 35.36 | ● | |
| 9 | ● | ● | ● | ● | 35.35 | ● | |
| 10 | ● | ● | ● | ● | 35.33 | ● | |
| 11 | ● | ● | ● | ● | 35.34 | ● | |
| 12 | ● | ● | ● | ● | 35.34 | ● | |
| **Total** | | | | **$5,132** | | | **$20,075** |

*Includes Global Adjustment and Uplift charges.
**CMSC payments of $4,402 in interval 4 and $1,477 in interval 5 were clawed back under Business Rule 3.

7.2.3.3 Representative Pattern of Operation

The bids, ramping and consumption on May 14, 2010 are typical of the Thunder Bay Facility's operating pattern on weekdays during the Relevant Period. On weekends, the Facility was not subject to the requirements of the DR2 Agreement. The Facility typically ramped down once on the weekend for a brief period of time (approximately 3 hours) before ramping back up. Although weekend ramp downs and ramp ups occurred at different times of day, they typically triggered CMSC payments in a similar manner as illustrated by the May 14th example.

The amount of the CMSC payments on any particular weekday or weekend ramp varied primarily in response to variations in the magnitude of the ramp, actual consumption relative to the constrained schedule, and the MCPs during the applicable ramp intervals. A summary of Bowater's five largest CMSC payment days at the Thunder Bay Facility during the Relevant Period is provided in Appendix I. Graphs comparable to Figure 7-1 which show the hourly constrained and unconstrained schedules, actual consumption and CMSC payments are also included in Appendix I.

### 7.3 Defects in *Market Rules* or Procedures

Even before the Ontario electricity market opened in 2002, the Market Design Committee and the MSP were both concerned that CMSC payments that more than compensate a market participant for any reduction in its operating profits could be self-induced and would be contrary to the overall purpose of the CMSC framework. Moreover, the MSP expressed concern that the CMSC regime was conducive to gaming [61] and the Market Design Committee suggested that "rules be developed to discourage gaming of side payments."[62]

One defect that can be subject to exploitation, and was of particular concern to the MSP, relates to the formula used for calculating CMSC payments. The formula determines the implied change in the operating profit for a dispatchable load based on the expectation that its bid reflects its Marginal Benefit of Consumption. As previously noted, the *Market Rules* contain the

[61] Independent Electricity Market Operator, *The Market Surveillance Panel In Ontario's Electricity Market: Monitoring, Investigating and Reporting – Backgrounder*, April 2002, online: http://www.ontla.on.ca/library/repository/mon/4000/10306902.pdf, p. 13.

[62] Market Design Committee, *Second Interim Report of the Market Design Committee: To the Honourable Jim Wilson, Minister of Energy, Science and Technology*, June 30, 1998, online: http://www.ieso.ca/imoweb/historical_devel/MDC/Reports/InterimReport2/2ndRept.pdf., p. 9 of the Appendix and p. 3-15.

assumption but not a requirement that bids will reflect the Marginal Benefit of Consumption. If a bid does not reflect the Marginal Benefit of Consumption, but instead is higher, then any constrained-off CMSC payment would exceed what is required to compensate a dispatchable load for operating profit reductions as a result of following dispatch instructions that are caused by Grid Conditions.

The interface between the CMSC regime and the two-schedule system also has defects that can be exploited in relation to quantity differences. As noted in Section 6.3 as well as Appendix D and Appendix E, there are differences between the optimization and ramping processes in the unconstrained and constrained modes of the dispatch algorithm. A market participant may be able to use ramping decisions or deviations from its constrained dispatch schedule to self-induce quantity differences that give rise to CMSC payments. Such payments are not compensating for reductions in operating profits caused by responding to Grid Conditions, but are an unintended consequence of the CMSC regime.

Another defect that can be subject to exploitation relates to the IESO's procedures for recovering (or "clawing back") CMSC payments that go beyond compensation for changes in operating profits arising from responding to constrained instructions that were based on Grid Conditions. As noted in Section 6.3.4 and Appendix H, the Business Rules and processes developed by the IESO to claw back payments in various circumstances do not recover all of the CMSC payments that are self-induced, either because they do not apply in certain situations, they fail to identify all instances of inappropriate CMSC payments, or they allow payments which exceed the amount needed to compensate for operating profit reductions. Bowater's self-induced CMSC payments are an example of payments that were not covered by the Business Rules.

**Finding #1 (Market Defects Related to Constrained-off CMSC):**

*The CMSC rules, formulas and clawback procedures that existed during the Relevant Period allowed a dispatchable load to receive constrained-off CMSC payments that exceeded the amount required to compensate for reductions in operating profits arising from responses to dispatch instructions caused by Grid Conditions.*

### 7.4 Exploitation of Constrained-Off CMSC

As set out in Section 5.5, an essential element of gaming is that the market participant engages in activity which exploits a market defect. The Panel considers that exploitation may exist where the market participant had some level of intention, knowledge or awareness of an opportunity arising from the market defect.[63] In order to determine whether Bowater exploited defects in the CMSC regime, the Panel examined the development of its ramping strategy and the following specific behaviours, each of which contributed to the large constrained-off CMSC payments received during ramp periods:

(i) Bowater submitted an extremely high bid price for ramping hours, which increased the amount of the CMSC payment for any difference between the unconstrained and constrained schedule quantities (see Section 7.4.2).

(ii) Between February and May 2010, Bowater raised its bid quantity above the level that the Thunder Bay Facility was generally consuming, which increased the quantity differences used to calculate the CMSC payments (see Section 7.4.3).

[63] See Market Surveillance Panel, *Report on an Investigation into Possible Gaming Behaviour Related to Infeasible Import Transactions by TransAlta Energy Marketing Corp. on the Manitoba-Ontario Intertie*, Investigation No. 2011-02, October 22, 2012, online: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_Investigation_TranAlta_20121022.pdf, p. 19.

(iii) Bowater bid such that its entire ramp down would occur within a single hour, which had the effect of prolonging the period over which a quantity spread existed between the unconstrained and constrained schedules (see Section 7.4.4).

(iv) On ramp downs, Bowater often ramped faster than submitted ramp rates, which reduced its actual consumption and increased the quantity differences used to calculate CMSC payments (see Section 7.4.5).

(v) Bowater occasionally failed to ramp up or down in accordance with its bid and dispatch instructions, which increased the quantity differences that give rise to CMSC payments (see Section 7.4.6).

(vi) Bowater periodically deviated significantly from its dispatch instructions in non-ramp hours, which triggered CMSC payments that were not always clawed back under IESO Business Rules (see Section 7.4.7).

### 7.4.1 Development of the Ramping CMSC Strategy

Prior to re-entering the wholesale market as a dispatchable load in February 2010, Bowater developed a detailed strategy to maximize CMSC payments during the ramping of the Thunder Bay Facility. Personnel at the Thunder Bay Facility worked closely with personnel at Abitibi's Fort Frances Facility who had experience with the relationship between ramping and CMSC payments. The key personnel involved in the development of the ramping strategy included:

- [Senior Bowater Personnel #3]: [Senior Bowater Personnel #3's position]
- [Senior Bowater Personnel #5]: [Senior Bowater Personnel #5's position]
- [Senior Abitibi Personnel #2]: [Senior Abitibi Personnel #2's position][64]

In particular, [Senior Abitibi Personnel #2] worked with [Senior Bowater Personnel #5] to develop detailed strategies, including bid laminations and ramping sequences, that would increase the Thunder Bay Facility's CMSC payments. The following email exchange is an example:

> From: [Senior Bowater Personnel #5]
>
> To: [Senior Abitibi Personnel #2]
>
> Dated: September 11, 2009 09:23 AM
>
> Subject: Ramp[s] rates and CMSC Payments
>
> [Senior Abitibi Personnel #2]:
>
> Our previous bidding strategy for the TMP [thermo-mechanical pulpmill] load used a down ramp rate of ●MW/min. The bulk of the ● MW to TMP load that is shutdown is the refiner loads. There are two lines of TMP each of about ● MW and a rejects refiner that is about ●MW. The balance of ●-● MW is for plant auxiliaries that take 20 to 30 minutes after the refiners are shut down. See the attached power point file for the shutdown timing that we were using during the DR2 transition program to ensure we were in compliance. <u>From this info can you see any potential for CMSC payments and what would we have to do differently to maximize these payments</u>.**[65]** (emphasis added)

[64] The main Bowater, Abitibi and affiliated company personnel involved in the activities discussed in this Report are listed in Appendix C.

[65] Responses to RFI, B.2.5.

[Senior Abitibi Personnel #2] replied as follows:

> From: [Senior Abitibi Personnel #2]
>
> To: [Senior Bowater Personnel #5]
>
> Dated: September 11, 2009 12:51 PM
>
> Subject: Ramp Rates and CMSC
>
> The attached is quick look at the potential for CMSC when moving the load. Notes: You can have different ramp rates applied to your ●MW load. A while ago the IESO moved us from 12x ramp rate to 3x. We should have a discussion on the impacts of this, however it should not be documented in an email.[66] (emphasis added)

The document attached to the above email contained ramp rates, calculations of the dispatch and market schedules, and the resulting CMSC payments arising from ramping. Abitibi also sent sample ramps and data "showing actual bids entered with ramp rates, the resulting dispatch instructions with time stamp and the load prior to dispatch… for a start-up and shut down"[67] from the Fort Frances Facility, to aid the Thunder Bay Facility in "forecasting the constrained schedule correctly."[68] Before and in the weeks after the Thunder Bay Facility became dispatchable, [Senior Abitibi Personnel #2] would review "ramp rates and start-up/shut down strategies with respect to CMSC"[69] with Thunder Bay Facility personnel, and provide input with the objective of maximizing CMSC. For example, [Senior Abitibi Personnel #2] advised that increasing the quantity bid from ● MW to ● MW would increase CMSC payments by approximately $4,000 per start up.[70] [Senior Abitibi Personnel #2] also advised that it was desirable to have the actual metered consumption quantity below the dispatch quantity when ramping, and in one email informed Thunder Bay Facility personnel that if they "stayed under

[66] Responses to RFI, B.2.6.

[67] Email from [Senior Bowater Personnel #5], January 7, 2010. Responses to RFI, B.2.12.

[68] Email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], January 12, 2010. Responses to RFI, B.2.12.

[69] Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], January 21, 2010. Responses to RFI, B.2.24.

[70] Email from [Senior Abitibi Personnel #2] to [Senior Bowater Personnel #5], February 12, 2010. Responses to RFI, B.2.15. This issue is discussed more fully in Section 7.4.3 below.

[their] dispatch this morning's ramp would pay out $57K."[71] In learning of the large CMSC amount on the first day of operation of the Thunder Bay Facility as a dispatchable load on February 8, 2010, [Senior Abitibi Personnel #2] advised to "wait for comment from the IESO and stay quiet. We are following market rules".[72]

Bowater's ramping CMSC strategy was known to senior management. During the period of development before the Thunder Bay Facility became dispatchable on February 8, 2010, ABI personnel were advised of and assisted with the strategy. For example, [Senior AbitibiBowater Inc Personnel #2], reviewed and commented on a proposed analysis for shutting down and starting the thermo-mechanical pulpmill or TMP at the Thunder Bay Facility which calculated "CMSC (based on actual load)" and "Optimized CMSC payment (actual load ≤ constrained schedule)."[73] [Senior AbitibiBowater Inc Personnel #2] commented as follows: "I have not looked at this for a while… I thought in ramping up you were allowed to keep 3 intervals in total (the first three), i.e. your total CMSC credit in ramping up would be limited to $406.25. Or maybe because your ramping up is so spread out, the tools will not claw back the CMSC in the second hour".[74] [Senior AbitibiBowater Inc Personnel #2]'s comments acknowledged the development of the Thunder Bay Facility's CMSC ramping strategy, and indicate that ABI was aware of Bowater's strategy.

In Fall 2009, prior to the Thunder Bay Facility becoming a dispatchable load, personnel at the Thunder Bay Facility prepared a PowerPoint presentation for two Vice-Presidents of ABI ([AbitibiBowater Inc Executive #4] and [AbitibiBowater Inc Executive #3]) entitled "Thunder Bay 2010 Power Cost – October 1st, 2009".[75] The presentation discussed the forecast impact of

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[71] Email from [Senior Abitibi Personnel #2] to [Senior Bowater Personnel #5], September 23, 2009, Responses to RFI, B.2.9, and email from [Senior Abitibi Personnel #2] to [Senior Bowater Personnel #5], February 8, 2010, Responses to RFI, B.2.14.

[72] Email from [Senior Abitibi Personnel #2] to [Senior Bowater Personnel #3], February 23, 2010. Responses to RFI, B.16.35.

[73] This analysis is reproduced in Appendix L.

[74] Email from [Senior AbitibiBowater Inc Personnel #2] to [Senior Bowater Personnel #5], January 26, 2010. Responses to RFI B.2.26.

[75] Attachment to email from [Senior Bowater Personnel #2] to [Senior Bowater Personnel #5] and [Senior Bowater Personnel #3], September 28, 2009. Responses to RFI, B.3.6. Relevant excerpts are reproduced in Appendix J.

several items, including CMSC payments, on Bowater's 2010 power cost. The first graph in the presentation (reproduced as Figure 7-2 below) contains a projection that Bowater would receive CMSC payments equivalent to $10.00/MWh on its 2010 energy consumption (which was revised upward from a prior estimate of $0.95/MWh[76]).

***Figure 7-2: Excerpt from "Thunder Bay 2010 Power Cost – October 1st, 2009", a presentation by Bowater to AbitibiBowater Inc.***

**Figure Redacted – Contains Confidential Information**

Another slide in the presentation correctly noted that "[t]he market rules assume that participants place bids and offers based on their marginal cost and benefit."[77] Despite Bowater's knowledge of what the *Market Rules* assumed, a further slide in the deck stated: "[b]id to run at $● defines

[76] *Ibid.* The PowerPoint presentation includes a second slide that is identical to the slide in Figure 7-2 except that the CMSC payments for 2010 are shown as $0.95/MWh instead of $10.00/MWh. CMSC payments of $0.95/MWh are consistent with the amount of CMSC payments received by Bowater when it was previously dispatchable (July 2003 to August 2006) and as calculated in a Bowater spreadsheet entitled "Power $/MWh 2010 Budget", which shows monthly CMSC receipts of between $0.92/MWh and $1.08/MWh for the years 2005 through 2008 (Responses to RFI, B.3.3). Bowater also stated that "[p]reliminary estimate *(sic)* of CMSC revenue in the power cost reduction initiative *(sic)* based on conservative historical amounts" (Responses to RFI, B.3). Bowater further stated that it estimated potential CMSC revenue using a bid of $●/MWh and that "2010 Budget presentations were adjusted to reflect this higher amount of CMSC revenues" (Responses to RFI, B.3).

[77] Attachment to email from [Senior Bowater Personnel #2] to [Senior Bowater Personnel #5] and [Senior Bowater Personnel #3], September 28, 2009. Responses RFI, B.3.6. Relevant excerpts are reproduced in Appendix J. The concept of Marginal Benefit of Consumption is discussed in Section 6.3.2.2.

the [CMSC] compensation."[78] A detailed calculation in the presentation shows CMSC payments of $38,005 during a ramp-down scenario based on the use of a bid price of $●/MWh.[79] It is clear that Bowater's CMSC projections involved increases in operating profits rather than recovery of operating profit reductions arising from responding to dispatch instructions caused by Grid Conditions.

Personnel at Bowater and its affiliates were also aware that the IESO might seek to recover some of the CMSC payments obtained as a result of their ramping strategies. As a result, on the advice of Abitibi personnel, Bowater did not "book" the entire amount of CMSC payments that appeared on its daily or monthly settlement statements from the IESO.[80] Instead, Bowater booked what it considered to be "legitimate CMSCs" arising from "planned shutdowns and start-ups… The balance was provisioned."[81] ABI was aware of the reasons for and supported this accounting technique. For example, in March 2010, [Senior AbitibiBowater Inc Personnel #1] enthusiastically reported to [Senior Bowater Personnel #3] and [Senior Bowater Personnel #5] (copying [AbitibiBowater Inc Personnel #4]) that the CMSC amount included in the settlement statement for February 2010 was substantially more than what originally had been booked:

[78] *Ibid.*

[79] *Ibid.*

[80] Email from [Senior Abitibi Personnel #2] to [Senior Bowater Personnel #3], February 23 and 24, 2010. Responses to RFI, B.16.37.

[81] Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], March 15, 2010. Responses to RFI, B.16.45.

From: [Senior AbitibiBowater Inc Personnel #1]

To: [Senior Bowater Personnel #3], [Senior Bowater Personnel #5]

c.c.: [AbitibiBowater Inc Personnel #4]

Date: March 12, 2010 1:39 PM

Subject: Power Bill Feb 2010

We received the bill. Our CMSC credits after clawbacks was $1,405,008.74! Which is $623,188.74 higher than what we booked. This is great news![82]

In April 2010, Bowater increased the portion of the CMSC payments that it was booking after monitoring the amounts being clawed back by the IESO. Bowater briefed ABI executives on its plans in this regard:

From: [Senior Bowater Personnel #3]

To: [AbitibiBowater Inc Executive #1], [AbitibiBowater Inc Executive #3]

c.c.: [AbitibiBowater Inc Personnel #4]

Date: April 22, 2010 11:06 AM

Subject: Fw: March Electricity summary – Confidential

Please find below an explanation for our March electricity price. Note the various programs we participate in from the different sections of the Government. The March bill arrived last Friday, April 16, and everything was as expected. <u>For the month of April</u>

[82] Responses to RFI, B.16.43.

> we will increase our CMSC booking to 85%, and adjust the March and February amounts accordingly. [83] (emphasis added)

In early June 2010, ABI financial executives decided to cease the practice of "holding back" some CMSC and to "book" the full amount of CMSC received. In response to an email containing a spreadsheet of the received and booked CMSC payments, [AbitibiBowater Inc Executive #1] instructed the [AbitibiBowater Inc Personnel #4] as follows:

> From: [AbitibiBowater Inc Executive #1]
>
> To: [AbitibiBowater Inc Personnel #4]
>
> Date: June 7, 2010 01:46 PM
>
> Subject: Re: TB Power – May 2010
>
> Based on the conversation I had with [Senior Abitibi Personnel #2] last week, we will need to book all of this in June and then every month going forward, we will no longer keep any hold backs with the exception of the amounts that [Senior Abitibi Personnel #2] calculates as not true numbers.[84] (emphasis added)

When pressed by the MAU on the rationale for Bowater's high bid prices and the financial impact if it was forced to reduce electricity consumption as a result of being constrained off [Senior Bowater Personnel #3] alerted [Senior Abitibi Personnel #2] as well as [Senior AbitibiBowater Inc Personnel #2] that there was a risk that Bowater's CMSC payments were at risk of being reduced or eliminated as shown in the following excerpt:

[83] Responses to RFI, B.16.70.

[84] Responses to RFI, B.16.75. This email was subsequently forwarded to [Senior Bowater Personnel #3].

From: [Senior Bowater Personnel #3]

To: [Senior Abitibi Personnel #2]

Cc: [Senior AbitibiBowater Inc Personnel #2]

Date: July 29, 2010 06:06 PM

Subject: Re: Fw: RE: Considerations relating to CMSC Repayments by Abitibi

Interesting e-mail. Does he want to debate line item, by line item? Decide for us what is valid and not? Does the market rules give him the authority to ask? Confidentiality of our numbers if he gets it.

Two schools of thought
1) We comply, he reads and accepts our numbers, no rule changes and we live happy ever after.

2) [We] don't comply, they go back to whoever and demand a rule change to protect the consumer against those big bad loads! <u>End of CMSC from ramping sometime in the future?</u>

3) We comply, they don't like our numbers and now [we're] negotiating against ourselves again. [85] (emphasis added)

These and other emails confirm that knowledge of the ramping strategy and its financial consequences was not limited to operational employees at the Thunder Bay Facility, but extended to senior management of Bowater and ABI.

**Finding #2 (CMSC Ramping Strategy):**

*Bowater developed strategies to self-induce CMSC payments at the Thunder Bay Facility, and these were known to senior management.*

The main behaviours that triggered constrained-off CMSC payments for Bowater are analyzed in the sections below.

[85] Responses to RFI, B.13.61.

### 7.4.2 Expanding the Magnitude of CMSC Using a High Bid Price

This section examines Bowater's knowledge of the operating profit principles underlying the CMSC regime (Section 7.4.2.1), and the relationship between its Marginal Benefit of Consumption and bid prices (Sections 7.4.2.2 to7.4.2.5). The Panel has also analyzed the three explanations for high bid prices that were provided by Bowater: [86]

- Bidding at a very high price reduced the risk of the facility being dispatched down (which can occur if the Nodal Price is above the bid price) (see Section 7.4.2.6).
- Bidding at a very high price reduced the risk of being activated to provide operating reserve (while still being able to obtain revenue from participating in the operating reserve market) (see Section 7.4.2.7).
- Dispatchable loads owned by Abitibi-Consolidated at Fort Frances, Fort William, and Iroquois Falls had bid at a similarly high price for a number of years (see Section 7.4.2.8).

7.4.2.1 Bowater Understood the Operating Profit Principles in the CMSC Regime

Bowater and affiliated company personnel understood that the CMSC regime was designed to compensate for reductions in operating profits based on an assumption that a dispatchable load's bids would reflect its Marginal Benefit of Consumption. In its initial discussions with the MAU in June of 2010, Bowater defended its $●/MWh bid price citing the reasons stated above. However, Bowater later acknowledged that $●/MWh did not reflect the financial impact of incremental decreases or increases in consumption[87] and lowered its bids to $●/MWh for ramping hours.[88] The internal communications related to this change included efforts to confirm that the IESO training materials had not discussed the relationship between bids and the actual financial impact of reduced consumption as shown in the following excerpt:

[86] Responses to RFI, B.3, p. 2 and B13, p.1 and 2.
[87] Responses to RFI, B.3, p. 2.
[88] Responses to RFI, B.13.40.

> From: [Senior Bowater Personnel #3]
>
> To: [Senior Abitibi Personnel #2], [Senior Bowater Personnel #5], [Senior Abitibi Personnel #4]
>
> Dated: June 28, 2010 08:57 PM
>
> Subject: Fw: Considerations relating to CMSC Repayments by Abitibi
>
> [Senior Bowater Personnel #5] review your course notes/hand written notes and ensure that during the training in January 2010 there was no mention of basing our bid on the "marginal lost opportunity cost". We were only trained on bidding high so as not to be activated [for operating reserve].[89]

In fact, Bowater and Abitibi personnel knew that CMSC payments were intended to compensate for operating profit reductions resulting from being dispatched differently than the economics of the bids in the market schedule. As noted above, a presentation to senior management, dated October 1st, 2009, contained a slide on CMSC which explained the operating profit calculation and the assumption that dispatchable loads' bids would reflect Marginal Benefit of Consumption.[90]

Other documents submitted by Bowater in response to the Panel's requests for information also demonstrate awareness of the economic purpose of CMSC payments before and while the Thunder Bay Facility was submitting a $●/MWh bid during its ramping hours. For example, Bowater's "March 2010 Purchased Electricity Summary", prepared by [Senior Bowater Personnel #5], included the following description of CMSC:

> Congestion Management Settlement Credits (CMSC) – Paid by the IESO due to being dispatchable. Credits are based [on] the difference between the constrained and unconstrained dispatch algorithms created by system constraints or the up and down ramp rates of generators and loads. <u>In our case when the TMP plant is constrained to a different dispatch [than] what it had bid for, the</u>

[89] Responses to RFI, B.13.32. (The IESO training materials in relation to operating reserve activation are discussed in Section 7.4.2.7 below.)

[90] See the second slide reproduced in Appendix J and quoted in Section 7.4.1.

> IESO provides a credit due to the lost opportunity to use that energy. Ramping up and down helps stabilize the grid. CMSC [costs] are shared by all consumers through uplift charges.[91] (emphasis added)

**Finding #3 (Knowledge of CMSC Compensation Principles):**

*Bowater was aware that the CMSC regime assumed that dispatchable loads would bid based on their Marginal Benefit of Consumption and that CMSC payments were designed to compensate a dispatchable load for operating profit reductions when it was directed by the IESO to follow a dispatch different from its market schedule.*

7.4.2.2 Bid Prices Exceeded Marginal Benefit of Consumption on Weekdays

Bowater's bid prices were consistently and significantly above its own estimates of the Marginal Benefit of Consumption.

As noted in Section 5.2.1, the MAU contacted Bowater in June 2010 to inquire about the anomalously high CMSC payments being made to the Thunder Bay Facility during ramping periods and whether they were obtained in part as a result of bid prices that exceeded the Marginal Benefit of Consumption. Bowater responded by calculating and implementing a bid price of $●/MWh during ramping periods beginning July 1, 2010, which it explained as follows:

> In response to your first question on the calculation of the opportunity-based bid, the the $●/ MWh opportunity cost is based on lost production, i.e. not running the TMP plant for a one hour period. The calculation uses the facilities net of paper, minus the direct costs associated to arrive at a contribution/tonne. The calculation is based on the amount of paper tonnes that would not have been manufactured during the one hour of lost production on the TMP plant. In addition to this, fixed cost recovery for the time we did not produce paper and unavoidable direct costs such as

[91] Attachment to an email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], April 20, 2010. Responses to RFI, B.16.59.

> electricity, chemicals and steam are included. Also added to the calculation is the restart time for the paper machine as it was shut down due to lost inventory (pulp) made by the TMP plant. The result is the sum of all the above, divided by one hour of TMP power consumption to arrive at $●/MWh.
>
> With respect to your second question regarding dispatch risk, during our discussions and email exchanges regarding the opportunity based bid cost, we changed the bid to $●/MWh from $●/MWh. This change reflects opportunity costs lost during ramping and does not reflect dispatch risk. Once our internal back-office tools have been reconfigured to allow for this new combination of price/quantity pairs structure, we will revert back to bidding $●/MWh during the non-ramping hours to cover our risk aversion.[92]

Bowater's rationale for this calculation was that the Thunder Bay Facility was "pulp limited" as a result of its obligation under its DR2 Agreement to operate its TMP plant off-peak on weekdays. Pulp from the TMP plant feeds the Facility's paper machine and, given limited pulp storage capacity, lost production at the TMP plant could lead to production losses on the paper machine later in the week when pulp inventories are lowest.[93] Bowater estimated the loss of one hour of TMP production would result in 3 hours of lost paper production which, based on its calculations of contribution as well as certain costs that were characterized as unavoidable, equated to $●/MWh.[94]

[Senior Bowater Personnel #5] also developed a "value of electricity" calculation of $●/MWh for weekdays.[95] This amount differs from the $●/MWh number originally used to support the $●/MWh bid price, mainly because it does not incorporate an additional hour of lost paper production due to a restart of the paper machine. A restart of the paper machine would not be necessary if the paper machine was able to draw on pulp storage, which even at its lowest point

[92] Excerpt of email from [Senior Abitibi Personnel #2] to MAU, July 29, 2010. Response to RFI, B.13.59.

[93] Responses to RFI, B.3, p.2.

[94] Responses to RFI, B.4, p.1.

[95] Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], July 22, 2010. Responses to RFI, B.13.44.

on Friday evenings normally had over 5 hours of TMP reserves.[96] Therefore, incorporating the paper machine restart overstated the expected impact on operating profit if the Facility was constrained off.

As noted above, Bowater indicated that its calculations included elements of "fixed cost recovery".[97] Fixed costs normally do not change in response to short term transitory changes in electricity consumption. Including fixed costs in the Marginal Benefit of Consumption could result in cases where a positive operating profit that could have contributed to offsetting fixed costs is foregone. Accordingly, they should not be included in calculating the Marginal Benefit of Consumption. Thus the Bowater calculations referenced above overstate the actual Marginal Benefit of Consumption. However, since the amount of the overstatement is not readily determinable, the Panel has used Bowater's own calculations as a conservative basis for analyzing whether Bowater was bidding at prices which exceeded its Marginal Benefit of Consumption.

The Panel also notes that, even on weekdays, Bowater's typical operating pattern allowed opportunities to make up lost production every morning. The morning ramp downs normally were completed in HE 6 or HE 7 (*i.e.*, one or two hours before Bowater was required to be operating at its reduced level for the 8 a.m. to 6 p.m. peak hours under the DR2 Agreement). While it is not necessary for purposes of this Investigation to make a definitive finding on this point, it appears that the impact of being constrained off in a morning ramp down hour (and potentially also on the ramp up hour the evening before) would likely be deferred rather than permanently lost production, and that the calculations provided by Bowater based on lost pulp and paper production would overstate the effect that being constrained off would have on its operating profits for ramp down hours.

[96] Data supplied in Bowater's Responses to RFI, B.3.1 shows that average TMP consumption between the hours of 7 pm and 7 am on weekdays was ● tonnes, or ● tonnes per hour. The data also shows TMP inventory was lowest at 7 pm on Friday evenings at ● tonnes, which at a consumption rate of ● tonnes per hour represents over 5 hours of TMP inventory before the paper machine would have to be stopped and restarted.

[97] Email from [Senior Abitibi Personnel #2] to MAU, July 29, 2010, reproduced above. Responses to RFI, B.13.59.

As indicated in Section 7.2.1, when operating as a dispatchable load from 2003 to 2006, the Thunder Bay Facility used bids in the range of $●/MWh to $●/MWh for much of its load during normal operations and ramping. This is generally consistent with the conclusion that bid prices of $●/MWh and $●/MWh were well above Bowater's Marginal Benefit of Consumption on weekdays.

7.4.2.3 Bid Prices Exceeded Marginal Benefit of Consumption on Weekends

In its responses to the Panel's requests for information, Bowater produced an internal email which indicated that when the Thunder Bay Facility was not pulp limited, such as on weekends, the impact on operating profits from being constrained off would be lower than $●/MWh:

> One thing we need [in respect of bid price rationale] is a better story for the weekend. [I'm] comfortable we have a good explanation for M-F, but [we're] weak for Saturday and Sunday.[98]

In a subsequent email, [Senior Bowater Personnel #5] noted: "since we are not pulp limited on the weekends as shown by the inventory outages, a lower price could be justified."[99]

When determining what Bowater would propose to the MAU as a price that reflected the impact of being constrained off during a weekend, [Senior Bowater Personnel #3] suggested that "[m]aybe the price should be HOEP, I don't know? But $● will give us a nice dividing number".[100] [Senior Bowater Personnel #3] also requested that personnel provide a number for "how much CMSC we have made on weekends, since we started."[101] [Senior Bowater Personnel #5] replied:

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[98] Email from [Senior Bowater Personnel #3] to [Senior Bowater Personnel #5], [Senior AbitibiBowater Inc Personnel #1] and [Senior Bowater Personnel #1], July 31, 2010. Responses to RFI, B.13.65.

[99] Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], August 16, 2010. Responses to RFI, B.13.86.

[100] Email from [Senior Bowater Personnel #3] to [Senior Bowater Personnel #5], August 18, 2010. Responses to RFI, B.13.91.

[101] Email from [Senior Bowater Personnel #3] to [Senior Bowater Personnel #5], August 18, 2010. Responses to RFI, B.13.91.

> From: [Senior Bowater Personnel #5]
>
> To: [Senior Bowater Personnel #3]
>
> Date: August 18, 2010 08:21 AM
>
> Subject: Re: CMSC updated per July billing
>
> Weekends and stat holidays have generated about $2.5MM [in CMSC payments] to end of July. Not sure what you are trying to do on the weekends with the $●. <u>One line shutdowns will generate minimal CMSC at any price. Lowering the price however does acknowledge that we have different economics on weekends because of the excess pulp capacity.</u> We could calculate a number using the same format as during the week without the impact on the machine. In any case <u>I think we should have a higher number than $● so that it doesn't make the $● look so high</u>.[102] (emphasis added)

As noted in Section 7.4.2.2, if the impact of being constrained off results in deferred rather than permanently lost production, then even Bowater's lower $●/MWh estimate might overstate the impact that being constrained off while ramping on a weekend would have.[103] However, it is not necessary for purposes of this Investigation to make a definitive finding on this point.

7.4.2.4 <u>Bowater's Marginal Benefit of Consumption is Lower in Self-Induced Ramping Hours</u>

Bowater's various calculations also overstate the operating profit reduction that would result from being constrained off during self-induced ramp down hours because of an implicit assumption that the whole hour would be affected.

Based on its submitted ramp rates, the Thunder Bay Facility takes five intervals to ramp down from ● MW to ● MW. During these five intervals, being constrained off would not have any negative impact on Bowater's operating profits because (i) Bowater's bids indicate that it no longer wishes to consume, and (ii) the Facility cannot be dispatched down faster or further than

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[102] Responses to RFI, B.13.91.

[103] As noted above, [Senior Bowater Personnel #3] identified HOEP as another possible measure of the impact of being constrained off on weekends. The average HOEP on weekends during the Relevant Period was $40.46/MWh, well below the $●/MWh amount noted in the same email. Responses to RFI, B.13, 91, quoted above.

the ramp rates and bid quantities it has submitted. Thus Bowater is only exposed to seven intervals of potential lost or delayed TMP production if it were dispatched down at the beginning of a self-induced ramp down hour.

Bowater did not demonstrate that being constrained off during some or all of the first seven intervals of a ramp down hour would result in an overall loss of production that could not be made up by adjusting its operations at a later time in which it had not planned to be running at full capacity. In such circumstances, there would be little or no reduction of operating profit from being instructed to ramp down a bit early on one morning. However, even if the production was permanently lost, a calculation based on an entire hour of lost energy consumption overstates the actual operating profit reduction.

In the Responses to RFI, Bowater stated that "during hours in which the Thunder Bay facility is deliberately altering [its] consumption level … 65% of the ramp down hour TMP pulp is still being produced."[104]

If the estimates provided by Bowater for the impact of lost production and the unavoidable costs of reducing consumption were otherwise correct, the estimated operating profit impact of being constrained off during a weekday ramp down would range from $0/MWh (if not constrained in intervals 1-7) to a maximum (if constrained from interval 1 forward) of $●/MWh ($●/MWh*65% using the calculation of the Marginal Benefit of Consumption in Bowater's internal correspondence in July 2010[105] and ignoring possible overstatements from deferred versus lost production and the inclusion of fixed cost recovery amounts).[106]

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[104] Responses to RFI, B.4. The Panel examined the total MWh of electricity consumption during a ramp down hour relative to a full hour of consumption. During a normal ramp down hour the Thunder Bay Facility consumes 73% of a full hour of electricity consumption. (This calculation assumes ● MWh of consumption during a full hour of consumption and ● MWh of consumption based on a ramp down profile from ● MW to ● MW using the ramp rates in Table 7-2.) The fact that the TMP pulp ratio is slightly lower likely reflects some additional use of electricity to effect the shut down properly.

[105] Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], July 7, 2010. Responses to RFI, B.13.71.

[106] Based on the calculation that Bowater submitted to the MAU, the prorated amount would be $●/MWh ($●/MWh * 65%). (Responses to RFI, B.4, p.1, discussed in Section 7.4.2.2).

The Panel previously noted that [Senior Bowater Personnel #3]'s $●/MWh estimate of the financial impact if the Thunder Bay Facility was constrained off during a weekend might overstate the actual impact (see Section 7.4.2.3), but uses it as a conservative approximation in the absence of other more detailed data. If pulp and paper production was not permanently lost, but merely delayed for a period of time during a weekend constrained-off event, then there would be little or no reduction of operating profits. Even if it is assumed that there would be permanently lost production (which appears to be questionable on weekends), the maximum estimated reduction of operating profit during a weekend ramp down hour if constrained off in interval 1 would be $●/MWh ($●/MWh*65%).

During ramp ups, there is a possibility of pulp and paper production being reduced if the Facility is constrained off in whole or in part during the first five intervals when ramping would normally occur, as well as in the remaining seven intervals when the Facility is seeking to consume at its bid quantity. Again, it is unclear whether these situations would involve delayed production that could be made up later (*e.g.* by delaying the start of the next ramp down), and therefore little, if any, impact on operating profits, or whether there would be permanently lost production.

Bowater indicated that TMP pulp is being produced during 75% of a ramp up hour.[107] Accordingly, even if there would be permanently lost production as a result of being constrained off for an entire ramp up hour, based on Bowater's own estimates above, the operating profit reduction would be no more than $●/MWh ($●/MWh*75%) on weekdays and $●/MWh ($●/MWh*75%) on weekends.

7.4.2.5 <u>Bid Price Increased CMSC Payments</u>

In summary, Bowater's Marginal Benefit of Consumption was no higher than $●/MWh and $●/MWh during ramp downs on weekdays and weekends, respectively. On ramp ups, it was no higher than $●/MWh and $●/MWh on weekdays and weekends, respectively. However, the

[107] Responses to RFI, B. 4. The Panel examined the total MWh of electricity consumption during a ramp up hour relative to a full hour of consumption. During a normal ramp up hour the Thunder Bay Facility consumes 76% of a full hour of electricity consumption. (This calculation assumes ● MWh of consumption during a full hour of consumption and ● MWh of consumption based on a ramp up profile from ● MW to ● MW using the ramp rates in Table 7-2.) The amount is almost identical to the TMP pulp ratio provided by Bowater.

actual financial impact of being constrained off while ramping may have been as little as zero in situations where the facility was not capacity constrained and could make up the lost production in a subsequent hour (particularly on weekends).

An estimate of the amount by which Bowater's high bid prices triggered CMSC payments in excess of operating profit reductions during self-induced ramp hours is set out in Table 7-5. This estimate is based on the following conservative assumptions: (i) there were always permanent losses of mill production resulting from being constrained off (as opposed to deferred production that could be recouped on subsequent hours or days when the Facility was not operating at capacity); (ii) estimates of the Marginal Benefit of Consumption are based on the conservative (maximum) estimates outlined above which ignore potential overstatements related to fixed costs; and (iii) all the quantity differences between the constrained schedule and the greater of the unconstrained schedule and actual consumption reflected Bowater responding to IESO dispatch instructions caused by Grid Conditions (which, as noted in Sections 7.4.3 – 7.4.7, was not, in fact, the case). The total CMSC impact of Bowater's high bid prices is estimated at $10.3 million.

***Table 7-5: Estimated Impact of Bowater's High Bid Prices on CMSC Payments for the Thunder Bay Facility February – August 2010 ($/MWh, MWh and $000)***

| | Weekdays | | | | Weekends | | | |
|---|---|---|---|---|---|---|---|---|
| | Ramp Up | | Ramp Down | | Ramp Up | | Ramp Down | |
| | Feb-June | July-Aug | Feb-June | July-Aug | Feb-June | July-Aug | Feb-June | July-Aug |
| **Bid Price ($/MWh)** | ● | ● | ● | ● | ● | ● | ● | ● |
| **Estimated Marginal Benefit of Consumption ($/MWh)** | ● | ● | ● | ● | ● | ● | ● | ● |
| **Difference ($/MWh)** | 1,589 | 390 | 1,644 | 445 | 1,924 | 725 | 1,934 | 735 |
| **Constrained-off Quantity (MWh)*** | 1,262 | 492 | 2,643 | 1,067 | 500 | 204 | 982 | 440 |
| **Total CMSC Impact ($000)** | $ 2,005 | $ 191 | $ 4,345 | $ 475 | $ 962 | $ 148 | $ 1,899 | $ 323 |

*For intervals where Bowater received a net CMSC payment.

**Finding #4 (Operating Profit Impact of Being Constrained Off):**

a) *During periods when Bowater was not operating the Thunder Bay Facility at capacity, there would be virtually no reduction in operating profits as a result of being constrained off during a ramping hour because production could be made up in a subsequent hour.*

b) *Even in situations where the Thunder Bay Facility was capacity constrained, Bowater's bid prices between February and August 2010 substantially exceeded its Marginal Benefit of Consumption and the reduction in operating profits that would result from the Thunder Bay Facility being constrained off during ramping hours.*

> c) *Based on data provided by Bowater, the difference between Bowater's February - June 2010 bid price of $●/MWh and its Marginal Benefit of Consumption when ramping down was at least $1,644/MWh on weekdays and $1,934/MWh on weekends.*
>
> d) *Based on data provided by Bowater, the difference between Bowater's February - June 2010 bid price of $●/MWh and its Marginal Benefit of Consumption when ramping up was at least $1,589/MWh on weekdays and $1,924/MWh on weekends.*
>
> e) *Based on data provided by Bowater, the difference between Bowater's July - August 2010 bid price of $●/MWh and its Marginal Benefit of Consumption when ramping down was at least $445/MWh on weekdays and $735/MWh on weekends.*
>
> f) *Based on data provided by Bowater, the difference between Bowater's July - August 2010 bid price of $●/MWh and its Marginal Benefit of Consumption when ramping up was at least $390/MWh on weekdays and $725/MWh on weekends.*
>
> g) *Bowater's high bid prices were used to obtain CMSC payments that more than compensated Bowater for operating profit reductions by at least $10.3 million.*

7.4.2.6 <u>The Risk of Being Constrained Off Did Not Justify Bowater's Bid Prices</u>

Bowater's assertion that high bid prices were necessary to deal with the risk of being constrained off while ramping is not consistent with (i) the actual consequences of being constrained off, (ii) the availability of other options to eliminate such a risk, and (iii) the fact that the risk was in fact remote.

The impact of being constrained off during a ramping hour can be summarized as follows:

- During periods where the Thunder Bay Facility is producing pulp, the impact of being dispatched down or off was that the plant's pulp operations would likely slow down or stop (and, if there was insufficient pulp in storage, then paper production would likely be similarly affected). However, during a self-induced ramp down, the facility's dispatch instructions were based on its own bid quantities that reflected its desire to shut down the pulp operations.

- During the five intervals of ramp down, dispatch instructions were reducing the Thunder Bay Facility's output at the ramp rate it submitted. Even if the Nodal Price rose above $●/MWh in these intervals, the facility would not be dispatched off any faster. Thus Bowater was at no risk of being dispatched any differently than it desired during the actual ramp down intervals.

- For the intervals before the scheduled ramp down begins (*i.e.* the first seven intervals in the ramping hour), the Thunder Bay Facility was at risk of being constrained off and losing pulp and possibly paper production (*i.e.* shutting down a bit sooner) if the Nodal Price exceeded its bid price.

- During a self-induced ramp up, the Thunder Bay Facility was dispatched to increase its consumption in accordance with the quantity bids and ramp rates that it submitted. It is possible that the Facility could be dispatched below its desired ramp up path if the Nodal Price rose above the bid price during the five ramp up intervals. This would result in a delay in reaching the planned pulp and possibly paper production levels. It could also be dispatched below its planned consumption level in the remaining seven intervals.

The foregoing summary of the possible impact of lost production during a ramping hour ignores the availability of CMSC payments. If the Thunder Bay Facility was constrained off during a ramp, Bowater would receive a CMSC payment. This would offset any negative effect on

Bowater's operating profits (unless it was using a bid price lower than its Marginal Benefit of Consumption, which was not the case at any time during the Relevant Period).[108]

Alternatively, Bowater could have bid at $2,000 MWh and become non-dispatchable. This would have eliminated any risk of being dispatched down in the early rather than later part of a ramp down hour, or during a ramp up hour. The Responses to RFI contain handwritten notes made by [Senior Abitibi Personnel #2] which indicate that [Senior Abitibi Personnel #2] was aware of the ability to bid at $2,000/MWh and that doing so would result in the facility being treated as non-dispatchable.[109] However, [Senior Abitibi Personnel #2] also understood that operating on a non-dispatchable basis would mean the load would no longer be eligible for CMSC payments. This is further confirmation that Bowater's assertion that a $●/MWh bid price was necessary to avoid the risk of being constrained off is not credible.

Bowater's assertion that there was a material risk of being constrained off during ramping hours is also not credible. The Northwest zone in the Ontario wholesale electricity market often has an oversupply of energy, resulting in low or even negative Nodal Prices much of the time. Nodal Prices above $●/MWh (or even Bowater's revised July to August 2010 ramping bid price of $●/MWh) are extremely rare at any time of day (including during HE 6 and HE 19, which were the normal hours used for weekday ramping by the Thunder Bay Facility, as well as during weekends). Thus, a high bid price normally would not be necessary to avoid being constrained off during either a planned ramp up or the first seven intervals in a planned ramp down hour.

To test Bowater's claim that a high bid price was necessary to avoid being dispatched down, the Panel conducted an analysis of Nodal Prices during Bowater's self-induced ramp hours on weekdays and weekends at the Thunder Bay Facility between February 8, 2010 and August 28, 2010. The Panel also conducted an analysis of Nodal Prices in HE 6 and HE 19 (the Facility's usual ramp down and ramp up hours, once it again became dispatchable) on weekdays and

[108] In fact, for the reasons discussed in Section 7.4.2.2 to 7.4.2.5 above, $●/MWh, $●/MWh or even $●/MWh bid prices exceed Bowater's Marginal Benefit of Consumption.

[109] Notes from a meeting of the IESO's Stakeholder Advisory Committee on March 31, 2010 (which is discussed in relation to other issues in Section 8.5 below). Responses to RFI, B.11.6.

weekends between January 2009 and December 2009. The analysis considered Bowater's original $●/MWh bid price, its revised $●/MWh bid price, and its alternative calculation of the Marginal Benefit of Consumption of $●/MWh contained in internal correspondence in July 2010.[110] During the Relevant Period, there were 8,820 five-minute intervals in self-induced ramp hours (6,384 on weekdays and 2,436 on weekends) and during 2009 there were 8,760 intervals in HE 6 and HE 19 (6,000 on weekdays and 2,760 on weekends). The results are shown in Table 7-6:

[110] Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], July 22, 2010. Responses to RFI, B.13.71.

***Table 7-6: Likelihood of the Thunder Bay Facility Being Constrained Off at Various Bid Prices During Self-Induced Ramping Hours January to December 2009 and February to August 2010 ($/MWh, number and % of intervals)***

| Period | Bid Price ($/MWh) | Number of Intervals Constrained Off | | | Percent of Intervals Constrained Off |
|---|---|---|---|---|---|
| January to December 2009 | **Weekday** | | | | |
| | | **HE 6** | **HE 19** | **Total** | |
| | ● | 0 | 6 | 6 | 0.100% |
| | ● | 0 | 6 | 6 | 0.100% |
| | ● | 0 | 22 | 22 | 0.367% |
| | ● | 1 | 27 | 28 | 0.467% |
| | ● | 1 | 27 | 28 | 0.467% |
| | **Weekend** | | | | |
| | | **HE 6** | **HE 19** | **Total** | |
| | ● | 0 | 0 | 1 | 0.036% |
| | ● | 0 | 0 | 1 | 0.036% |
| | ● | 19 | 21 | 40 | 1.449% |
| | ● | 39 | 17 | 56 | 2.029% |
| | ● | 59 | 20 | 79 | 2.862% |
| February to August 2010 | **Weekday** | | | | |
| | | **Ramp Down** | **Ramp Up** | **Total** | |
| | ● | 0 | 0 | 0 | 0.000% |
| | ● | 0 | 5 | 5 | 0.078% |
| | ● | 0 | 6 | 6 | 0.094% |
| | ● | 0 | 16 | 16 | 0.251% |
| | ● | 1 | 19 | 20 | 0.313% |
| | **Weekend** | | | | |
| | | **Ramp Down** | **Ramp Up** | **Total** | |
| | ● | 0 | 0 | 0 | 0.000% |
| | ● | 0 | 0 | 0 | 0.000% |
| | ● | 19 | 46 | 65 | 2.668% |
| | ● | 39 | 69 | 108 | 4.433% |
| | ● | 59 | 75 | 134 | 5.501% |

This analysis confirms that a high bid price of $●/MWh, or even $●/MWh or $●/MWh, was almost never necessary to prevent the Thunder Bay Facility from being dispatched down when ramping. Based on the outcomes in 2009, which was the most recent information that would have been available to Bowater before it again became dispatchable, the probability of being constrained off was remote. Moreover, the results throughout the Relevant Period confirm that the probability was remote. Even if Bowater had bid at the estimated levels of Marginal Benefit of Consumption discussed in Section 7.4.2.5, the likelihood of being constrained off during a ramping hour would have been remote on weekdays and very low on weekends (and any negative impact on Bowater's operating profits would have been compensated by a CMSC payment).

> **Finding #5 (Risk of Being Constrained Off):**
> *The risk of being constrained off during self-induced ramping hours did not justify Bowater's use of a bid price of $●/MWh or $●/MWh, or any other level above the Marginal Benefit of Consumption of the Thunder Bay Facility.*

7.4.2.7 <u>The Risk of Operating Reserve Activations Did Not Justify Bowater's Bid Prices</u>

As a dispatchable facility, Bowater is eligible to participate in the IESO's operating reserve (OR) market. During the Relevant Period Bowater received over $174,000 in OR (or OR CMSC) payments in exchange for its offers to reduce energy consumption if activated to provide OR.

OR is standby capacity to produce power (or, equivalently, reduce load) that the IESO can call upon with short notice when an unexpected event on the grid creates a need to rebalance supply and demand. Dispatchable resources that are scheduled to provide OR receive standby payments in exchange for being prepared to respond (*i.e.* to reduce consumption, in the case of a dispatchable load) in the event of a contingency. When a contingency event occurs, and unless a reliability concern dictates otherwise, the IESO will activate the resource with the lowest energy offer or bid price to provide the required amount of OR up to the quantity of OR for which it has been scheduled.[111]

[111] The least costly resource is identified based on energy market offers or bids, since the activated power (or load reduction) must be paid a minimum of the facility's offer (or bid) price.

Bowater claimed that its strategy of using high bid prices to reduce the risk of being activated for OR (while also being able to generate revenue from the OR market) "was confirmed in on-site training provided by the IESO".[112] In fact, the IESO training materials simply include an example which illustrates how the IESO decides to activate a dispatchable resource for operating reserve. In the example, a load bids for energy at $1,990/MWh while a generator offers energy at $200/MWh. Both also offer OR, and when an OR activation is required, the IESO selects the generator because it is the less expensive resource.[113] While the IESO training materials use a very high bid price for the load, this is merely an illustration using hypothetical prices (that fall between the MMCP and negative MMCP). The illustration also relates to a period of regular operation by a dispatchable load, not a self-induced ramp up or ramp down. The training materials do not instruct dispatchable loads to bid at very high levels or contrary to their Marginal Benefit of Consumption during normal operations or during ramping periods.

If the Thunder Bay Facility was activated for OR during a ramping hour, Bowater would be compensated for its reduced energy consumption based on its bid price. Thus, as long as its bid price was not lower than its Marginal Benefit of Consumption, there would be no reduction of operating profit as a result of an OR activation during a self-induced ramping hour.[114] This demonstrates that Bowater's claim about the necessity of using a very high bid price to prevent OR activations is not credible.

If the risk of being constrained off was in fact regarded as serious, Bowater could have chosen not to offer OR during self-induced ramping hours. Alternatively, as noted in Section 7.4.2.6 above, it could have bid $2,000/MWh (*i.e.* an extra $●/MWh) to become non-dispatchable in the energy market and thereby avoid the OR activation risk. Presumably it chose not to do so

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[112] Responses to RFI, B.3, p. 2.

[113] See IESO, *Introduction to Ontario's Physical Markets*, online: http://www.ieso.ca/imoweb/pubs/training/IntroOntarioPhysicalMarkets.pdf, p. 58. (This training document was revised in October 2011, but the OR example cited in Bowater's Responses to RFI, B.3, is unchanged.)

[114] For the reasons discussed in Sections 7.4.2.2 to 7.4.2.5, a $●/MWh, $●/MWh, or even $●/MWh bid price would exceed the Facility's Marginal Benefit of Consumption and more than compensate Bowater for reduced operating profit if it was constrained off.

because this would have eliminated the availability of CMSC payments and/or the OR standby payments.

The impact of being activated for OR during a self-induced ramping hour is similar to the impact of being constrained off (described previously in Section 7.4.2.6):

- There is a risk of an earlier-than-expected reduction of energy consumption, and hence lost or delayed pulp and possibly paper production, if an OR activation occurs during the first seven intervals of a ramp-down hour.
- There is a risk of delayed energy consumption, and hence lost or delayed pulp and possibly paper production, if an OR activation occurs during the ramp-up hour.

In order to assess Bowater's claim that it was necessary to bid at a high price to avoid OR activation, the Panel examined the frequency of OR activations in the Northwest zone during the hours in which the Thunder Bay Facility was ramping up or down. There were none during the Relevant Period.[115] The Panel also examined the number of OR activations in HE 6 and HE 19 (the usual ramp down and ramp up hours after Bowater again became dispatchable) in 2009. There were no activations in HE 19 and only two activations in HE 6, totaling 8 MW of operating reserve activation. Thus the use of a high bid price was not necessary to mitigate OR activation risk based on the information that would have been available when Bowater developed its dispatchable load bidding strategy. Indeed, a presentation to ABI senior management in October 2009 showed projected OR revenues averaging $●/MWh while at the same time noting the miniscule activation risk: "Experience less than one dispatch per year (FF [Fort Frances]: twice in 4 years)".[116]

[115] OR activations are infrequent in the Northwest. Of the 84 days during the Relevant Period with an OR activation in Ontario, there were only four days in which OR was activated in the Northwest. Of these, only one affected the Thunder Bay Facility. However, it did not occur in a ramping hour.

[116] See "Thunder Bay 2010 Power Cost – October 1st, 2009." Responses to RFI, B.3.6. p.3, reproduced in Appendix J (the Fort Frances Facility is in the same region as the Thunder Bay Facility and the OR activation risks at the two Facilities are similar.)

**Finding #6 (Risk of Being Activated for Operating Reserve):**

*The risk of being activated to provide operating reserve during self-induced ramping hours did not justify Bowater's use of an energy market bid price of $●/MWh or $●/MWh, or any other level above the Marginal Benefit of Consumption of the Thunder Bay Facility.*

7.4.2.8 Historical Use of High Bid Prices by Affiliates Did Not Justify Bowater's Bid Prices

Bowater's argument that a $●/MWh bid price was used by the Abitibi Consolidated dispatchable loads at Fort Frances, Fort William and Iroquois Falls[117] is not a justification for Bowater's high bid prices for at least four reasons. First, the fact that other dispatchable loads may have engaged in conduct that may be exploiting a market defect does not have any bearing on whether Bowater was exploiting a market defect during the Relevant Period. Second, it is possible that other facilities could have a Marginal Benefit of Consumption equal to or greater than this level, whereas Bowater does not (see Sections 7.4.2.2 to 7.4.2.5). Third, it is possible that high bid prices may be used by dispatchable loads that ramp quickly and therefore trigger negligible CMSC payments. Fourth, the specific reference to Abitibi's use of this bidding strategy carries no weight based on the separate analysis of the bid prices used by the Fort Frances Facility in Section 8.4.2 of this Report.

**Finding #7 (High Bid Prices by Other Loads):**

*The historical use of high bid prices by other dispatchable loads does not provide a justification for Bowater's high bid prices during self-induced ramping hours.*

[117] Responses to RFI, B.13, p.1.

### 7.4.3 Submitting Maximum Bid Quantities in Excess of Consumption

When Bowater began to develop its ramping strategy in September 2009, [Senior Bowater Personnel #5] outlined the Thunder Bay Facility's normal operations in a PowerPoint presentation. The presentation shows the facility consuming between ● MW and ● MW when both TMP lines were in operation.[118] In subsequent emails between personnel at the Thunder Bay Facility and the Fort Frances Facility, the load at the Thunder Bay Facility is referred as being in the ● MW to ● MW range.[119]

Shortly after Bowater re-entered the market as a dispatchable load, [Senior Abitibi Personnel #2] advised that increasing the quantity bid from ● MW to ● MW would increase CMSC payments by $4,000 per ramp-up. It is notable that the suggested change originated from [Senior Abitibi Personnel #2] rather than the personnel responsible for operating the Thunder Bay Facility. The appropriateness of the proposed change (as well as the appropriateness of ramping below the facility's dispatch signal, which is analyzed in Section 7.4.5 below) was explored by email.[120] [Senior Bowater Personnel #5] concluded that "[t]he others need to hear your recommendations and know that there is still money to be had here. How we go after it will be the question?".[121] Two days later [Senior Bowater Personnel #5] informed [Senior Abitibi Personnel #2] that "[b]ids have been changed to ● MW vs ● MW as you recommended."[122]

From February 19, 2010 to May 11, 2010 Bowater bid ● MW instead of ● MW as its maximum bid quantity. Although Bowater consistently bid to consume a maximum bid quantity of ● MW,

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[118] Email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], September 11, 2009. Responses to RFI, B.2.5.

[119] Email from [Senior Abitibi Personnel #2] to [Senior Bowater Personnel #5], September 11, 2009, Responses to RFI, B.2.6; email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], September 24, 2009, Responses to RFI, B.2.10; email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], February 8, 2010, Responses to RFI, B.2.14; and attachment to email from [Senior Bowater Personnel #5] to [Senior AbitibiBowater Inc Personnel #2] and [Senior Abitibi Personnel #2], January 22, 2010, Responses to RFI, B.2.25.

[120] Email exchange between [Senior Bowater Personnel #5] and [Senior Abitibi Personnel #2], February 12-16, 2010. Responses to RFI, B.2.16.

[121] Email exchange between [Senior Bowater Personnel #5] and [Senior Abitibi Personnel #2], February 16, 2010. Responses to RFI, B.2.16.

[122] Email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], February 18, 2010. Responses to RFI, B.2.17.

the Thunder Bay Facility's consumption varied and followed a decreasing trend during this period. In the month of February and the first half of the month of March, the Thunder Bay Facility's consumption varied between ● MW and ● MW, and at times consumption was well below ● MW. Beginning in the middle of March the Thunder Bay Facility's consumption was declining, and varied between ● MW and ● MW. By the time Bowater revised its bids down from ● MW in May, the facility was consuming between ● MW and ● MW, well below the bid quantity.

Personnel at the Thunder Bay Facility recognized that consumption was usually less than ● MW. For example, [Senior Bowater Personnel #5] observed in March 2010 that the load was incapable of achieving a target of ● MW on start-ups and on occasion was significantly below target prior to shutdowns.[123] In emails on May 4 and 5, 2010, [Senior Bowater Personnel #5] reported on the actual performance of the Thunder Bay Facility with statistics showing consumption in the range of ● MW to ● MW.[124] Six days later, Bowater revised down its maximum bid quantity from ● MW to ● MW.[125]

The *Market Rules* allow for variations in consumption around the dispatch instruction (referred to as the "Compliance Deadband"). The Compliance Deadband for a resource with the characteristics of the Thunder Bay Facility is 15 MW above or below its dispatch instruction.[126] When dispatched at ● MW, the Facility is considered compliant while consuming anywhere between ● MW and ● MW. During the period when it used a maximum bid quantity of ● MW,

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[123] Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], [Senior Bowater Personnel #1], [Senior Bowater Personnel #2], [Senior Bowater Personnel #4] and [Senior Abitibi Personnel #2], March 22, 2010. Responses to RFI, B.16.52.

[124] Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #2], May 4, 2010, Responses to RFI, B.2.19; email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], May 4, 2010, Responses to RFI, B.2.20; and email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #2], May 5, 2010, Responses to RFI, B.2.21.

[125] On September 2, 2010, [Senior Bowater Personnel #5] noted the possibility of a further change in the bid quantity as an option for reducing the high CMSC payments that had been identified by the MSP and IESO: "Reduce target from ● to ● MW <u>(closer to actual)</u>" and "Lower target [of] ● MW for start up hour <u>(closer to what we actually achieve)</u>" (emphasis added). Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], September 2, 2010. Responses to RFI, B.13.111 (reproduced in full below).

[126] IESO, *Market Rule Interpretation Bulletin, Compliance with Dispatch Instructions Issued to Dispatchable Facilities*, June 29, 2009, online: http://www.ieso.ca/imoweb/pubs/interpretBulletins/ib_IMO_MKRI_0001.pdf.

the Thunder Bay Facility was never consuming above the Compliance Deadband. However, it consumed below its Compliance Deadband in 990 intervals. Had Bowater bid a maximum quantity of ● MW, the facility would have consumed above the Compliance Deadband in only 1 interval and below in 300 intervals.

By raising its maximum bid quantity to ● MW, Bowater increased the number of constrained-off MWs for which CMSC payments would be made. Compared to a bid quantity of ● MW, Bowater received CMSC payments for an additional 5 MW in each interval in which it was constrained off. After March 15, 2010 and until May 11, 2010, Bowater received a net CMSC payment after clawbacks in 402 intervals during which it had an unconstrained schedule of ● MW. As a result, Bowater was paid approximately $330,000 in additional constrained-off CMSC payments based on its submitted quantity bid of ● MW, relative to the CMSC payments that would have been made if a ● MW maximum bid level quantity had been used.[127]

**Finding #8 (Maximum Bid Quantity):**

a) *Bowater's change in its maximum bid quantity from ● MW to ● MW from February 19 to May 11, 2010 was undertaken to, and did, increase constrained-off CMSC payments.*

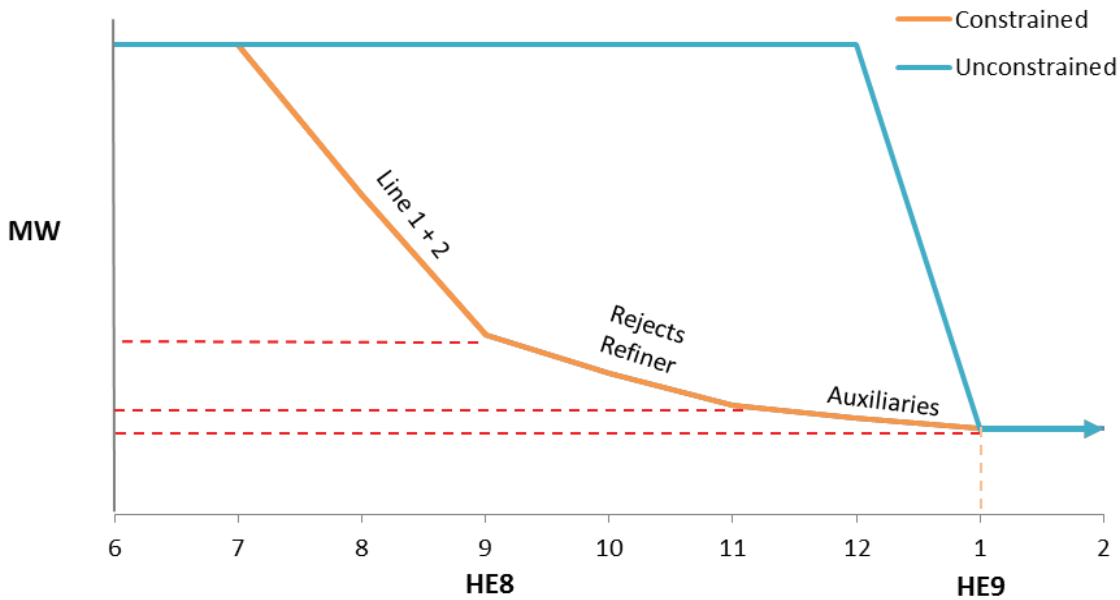
b) *The estimated amount of incremental CMSC payments derived from Bowater's use of a ● MW maximum bid quantity at the prices Bowater was bidding was $330,000.*

[127] This calculation is based on Bowater's actual bid prices. It therefore overlaps with the estimate of the impact of Bowater's high bid prices in Table 7-5. If Bowater had bid at the Panel's conservative estimates of the Facility's Marginal Benefit of Consumption of $●/MWh during non-ramping hours, $●/MWh and $●/MWh during ramp up and ramp down respectively on weekdays, and $●/MWh and $●/MWh during ramp up and ramp down respectively on weekends (as estimated in Sections 7.4.2.2 and 7.4.2.23), the extra CMSC payments related to the elevated maximum bid quantity would have amounted to approximately $42,000.

### 7.4.4 Expanding Schedule Quantity Differences Through Ramp Down Timing

Beginning in September 2009, Bowater was planning a ramping sequence for the Thunder Bay Facility that would have the load ramp down by 7:00 a.m. (*i.e.* interval 12 in HE 7) every weekday, and back up starting at 7:00 p.m. (*i.e.* interval 12 in HE 19) every weekday evening.[128] Figure 7-3 shows the typical sequence of ramp down steps and dispatch instructions during the Relevant Period.

***Figure 7-3: Typical Ramp Down Pattern Used by the Thunder Bay Facility February – August 2010 (MW by interval)***




Of note in Figure 7-3 is the low ramp rate attributable to the shutdown of the auxiliaries. Bidding the auxiliaries to shut down in the same hour as the main line and rejects refiners increased the quantity differences between the constrained and unconstrained schedules. To provide the minimum commitment of ● MW of demand reduction under the DR2 Agreement, it was not necessary to ramp the auxiliaries down in HE 7. In fact, [Senior Bowater Personnel #5] had

[128] Bowater's DR2 Agreement required a demand reduction of ● MW during on-peak hours, which were defined as 8 a.m. (*i.e.* interval 12 in HE 8) to 6 p.m. (*i.e.* interval 12 in HE 18).

recognized this flexibility with respect to ramping the auxiliaries down prior to re-registering as a dispatchable load:

> I have set the strategy up with DR2 in mind and our need to stay out of the peak period of 7 am to 7 pm with any significant load, but to also maximize the up time of the refiners in the off peak period. As a result you will see that I have given the operation the flexibility to run the auxiliaries in the on peak period. So on the way down set [our] bids up to go to ● MW at 7am and to ● MW at 8am, however we would shut the auxiliaries down anytime between 7am and 8 am, probably within 15 minutes.[129]

Despite bidding the auxiliaries down in HE 7, personnel at the Thunder Bay Facility were nonetheless instructed that it was permissible to ramp auxiliaries down into the start of the next hour.[130] The Panel also notes the contradictory explanations provided by Bowater for the operations of the Facility. On the one hand, Bowater claimed that it submitted a high bid price of $●/MWh (or $●/MWh) in a ramp hour to avoid being dispatched down and to have a high uptime of the TMP in the off-peak hours in order to maximize the payments under its DR2 Agreement with the OPA.[131] On the other hand, Bowater elected to bid its auxiliaries down in HE 7, which reduced the uptime of the TMP in the off-peak hours and contradicted the analysis provided by [Senior Bowater Personnel #5].

Had Bowater bid to ramp the auxiliaries down in HE 8 rather than in HE 7, the CMSC payments during a ramp down would have been much less, as shown in Figure 7-4. In addition, the Facility would have been able to consume electricity (and produce pulp and paper) for two additional intervals in HE 7 at market prices well below its bid price. The Thunder Bay Facility could have maintained an orderly shutdown of its pulping operations by ramping its mainline and reject lines during HE 7 and its auxiliaries during HE 8. The sequence of the shutdown would remain unchanged (see the actual curve in Figure 7-3) but the CMSC payments would be significantly

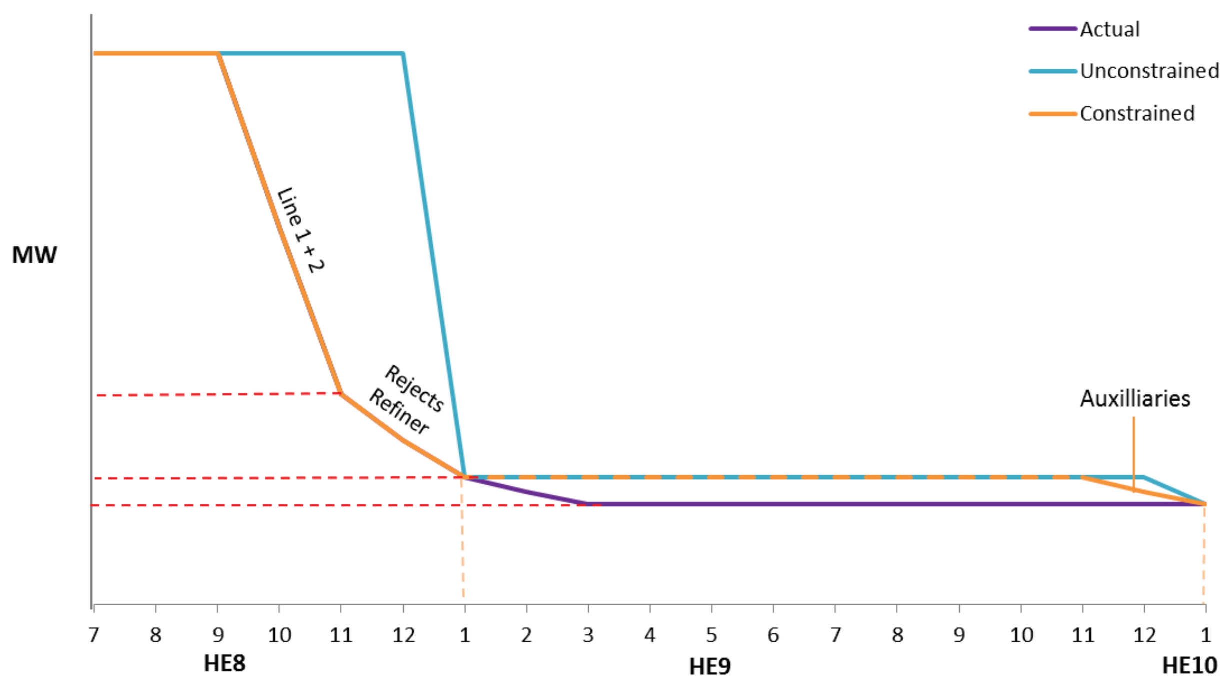
[129] Email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], September 24, 2009. Responses to RFI, B.2.10.

[130] Email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #4], February 1, 2010. Responses to RFI, B.2.28.

[131] Responses to RFI, B.2, p.1 and Responses to RFI, B.3.

reduced. When Bowater was using a $●/MWh bid price, the CMSC payments under the ramping scenario in Figure 7-4 would have been approximately $30,000,[132] compared to payments of over $50,000 on a typical ramp down using the approach adopted by Bowater.

***Figure 7-4: Alternative Ramp Down Bid Structure for the Thunder Bay Facility (MW)***




Bowater asserted that its ramp rates and sequence were necessary to ensure an orderly shutdown and start up of the plant. When the Thunder Bay Facility first submitted its ramp rates the week before it became dispatchable, IESO staff noticed that they were very low and contacted the Facility.[133] Bowater explained that the ramp rates were designed "to have an orderly shutdown and have the TMP plant completely down by 7 am" and that the Facility required time "to purge the process, minimizing the potential plugged lines and equipment that would delay start up."[134]

[132] This calculation is based on an average MCP of $30/MWh.

[133] Responses to RFI, B.2, p.2.

[134] Responses to RFI, B.2, p.2.

However, after an urgent *Market Rule* amendment was introduced by the IESO on August 28, 2010 to temporarily eliminate all constrained-off CMSC payments to dispatchable loads,[135] personnel at the Thunder Bay Facility contemplated a number of changes to future bids that would reduce CMSC payments — including a new ramping sequence whereby it would ramp the auxiliaries down in the hour after, instead of the same hour as, the refiners were ramped down. [Senior Bowater Personnel #5] reported to the [Senior Bowater Personnel #3] as follows:

> From: [Senior Bowater Personnel #5]
>
> To: [Senior Bowater Personnel #3]
>
> Cc: [Senior Bowater Personnel #1], [Senior Bowater Personnel #2]
>
> Date: September 2, 2010 11:11 AM
>
> Subject: Potential Bid Change and impact
>
> Changing the bids as follows:
>
> Reduce target from ● to ● MW (closer to actual)
>
> <u>Bid auxiliaries down in second hour instead of the same hour (reverse of start up)</u>
>
> Lower target or ● MW for start up hour (closer to what we actually achieve)
>
> One line shutdowns for inventory management on weekends
>
> CMSC
>
> -$10,200 for shutdowns
>
> -$6,200 per startup
>
> Monthly total $328,000 based on 20 days. No CMSC generated on weekends. If ramp downs are totally eliminated with pending rule

[135] IESO, *Urgent Rule Amendment Proposal*, MR-00373-R00, August 27, 2010, online: http://www.ieso.ca/Documents/mr/MR_00373-R00.pdf. (This change is discussed in Section 9.)

> change and only ramp ups are left monthly CMSC will be about $124,000 per month with good start ups.[136] (emphasis added)

The evidence regarding potential changes to operations after the Urgent Market Rule Amendment (after the Relevant Period) is consistent with the evidence regarding actual operations prior to Bowater's re-registration as a dispatchable load (before the Relevant Period). Both demonstrate that during the Relevant Period the Thunder Bay Facility was operated using a ramping sequence that was not operationally necessary, and that had the effect of significantly increasing CMSC payments.

Table 7-7 contains an estimate of the incremental impact of the alternative ramp down timing identified in the above email on CMSC payments. Bowater's actual ramping timing generated an additional $3.9 million in CMSC payments when measured at Bowater's actual bid prices (*i.e.*, $8.0 million under Bowater's actual ramping pattern compared to $4.1 million under the alternative ramping pattern). If Bowater had been bidding at its Marginal Benefit of Consumption (based on the Panel's conservative maximum estimates set out in Section 7.4.2.4), the differential between the two ramping patterns would have been $0.6 million in CMSC payments ($1.2 million under Bowater's actual ramping pattern compared with $0.6 million under the alternative ramping pattern).[137]

[136] Responses to RFI, B.13.111.

[137] To avoid overlapping calculations with section 7.4.2 and Finding #4, the estimate of the incremental CMSC impact from Bowater's ramp down pattern is calculated based on the Panel's conservative estimate of Bowater's maximum Marginal Benefit of Consumption.

***Table 7-7: Estimated Impact of Bowater's Ramp Down Timing on CMSC Payments for the Thunder Bay Facility February – August 2010 ($/MWh, MW and $000)***

| | **Bowater's Ramp Down Timing** | | | | **Alternative Ramp Down Timing** | | | |
|---|---|---|---|---|---|---|---|---|
| | **@Bowater's Bid Prices** | | **@Marginal Benefit of Consumption**** | | **@Bowater's Bid Prices** | | **@Marginal Benefit of Consumption**** | |
| | **Feb-June** | **Jul-Aug** | **Weekday** | **Weekend** | **Feb-June** | **July-Aug** | **Weekday** | **Weekend** |
| **Bid Price ($/MWh)** | ● | ● | ● | ● | ● | ● | ● | ● |
| **Average MCP ($/MWh)** | ● | ● | ● | ● | ● | ● | ● | ● |
| **Price Difference ($/MWh)** | ● | ● | ● | ● | ● | ● | ● | ● |
| **Quantity Difference (Constrained-off MWh/Ramp)** | ● | ● | ● | ● | ● | ● | ● | ● |
| **$/Ramp Down** | 57,043 | 22,127 | 9,338 | 841 | 29,505 | 11,445 | 4,830 | 435 |
| **Ramp Downs (#)*** | 120 | 53 | 127 | 46 | 120 | 53 | 127 | 46 |
| **Total CMSC ($000)** | 6,845 | 1,173 | 1,186 | 39 | 3,541 | 607 | 613 | 20 |
| | **$8,018** | | **$1,225** | | **$4,147** | | **$633** | |

** Based on the estimated maximum Marginal Benefit of Consumption as set out in Section 7.4.2.4 and Finding #4.

* Based on the number of ramp downs with a bid quantity change of ● MW or more (indicating a shutdown of both TMP lines, rejects refiners and auxiliaries).

**Finding #9 (Ramp Down Timing):**

*a) Bowater used a ramp down pattern for its auxiliaries that triggered increased CMSC payments during the Relevant Period when there was a known alternative ramping pattern that would have generated significantly lower CMSC payments and that was compatible with the Thunder Bay Facility's operational requirements (having been used before and considered for use after the Relevant Period).*

*b) The estimated amount of incremental CMSC payments derived from Bowater's ramp down pattern was $3.9 million at the prices Bowater was bidding.*

### 7.4.5 Ramping Faster than Submitted Ramp Rates

Ramping down at faster than submitted ramp rates is significant for two reasons. First, it increases the difference between the quantities (constrained schedules or actual consumption, versus unconstrained schedules) used to calculate CMSC payments.[138] In addition, it indicates that the submitted ramp rates were lower than the facility's capabilities and operating levels, which results in a longer ramping period and higher CMSC payments.

An analysis of the ramping behaviour of the Thunder Bay Facility reveals that the Facility ramped down faster than its submitted ramp rates in at least one interval during 82% (191 of 233) of its ramp downs during the Relevant Period.

[138] Ramping faster than the submitted rate has an impact because of the way in which CMSC payments are calculated. The value for the dispatch quantity is derived from the constrained schedule <u>at the end of each five-minute interval</u>. The value for actual consumption is derived from the revenue meter data, <u>which is averaged over the five-minute interval</u>. As indicated in Appendix F, a facility that follows dispatch instructions which match its ramp rates on a ramp down will meet the dispatch consumption target at the end of the interval and will therefore have average consumption greater than this amount over the interval. Ramping down faster than submitted ramp rates will bring the average of the revenue meter data over a five-minute interval closer to what the dispatch schedule indicates at the end of the five-minute interval.

Had Bowater submitted the faster ramp rates it actually followed, the dispatch algorithm would have created a dispatch schedule that was closer to the market schedule, resulting in smaller quantity differences and lower CMSC payments.

Bowater personnel were aware of this aspect of the CMSC formula. For example, [Senior Bowater Personnel #5] explained the concept to [Senior Bowater Personnel #3] using the chart in Appendix L. Similarly, shortly after the Thunder Bay Facility again became dispatchable, personnel from the Fort Frances Facility and the Thunder Bay Facility exchanged multiple emails regarding the review of ramp down events and CMSC payments. Their awareness of the impact of ramping faster than submitted rates is indicated in exchanges such as the following:

> From: [Senior Bowater Personnel #5]
>
> To: [Senior Abitibi Personnel #2]
>
> Date: February 12, 2010 1:45PM
>
> Subject: Re: Fw: Thunder Bay Bowater Bids /Offers in the Trade App
>
> In order for us to be closer to the dispatch eng amount we would have to anticipate the dispatch signal and take the chips off earlier. Danger is that the load may come off before the dispatch. It would also show that we are capable of a much faster down ramp rate. The first constrained dispatch signal goes from ● MW to ● MW with the expectation that we will be at ● MW by the end of the 5 minutes, which we are.... Your points are well taken, however with the CMSC potential I wonder if we shouldn't try and stay a bit under the radar as well as be able to defend the way we operate if questioned.[139] (emphasis added)

A few days later, [Senior Bowater Personnel #5] advised [Senior Abitibi Personnel #2] at the Fort Frances Facility as follows:

> As far as following the dispatch, we are meeting the requirements of the dispatch if we are at or below the dispatch energy level by the end of the interval, not averaging that amount. The only way to

[139] Responses to RFI, B.2.15. There were also further email exchanges between [Senior Abitibi Personnel #2] and [Senior Bowater Personnel #5] to similar effect on February 8 and 12, 2010: Responses to RFI, B.2.14, B.2.15 and B.2.16.

> actually average less than or equal to the dispatch energy amount is start before the dispatch or remove more load and get far enough below the dispatch energy amount sufficiently before the end of the interval so that [the] average of the energy consumed in that 5 minute interval is less [then] dispatch amount. <u>We don't want to go [too] far below the dispatch level or they may think that we are too conservative with our ramp rates and can shutdown faster.</u> This is turning out to be a significant amount of CMSC payments, close to 10% of the amount paid out to the whole province in 2008, generators included. I can't believe that IESO won't be taking a close look at this. What we are doing now is very defendable, not sure I can say that if we start before the dispatch [signal], as it is not necessary to meet the target energy level by the end of the interval.[140] (emphasis added)

An excerpt from a subsequent email confirms that [Senior Bowater Personnel #5] and [Senior Abitibi Personnel #2] were aware that ramping down faster than the dispatch schedule could constitute gaming:

> From: [Senior Bowater Personnel #5]
>
> To: [Senior Abitibi Personnel #2]
>
> Date: February 16, 2010 10:16AM
>
> Subject: Re: Fw: Thunder Bay Bowater Bids /Offers in the Trade App
>
> <u>Wouldn't anticipating the dispatch be considered gaming</u>. There is also potential that the [load will] come off before the dispatch signal is received. <u>If we were bidding economically we would not be able to anticipate the dispatch when dispatched off on price[.]</u> Having to allow time for removing the feed to the refiners is part of our justification for the ramp rates that we have. There are more subtle moves we can make prior to our dispatch that will reduce our transport lag time as well as move us to [an] energy

[140] Email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], February 16, 2010. Responses to RFI, B.2.16.

> level below the energy dispatch target getting us closer on average to the constrained dispatch energy target.[141] (emphasis added)

The internal emails indicate that Bowater was attempting to increase its CMSC payments on ramp down by getting its revenue meter data closer to or below the dispatch schedule. This is also evident in Bowater's analyses of shutdown and start-up scenarios for the TMP plant. For example, attached as Appendix K is a spreadsheet prepared by Thunder Bay Facility personnel which shows how they planned and forecasted their "Optimized CMSC Payment (actual load ≤ constrained schedule)."[142] As the title indicates, the objective was to achieve actual load consumption that was less than the dispatch schedule.[143]

Bowater also acknowledged that it could ramp faster than its submitted ramp rates in a presentation on reducing power costs prepared for creditors in November 2009 (when Bowater was in the midst of formulating its ramping strategy):

> The Congestion Management credit ($10.00) is a side benefit from participating in the OR market and from shutting down and starting up every week day for DR2. Since <u>we would much rather shut down as quickly as possible but the grid operator request us to ramp down to protect the integrity of the grid, we get compensated</u>. Conservative number based on FF experience.[144] (emphasis added)

Bowater's comment that the IESO instructed it to ramp down slower than it preferred does not reflect IESO practice. The IESO does not normally instruct market participants on what ramp rates to submit and Bowater provided no evidence to the contrary.

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[141] Responses to RFI, B.2.16.

[142] Email attachment from [Senior Bowater Personnel #5] to [Senior AbitibiBowater Inc Personnel #2], [Senior Abitibi Personnel #2] and [Senior Bowater Personnel #3], January 22, 2010. Responses to RFI, B.2.25.

[143] CMSC payments are made for the difference between the unconstrained schedule and the greater of actual consumption or the constrained schedule – see Appendix F.

[144] PowerPoint attached to email from [Senior Bowater Personnel #3] to [AbitibiBowater Inc Executive #3], November 12, 2009**.** Responses to RFI, B.16.25. In fact, CMSC payments result primarily from participation as a dispatchable facility in the energy market. (CMSC payments may also result from participation in the OR market, such as when the facility is constrained on to provide OR during OR shortages, or when the facility is constrained off during OR activations).

An example of one of the 191 ramp downs where the Thunder Bay Facility ramped faster than submitted ramp rates is June 7, 2010 in HE 6. Bowater bid $●/MWh and submitted the ramp rates in Table 7-2. The ramping of consumption, and the CMSC payments triggered during the ramping intervals, are shown in Table 7-8. The actual CMSC payments earned during the ramp down ($54,933) exceeded the CMSC payments that would have been made had the Thunder Bay Facility ramped from one dispatch instruction to the next at its submitted ramp rate ($50,712). The Facility ramped down faster than its submitted ramp rates in intervals 10 and 11. In interval 10 it ramped from ● MW to ● MW in a five-minute period. According to Bowater's submitted ramp rates, the Facility was only capable of reaching ● MW from a starting point of ● MW, not ● MW. Similarly, in interval 11, the Facility was only capable of reaching ● MW from a starting point of ● MW, not ● MW.[145] Although the deviations appear small, each increase in constrained off MWs was paid the difference between Bowater's bid price of $●/MWh and the MCP (which was approximately $33/MWh during these intervals).

[145] Bowater's actual ramp rate in interval 11 of ● MW/minute was 57% faster than its submitted ramp rate of ● MW/minute.

***Table 7-8: CMSC Payments on a Fast Ramp Down of the Thunder Bay Facility***
***June 7, 2010, HE 6***
***(MW, $/MWh and $)***

| Interval | Unconstrained Schedule (MW) | Constrained Schedule (MW) | Actual Consumption (MW) | MCP ($/MWh) | Net CMSC ($) | Expected Consumption (MW) | Expected Net CMSC ($) |
|---|---|---|---|---|---|---|---|
| 1 | ● | ● | ● | 17.15 | | ● | |
| 2 | ● | ● | ● | 17.60 | | ● | |
| 3 | ● | ● | ● | 17.95 | | ● | |
| 4 | ● | ● | ● | 17.95 | | ● | |
| 5 | ● | ● | ● | 26.78 | | ● | |
| 6 | ● | ● | ● | 28.57 | | ● | |
| 7 | ● | ● | ● | 30.00 | | ● | |
| 8 | ● | ● | ● | 31.20 | 4,630 | ● | 2,870 |
| 9 | ● | ● | ● | 31.58 | 9,844 | ● | 8,607 |
| 10 | ● | ● | ● | 32.54 | 12,532 | ● | 12,045 |
| 11 | ● | ● | ● | 33.35 | 13,760 | ● | 13,186 |
| 12 | ● | ● | ● | 33.53 | 14,168 | ● | 14,004 |
| **Total** | | | | | **$54,933** | | **$50,712** |

The Panel has not estimated the aggregate incremental impact of Bowater's faster ramp down on CMSC payments as it is partially subsumed in the estimate contained in Section 7.4.2.5. This calculation is partially subsumed in Section 7.4.2.5 because the estimate in that section is based on the difference between the unconstrained and the greater of the constrained schedule and the actual quantity consumed which accounts for any constrained-off megawatts from fast ramping. The estimate in Section 7.4.2.5, however, only accounts for the incremental CMSC payments for fast ramping constrained-off megawatts based on the difference between Bowater's actual bid prices and the estimated Marginal Benefit of Consumption of the Thunder Bay Facility. Fast ramping constrained-off megawatts are entirely self-induced and should not be compensated for at any bid price. The estimate in Section 7.4.2.5 therefore underestimates the impact of fast ramping on constrained-off CMSC payments by the number of fast ramping constrained-off megawatts multiplied by the difference between the estimated Marginal Benefit of Consumption of the Thunder Bay Facility and the MCP. The Panel has not undertaken an interval by interval estimation of the incremental impact of Bowater's fast ramping beyond what is already accounted for in Section 7.4.2.5. The Panel is nevertheless satisfied that the vast majority of CMSC payments associated with Bowater's fast ramping is subsumed in Section 7.4.2.5.

**Finding #10 (Ramping Down Faster than Submitted Rates):**

*a) Bowater's Thunder Bay Facility was able to, and frequently did, ramp down faster than its submitted ramp rates during the Relevant Period, indicating that its submitted ramp rates were lower than the Facility's operational capabilities.*

*b) The submission of ramp down rates that were lower than the Facility's operational capabilities increased the magnitude of constrained-off CMSC payments to Bowater.*

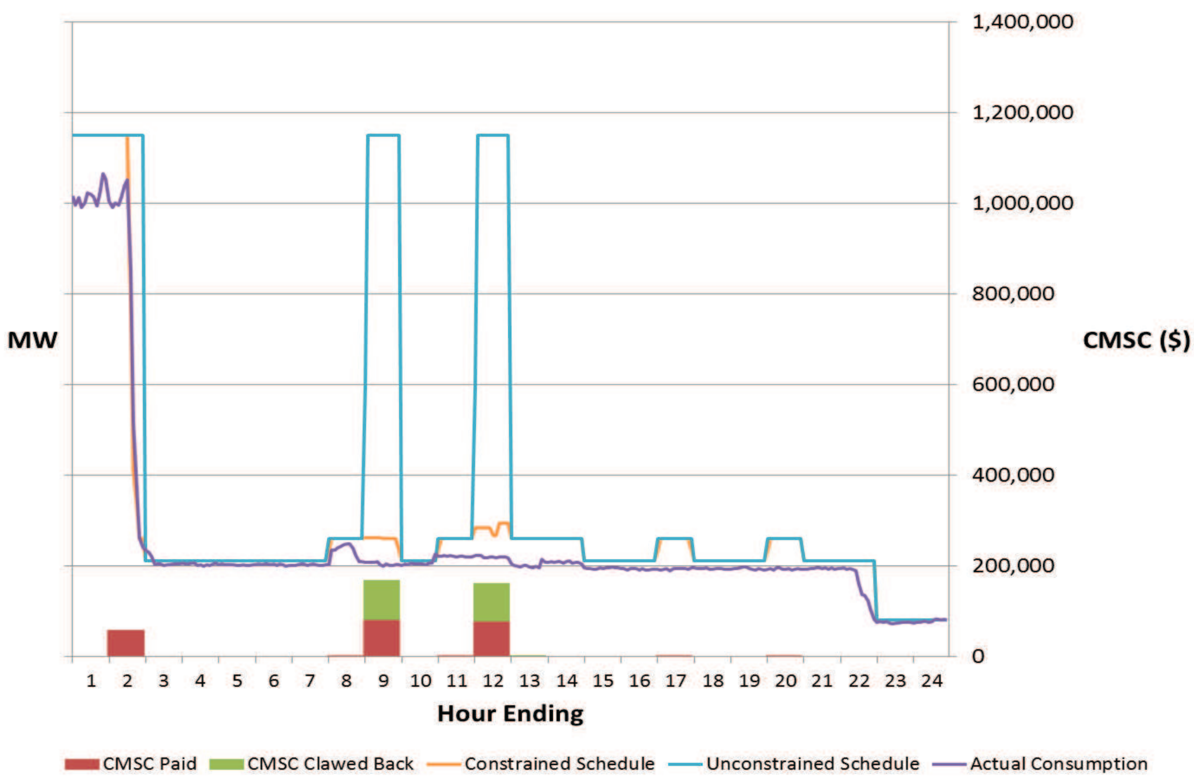
*c) The ramping down of the Facility faster than the submitted ramp rates increased the magnitude of constrained-off CMSC payments to Bowater.*

#### 7.4.6 Failure to Ramp

During the course of the Investigation, it was noted that during the Relevant Period the Thunder Bay Facility occasionally failed to ramp up and/or down, even though Bowater had submitted bid quantities that indicated it wanted to increase or decrease energy consumption. Such failures to ramp resulted in differences between the market and dispatch schedules, and therefore triggered constrained-off CMSC payments.

For example, on April 11, 2010, in HE 9 and HE 12, Bowater twice bid to ramp up, but then failed to follow the dispatch schedule that reflected the planned ramp. The scheduled and actual consumption, as well as the CMSC payments triggered during the planned ramping periods, are illustrated in Figure 7-5:

***Figure 7-5: Scheduled and Actual Consumption and CMSC Payments at the Thunder Bay Facility During a Failure to Ramp April 11, 2010 (MW and $ Dollars)***




The market schedule was determined by the Facility's submitted bid quantity, which was ● MW for HE 9 and HE 12. The dispatch schedule was determined, in part, by the Facility's actual consumption in the prior interval, since it can only be moved within a "Dispatch Envelope" (the range between the maximum and minimum dispatch instruction based on the load's current consumption level and submitted ramp rates). Because the Facility did not increase its energy consumption, the dispatch schedule remained at around ● MW. Had the Facility followed its dispatch instructions: (i) the dispatch schedule would have increased toward the market schedule, (ii) there would have been smaller quantity differences between the two schedules, and (iii) smaller CMSC payments would have been triggered. By not increasing its consumption levels (*i.e.* failing to ramp), Bowater received over $200,000 in net CMSC payments (the highest daily CMSC payment made to the Thunder Bay Facility during the Relevant Period).

Bowater stated that this and other failures to ramp occurred because the Facility experienced equipment failures.[146] Failure to ramp occurred on an infrequent basis. In the absence of evidence indicating that these failures to ramp were deliberate, the Panel has concluded that this behaviour was not an attempt to exploit a market defect. Even though the CMSC payments triggered by the failures to ramp did not arise from exploitative conduct, they were unwarranted and should have been clawed back because they were caused by the conditions at the participant's facility, not Grid Conditions. However, Business Rule 3 does not provide for recovery of CMSC payments when a load is deviating during a ramp (see Appendix H and the further discussion in Section 9 below).

**Finding #11 (Failure to Ramp):**

*The occasions during the Relevant Period where the Thunder Bay Facility failed to ramp after bidding to do so were infrequent. While the resulting CMSC payments were self-induced and should have been clawed back, the available evidence does not indicate that the failures to ramp were intentional attempts by Bowater to exploit a market defect.*

### 7.4.7 Dispatch Deviation in Non-Ramping Hours

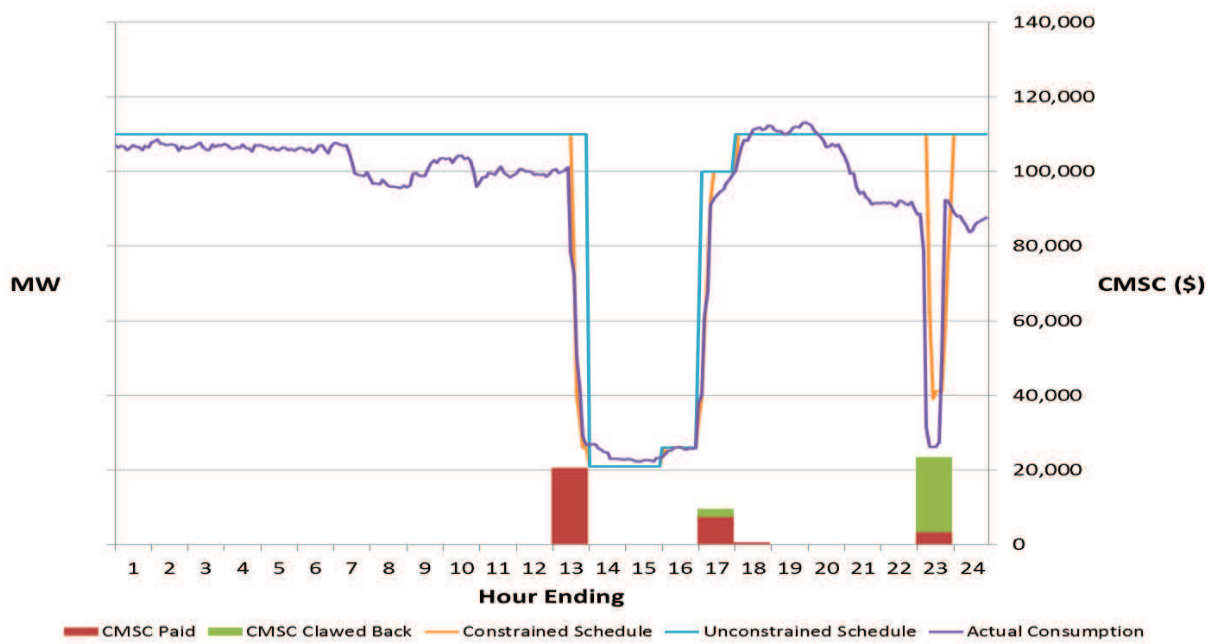
During the course of the Investigation, instances of constrained-off CMSC payments arising from dispatch deviation when the Thunder Bay Facility was not ramping during the Relevant Period were also noted. When dispatch deviation occurs outside of ramping hours, the IESO typically claws back the CMSC payments that are triggered pursuant to Business Rule 3. However, due to a flaw in Business Rule 3, there are occasions where such self-induced CMSC payments are not clawed back.

Figure 7-6 illustrates an occasion on July 10, 2010 where the Thunder Bay Facility deviated from its dispatch instruction in a non-ramping hour (HE 23) and the resulting CMSC payments were

[146] Responses to RFI, B.11.

not fully clawed back. The Thunder Bay Facility's consumption deviated substantially during intervals 5 through 12 of HE 23. In all but the last three of these intervals, CMSC payments were clawed back under Business Rule 3. However, CMSC payments totalling $3,335 were made for intervals 10, 11 and 12.

***Figure 7-6: Scheduled and Actual Consumption and CMSC Payments During Non-Ramp Dispatch Deviation at the Thunder Bay Facility July 10, 2010 (MW and $)***




The CMSC payments made to Bowater during dispatch deviations in non-ramping hours occurred infrequently and most of it was clawed back. In certain circumstances, the Facility may have been returning to its dispatch level after experiencing a consumption decrease, and may have received CMSC payments that should have been clawed back but was missed by the dispatch deviation Business Rule. The Panel did not identify evidence indicating an awareness of, or deliberate attempts to exploit, this particular defect in the Business Rule 3 clawback formula. Nevertheless, such CMSC payments were unwarranted and should have been clawed back because they were caused by conditions at the participant's facility, not Grid Conditions (see further discussion in Section 9 below).

**Finding #12 (Constrained-off Dispatch Deviations in Non-Ramping Hours):**

*Instances of dispatch deviation in non-ramping hours by the Thunder Bay Facility during the Relevant Period were infrequent. While the resulting CMSC payments were self-induced and should have been clawed back, the available evidence does not indicate that these deviations were intentional attempts by Bowater to exploit a market defect.*

### 7.5 Profits or Benefits to the Market Participant

The mere receipt of a CMSC payment does not necessarily mean that a market participant has profited or benefited. A market participant will profit or benefit when the CMSC payments that it receives exceed the reduction in operating profits caused by adhering to an IESO dispatch instruction to consume less or more electricity than its quantity in the market schedule.

The Panel has analyzed detailed hourly and interval-by-interval data relating to prices, differences in schedules, the reasons for those differences, and the amount of CMSC payments, in order to assess whether Bowater profited from the CMSC payments it received. As indicated in Section 7.4.2 above, the bid prices used by Bowater substantially exceeded the operating profit reductions resulting when expected consumption was constrained off during ramp down or ramp up hours on weekdays, and even more so on weekends. Similarly, Bowater self-induced quantity differences between the market and dispatch schedules by submitting bid quantities in excess of expected consumption, by its chosen ramp down timing pattern, and by ramping faster than its submitted ramp rates (see Sections 7.4.3, 7.4.4 and 7.4.5). The evidence summarized in Section 7.4 clearly shows that Bowater viewed its behaviour and the associated CMSC payments as sources of incremental profits rather than as compensation for reduced operating profits caused by responding to dispatches arising from Grid Conditions. With the exception of occasional failures to ramp and dispatch deviations in non-ramping hours, almost all of

Bowater's CMSC payments was the result of exploiting market defects (Finding #1) by using high bid prices (Finding #4)[147], submitting maximum bid quantities in excess of consumption (Finding #8)[148], expanding schedule quantity differences through ramp down timing (Finding #9)[149] and ramping faster than submitted ramp rates (Finding #10)[150].The Panel has determined that Bowater profited by $11.0 million from the CMSC payments it received.

The CMSC payments to Bowater were earned almost exclusively during ramp down and ramp up hours. As detailed in Section 7.2.3, during these hours Bowater was receiving CMSC payments to implement its own self-induced changes in consumption. In fact, the CMSC payments received were substantially greater than the cost of energy consumed during ramping hours. During the Relevant Period, Bowater received self-induced CMSC payments in 735 hours by ramping. During these hours Bowater received $12.0 million in net CMSC (of the total of $12.3 million in Table 4-2) but paid only $3.2 million in energy charges (including the applicable Global Adjustment and Uplift amounts). Bowater has not identified any costs or other reductions in its operating profits arising from responding to IESO dispatches during its self-induced ramps. It is therefore clear that Bowater profited substantially from the constrained-off CMSC payments generated by self-induced ramping of the Thunder Bay Facility.

**Finding #13 (Profit or Benefit to Bowater):**

*Bowater profited $11.0 million from the CMSC payments received as a result of the behaviours set out in Findings #4 and #8 – 10, which exploited the market defects set out in Finding #1.*

[147] The Panel estimates a CMSC impact of $10.3 million.

[148] The Panel estimates an incremental CMSC impact of $42,000.

[149] The Panel estimates an incremental CMSC impact of $0.6 million.

[150] The incremental CMSC impact is subsumed in Finding #4.

### 7.6 Expense or Disadvantage to the Market

Net CMSC payments (after the IESO's clawback procedures are applied) are charged to all Ontario wholesale electricity market customers as part of Uplift charges. Wholesale market participants that are distributors ultimately pass these costs on to their customers. When one participant exploits market defects in the CMSC system and profits from its behaviour, this imposes an expense and disadvantage throughout the market. All customers bear the cost by paying higher Uplift charges than would otherwise have been incurred. Indeed Bowater personnel explicitly recognized that the CMSC payments it was receiving "are shared by all consumers through uplift charges".[151]

Between February and August 2010, Bowater received $12.3 million in net CMSC payments. The Panel has determined that Bowater profited by $11.0 million from the CMSC payments it received and increased Uplift charges by $0.12/MWh.[152]

**Finding #14 (Expense or Disadvantage to the Market):**

*All customers in the wholesale energy market were disadvantaged by paying additional Uplift charges of $0.12/MWh as a result of Bowater's behaviours.*

### 7.7 Conclusion

Bowater is a large and sophisticated market participant. The exploitative behaviours identified above were engaged in with the knowledge of many personnel, including senior management at Bowater and its ultimate parent company, Abitibi Bowater Inc. Bowater repeatedly and deliberately engaged in multiple behaviours to exploit market defects in a manner which triggered substantial CMSC payments for Bowater at the expense of wholesale loads who pay the Uplift charges in the Ontario wholesale electricity market.

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[151] Attachment to an email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], April 20, 2010. Responses to RFI, B.16.59.

[152] Total Market Demand between February to August 2010 was approximately 90 TWh.

The Panel concludes that during the Relevant Period, four of the behaviours giving rise to $11.0 million in CMSC payments to Bowater were intentional and that the behaviours constituted gaming: using bid prices well above the Marginal Benefit of Consumption; submitting bid quantities in excess of consumption levels; the ramp down timing pattern; and ramping faster than submitted ramp rates.

The Panel did not find the infrequent occasions where Bowater failed to ramp or deviated from dispatch in non-ramping hours and received constrained-off CMSC payments to be exploitative. Nevertheless, such CMSC payments were unwarranted and should have been clawed back. In Section 9 the Panel examines the need for further improvements in the *Market Rules* and IESO procedures to prevent unwarranted CMSC payments in the future.

**Finding #15 (Finding of Gaming):**

*Bowater exploited market defects. In so doing, Bowater received $11.0 million in CMSC payments during the Relevant Period, and there was a corresponding disadvantage or expense to the market. Bowater's conduct constitutes gaming.*

## 8. ABITIBI'S CONDUCT IN RESPECT OF THE FORT FRANCES FACILITY

This section contains the Panel's assessment of whether Abitibi engaged in gaming in relation to CMSC payments in respect of the Fort Frances Facility. The introductory sections (Sections 8.1 and 8.2) describe the constrained-off and constrained-on CMSC payments received and Abitibi's typical operating pattern for the Facility, including its bidding strategy and ramping pattern. The subsequent sections (Sections 8.3 to 8.7) assess the four elements of the gaming framework set out in Section 5.5, namely whether there were market defects which were exploited by Abitibi to its profit or benefit and to the expense or disadvantage of the market. The Panel concludes (Section 8.8) that five of Abitibi's behaviours constituted gaming.

### 8.1 CMSC Payments to Abitibi

Between January and August 2010, Abitibi received approximately \$9.7 million in net CMSC payments. The gross constrained-off CMSC payments were approximately \$18.5 million, of which \$10.7 million was clawed back by the IESO. The gross constrained-on CMSC payments were approximately \$3.7 million, of which approximately \$1.8 million was later voluntarily repaid by Abitibi. Table 8-1 summarizes the CMSC payments, clawbacks and repayment applicable to the Relevant Period.

***Table 8-1: Gross and Net CMSC Payments to Abitibi for the Fort Frances Facility January – August 2010 (\$000)***

| Month | Gross Constrained-On CMSC | Gross Constrained-Off CMSC | Clawback of Constrained-Off CMSC | Net CMSC |
|---|---|---|---|---|
| **January** | -23 | 861 | 453 | 385 |
| **February** | - | 2,481 | 2,068 | 413 |
| **March** | -5 | 3,322 | 2,183 | 1,134 |
| **April** | 819 | 1,446 | 408 | 1,857 |
| **May** | 606 | 1,588 | 914 | 1,280 |
| **June** | 1,253 | 2,639 | 1,203 | 2,689 |
| **July** | 656 | 2,976 | 1,988 | 1,644 |
| **August** | 386 | 3,231 | 1,500 | 2,117 |
| **Voluntary Repayment** | -1,825 | – | – | -1,825 |
| **Total** | **\$1,867** | **\$18,544** | **\$10,717** | **\$9,694** |

## 8.2 Typical Operating Pattern

The Fort Frances Facility's energy consumption pattern in 2010 varied on a daily basis. The quantity consumed varied, as did the hours, duration and magnitude of ramps. Abitibi explained its varied operating pattern as the result of ongoing internal changes in the process of making paper which influenced the amount of load required at different times of the day throughout the year.[153] Abitibi further explained that the permanent idling of one paper machine in April 2009 created excess pulp capacity and a "need to schedule several outages for inventory control during a 24-hour period of operation."[154]

On January 22, 2010, Abitibi registered with the IESO to operate as a "net" load or generator under the *Market Rules*.[155] Prior to this date, Abitibi was party to a Power Purchase Agreement (PPA) with the Ontario Electricity Financial Corporation. On January 21, 2010 the PPA expired and Abitibi was free to combine the load and generator. This change had the effect of reducing hourly Uplift and Global Adjustment charges, as those charges were then levied on net rather than gross consumption.[156]

### 8.2.1 Operating as a Net Load or Generator

To operate on an aggregated basis, Abitibi submitted offers and bids based on its expected combined operations. For example, if the generator was expecting to produce ● MW and the load was expecting to consume ● MW, Abitibi could submit economic offers for ● MW of generation and an uneconomic bid (or no bid) for the load. Conversely, if the generator was expecting to produce ● MW and the load was expecting to consume ● MW, Abitibi could submit an uneconomic offer (or no offer) for the generator and economic bids for ● MW of load. The

[153] Responses to RFI, B.9, p.1.
[154] Responses to RFI, B.9, p.1.
[155] IESO, *Market Rules*, Chapter 7, Section 2.3 (Issue 21, December 9, 2009).
[156] Responses to RFI, B.5, p.1.

IESO tools continued to issue separate dispatches for each resource — a zero dispatch for one and the net portion for the other.[157]

### 8.2.2 Bidding Strategy

Abitibi had historically utilized an extremely high bid price for the load at the Fort Frances Facility. Since 2004, it had regularly bid $●/MWh for approximately ● MW of its load capacity, with the remaining consumption bid at $2,000/MWh (making the load non-dispatchable). On January 29, 2010, it changed its regular bid for its net load amount to $●/MWh at all times for nearly all of its bid capacity, with only ● MW of capacity bid at the non-dispatchable price of $2,000/MWh.

For select hours between April 7, 2010 and September 2, 2010, Abitibi adopted an extreme negative bid price strategy by bidding a substantial portion of its net load capacity at -$●/MWh. A negative bid price suggested that Abitibi was only willing to consume if it was paid $●/MWh to do so. At times the Facility would bid with $●/MWh and -$●/MWh laminations. The negative price lamination was bid at a quantity that was no more than 15 MW above the quantity that was bid at $●/MWh. The extreme low bid price had no effect on the amount of CMSC payments to Abitibi during ramping (see Section 8.4). However, it is relevant to the constrained-on CMSC payments received by Abitibi (see Section 8.5).

### 8.2.3 Ramping Pattern

Abitibi stated that the permanent idling of paper machine number 6 required it to ramp frequently throughout the day and, in particular, to ramp down when it experienced high pulp levels but had no capacity to store pulp.[158] On both weekdays and weekends, the Fort Frances Facility would typically ramp multiple times. To implement a ramp down, Abitibi changed its quantity bid for the net load from a higher level to a lower level. The bid price remained at

[157] Settlement statements are still issued for both the generator and the load, but are based on the net output. For those intervals where the aggregated facility operates as a net load, the load is charged for the net consumption. In intervals where the facility operates as a net generator, the generator is paid for the net output.

[158] Responses to RFI, B.9, p.1.

$●/MWh or $●/MWh in the ramp down hour. To implement a ramp up, Abitibi changed its quantity bid from a lower level to a higher level. The bid price remained at $●/MWh or $●/MWh in the ramp up hour.

Prior to combining the load and generator, Abitibi used ramp rates which ramped the dispatchable load at the Fort Frances Facility up or down in three stages, as summarized in Table 8-2. When Abitibi aggregated its load and generator, the net load began using modified ramp rates of ● MW/min at every stage.

***Table 8-2: Ramp Rates for the Dispatchable Load at the Fort Frances Facility January 2009 – August 2010 (MW and MW/min)***

| RAMP DOWN | | | RAMP UP | | |
|---|---|---|---|---|---|
| **MW Range** | **Pre-February 2010** | **February-August 2010** | **MW Range** | **Pre-February 2010** | **February-August 2010** |
| ●[159] to ● | ● MW/min | ● MW/min | ● to ● | ● MW/min | ● MW/min |
| ● to ● | ● MW/min | ● MW/min | ● to ● | ● MW/min | ● MW/min |
| ● to ● | ● MW/min | ● MW/min | ● to ● | ● MW/min | ● MW/min |

Abitibi explained the change to its ramp rates as follows:

> The first lamination of load is rated at ● MW/Min while the remaining load maintains the slower rate of ● MW/Min. It is because the load is now netted with the generation at the delivery point that the first lamination is not seen by the IESO because of the ● MWh of generation subtracted from the ● MWh of gross load. The net effect of this is measured at the point of connection, equal to approximately ● to ● MWh at the applicable ramp rate of ● MW/Min.[160]

In other words, when bidding as a net load, Abitibi was indicating that all the (net) MWs that were available for dispatch had a ramp rate of ● MW/min. It did not explain why the

[159] Abitibi submitted ramp rates for up to ● MW, although it never bid to consume more than ● MW.
[160] Responses to RFI, B.6, p.1.

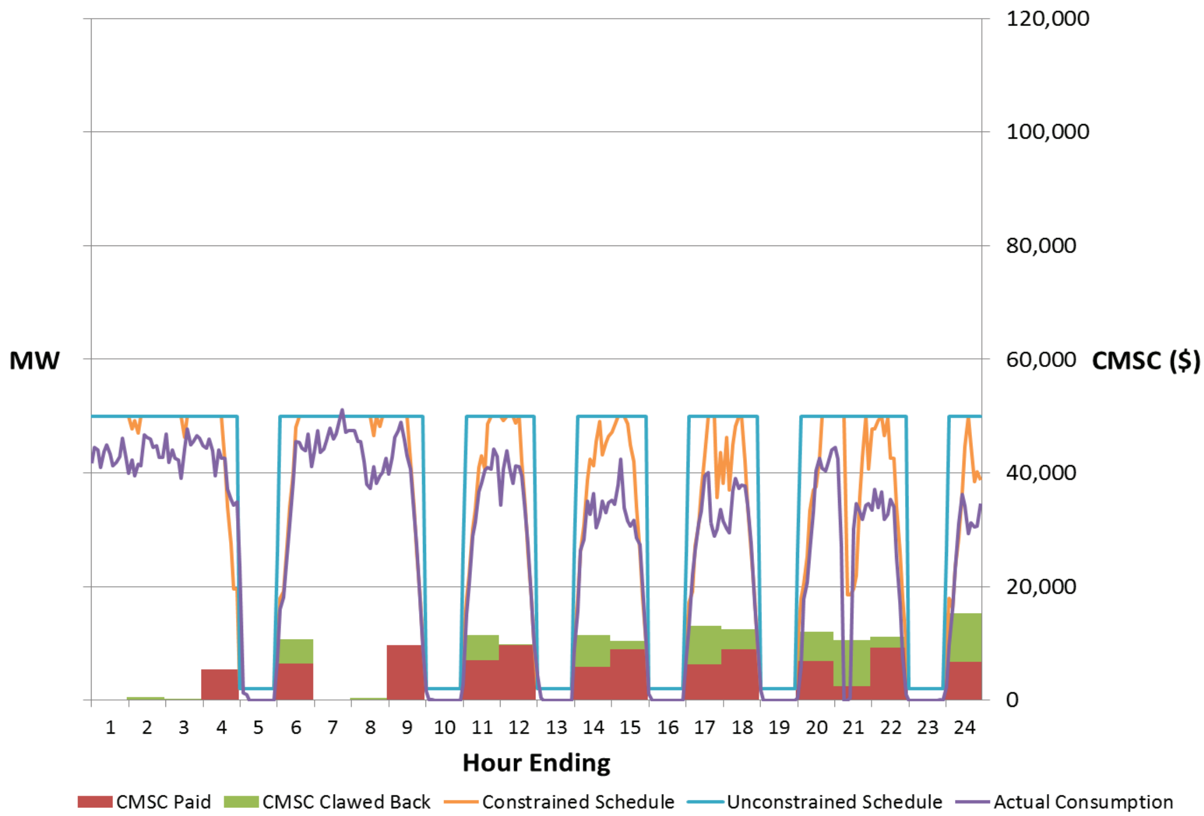
● MW/Min and ● MW/Min rates were lowered. The relationship between Abitibi's ramp rates and the CMSC payments it received is discussed in Sections 8.4.3, 8.4.4, 8.4.5.2 and 8.5.4.

### 8.2.4 Constrained-off CMSC Payments During Ramping

As discussed in Section 6.3.4 and Appendix G, a dispatchable load can initiate ramping through a self-induced dispatch by changing the prices and/or quantities that it bids. The same applies for a net load. Both the market and the constrained schedules will change to allow the facility to ramp to its desired new level of net consumption. The changes to the load's dispatch are caused by the ramping decision manifested in the participant's bid, not by Grid Conditions. Nevertheless, CMSC will be paid if the schedule quantities diverge as a result of a change in the load's price/quantity bids. The resulting payments are self-induced CMSC.

Like Bowater, Abitibi induced changes in its desired energy consumption by changing its quantity bid from one hour to the next hour. This in turn triggered self-induced constrained-off CMSC payments because the quantity in the constrained schedule falls below the market schedule quantity during the ramp period. Although the frequency and magnitude of ramping varied from day to day for the Fort Frances Facility, the bid price and ramp rates were generally consistent. An example of a day where the Fort Frances Facility ramped frequently is Sunday, March 21, 2010, when Abitibi received over $93,000 in constrained-off CMSC payments (net of clawbacks). Abitibi bid the net load at $●/MWh in every ramping hour with the ramp rates of ● MW/min. The ramping of consumption, and the CMSC payments triggered during the ramping periods, are shown in Figure 8-1.

***Figure 8-1: Sample Ramping Pattern and CMSC Payments for the Net Load at the Fort Frances Facility March 21, 2010 (MW and $)***




8.2.4.1 <u>CMSC on Ramp Down</u>

On March 21, 2010 the Fort Frances Facility bid to ramp six times, triggering CMSC payments each time. Each ramp down and each ramp up took six intervals to complete, resulting in five intervals where the constrained schedule differed from the unconstrained schedule and the facility received constrained-off CMSC payments. For example, Abitibi changed its quantity bid for the net load from ● MW in HE 9 to ● MW in HE 10, indicating that it wanted to ramp down. The bid price remained at $●/MWh. To accommodate the change in its consumption bid, the IESO began to dispatch the Fort Frances Facility down beginning in interval 8 of HE 9 using the maximum submitted ramp down rate of ● MW/minute. To calculate CMSC payments, the IESO settlement tool took the difference between (i) the market schedule and (ii) the constrained schedules for each interval during the ramp period, and multiplied each quantity difference by (iii) the $●/MWh bid price less (iv) the MCP for the interval (which was in the $25-30/MWh range). In the result, nearly $10,000 in CMSC payments were triggered by this particular ramp down event.

Table 8-3 shows the total energy charges and CMSC payments to Abitibi for each interval in HE 9 on March 21, 2010 when the Fort Frances Facility was ramping down. The net CMSC payments ($9,744) were substantially larger than the energy charges ($1,244), such that Abitibi was actually receiving $8,500 while consuming the amount of energy it wanted to during its self-induced ramp down.

***Table 8-3: Energy Charges and CMSC Payments Received on a Typical Ramp Down of the Net Load at the Fort Frances Facility***
***March 21, 2010, HE 9***
***(MW, $/MWh and $)***

| Interval | Unconstrained Schedule (MW) | Constrained Schedule (MW) | Actual Consumption (MW) | Energy Charges* ($) | MCP ($/MWh) | Bid Price ($/MWh) | Net CMSC ** ($) |
|---|---|---|---|---|---|---|---|
| 1 | ● | ● | ● | ● | 27.95 | ● | |
| 2 | ● | ● | ● | ● | 25.20 | ● | |
| 3 | ● | ● | ● | ● | 25.91 | ● | |
| 4 | ● | ● | ● | ● | 26.27 | ● | |
| 5 | ● | ● | ● | ● | 26.98 | ● | |
| 6 | ● | ● | ● | ● | 27.43 | ● | |
| 7 | ● | ● | ● | ● | 27.44 | ● | |
| 8 | ● | ● | ● | ● | 27.45 | ● | 657 |
| 9 | ● | ● | ● | ● | 29.45 | ● | 1,313 |
| 10 | ● | ● | ● | ● | 29.45 | ● | 1,868 |
| 11 | ● | ● | ● | ● | 29.89 | ● | 2,625 |
| 12 | ● | ● | ● | ● | 30.49 | ● | 3,281 |
| **Total** | | | | **$1,244** | | | **$9,744** |

* Includes Global Adjustment and Uplift charges.
** None of the Business Rules applied to claw back CMSC on the ramp down.

8.2.4.2 CMSC on Ramp Up

For HE 11, Abitibi changed its quantity bid for the net load from ● MW to ● MW, indicating that it wanted to ramp up back to the consumption level it had been at in HE 8. To accommodate

Abitibi's change in consumption bid, the constrained schedule began to dispatch the Fort Frances Facility up beginning in interval 1 of HE 11 using the submitted ramp up rate of ● MW/minute. Accordingly, it was dispatched from ● MW to ● MW over six intervals. The market schedule moved to ● MW in interval one, using the 3x ramp rate multiplier, before moving to ● MW for the remaining intervals. To calculate CMSC payments, the IESO settlement tool took the difference between (i) the market schedule and (ii) the constrained schedule for each interval during the ramp period, and multiplied each quantity difference by (iii) the $●/MWh bid price less (iv) the MCP for the interval (which was approximately $26/MWh). In the result, over $7,000 in CMSC payments were triggered by this particular ramp up event.

Table 8-4 shows the total energy charges and CMSC payments to Abitibi for every interval in HE 11 on March 21, 2010 when the Fort Frances Facility was ramping up. The net CMSC payments ($7,002) were substantially larger than the energy charges ($1,104), such that Abitibi was actually receiving nearly $5,900 while consuming the amount of energy it wanted to during its self-induced ramp up.

***Table 8-4: Energy Charges and CMSC Payments Received on a Typical Ramp Up of the Net Load at the Fort Frances Facility***
***March 21, 2010, HE 11***
***(MW, $/MWh and $)***

| Interval | Unconstrained Schedule (MW) | Constrained Schedule (MW) | Actual Consumption (MW) | Energy Charges* ($) | MCP ($/MWh) | Bid Price ($/MWh) | Net CMSC *** ($) |
|---|---|---|---|---|---|---|---|
| 1 | ● | ● | ● | ● | 25.55 | ● | 1,316 |
| 2 | ● | ● | ● | ● | 26.62 | ● | 2,630 |
| 3 | ● | ● | ● | ● | 26.62 | ● | 2,285 |
| 4 | ● | ● | ● | ● | 26.62 | ● | |
| 5 | ● | ● | ● | ● | 26.98 | ● | |
| 6 | ● | ● | ● | ● | 26.62 | ● | |
| 7 | ● | ● | ● | ● | 26.98 | ● | |
| 8 | ● | ● | ● | ● | 27.69 | ● | 772 |
| 9 | ● | ● | ● | ● | 26.98 | ● | |
| 10 | ● | ● | ● | ● | 27.34 | ● | |
| 11 | ● | ● | ● | ● | 27.34 | ● | |
| 12 | ● | ● | ● | ● | 25.91 | ● | |
| **Total** | | | | **$1,104** | | | **$7,002** |

*Includes Global Adjustment and Uplift charges.
**CMSC payments of $1,627, $1,348, $740, $575 and $115 in intervals 4, 5, 6, 7 and 9, respectively, were clawed back under Business Rule 3.

### 8.2.5 Constrained-on CMSC Payments with Negative Bid Prices

On numerous occasions beginning on April 7, 2010 and continuing to the end of the Relevant Period, Abitibi submitted a bid price of -$●/MWh for as little as ● MW or as much as ● MW of consumption by the Fort Frances Facility. The negative bids were most frequently submitted between HE 7 and HE 21. While a bid at a negative price indicates a strong desire not to consume (*i.e.* the load is only willing to consume if paid the amount of the negative bid), the Fort Frances Facility in fact was often consuming during such hours.

There were two different scenarios in which the Fort Frances Facility consumed energy during hours for which it submitted negative-price bids:

> <u>Constrained-on Consumption (Scenario #1):</u> When the Nodal Price at the Facility fell below the submitted bid price of -$●/MWh, the (net) load was constrained on.

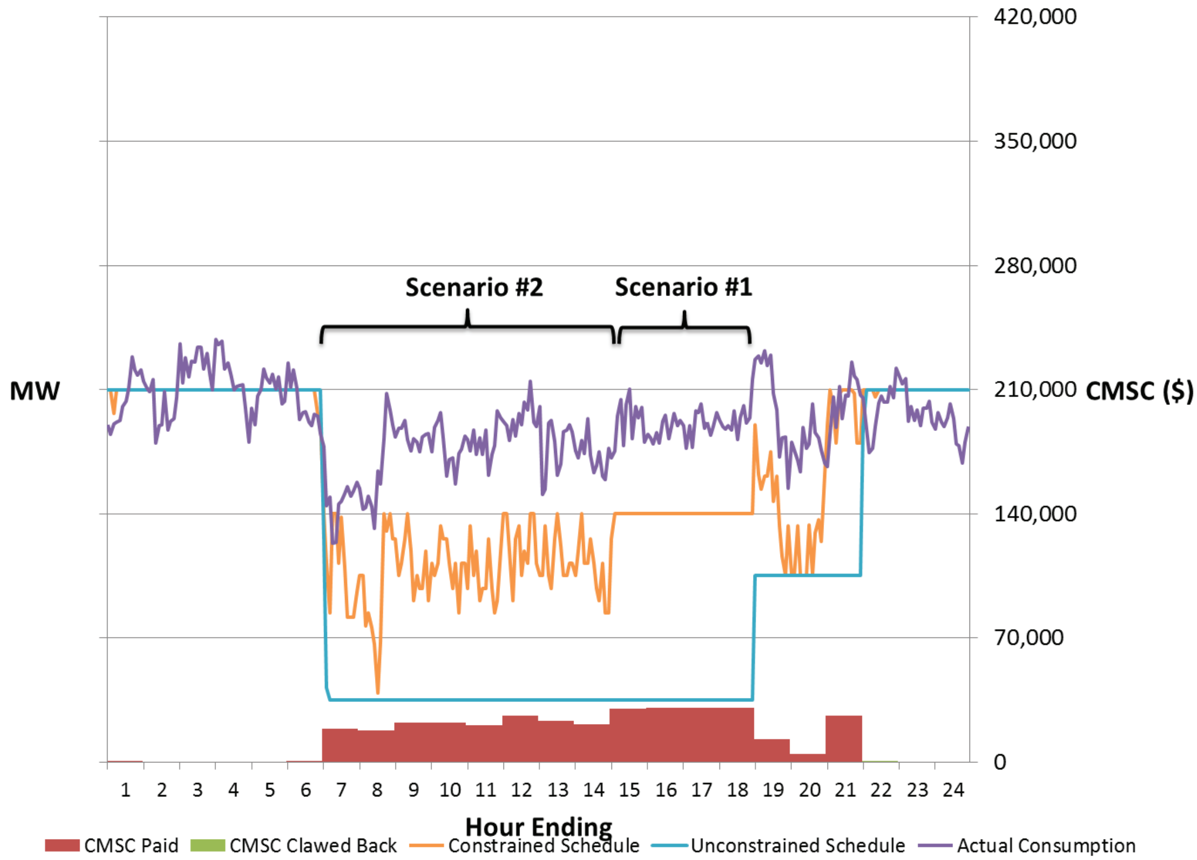
> Consumption Deviation (Scenario #2): When the Nodal Price at the Facility was above the submitted bid price of -$●/MWh and the Facility was scheduled to not be consuming, it deviated from its dispatch schedule with the result that it appeared to be constrained on. As noted above, consuming in such circumstances is inconsistent with a highly negative bid price, which indicates a desire not to consume.

Of the $3.7 million in constrained-on CMSC payments received by Abitibi between April and August 2010, approximately $1.8 million arose when the Fort Frances Facility was constrained on while using a negative bid price (scenario #1) and approximately $1.9 million resulted from a negative bid price combined with deviation from the dispatch schedule (scenario #2).[161]

A representative example involving both scenarios (during different hours) occurred on June 1, 2010. Figure 8-2 shows the unconstrained and constrained schedules as well as the actual consumption and CMSC payments for each hour of the day.

[161] Abitibi voluntarily repaid $1.825 million in CMSC payments that resulted under scenario #2.

***Figure 8-2: Schedules and CMSC Payments During Hours with Negative Bid Prices for the Net Load at the Fort Frances Facility June 1, 2010 (MW and $)***




On this particular day, Abitibi received over $330,000 in constrained-on CMSC payments by using a bid price of -$●/MWh for the hours of HE 7 through HE 18 inclusive. The CMSC payments earned in each of the two scenarios identified above is described in the following sections.

8.2.5.1 <u>CMSC Payments for Constrained-on Consumption (Scenario #1)</u>

In scenario #1, Abitibi received CMSC payments when it was constrained on while using the -$●/MWh bid price (*i.e.* when the bid price of -$●/MWh was greater than the Nodal Price for the Fort Frances Facility but less than the MCP). As shown in Figure 8-2, this scenario resulted in CMSC payments between the hours of HE 15 and HE 18 inclusive. The constrained-on CMSC payment was equal to MCP + $● (refer to the constrained-on CMSC formula in Section 6.3.2). As a result, Abitibi received over $170,000 in CMSC payments during this four-hour period.

8.2.5.2 CMSC Payments for "Constrained-on" Consumption Deviation (Scenario #2)

For June 1, 2010 Abitibi submitted net load bids for the Fort Frances Facility as listed in Table 8-5 below. Beginning in HE 7, it lowered the second lamination quantity and added a third lamination at -$●/MWh. These bids indicate that (i) Abitibi was treating its first ● MW of load as non-dispatchable, (ii) it was only willing to be dispatched below ● MW if the Nodal Price or the MCP rose above $●/MWh, and (iii) it was willing to consume between ● and ● MW only if it was paid $●/MWh to do so.

***Table 8-5: Consumption Bids for the Net Load at the Fort Frances Facility June 1, 2010 (MW and $/MWh)***

| Lamination | HE 1 to HE 6 | | HE 7 to HE 18 | | HE 19 to HE 21 | | HE 22 to HE 24 | |
|---|---|---|---|---|---|---|---|---|
| | Quantity | Price | Quantity | Price | Quantity | Price | Quantity | Price |
| 1 | ● | ● | ● | ● | ● | ● | ● | ● |
| 2 | ● | ● | ● | ● | ● | ● | ● | ● |
| 3 | - | - | ● | ● | ● | ● | - | - |

Just prior to the beginning of HE 7, the Fort Frances Facility was consuming around ● MW and was receiving dispatch instructions to reduce consumption toward the ● MW level that Abitibi had submitted for HE 7. However, the Facility only reduced its consumption to ● MW in HE 7 and HE 8. With the ● MW lamination still in place for HE 9 through HE 18, it actually increased its consumption to around the ● MW range for the next 10 hours.

The constrained schedule is determined, in part, by the actual consumption of the load. For every five-minute interval, the IESO dispatch tool re-calculated the Dispatch Envelope within which it could move the facility, given its submitted ramp rates and starting consumption level. By constantly consuming well above its dispatch schedule, Abitibi raised the dispatch schedule upwards (above and away from the market schedule) and the IESO dispatch tool was unable to dispatch it down to the ● MW quantity bid. However, the market schedule remained at ● MW in response to Abitibi's submitted bid quantity. In other words, Abitibi induced a divergence between the dispatch and market schedules and made it appear that the load was constrained on.

Abitibi received self-induced CMSC payments equal to the MCP less -$● (*i.e.* MCP + $●) for each MW of difference between the constrained and unconstrained schedules during the hours of HE 7 and HE 14 inclusive (refer to the constrained-on CMSC formula in Section 6.3.2). As a result, Abitibi received over $160,000 in CMSC payments by deviating from its dispatch instructions while using this bid strategy on June 1, 2010.

### 8.2.6 Representative Pattern of Operation

While the Fort Frances Facility did not have a standard operating pattern repeated each day, the bid, ramp, consumption and CMSC payments on March 21, 2010 and June 1, 2010 are illustrative of the manner in which CMSC payments arose at the Fort Frances Facility on weekdays and weekends during the Relevant Period. The amount of the CMSC payments on any particular weekday or weekend varied primarily in response to variations in the magnitude and frequency of ramping, actual consumption relative to scheduled consumption (deviation), and the MCPs during the applicable ramp and deviation intervals. A summary of Abitibi's five largest CMSC payment days at the Fort Frances Facility during the Relevant Period is provided in Appendix M.

## 8.3 Defects in *Market Rules* or Procedures

The market defects discussed in Section 7.3 are also relevant to the constrained-off CMSC payments received by Abitibi in respect of the Fort Frances Facility. The Panel therefore reiterates its prior finding, which is applicable to Abitibi as well as Bowater:

**Finding #1 (Market Defects Related to Constrained-Off CMSC):**

*The CMSC rules, formulas and clawback procedures that existed during the Relevant Period allowed a dispatchable load to receive constrained-off CMSC payments that exceeded the amount required to compensate for reductions in operating profits arising from responses to dispatch instructions caused by Grid Conditions.*

An additional defect that is relevant to the CMSC payments made to Abitibi is the lack of IESO procedures for recovering (or "clawing back") self-induced constrained-on CMSC payments. Such payments may provide a dispatchable load with compensation that exceeds the operating profit reductions arising from being dispatched to consume more electricity than it wanted to. Moreover, dispatchable loads may be able to self-induce such payments in situations where the constrained-on dispatch instruction is not the result of Grid Conditions. Although it is not particularly common for a dispatchable load to be constrained on, the absence of any clawback rules presented a gap within the *Market Rules* and the IESO's CMSC procedures that could be exploited.

**Finding #16 (Market Defects Related to Constrained-on CMSC):**

*The CMSC rules, formulas and clawback procedures that existed during the Relevant Period allowed a dispatchable load to receive constrained-on CMSC payments that exceeded the amount required to compensate for reductions in operating profits arising from responses to dispatch instructions caused by Grid Conditions.*

### 8.4 Exploitation of Constrained-Off CMSC

As set out in Section 5.5, an essential element of gaming is that the market participant engages in activity which exploits a market defect. The Panel considers that exploitation may exist where the market participant had some level of intention, knowledge or awareness of an opportunity arising from the market defect. In order to determine whether Abitibi exploited defects in the CMSC regime, the Panel examined the development of its ramping strategy and the following specific behaviours, each of which contributed to the large constrained-off CMSC payments received during ramp periods:

(i) Abitibi submitted an extremely high bid price for ramping hours, which increased the amount of the CMSC payment for any difference between the unconstrained and constrained schedule quantities (see Section 8.4.2).

(ii) On ramp downs, Abitibi often ramped down faster than its submitted ramp rates, which reduced its actual consumption and increased the quantity differences used to calculate CMSC payments (see Section 8.4.3).

(iii) Abitibi ramped the Fort Frances Facility up and down frequently, which increased the number of CMSC payments that were received (Section 8.4.4).

(iv) Abitibi used its generator to respond to self-induced changes in its net load, which triggered CMSC payments for the net load based on submitted bid prices and ramp rates that were not reflective of the generator's marginal costs and ramping capabilities (see Section 8.4.5).

(v) Abitibi occasionally failed to ramp up or down in accordance with its bid and dispatch instructions, which increased the quantity differences that give rise to CMSC payments (see Section 8.4.6).

(vi) Abitibi periodically deviated significantly from its dispatch instructions in non-ramp hours, which triggered CMSC payments that were not always clawed back under the IESO Business Rules (see Section 8.4.7).

### 8.4.1 Development of the Ramping CMSC Strategy

As early as 2007, Abitibi had actively engaged in developing strategies to increase CMSC payments during the ramping of the Fort Frances Facility. For example, [Senior Abitibi Personnel #2], described the implementation of an auto-load shedding program in the groundwood mill for the purpose of "optimizing on the CMSC revenue".[162] At that time the IESO was proceeding with a revision of the ramp rate multiplier from 12x to 3x, a change that would reduce the divergence between the constrained and unconstrained schedules of dispatchable facilities. [Senior Abitibi Personnel #2] was attuned to the CMSC implications of such a change and began "the process of determining a new operating strategy to again optimize on the revenue."[163] Similarly, correspondence between [Senior Abitibi Personnel #2] and operating personnel contained a detailed analysis with supporting spreadsheet calculations which showed, for each interval, the megawatts for the constrained and unconstrained schedules, actual metered energy consumed, and the amount of the CMSC payment that would be received for a particular ramping strategy. [164]

In 2009, Abitibi continued to devise ramping strategies that would trigger CMSC payments as it made changes to its operations. For example, a number of factors, in particular the permanent idling of one paper machine (PM6)[165], were identified as providing opportunities to engage in ramping. In an email with the subject "CMSC training", [Senior Abitibi Personnel #5] referred to CMSC payments being "scheduled" through ramping:

[162] Email from [Senior Abitibi Personnel #2] to [Senior Bowater Personnel #2], September 7, 2007. Responses to RFI, B.16.102.

[163] Email from [Senior Abitibi Personnel #2] to [Senior Bowater Personnel #2], September 7, 2007. Responses to RFI, B.16.102.

[164] Emails between [Senior Abitibi Personnel #2] and [AbitibiBowater Inc Personnel #5], March 14, 2007. Responses to RFI, B.16.82.

[165] Responses to RFI, B.9, p.1.

> From: [Senior Abitibi Personnel #5]
>
> To: [AbitibiBowater Inc Personnel #2], [AbitibiBowater Inc Personnel #3], [AbitibiBowater Inc Personnel #1]
>
> Cc: [Senior Abitibi Personnel #2]
>
> Date: April 17, 2009 03:28 PM
>
> Subject: CMSC training
>
> With PM6 down we will have more inventory than usual, therefore we will be able to use this opportunity to do clean up or maintenance in the department. I would like to train you gents how to schedule CMSC's (ramping). If we take the floor down to do maintenance or cleaning we should always try to "ramp" it down and up again.[166]

Similarly, an internal request regarding what "the financial difference to our mill would be if we were to only have 12 grinders vs 14 grinders available for ramping in 2010?"[167] resulted in the following response:

> From: [Senior Abitibi Personnel #2]
>
> To: [Senior Bowater Personnel #6]
>
> Cc: [Senior Abitibi Personnel #6], [Senior Abitibi Personnel #5]
>
> Date: December 17, 2009 03:16 PM
>
> Subject: Re: Groundwood ramping
>
> [Senior Bowater Personnel #6],
>
> A successful ramp of ● mw (● stones) = $20,000 in cmsc payment
>
> If you are not running #5 grinder line, this would reduce the ramp to ● mw (● stones) = $17,000 in cmsc payment

[166] Responses to RFI, B.9.1.

[167] Email from [Senior Bowater Personnel #6] to [Senior Abitibi Personnel #2], December 17, 2009. Responses to RFI, B.9.4.

> Loss of cmsc per ramp = $3,000
>
> In August we ramped 60 times
>
> But, you should also consider the loss of storage capacity and lost opportunities to ramp because of this. Maybe [Senior Abitibi Personnel #5] has better tools to calculate this.[168]

In 2010 Abitibi continued to analyze CMSC payments arising from plant operating decisions as a source of profit on a per ramp, per machine basis:

> When tank levels allow, we have been manually ramping ● mw of grwd [groundwood], approx $5500 a ramp…. With #6 grinder line back on we should be able to ramp ● mw of load, approx $7500 a ramp… The generator continues to be dispatched on in the morning and at night. I am going to run an analysis to compare with the start up and shutdown of the thunder bay ● mw load… Today the drawbacks are starting to come through, so I will see how much money is left on the table in all this.[169]

Personnel at the Fort Frances Facility were also aware that they needed:

> … to be careful when scheduling the ramps, from a compliance perspective. If there are not legitimate reasons to schedule an outage, this is considered gaming by IESO. They have the right to remove us from the market and have us pay back the CMSC we generated. All ramps needs to be justified and should not be scheduled at the same time every day.[170]

As discussed in Section 7.4, Abitibi personnel (particularly [Senior Abitibi Personnel #2]) were also instrumental in advising Bowater's Thunder Bay Facility on its ramping strategy. This advice drew upon extensive experience and in-depth knowledge of the relationship between ramping and CMSC at the Fort Frances Facility. It is clear from the foregoing examples and other documents provided during the Investigation that Abitibi actively engaged in strategies to increase its CMSC payments during ramping.

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[168] Responses to RFI, B.9.4.

[169] Email from [Senior Abitibi Personnel #2] to [Senior Abitibi Personnel #3], February 12, 2010. Responses to RFI, B.5.1.

[170] Email from [Senior Abitibi Personnel #2] to [Senior Abitibi Personnel #1], April 23, 2009. Responses to RFI, B.9.2.

**Finding #17 (CMSC Ramping Strategy):**

*Abitibi developed strategies to self-induce CMSC payments at the Fort Frances Facility, and these were known to senior management.*

The main behaviours which triggered large constrained-off CMSC payments for Abitibi are analysed in the sections below.

### 8.4.2 Expanding the Magnitude of CMSC Using a High Bid Price

This section examines Abitibi's knowledge of the operating profit principles underlying the CMSC regime (Section 8.4.2.1) and the relationship between its Marginal Benefit of Consumption and bid prices (Sections 8.4.2.2 to 8.4.2.4). The Panel has also analysed the three explanations for high bid prices that were provided by Abitibi:[171]

- Bidding at a very high price reduced the risk of the facility being dispatched down (which can occur if the Nodal Price is above the bid price) (see Section 8.4.2.5).

- Bidding at a very high price reduced the risk of being activated to provide OR (while still being able to obtain revenue from participating in the OR market) (see Section 8.4.2.6).

- The Fort Frances Facility as well as the dispatchable load owned by Abitibi-Consolidated at Fort William had bid at a similarly high price for a number of years (see Section 8.4.2.7).

8.4.2.1 Abitibi Understood the Operating Profit Principles in the CMSC Regime

Abitibi and affiliated company personnel understood that the CMSC regime was designed to compensate for reductions in operating profits based on an assumption that a dispatchable load's

[171] Responses to RFI, B.3, p.2 and B.13 pages 1 and 2.

bids would reflect the Marginal Benefit of Consumption. As outlined in Section 7.4.2.1, personnel at the Fort Frances Facility and the Thunder Bay Facility communicated regularly on the development of CMSC ramping strategies, including bid prices. [Senior Abitibi Personnel #2] acted as an advisor to Bowater on an ongoing basis. [Senior Abitibi Personnel #2] was involved in communications with personnel at the Thunder Bay Facility on the relationship between bidding strategies and CMSC, the ability to anticipate dispatch instructions,[172] whether opportunity costs were covered in IESO training materials and other matters.[173] Moreover, a presentation to executives at Abitibi's parent company, ABI, expressly stated that "[t]he market rules assume that participants place bids and offers based on their marginal cost and benefit."[174] It is clear that Abitibi understood that the CMSC regime assumed bids by dispatchable loads would reflect their Marginal Benefit of Consumption.

**Finding #18 (Knowledge of CMSC Compensation Principles):**

*Abitibi was aware that the CMSC regime assumed that dispatchable loads would bid based on their Marginal Benefit of Consumption and that CMSC payments were designed to compensate a dispatchable load for operating profit reductions when it was directed by the IESO to follow a dispatch different from its market schedule.*

8.4.2.2 Bid Prices Exceeded Marginal Benefit of Consumption

In 2009, the Fort Frances Facility permanently idled one of its paper machines (PM6), after which the Facility was no longer pulp-limited in terms of groundwood. Abitibi stated that the energy efficiency of the groundwood equipment was maximized by running as fast as possible, filling up the storage tank and taking short outages. Having to take additional downtime in the

[172] Email from [Senior Bowater Personnel #5] to [Senior Abitibi Personnel #2], February 16, 2010. Responses to RFI, B.2.16.

[173] Email from [Senior Bowater Personnel #3] to [Senior Abitibi Personnel #2], [Senior Bowater Personnel #5] and [Senior Abitibi Personnel #4], June 28, 2010. Responses to RFI, B.13.32. (The IESO training materials in relation to OR activation are discussed in Sections 7.4.2.7 and 8.4.2.5.)

[174] Responses to RFI, B.3.6. See the second slide reproduced at Appendix J.

groundwood mill will result in a loss of paper production and an increase in manufacturing costs.[175] In its Responses to RFI, Abitibi calculated that the financial impact of the Fort Frances Facility being constrained off was $●/MWh in 2010 based on one hour of lost paper production. However, unlike Bowater, it did not lower its bid prices to this level after the June 2010 communications with the MAU.

Abitibi also indicated that its calculations included fixed costs.[176] Fixed costs normally do not change in response to short term transitory changes in electricity consumption. Including fixed costs in the Marginal Benefit of Consumption could result in cases where a positive operating profit that could have contributed to offsetting fixed costs is foregone. Accordingly, they should not be included in calculating the Marginal Benefit of Consumption. Thus the Abitibi calculations referenced above overstate the actual Marginal Benefit of Consumption. Since, as in the case with Bowater, the amount of the overstatement is not readily determinable, the Panel has used Abitibi's own calculations as a conservative basis for analyzing whether Abitibi was bidding at prices which exceeded its Marginal Benefit of Consumption.

In summary, based on Abitibi's own calculation, the financial impact of one hour of lost production was no more than $●/MWh in 2010. Thus its bid prices for the net load of $●/MWh or $●/MWh were well above the Marginal Benefit of Consumption.

8.4.2.3 Marginal Benefit of Consumption is Lower in Self-Induced Ramping Hours

As discussed in Section 7.4.2.2 with respect to Bowater, a Marginal Benefit of Consumption calculated on a full hour of lost production overstates the financial impact of being dispatched down during any ramp hour where the facility is only exposed to a fraction of an hour of lost pulp and paper production.

Abitibi did not demonstrate that the effect of being constrained off while ramping would be permanently lost mill production, rather than a deferral of production that could be made up later in the day or week. Given the variations in energy consumption on a daily basis, the Fort

[175] Responses to RFI, B.8, p.1.
[176] Responses to RFI, B.8. p.1.

Frances Facility generally does not appear to have been operating at capacity on a continuing basis. Thus any reduced consumption that would arise if constrained off during ramping could potentially have been recouped soon afterwards.

Even if there would have been lost production as a result of being constrained off, a calculation based on an hour of lost production overstates the actual financial impact because the Fort Frances Facility does not operate at full production while ramping up or down. For example, during ramp downs, when Abitibi self-induced a ramp of ● MW with a ramp rate of ● MW/min, the Fort Frances Facility was already expecting to reduce consumption of electricity and mill production in the last six intervals of the hour. Similarly, the Facility was not expecting to operate at full electricity consumption or mill production during the first six intervals of a ramp up hour.

Unlike Bowater, Abitibi did not provide data on the portion of ramping hours in which mill production is occurring. However, the ratio between electricity consumption during a ramping hour and a full production hour is likely a good and slightly conservative proxy for the level of mill production during a ramping hour.[177] As noted in Section 8.2, the Fort Frances Facility's energy consumption pattern in 2010 varied on a daily basis and therefore the ratio between electricity consumption during a ramping hour and a full hour of production would vary with each ramp. To estimate this ratio, the Panel considered a commonly used ramp profile by Abitibi, ramping between ● MW to ● MW of net load at the ramp rates in Table 8-2. Abitibi used this ramp profile on 376 of its 986 self-induced ramps. During both a ramp up and a ramp down, electricity consumption during the ramp hour is 80% of consumption during a full hour of consumption at ●MW. Accordingly, even if there would be permanently lost production as the result of being constrained off for an entire ramp hour, based on Abitibi's own estimates above the operating profit reduction would be no more than $●/MWh ($●*80%).

[177] As noted in Section 7.4.2.4, electricity consumption in a normal ramp down hour at the Thunder Bay Facility was 73% of a regular operating hour, which is slightly higher than Bowater's data that in 65% of a ramp down hour TMP pulp is still being produced. Similarly, the electricity consumption in a normal ramp up hour was 76% of a regular operating hour, which is higher than Bowater's data that in 75% of a ramp up hour TMP pulp is still being produced.

8.4.2.4 Abitibi's Bid Prices Increased CMSC Payments

An approximate estimate of the amount by which Abitibi's bid prices generated CMSC payments in excess of operating profit reductions is set out in Table 8-6. This estimate is based on the conservative assumptions that: (i) there were permanent losses of mill production resulting from being constrained off (as opposed to deferred production that could be recouped on subsequent hours or days when the facility was not operating at capacity); (ii) the Marginal Benefit of Consumption is based on the conservative (maximum) estimates outlined above, which ignore potential overstatements related to fixed costs; and (iii) all the quantity differences between the constrained and the greater of the unconstrained schedule and actual consumption reflected Abitibi responding to IESO dispatch instructions caused by Grid Conditions (which, as noted in Sections 8.4.3 – 8.4.7, was not, in fact, the case). The total CMSC impact of Abitibi's high bid prices is estimated at $5.9 million.

***Table 8-6: Estimated Impact of Abitibi's High Bid Prices on CMSC Payments for the Fort Frances Facility***
***January – August 2010***
***($/MWh, MWh and $000)***

| | **Ramp Up and Down** | |
|---|---|---|
| **Bid Price ($/MWh)** | ● | ● |
| **Estimated Marginal Benefit of Consumption ($/MWh)** | ● | ● |
| **Difference ($/MWh)** | 1,418 | 1,369 |
| **Constrained-off Quantity (MWh)*** | 3,924 | 229 |
| **Total CMSC Impact ($000)** | 5,564 | 314 |

*For intervals where Abitibi received a net CMSC payment.

**Finding #19 (Operating Profit Impact of Being Constrained Off):**

*(a) During periods when Abitibi was not operating the Fort Frances Facility at capacity, there would be virtually no reduction in operating profits as a result of being constrained off during a ramping hour because production could be made up in a subsequent hour.*

*(b) Even in situations where the Fort Frances Facility was capacity constrained, Abitibi's bid prices during the Relevant Period substantially exceeded its Marginal Benefit of Consumption and the reduction in operating profits that would result from the net load at the Fort Frances Facility being constrained off during ramping hours.*

*(c) Based on data provided by Abitibi and the Facility's electricity consumption pattern, the difference between Abitibi's bid price of $●/MWh (or $●/MWh) and its Marginal Benefit of Consumption when ramping (up or down) was at least $1,418/MWh (or $1,369/MWh).*

*(d) Abitibi's high bid prices were used to obtain CMSC payments that more than compensated Abitibi for operating profit reductions by at least $5.9 million.*

8.4.2.5 The Risk of Being Constrained Off Did Not Justify Abitibi's Bid Prices

The Panel has analyzed Bowater's claim that a high bid price was necessary to prevent being constrained off during ramping in Section 7.4.2.6. The analysis in respect of Abitibi is similar.

For the reasons discussed in Section 7.4.2.6, in a situation where Abitibi was constrained off during a ramp, it would receive a CMSC payment. This would offset any negative effect on

Abitibi's operating profits (unless it was using a bid price lower than its Marginal Benefit of Consumption, which was not the case at any time during the Relevant Period).[178]

As also noted in Section 7.4.2.6, if Abitibi was genuinely concerned about the risk of being dispatched down, it could have bid $2,000/MWh to render the facility non-dispatchable during a ramp down or ramp up hour. By bidding an extra $●/MWh (or $●/MWh, when using a $●/MWh bid), it could readily have eliminated such a risk but would have not been eligible for CMSC payments. The fact that it chose not to do so is further confirmation that Abitibi's assertion that its very high bid prices were necessary to avoid the risk of being constrained off is not credible.

Abitibi's assertion that there was a material risk of being constrained off while ramping is also not credible. The Panel conducted an analysis of Nodal Prices at the Fort Frances Facility during the Relevant Period and during the immediately preceding year (*i.e.* between January and December 2009). The analysis considered Abitibi's actual bid prices of $●/MWh or $●/MWh, as well as an alternative bid price that reflected Abitibi's calculation of a $●/MWh Marginal Benefit of Consumption (see Section 8.4.2.2) and a further alternative bid price that reflected the Panel's estimate of Abitibi's Marginal Benefit of Consumption during a ramping hour ($●/MWh) (see Section 8.4.2.3). During the 20-month period in question, there were 22,161 five-minute intervals during self-induced ramp hours (10,329 intervals in 2009 and 11,832 in 2010). The results are shown in Table 8-7.

[178] In fact, for the reasons discussed in Section 8.4.2.3 the $●/MWh amount exceeded Abitibi's Marginal Benefit of Consumption during ramping hours.

***Table 8-7: Likelihood of the Fort Frances Facility Being Constrained-Off at Various Bid Prices During Self-Induced Ramping Hours January 1, 2009 to August 28, 2010 ($/MWh, number and % of intervals)***

| Period | Bid Price ($/MWh) | Number of Intervals Economically Constrained Off | | | Percent of Intervals Economically Constrained Off |
|---|---|---|---|---|---|
| | | Ramp Down | Ramp Up | Total | |
| January to December 2009 | ● | 17 | 2 | 19 | 0.184% |
| | ● | 30 | 11 | 41 | 0.397% |
| | ● | 36 | 12 | 48 | 0.465% |
| | ● | 46 | 13 | 59 | 0.571% |
| | | Ramp Down | Ramp Up | Total | |
| January to August 2010 | ● | 9 | 2 | 11 | 0.093% |
| | ● | 14 | 6 | 20 | 0.169% |
| | ● | 14 | 6 | 20 | 0.169% |
| | ● | 28 | 16 | 44 | 0.372% |

This analysis confirms that a high bid price of $●/MWh or $●/MWh was almost never necessary to prevent the Fort Frances Facility from being dispatched down when ramping. Based on the outcomes in 2009, which would have been the most recent information available to Abitibi, the probability of being constrained off was remote. Moreover, the results throughout the Relevant Period confirm that the probability was remote. Even if Abitibi had bid at a significantly lower price reflecting its own estimated Marginal Benefit of Consumption, the likelihood of being constrained off during a ramping hour would have been remote (and any negative impact on Abitibi's operating profits would have been compensated by a CMSC payment).

**Finding #20 (Risk of Being Constrained Off):**

*The risk of being constrained off during self-induced ramping hours did not justify Abitibi's use of a bid price of $●/MWh or $●/MWh, or any other level above the Marginal Benefit of Consumption of the Fort Frances Facility.*

8.4.2.6 The Risk of Operating Reserve Activations Did Not Justify Abitibi's Bid Prices

As a dispatchable load, Abitibi is eligible to participate in the IESO's OR market. For most of the Relevant Period (from January to July 2010), Abitibi did not offer OR for its dispatchable net load. Accordingly, it is not credible for Abitibi to claim that it was necessary to bid at a high price to avoid OR activation during those months.

Starting in August 2010 Abitibi began offering between ● MW and ● MW of OR from the Fort Frances Facility. For the same reasons as noted in Section 7.4.2.7, the Panel rejects Abitibi's claim that it was necessary to bid at a high price to avoid OR activation:

- Contrary to Abitibi's claim, IESO training materials did not require or instruct dispatchable loads to bid at high prices to avoid OR activation.
- If a dispatchable load is activated for OR (during a ramping hour or otherwise), it would be compensated for its reduced energy consumption based on its bid price. Thus, as long as Abitibi's bid price was not lower than its Marginal Benefit of Consumption (which was never the case during the Relevant Period), there would be no reduction of operating profit as a result of an OR activation during a self-induced ramping hour.
- Abitibi could have eliminated any OR activation risk entirely by either: (i) not bidding into the OR market during self-induced ramping hours, or (ii) using a $2,000/MWh (non-dispatchable) energy bid price (which would preclude being activated to provide OR).

- The actual risk of an OR activation in the Northwest region during a self-induced ramping hour was remote.

To confirm the level of activation risk, the Panel examined the frequency of all OR activations in the Northwest region during the hours in which the Fort Frances Facility was ramping up or down. There were no OR activations in the Northwest region during the Fort Frances Facility's self-induced ramping hours in August 2010 (or indeed in any self-induced ramping hour during Relevant Period). The frequency of all OR activations during the hours in which the Fort Frances Facility was ramping up or down in 2009 was also examined. There were no activations in the Northwest during the self-induced ramping hours of the Fort Frances Facility in 2009.[179] As noted above, an internal document prepared for ABI management referred to the historical experience at the Fort Frances Facility as "twice in 4 years".[180] This confirms that Abitibi knew that the OR activation risk at the Fort Frances Facility was minimal, and its claim to the contrary is not credible.

**Finding #21 (Risk of Being Activated for Operating Reserve):**

*The risk of being activated to provide operating reserve during self-induced ramping hours did not justify Abitibi's use of an energy market bid price of $●/MWh or $●/MWh, or any other level above the Marginal Benefit of Consumption of the Fort Frances Facility.*

8.4.2.7 <u>Historical Use of High Bid Prices by Abitibi or Affiliates Did Not Justify Abitibi's Bid Prices</u>

Abitibi's argument that $●/MWh or higher bid prices have been its past practice and has also been used by another dispatchable load is not a justification for possible gaming behaviour for at

[179] The Fort Frances Facility was activated for OR on 3 occasions during non-ramping hours in 2009 and none during the Relevant Period.

[180] See "Thunder Bay 2010 Power Cost – October 1st, 2009" (reproduced in Appendix J). Responses to RFI, B.3.6, p. 3.

least three reasons. First, the fact that Abitibi or other participants engaged in conduct in the past that may or may not have exploited a market defect does not have any bearing on whether Abitibi was exploiting a market defect during the Relevant Period. Abitibi reviewed the MSP's *Monitoring Report on the IESO-Administered Electricity Markets for the period from November 2009 – April 2010* that reported on high CMSC payments to dispatchable loads. A communication to ABI noted: "It is interesting in the write up below that there is very little mention of ramping and bidding at Fort Frances. I believe this is because the process at FF is 5-6 years old, well established and condoned by the IESO."[181] The Panel does not agree that the lack of IESO action or a prior investigation by the MSP in any way condones behaviour that may constitute gaming. Second, it is possible that other market participants could have a Marginal Benefit of Consumption equal to or greater than this level, whereas Abitibi does not (see Sections 8.4.2.2 and 8.4.2.3). Third, it is possible that high bid prices may be used by dispatchable loads that ramp quickly and therefore trigger negligible CMSC payments.

**Finding #22 (High Bid Prices by Other Loads):**

*The historical use of high bid prices by Abitibi or any other dispatchable loads does not provide a justification for Abitibi's high bid prices during self-induced ramping hours.*

### 8.4.3 Ramping Faster than Submitted Ramp Rates

As discussed in Section 7.4.5, a pattern of ramping faster than submitted ramp rates has the effect of creating greater divergence between the quantities (constrained schedule or actual consumption, and the unconstrained schedule) used to calculate CMSC payments. It also indicates that the submitted ramp rates understate the actual ramping capability of the facility, which results in a longer ramping period and higher CMSC payments. As noted in Section 7.4.5, [Senior Abitibi Personnel #2] was well aware that ramping faster than submitted ramp rates

[181] Email from [Senior Bowater Personnel #3] to [AbitibiBowater Inc Executive #3], August 31, 2010. Responses to RFI, B.13.107.

increased in CMSC payments, and [Senior Abitibi Personnel #2] advised Bowater on these issues.[182]

Abitibi stated that it was forced to ramp down faster than its submitted ramp rates when the Fort Frances Facility was exposed to “uncontrolled upsets” or “environmental and safety” issues.[183] However, the Panel’s analysis indicates that the Fort Frances Facility ramped down faster than its submitted ramp rates in one or more intervals in 68% (356 of 524) of its ramp downs during the Relevant Period. This indicates that the net load was being ramped faster than its submitted ramp rates more frequently than just in response to unexpected operating conditions.

An example of one of the 356 ramp downs where the Fort Frances Facility ramped faster than submitted ramp rates is March 5, 2010 in HE 3. Abitibi bid $●/MWh in the hour and submitted the ramp rates in Table 8-2. The ramping of consumption, and the CMSC payments triggered during the ramping intervals, are shown in Table 8-8. The CMSC payments obtained during the ramp down ($9,078) exceeded the CMSC payments that would have been received had the Fort Frances Facility ramped from one dispatch instruction to the next at its submitted ramp rate ($8,241). The Facility ramped faster than its submitted ramp rate in interval 9, moving from ● MW to ● MW in a five-minute period. According to Abitibi’s submitted ramp rate, the Facility was only capable of reaching ● MW, and not ● MW, from a starting point of ● MW.[184] The actual ramp rates in intervals 10 and 11 were as submitted, but the faster ramping in interval 9 resulted in further quantity differences between the actual CMSC payment and the payment that would otherwise have been triggered intervals 10 and 11. Although the MW difference resulting from faster ramping may appear to be small, each constrained-off MW was being paid the difference between Abitibi’s bid price of $●/MWh and the MCP (which was less than $25/MWh during these intervals).

[182] See the correspondence between [Senior Abitibi Personnel #2] and [Senior Bowater Personnel #5] between February 8-16, 2010, reproduced above. Responses to RFI, B.2.14-B.2.16.

[183] Responses to RFI, B.6, p.1.

[184] Abitibi’s actual ramp rate in interval 9 of ●MW/minute was 40% faster than its submitted ramp rate of ● MW/minute.

***Table 8-8: CMSC Payments on a Fast Ramp Down of the Fort Frances Facility March 5, 2010, HE 3 (MW, $/MWh and $)***

| Interval | Unconstrained Schedule (MW) | Constrained Schedule (MW) | Actual Consumption (MW) | MCP ($/MWh) | Net CMSC ($) | Expected Consumption (MW) | Expected Net CMSC ($) |
|---|---|---|---|---|---|---|---|
| 1 | ● | ● | ● | 25.87 | | ● | |
| 2 | ● | ● | ● | 24.76 | | ● | |
| 3 | ● | ● | ● | 13.72 | | ● | |
| 4 | ● | ● | ● | 24.51 | | ● | |
| 5 | ● | ● | ● | 24.38 | | ● | |
| 6 | ● | ● | ● | 24.38 | | ● | |
| 7 | ● | ● | ● | 13.72 | | ● | |
| 8 | ● | ● | ● | 23.64 | 386 | ● | 329 |
| 9 | ● | ● | ● | 24.10 | 1,317 | ● | 987 |
| 10 | ● | ● | ● | 23.76 | 1,975 | ● | 1,646 |
| 11 | ● | ● | ● | 13.72 | 2,492 | ● | 2,316 |
| 12 | ● | ● | ● | 24.10 | 2,908 | ● | 2,962 |
| **Total** | | | | | **$9,078** | | **$8,241** |

The Panel has not estimated the aggregate incremental impact of Abitibi's faster ramp down on CMSC payments. This calculation is partially subsumed in the estimate set out in Section 8.4.2.4 because the estimate in that section is based on the difference between the unconstrained and the greater of the constrained schedule and the actual quantity consumed, and therefore accounts for any constrained-off megawatts from fast ramping. The estimate in Section 8.4.2.4, however, only accounts for the incremental CMSC payments for fast ramping constrained-off megawatts based on the difference between Abitibi's actual bid prices and its estimated Marginal Benefit of Consumption. Fast ramping constrained-off megawatts are entirely self-induced and should not be compensated for at any bid price. The estimate in Section 8.4.2.4 therefore underestimates the impact of fast ramping on constrained-off CMSC payments by the number of fast ramping constrained-off megawatts multiplied by the difference between Abitibi's estimated Marginal Benefit of Consumption and the MCP. While the Panel has not undertaken an interval by interval estimation of the incremental impact of Abitibi's fast ramping beyond what is already accounted for in the estimate set out in Section 8.4.2.4, the Panel is nevertheless satisfied that the vast majority of CMSC payments associated with Abitibi's fast ramping is subsumed in Section 8.4.2.4.

**Finding #23 (Ramping Down Faster than Submitted Rates):**

a) *Abitibi's Fort Frances Facility was able to, and frequently did, ramp down the net load faster than its submitted ramp rates, indicating that its ramp rates were lower than its operational capabilities.*

b) *The submission of ramp rates that were lower than the Fort Frances Facility's operational capabilities increased the magnitude of constrained-off CMSC payments to Abitibi.*

c) *The ramping down of the Fort Frances Facility faster than the submitted ramp rates increased the magnitude of constrained-off CMSC payments to Abitibi.*

### 8.4.4 Frequent Ramping

During the CCAA restructuring of the Abitibi Bowater entities in 2009, the Fort Frances Facility shut down paper machine number 6. As a result, the Facility had excess pulp but limited capacity to store it. Abitibi stated that this required it to ramp frequently throughout the day and, in particular, to ramp down when it experienced high pulp levels with insufficient further storage capacity. Documents provided to the Panel during the Investigation indicate that the ramping strategy was closely connected to the impact on CMSC payments. For example, operating personnel at the Fort Frances Facility were given "CMSC training" related to the facility's inventory conditions and "how to schedule CMSC's (ramping)". [185]

[185] Email from [Senior Abitibi Personnel #5] to [AbitibiBowater Inc Personnel #2], [AbitibiBowater Inc Personnel #3] and [AbitibiBowater Inc Personnel #1], April 17, 2009. Responses to RFI, B.9.1.

A detailed analysis of ramping options and CMSC implications occurred in preparation for combining the load and generator in late 2009:

> From: [Senior Bowater Personnel #6]
>
> To: [Senior Abitibi Personnel #2]
>
> Cc: [Senior Abitibi Personnel #6], [Senior Abitibi Personnel #5]
>
> Date: December 17, 2009 11:34 AM
>
> Subject: Groundwood ramping
>
> [Senior Abitibi Personnel #2]
>
> can you please tell me what the financial difference to our mill would be if we were to only have 12 grinders vs 14 grinders available for ramping in 2010?
>
> We have a problem with one of our grinders and do not know whether it will require a rewind and we will have FF6 down in 2010 so the demand for groundwood will be lower – this <u>information on the lost financial opportunity by having 1 less grinder motor to ramp</u> will help us make the right business decision.[186] (emphasis added)

[186] Responses to RFI, B.9.4.

[Senior Abitibi Personnel #2] responded with the financial implications as follows:

> From: [Senior Abitibi Personnel #2]
>
> To: [Senior Bowater Personnel #6]
>
> Cc: [Senior Abitibi Personnel #6], [Senior Abitibi Personnel #5]
>
> Date: December 17, 2009 03:16 PM
>
> Subject: Re: Groundwood ramping
>
> [Senior Bowater Personnel #6],
>
> A successful ramp of ● mw (● stones) = $20,000 in cmsc payment
>
> If you are not running #5 grinder line, this would reduce the ramp to ● mw (● stones) = $17,000 in cmsc payment
>
> Loss of cmsc per ramp = $3,000
>
> In August we ramped 60 times
>
> But, you should also consider the loss of storage capacity and lost opportunities to ramp because of this. Maybe [Senior Abitibi Personnel #5] has better tools to calculate this.[187]

[187] Responses to RFI, B.9.4.

In a subsequent portion of the email chain, [Senior Abitibi Personnel #2] concluded as follows:

> From: [Senior Abitibi Personnel #2]
>
> To: [Senior Abitibi Personnel #6]
>
> Cc: [Senior Bowater Personnel #6], [Senior Abitibi Personnel #5]
>
> Date: December 17, 2009 3:59 PM
>
> Subject: Re: Groundwood ramping
>
> Once the PPA is terminated (jan 20), we will be combining the load and generation delivery points in order to net out the monthly/hourly uplifts. Approx savings of $1.5M/month.
>
> This will require a new operating strategy until the grid valve replacement is done on cogen in June.
>
> The strategy for the ramps is still being determined at this point, but it is likely they will be done more frequently and only shedding ● mw instead of ● mw.
>
> By not having #5 grinder line running we would be limiting ourselves on the number of ramps.
>
> We should meet in the new year to discuss.[188] (emphasis added)

It is clear from this and other emails that Abitibi viewed CMSC payments as a financial flow that could be managed and forecasted. This is inconsistent with the design of the CMSC regime, which is to provide market participants with compensation for unexpected reductions in operating profits caused by unpredictable Grid Conditions.

In addition to understanding the impact of frequent ramping on CMSC payments, Abitibi personnel were aware that the frequent ramping strategy could constitute gaming. For example, six days after the "CMSC training" email (reproduced in Section 8.4.1) was sent, [Senior Abitibi

[188] Responses to RFI, B.9.4.

Personnel #2] warned colleagues (including [Senior Abitibi Personnel #3] at the time as well as a member of Abitibi Bowater Inc.'s management) as follows:

> From: [Senior Abitibi Personnel #2]
>
> To: [Senior Abitibi Personnel #1]
>
> Cc: [Senior Abitibi Personnel #3], [Senior Abitibi Personnel #5], [Senior Abitibi Personnel #6], [Senior AbitibiBowater Inc Personnel #2]
>
> Date: April 23, 2009 03:42 PM
>
> Subject: Re: Groundwood meeting
>
> Hello [Senior Abitibi Personnel #1],
>
> [Senior Abitibi Personnel #5] just stopped by to review what was discussed at your mtg this afternoon. (I did not receive an invitation, otherwise I would have been there)
>
> I just want to make sure everyone is aware that we need to be careful when scheduling the ramps, from a compliance perspective. If there are not legitimate reasons to schedule an outage, this is considered gaming by the IESO. They have the right to remove us from the market and have us pay back the CMSC we generated.
>
> All ramps [need] to be justified and should not be scheduled at the same time every day.[189]

The Panel examined the frequency and magnitude of self-induced ramping of more than ● MW by Abitibi at the Fort Frances Facility over a four-year period.[190] The results are shown in Table 8-9.

[189] Responses to RFI, B.9.2.

[190] Self-induced ramps of ●MW or less can be achieved in the unconstrained and constrained schedule in one interval at a ramp rate of ●MW/min and therefore generate no CMSC.

***Table 8-9: Self-Induced Ramps Greater than ● MW at the Fort Frances Facility 2007 to 2010 (MW)***

| | Self-Induced Ramps During the Year | | Self-Induced Ramps January-August | |
|---|---|---|---|---|
| **Year** | **#** | **MWs** | **#** | **MWs** |
| **2007** | 524 | 8,879 | 323 | 5,740 |
| **2008** | 492 | 6,699 | 382 | 5,068 |
| **2009** | 710 | 18,888 | 588 | 15,690 |
| **2010** | 1,191 | 24,286 | 1,087 | 22,327 |

Between January and August 2010, Abitibi self-induced a ramp (either up or down) at the Fort Frances Facility in 1,087 hours. This represents an 85% increase in frequency from the previous year and a 150% increase relative to the 2007-2009 average. Similarly, the total MWs of self-induced ramping during the first 8 months (January-August) of 2010 was 40% higher than in the first 8 months of 2009 and 150% higher than the January-August average for 2007-2009. As indicated in emails reproduced above, Abitibi ramped with the knowledge that, in combination with its high bid price, each ramp would generate significant CMSC payments.

The impact of frequent ramping on CMSC payments depends upon the quantity of affected MWs and the bid price. Assuming that the percent difference between the January to August 2010 versus 2009 quantities (i.e. 40%) is used as an estimate of increased ramping frequency, the CMSC impact was approximately $5.8 million[191] at Abitibi's bid prices and would have been $1.6[192] million if Abitibi had been bidding at the estimated Marginal Benefit of Consumption of $●/MWh (see Section 8.4.2.3) during ramping hours.

[191] Calculated based on the ramping data in Table 8-6 and average MCP between January and August, 2010, as: 3,924/1.4*(●-38) + 229/1.4*(●-38).

[192] To avoid overlapping calculations with the estimates in Section 8.4.2.4 and in Finding #19, the estimate of the incremental CMSC impact from Abitibi's frequent ramping is calculated based on the estimated Marginal Benefit of

***Finding #24 (Frequent Ramping):***

*Abitibi increased its CMSC payments through frequent ramping of the Fort Frances Facility during the Relevant Period by at least $5.8 million.*

### 8.4.5 Combination of Load and Generator

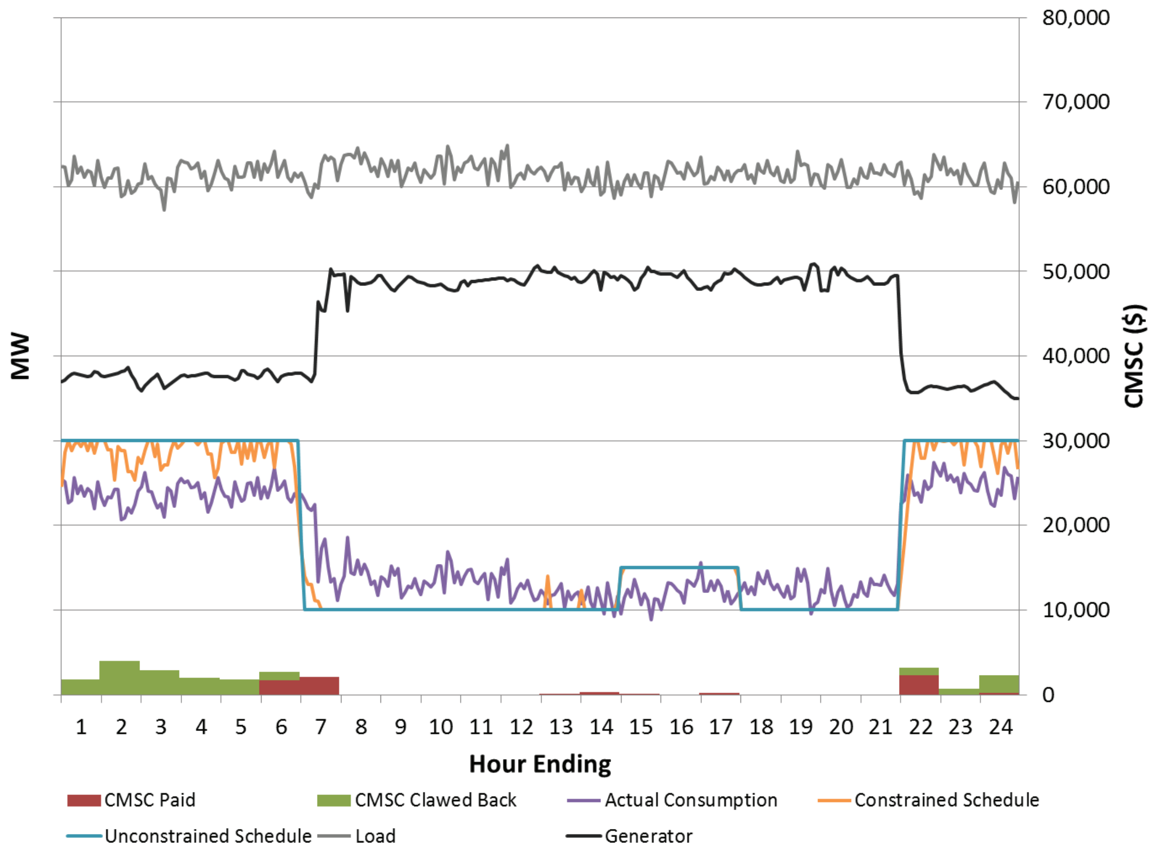
During the course of the Investigation, it was noted that there were instances during the Relevant Period where Abitibi used its generator at the Fort Frances Facility to respond to a self-induced ramp in its net load consumption. As a net load, Abitibi can respond to a dispatch instruction to increase (decrease) consumption either by the load consuming more (less), or by the generator producing less (more) output. (The effect at the revenue meter of the aggregated facility is the same.) Where the generator is used for a self-induced ramp, the load does not move, but Abitibi receives CMSC payments based on the schedule quantity differences for the net load during the ramping period.

8.4.5.1 Operating Profit Impact of Net Consumption Changes

Constrained-off CMSC payments were made for each constrained-off MW at an amount equal to the interval MCP less the net load's bid price of $●/MWh. For example, Figure 8-3 shows the meter readings of the actual load and generator as well as the actual consumption and the constrained and unconstrained schedules for the Fort Frances Facility on a net basis on July 28, 2010. From HE 6 to HE 7 Abitibi bid to reduce the consumption of its net load from ● MW to ● MW. To meet the dispatch instruction, it increased the output from its generator rather than reducing consumption from its load. Similarly, from HE 21 to HE 22 Abitibi bid to increase its net load from ● MW back up to ● MW and achieved this change by decreasing output from its generator.

Consumption. If Abitibi had bid its estimated Marginal Benefit of Consumption, the extra CMSC payments related to the ramp down pattern would have amounted to approximately $1.7 million.

***Figure 8-3: Schedules and CMSC Payments when Using the Generator to Ramp Changes in the Net Load at the Fort Frances Facility July 28, 2010 (MW and $)***




Abitibi received CMSC payments for both these self-induced ramps. The net amounts after clawback were $1,700 for the morning ramp down and $2,300 for the evening ramp up.

Where the generator effects a change in the net load, the impact on Abitibi's operating profits is a function of the marginal cost of the generator rather than the Marginal Benefit of Consumption (since the electricity consumed by, and presumably the pulp and paper produced by, the Fort Frances Facility are not affected). In its Responses to RFIs, Abitibi stated that the marginal cost of the generator was $●/MWh.[193] Using this amount in the CMSC calculation for the morning

[193] Responses to RFI, B.7.48. In 2009, prior to combining the generator with the load, Abitibi generally submitted a bid price of -$●/MWh for the output of the generator at the Fort Frances Facility, indicating its intention to generate in almost all market conditions.

ramp down would have resulted in CMSC payments of $42 (a reduction of $1,658, or about 97%). If Abitibi had bid at its estimate of the generator's marginal cost ($●/MWh) for the evening ramp up hour, it would have resulted in the net load being uneconomic in the market schedule in certain intervals (because the MCP ranged between $80/MWh to $90/MWh) or being constrained off (because the Nodal Price was greater than $86/MWh). The Fort Frances Facility's generator would have had to delay its ramp down until HE 2 — which is what would be expected to occur when a generator is economic based on market conditions.[194] The consumption of electricity to operate the load at the Fort Frances Facility would not have been affected, and the CMSC payments would have been negligible.

The behaviour referred to above occurred on an infrequent basis. In the absence of evidence indicating Abitibi deliberately exploited a market defect by submitting the load's bid of $●/MWh for a ramp up or down of the generator, the Panel has concluded that this behaviour was not exploitative, although the CMSC payments that were triggered were unwarranted.

[194] If there were reasons why the generator needed to stop operating in HE 21, or had increased costs for operating in HE 22, those could justify a higher bid price, but it is unlikely that such a price would be anywhere near the bid prices that Abitibi was using. For a discussion of similar issues related to CMSC payments to generators on self-induced ramp downs, see Market Surveillance Panel, *Monitoring Document on Generator Offer Prices Used to Signal an Intention to Come Offline*, August 19, 2011, online: http://www.ontarioenergyboard.ca/OEB/Industry/About%20the%20OEB/Electricity%20Market%20Surveillance/Monitoring%20Document%20-%20Generator%20Offers.

**Finding #25 (Bid Prices When Using Generator to Alter Net Consumption):**

*When Abitibi used the generator to implement self-induced changes to the net load at the Fort Frances Facility, the bid prices it submitted did not reflect the marginal cost of the generating facility, resulting in CMSC payments that substantially exceeded the amount needed to compensate Abitibi for any operating profit reductions, but was not a deliberate attempt to exploit a market defect.*

8.4.5.2 Ramp Rates for Changes to the Net Load

Similarly, where the generator is used to implement a self-induced ramp, the generator's ramp rates rather than the load's ramp rates reflect the pace at which the net load would be able to change. Abitibi consistently submitted a ramp rate of ● MW/min (up and down) for the entire capacity of the generator during the Relevant Period. If the generator ramp rate had been submitted by Abitibi for the changes in the net load discussed previously in this section, which were implemented by adjusting generator output, no CMSC payments would have been made because the constrained and unconstrained schedules would have achieved the entire ramps in a single interval. In the absence of evidence indicating Abitibi deliberately exploited a market defect by submitting ramp rates that did not reflect the actual ramping of the net load, the Panel has concluded that this behaviour was not exploitative, although the CMSC payments that were triggered were unwarranted.

**Finding #26 (Ramp Rates When Using Generator to Alter Net Consumption):**

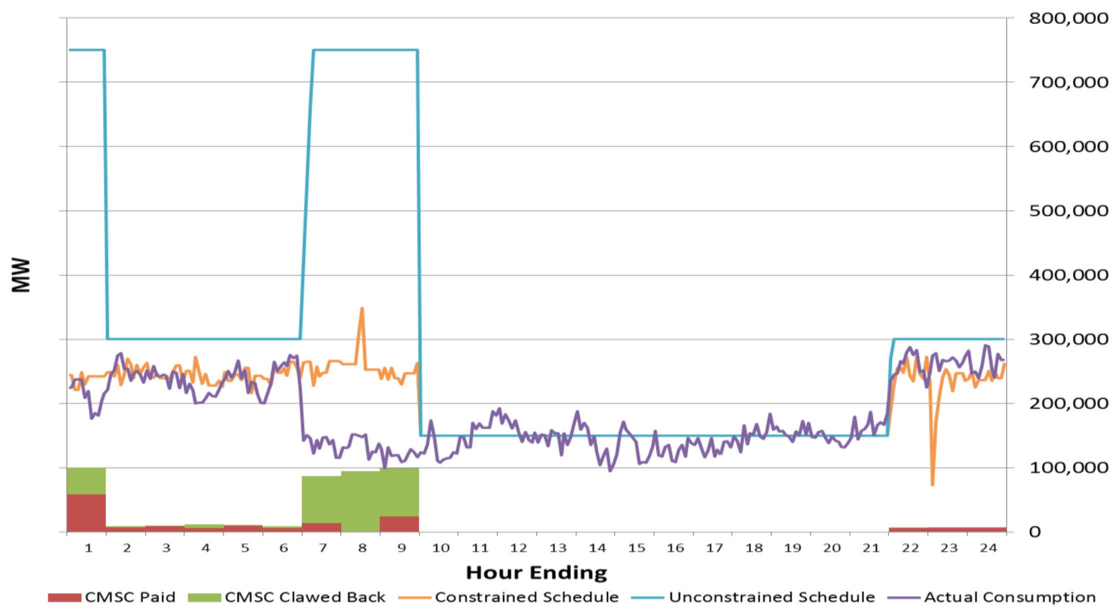
*When Abitibi used the generator to implement self-induced changes to the net load at the Fort Frances Facility, the ramp rates it submitted did not reflect the actual ramping capabilities of the generator, resulting in CMSC payments that substantially exceeded the amount needed to compensate Abitibi for any operating profit reductions, but was not a deliberate attempt to exploit a market defect.*

### 8.4.6 Failure to Ramp

During the course of the Investigation, it was noted that there were occasional situations during the Relevant Period where the Fort Frances Facility failed to ramp up or down, even though Abitibi had submitted bid quantities that indicated it wanted to increase or decrease energy consumption. Such failures to ramp resulted in discrepancies between the market and dispatch schedules, and therefore triggered constrained-off CMSC payments.

For example, on August 16, 2010, in HE 7, Abitibi bid for the net load to ramp up, but then failed to follow the dispatch schedule that reflected the planned ramp for that hour as well as HE 8 and HE 9. The scheduled and actual consumption, as well as the CMSC payments triggered during the planned ramping periods, are shown in Figure 8-4.

***Figure 8-4: Scheduled and Actual Consumption and CMSC Payments for the Net Load at the Fort Frances Facility During a Failure to Ramp August 16, 2010 (MW and $)***




The market schedule was determined by the load's submitted bid price and quantity, and moved up to the load's identified consumption level of ● MW. However, the dispatch schedule can only move within the Dispatch Envelope.[195] Because the load did not increase its energy consumption, the dispatch schedule remained at around ● MW. Had the Fort Frances Facility followed its dispatch instructions: (i) the dispatch schedule would have increased toward the market schedule; (ii) there would have been smaller quantity differences between the two schedules; and (iii) smaller CMSC payments would have been triggered. While portions of the CMSC payments were clawed back, the quantity difference resulting from the failure to ramp triggered over $37,000 in net CMSC payments during HE 7 and HE 9.

Abitibi stated that the failures to follow dispatch instructions occurred when the Fort Frances Facility experienced equipment failures.[196] This behaviour occurred on an infrequent basis. In

[195] See the discussion in Section 7.4.6.

[196] Responses to RFI, B.11, p.1.

the absence of evidence indicating that such failures to ramp were deliberate, the Panel has concluded that this behaviour was not an attempt to exploit a market defect. Even though the CMSC payments triggered when the net load failed to ramp did not arise from exploitative conduct, they were unwarranted and should have been clawed back because they were caused by conditions at the participant's facility, not Grid Conditions. However, Business Rule 3 does not provide for the recovery of CMSC payments where a load is deviating during a ramp (see Appendix H and the further discussion in Section 9 below).

**Finding #27 (Failure to Ramp):**

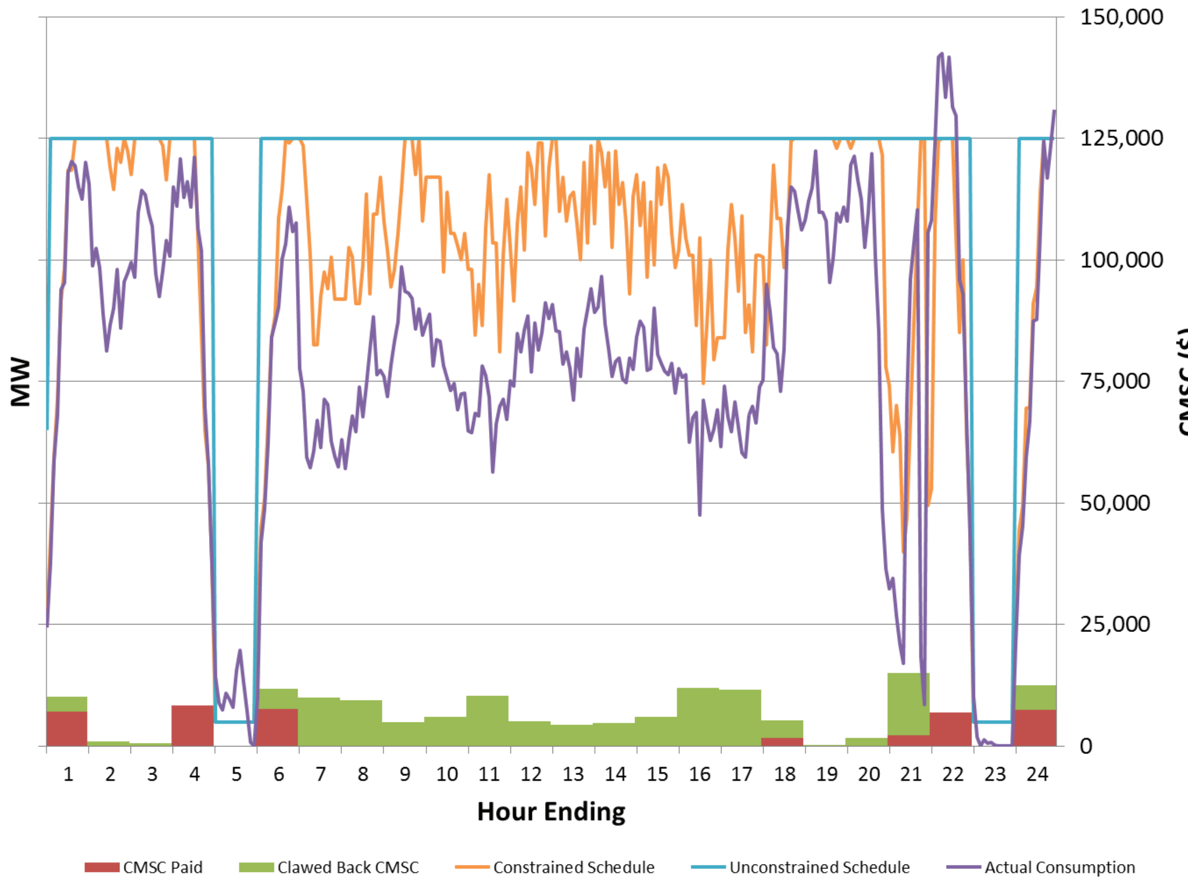
*The occasions during the Relevant Period where the Fort Frances Facility failed to ramp after bidding to do so were infrequent. While the resulting CMSC payments were self-induced and should have been clawed back, the available evidence does not indicate that these failures to ramp were attempts by Abitibi to exploit a market defect.*

### 8.4.7 Dispatch Deviation in Non-Ramping Hours

During the course of the Investigation, it was noted that there were instances of constrained-off CMSC payments during non-ramping hours in the Relevant Period where the Fort Frances Facility deviated from intended consumption and/or the market schedule. As discussed in Section 7.4.7 above, when dispatch deviation occurs outside of ramping hours the IESO typically claws back the CMSC payments that are generated, although as a result of a flaw in Business Rule 3 this does not always happen.

Figure 8-5 illustrates an occasion on March 14, 2010 where the Fort Frances Facility deviated from its dispatch instructions between HE 7 and HE 18. The vast majority of the CMSC payments were clawed back. However, in HE 18, CMSC payments totalling $1,721 were made for intervals 2 and 3, and were not clawed back under Business Rule 3.

***Figure 8-5: Schedules and CMSC Payments During Non-Ramp Dispatch Deviation at the Fort Frances Facility March 14, 2010 (MW and $)***




The net CMSC payments to Abitibi during non-ramp dispatch deviations were modest and haphazard. The Panel did not identify evidence indicating an awareness of, or deliberate attempts to exploit, this particular defect in the Business Rule 3 clawback formula. Nevertheless, as noted in Section 7.4.7, such CMSC payments were unwarranted and should have been clawed back because they were caused by conditions at the participant's facility, not Grid Conditions (see further discussion in Section 9 below).

**Finding #28 (Constrained-Off Dispatch Deviations in Non-Ramping Hours):**

*Instances of dispatch deviation in non-ramping hours by the Fort Frances Facility were infrequent. While the CMSC payments were self-induced and should have been clawed back, the available evidence does not indicate that these deviations were intentional attempts by Abitibi to exploit a market defect.*

### 8.5 Exploitation of Constrained-On CMSC

The large amounts of generation compared to demand within the Northwest region, as well as the limited transmission connections between this region and the rest of Ontario and neighbouring jurisdictions, often results in very low or negative Nodal Prices.[197] In its January 2010 Monitoring Report, the Panel noted that distorted price signals in the Northwest created potential opportunities for market participants "to obtain excessive CMSC payments from the marketplace through strategic bidding practices" and that there was a risk that market participants could "game the market."[198] Three months after the publication of the Panel's report, Abitibi began to receive large constrained-on CMSC payments through the adoption of a negative-price bidding strategy in certain hours for the Fort Frances Facility. In total it received constrained-on CMSC payments of $3.7 million over five months, $1.8 million for constrained-on consumption (Scenario #1 from Section 8.2.5.1) and $1.9 million for consumption deviation (Scenario #2 from Section 8.2.5.2). Abitibi subsequently voluntarily repaid $1.825 million of the latter amount (see Section 8.5.1).

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[197] See, *e.g.*, the discussion in Market Surveillance Panel, *Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2009 to Oct 2009*, online: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_201001.pdf (the "January 2010 Monitoring Report"), p. 89.

[198] *Ibid.*, p. 101.

The Panel examined the development of Abitibi's negative-price bidding strategy (Section 8.5.2) and assessed whether the large constrained-on CMSC payments received by Abitibi resulted from the following behaviours:

- Bidding an extremely negative price of -$●/MWh, which contributed to large CMSC payments when the Fort Frances Facility was constrained on (see section) Section 8.5.3.
- Deviating from dispatch instructions, which triggered large constrained-on CMSC payments that were not subject to claw back under the Business Rules (see Section 8.5.4).

### 8.5.1 Repayment of Portions of the Constrained-on CMSC

In discussions with the MAU that occurred prior to the initiation of the Investigation regarding constrained-on CMSC payments at the Fort Frances Facility, Abitibi asserted that its deviations from dispatch were unintentional, as were the associated CMSC payments. Abitibi therefore agreed to repay the portions of constrained-on CMSC payments arising from dispatch deviation during scheduling changes at 6:00 a.m. and 6:00 p.m.:

> With respect to the constrained on payments at Fort Frances, it should be noted that these payments are not a pure windfall brought about by the reclassification of the net load/gen as stated in your e-mail, but as a result of a change in the bidding strategy during on peak hours. During times when the shadow price drops below the bid price, the load is constrained on to consume while the generator is constrained off. Fort Frances follows these dispatches both on the load and generator, resulting in legitimate constrained on payments for the load. <u>During the June 18 phone call it was pointed out that the load was not following its dispatches during schedule changes (6 AM and 6 PM). Fort Frances has since changed the operating procedure to follow dispatches during these types of schedule changes eliminating the deviation from dispatch. Abitibi agreed with the IESO on the call that a portion of the CMSC generated during the constrained on</u>

> periods should be clawed back. But this is not to say all of it ($2.7M) should be clawed back. …[199] (emphasis added)

Abitibi calculated the constrained-on CMSC associated with these dispatch deviations as follows:[200]

| Fort Frances CMSC Payments | | |
|---|---|---|
| Constrained ON During Negative Bid Pricing | | |
| | Legit | Non-Legit |
| April | $71,996.50 | $740,886.64 |
| May | $238,198.39 | $384,462.69 |
| June | $611,713.58 | $621,469.23 |
| July | $543,068.88 | $78,191.47 |
| Total | $1,464,977.35 | $1,825,010.03 |

The $1.825 million amount was repaid by Abitibi through an adjustment to its September 2010 invoice from the IESO. However, the repayment does not preclude the Panel from assessing whether the behaviour constituted gaming, and that assessment is discussed in Section 8.5.4. The Panel also notes that Abitibi continued to bid at -$●/MWh throughout the month of August 2010 and into September 2010 and received more than $15,000 in further constrained-on CMSC payments in analogous situations. Abitibi received nearly $1.924 million in constrained-on CMSC payments as a result of dispatch deviation. The $100,000 difference between Abitibi's repayment and the amount it received has not been repaid.

Abitibi also received CMSC payments when the Nodal Price fell below the net load's submitted bid price of -$●/MWh. Abitibi advised the MAU that it intended to retain all CMSC payments which were triggered when "a portion of the load was bid in at -$●, and the shadow price triggered the dispatch to the generator to decrease production while the load received the signal to increase consumption and both resources were able to follow dispatch. This is the CMSC we

[199] Excerpt of email from [Senior Abitibi Personnel #2] to MAU, August 17, 2010. Responses to RFI, B.13.27.

[200] Responses to RFI, B.13.85. The CMSC payments that Abitibi considered to be "non-legit", because they arose from consumption deviation during the Fort Frances Facility's schedule changes, relate to "Scenario #2" described in Section 8.2.5.2.

believe to be appropriate”.[201] Whether this behaviour constituted gaming is assessed in Section 8.5.3.

### 8.5.2 Development of the Negative-Price Bidding Strategy

On March 31, 2010, Abitibi personnel attended an IESO Stakeholder Advisory Committee (SAC) meeting where the Chair of the MSP made a presentation regarding the Panel’s January 2010 Monitoring Report, including the prevalence of negative Nodal Prices in the Northwest and the Panel’s concerns that these conditions could provide dispatchable resources with an opportunity to bid strategically in order to obtain significant constrained-on CMSC payments.[202] The Panel recommended that the IESO revise the constrained-on CMSC payment calculation when market participants bid at a negative price:

> Recommendation 3-4: The Panel recommends that, for the purposes of calculating Congestion Management Settlement Credit (CMSC) payments, the IESO should revise its constrained-on payment calculation using a replacement bid (such as $0/MWh) when market participants (both exporters and dispatchable loads) bid at a negative price. This would create more consistent treatment with generators and importers that are constrained-off.[203]

The January 2010 Monitoring Report stated, and the MSP Chair’s presentation reiterated, that the constrained-on CMSC payments in the Northwest as a result of negative Nodal Prices were an unintended consequence of the two-schedule design of the market, and created a potential risk that dispatchable resources could game the market.[204]

One week after the SAC meeting, Abitibi introduced a new lamination in its bids for the Fort Frances Facility: for the ● to ● MW quantity range, it submitted a bid price of -$●/MWh. [Senior

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[201] Email from [Senior Abitibi Personnel #2] to MAU, August 17, 2010. Responses to RFI, B.13.28.

[202] Market Surveillance Panel, Monitoring Report on the IESO-Administered Electricity Markets for the period from May 2009 to Oct 2009, online: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/msp_report_201001.pdf, section 3.1.

[203] *Ibid.*, p. 104.

[204] *Ibid.*, pp. 100-105.

Abitibi Personnel #2] subsequently described the bidding strategy to [AbitibiBowater Inc Executive #1] as follows:

> From: [Senior Abitibi Personnel #2]
>
> To: [AbitibiBowater Inc Executive #1]
>
> Date: 06/10/2010 09:30 AM
>
> Subject: Re: Clearing Prices
>
> <u>The strategy:</u>
>
> Bid ● MWh of load during on peak times at -$●/MWh.
>
> <u>Whenever there is too much generation in the area the load will be dispatched on to consume anywhere from ● to ● MWh of power from the grid. This generates the large CMSC revenue.</u>
>
> <u>When the load is not being dispatched on to consume, they are still able to consume because of a 15MWh deadband the IESO has given them. The result is that they consume power without any CMSC payments while still respecting all market rules.</u>
>
> After the market rule change (September), all dispatchable loads bidding negative will be automatically reverted to $0/MWh. After this change, the load will only receive the Market Clearing price when dispatched on to consume.[205] (emphasis added)

This email was forwarded to other parent company executives with the comment that "If we don't want [Senior Abitibi Personnel #2] to pursue this method and would prefer to be more conservative, we will need to inform [Senior Abitibi Personnel #2] of our decision/concerns."[206] After receiving this email, [AbitibiBowater Inc Executive #3], followed up with [Senior Abitibi Personnel #4] and [Senior Bowater Personnel #3], asking: "Do you think this is good practice or

[205] Responses to RFI, B.13.4.

[206] Email from [AbitibiBowater Inc Executive #1] to [AbitibiBowater Inc Executive #3], [AbitibiBowater Inc Executive #4], [AbitibiBowater Inc Executive #3] and [AbitibiBowater Inc Executive #2], June 10, 2010. Responses to RFI, B.13.4.

is it going too far? I just want to make sure we do not do something that attracts too much attention and [puts] in jeopardy what we now use (ramps) in this program."[207]

Senior management corresponded about the appropriateness of the constrained-on CMSC strategy by email as follows:

> From: [Senior Abitibi Personnel #4]
> Sent: 06/15/2010 03:30 PM
> To: [AbitibiBowater Inc Executive #3]
> Cc: [Senior Abitibi Personnel #2]
> Subject: Re: Tr: Clearing prices – Ontario
>
> [AbitibiBowater Inc Executive #3], can we have a discussion about this?
>
> <u>[Senior Abitibi Personnel #2] just copied me on a note from</u> [AbitibiBowater Inc Executive #1] <u>that says we should stop this practice.</u>
>
> <u>After spending the morning getting brought up to speed on the way we are using the program – I disagree.</u>
>
> In April and May we generated a CMSC of $309,000 and so far in June $480,000. The reason we changed our bidding structure on April 7th was the result of [Senior Abitibi Personnel #2] having a discussion with someone from the IESO. The way I personally look at it is that when we are constrained on, we are forced to buy and sometimes we are forced to reduce generation from Biomass. In other words, stop using an asset to its full potential.
>
> <u>The other side of this story is $1,140,000 created in April and May, and $535,000 so far in June that is self created CMSC that we should **not** consider to be ours.</u>
>
> If we are going to create any attention through this process, we have already done so. <u>Why stop now?</u>[208] (emphasis added)

[207] Email from [AbitibiBowater Inc Executive #3] to [Senior Bowater Personnel #3] and [Senior Abitibi Personnel #4], June 14, 2010. Responses to RFI, B.13.4. The negative-price bid strategy was also described to [Senior Abitibi Personnel #4] in an email from [Senior Abitibi Personnel #2], June 4, 2010. Responses to RFI, B.9.22.

[208] Responses to RFI, B. 13.4.

[AbitibiBowater Inc Executive #3] responded to the email on June 15, 2010:

> From: [AbitibiBowater Inc Executive #3]
>
> To: [Senior Abitibi Personnel #4]
>
> c.c.: [Senior Bowater Personnel #3]
>
> Date: 06/15/2010 07:04 PM
>
> Subject: Re: Tr: Clearing prices – Ontario
>
> No problem. Just want to make sure we are not putting at risk our ramps for a temporary higher benefit. Call [Senior Bowater Personnel #3] and schedule a conf call to get an alignment. Invite [AbitibiBowater Inc Executive #1] and [Senior Abitibi Personnel #2] if available. I am open tomorrow from 2 to 5 pm or Thurs am.[209]

It is clear from these emails that: (i) Abitibi recognized that a market defect in the constrained-on CMSC regime would allow it to obtain additional CMSC payments; and (ii) Abitibi consciously exploited this opportunity by "[bidding] ● MWh of load during on peak times at -$●MWh… This generates the large CMSC revenue." It is also clear that the strategy was known to and effectively condoned by senior management at Abitibi and its parent company. Moreover, Abitibi knew that these CMSC payments were not compensating for reductions in operating profits resulting from responding to dispatch instructions caused by Grid Conditions.

On June 11, 2010, the MAU reminded Abitibi that gaming can be found by the Panel where there is "exploitation of opportunities to profit or benefit from defects in the design of the market, from poorly specified rules or procedures, or from circumstances that are not expressly covered by Market Rules or procedures…".[210] However, Abitibi maintained its position that the new bid strategy with the -$●/MWh lamination was justified because it was not contravening the *Market Rules*. In its Responses to RFI, Abitibi also stated that:

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[209] Responses to RFI, B. 13.4.

[210] Email from MAU to [Senior Abitibi Personnel #2], June 11, 2010, citing the MSP's *Monitoring Document: Monitoring of Offers & Bids in the IESO-Administered Markets*, online: http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Monitoring_Offers_Bids_Document_20100310.pdf. Responses to RFI, B.13.1.

> The standard bidding practice in Fort Frances had been to bid all load at a high price to avoid being constrained off during peak production times. However it was learned that in the northwest region there is potential to bid the load at a low price in times when there is too much generation in the area which could trigger the IESO to constrain the load on, thereby creating CMSC payments. It was at the March 31, 2010 Stakeholders Advisory Committee (SAC) meeting where [the Chair of the Market Surveillance Panel] presented the May – October 2009 MSP report which addressed constrained-on payment in the Northwest area. After the presentation [Senior Abitibi Personnel #2] had a conversation with [Senior IESO personnel] at which time [Senior Abitibi Personnel #2] questioned dispatchable loads bidding negative in the northwest. The response from [Senior IESO personnel] was presented back in a question. “Why would you not bid negative?” [Senior IESO personnel] then proceeded to explain in detail the mechanics of bidding negative in the market. Shortly following this discussion, Fort Frances changed their bid structure where a portion of their load would be bid in at a negative price.[211]

The Panel asked the MAU to interview the [Senior IESO personnel]. [Senior IESO personnel] indicated the following:

- [Senior IESO personnel] did not specifically recall conversations with Abitibi personnel about this issue at the SAC meeting on March 31, 2010.
- [Senior IESO personnel] does not recall telling Abitibi personnel how to bid or offer. As a general rule, [Senior IESO personnel] does not advise market participants on how to bid or offer. If asked, [Senior IESO personnel]’s normal practice is to be forthcoming and answer questions about the implications of certain bidding/offering behaviour and the mechanics of payments.

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[211] Responses to RFI, B.11.5.

- [Senior IESO personnel] recalled that Abitibi was very active during the dispatchable loads rule amendment process in the fall of 2010[212], and those stakeholdering discussions would have included detailed descriptions and implications of bidding in certain ways.

As noted above, Abitibi's Responses to RFI stated that, when asked by [Senior Abitibi Personnel #2] about bidding at a negative price in the Northwest, [Senior IESO personnel] responded "[w]hy would you not bid negative?" during the SAC meeting – implying that the IESO was counselling the behaviour or at least endorsing it. However, [Senior Abitibi Personnel #2]'s notes from that meeting do not record this statement and do not demonstrate encouragement or approval of a strategy designed to obtain larger CMSC payments. They are not inconsistent with [Senior IESO personnel]'s statement that he would not go beyond forthright explanations of the implications of certain bidding/offering behaviour or the mechanics of payments.[213] [Senior Abitibi Personnel #2]'s internal follow up emails also do not contain references to being encouraged or authorized by the IESO to adopt the constrained-on CMSC strategy.

Even if the [Senior IESO personnel] had made the comment that [Senior Abitibi Personnel #2]'s claims was made, it does not constitute a defence or justification for gaming behaviour. Market participants are ultimately responsible for their actions in or affecting the wholesale market, not only in respect of compliance with the *Market Rules* but also in respect of conduct that may be subject to review by the Panel for gaming or abuse of market power. The [Senior IESO personnel] does not have authority to determine what conduct would or would not constitute gaming.

When assessing the exploitation element of gaming, the Panel will consider all relevant evidence relating to the decision-making by the market participant that engaged in the conduct. As a general observation, the Panel notes that, if a market participant intends to use IESO advice as a

[212] Referring to the IESO's stakeholder engagement Constrained-off Congestion Management Settlement Credits for Dispatchable Loads (SE-89).

[213] Responses to RFI, B.11.6. For example, [Senior Abitibi Personnel #2] notes indicate that a $●/MWh offer would reflect a bid to consume, and that the constrained payments would be high, whereas a $2,000/MWh bid would make the facility non-dispatchable.

basis for conduct it has engaged in, it would be prudent to ensure that the precise questions and IESO responses are comprehensively and contemporaneously documented. In this case, the overall evidence, including the emails reproduced or summarized above, indicates that Abitibi's decision to adopt the new strategy for obtaining constrained-on CMSC payments was not based on authorization or encouragement from the IESO, nor was it based on any business reasons relating to the operation of the Fort Frances Facility. The Panel also notes that, based again on the overall evidence, [Senior Abitibi Personnel #2] repeatedly led other initiatives by both Abitibi and Bowater to exploit other market defects in order to increase CMSC payments.[214]

It was clear from the presentation at the SAC meeting that the possibility of self-induced CMSC payments arising from negative-price bids was an unintended consequence of the two-schedule design of the market, that the Panel regarded these payments as unwarranted, and that the IESO was taking steps to eliminate them.[215] Nevertheless, Abitibi continued to exploit the situation before the *Market Rules* changed:

> From: [AbitibiBowater Inc Executive #3]
>
> To: [AbitibiBowater Inc Executive #1]
>
> Date: June 15, 2010 10:52 AM
>
> Re: TR: FW: High CMSC Payments made to Abitibi Facilities
>
> Fyi.
>
> I still think we need to be careful not to go too far (negative bidding) with the power programs as we might attract too much attention and [lose] what we now have. <u>This is especially true as, if I understood well, it is only a temporary hole in the program that will disappear soon</u>.[216] (emphasis added)

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[214] See the various correspondence and other documents cited in Sections 7 and 8 of this report.

[215] Market Rule Amendment Submission to the Technical Panel, Limiting Constrained-on CMSC Payments for Exporters and Dispatchable Loads, online: http://www.ieso.ca/imoweb/pubs/icms/tp/2010/05/IESOTP_236_4b_MR_00370_Q00_Amendment_Submission.doc
.

[216] Responses to RFI, B.13.3. See also the various correspondence reproduced earlier in this Section.

The *Market Rules* were subsequently amended by the IESO to provide for use of a replacement bid of -$50/MWh for the purposes of calculating constrained-on CMSC payments for all dispatchable load transactions.[217] Abitibi stopped using negative-price laminations in its bid submissions for the Fort Frances Facility on September 2, 2010. Abitibi has not used a negative-price lamination since that time. This is a further indication that the -$●/MWh bidding strategy was deliberate behaviour adopted to exploit a market defect.

In its Responses to RFI, Abitibi acknowledges that it understood that the introduction of a negative-price bid lamination for a load in the northwest could trigger constrained-on CMSC payments.[218] The -$●/MWh lamination did not coincide with any associated cost of being constrained on to consume additional electricity. To the contrary, as noted above, Abitibi intended to deviate from its submitted bids by consuming within the 15 MW Compliance Deadband when it was not constrained on.

**Finding # 29 (Constrained-On CMSC Payment Strategy):**

*Abitibi's adoption of a negative-price bidding strategy between April and August 2010, which was known to senior management, was a deliberate attempt to exploit a market defect in the CMSC regime that had been publicly identified as such by the Panel and was in the process of being rectified by the IESO.*

### 8.5.3 Expanding the Magnitude of CMSC Using a Low Bid Price

Dispatchable loads have an opportunity to receive constrained-on CMSC payments that more than compensate them for operating profit reductions if they bid at prices that understate their Marginal Benefit of Consumption in circumstances where the Nodal Price falls below the load's bid price. For example, assume a load bids to consume 1 MW at -$1,999/MWh and the MCP is

[217] *Market Rules*, Chapter 9, Section 3.6.5A, added by MR-00370, online: http://www.ieso.ca/Documents/Amend/mr2010/MR-00370-R00-BA.pdf.
[218] Responses to RFI, B.11.5.

$30/MWh. This bid implies that the load is only willing to consume an additional MW for an hour if it is paid $1,999 to do so. In other words, there is a cost, not a benefit, associated with the additional consumption. If the Nodal Price falls below -$1,999/MWh, the load will be constrained on and will pay the MCP for the energy it uses; but it will also receive a CMSC payment equal to the difference between the bid price and the MCP multiplied by the MWs that were constrained on for each interval (*i.e.* $2,029 for 1 MW for 1 hour).

If the load's Marginal Benefit of Consumption for additional energy is greater than -$1,999/MWh, the CMSC payment will more than compensate the load for any reduction in operating profits caused by being forced to consume. For example, if the load actually receives a marginal benefit of $200/MWh from consuming an additional MW, but bids -$1,999/MWh and is constrained on, it will receive a CMSC payment of $2,029 and pay the $30 MCP, even though it would have been kept whole by paying $200 for its additional consumption. The load actually receives an increase in its operating profits in the amount of $2,199 by bidding -$1,999/MWh and being constrained on to consume.

The evidence referenced above indicates that Abitibi was profiting when it switched a portion of the bid quantity for the Fort Frances Facility to -$●/MWh. It is clear from the description of the strategy that Abitibi placed a positive value on consumption even when it was bidding -$●/MWh. In fact, Abitibi planned on consuming within the 15 MW Compliance Deadband when it was not constrained on. It also claimed in its Responses to RFI that one hour of lost paper production would reduce its operating profits by $●/MWh.[219] Therefore, when the load bid at -$●/MWh and was constrained on (or appeared to be constrained on due to its own deviations, as discussed in Section 8.5.4), Abitibi was actually paid to consume electricity it wanted to consume and would, based on its own calculations, have benefited by consuming at any price below $●/MWh. Abitibi consumed as it intended to consume, there was no operating profit reduction resulting from responding to a dispatch instruction caused by Grid Conditions, and therefore no need for a CMSC payment to compensate Abitibi.

[219] Responses to RFI, B.8.1. (As indicated in Section 8.4.2.2 above, the Panel believes that this calculation overstates the actual Marginal Benefit of Consumption, but that does not negate the fact that Abitibi was submitting a bid price which was inconsistent with its own claims regarding the benefit of incremental energy consumption.)

**Finding #30 (Negative Bid Prices):**

a) *Abitibi's -$●/MWh bid price was well below its Marginal Benefit of Consumption during the hours in which such bids were submitted for the net load at the Fort Frances Facility.*

b) *Abitibi's low bid price was used to obtain CMSC payments that more than compensated Abitibi for operating profit reductions by at least $1.8 million.*

### 8.5.4 Deviating from Dispatch Instructions to Appear to be Constrained On

When a load deviates from its market schedule but remains within its Compliance Deadband, it can effectively manipulate the dispatch schedule without being exposed to sanctions for breaching a *Market Rule*. It can submit a specific bid quantity that will be used to determine the market schedule, then deviate from the submitted quantity (by consuming more) and thereby force the dispatch schedule above and away from the market schedule and toward its actual consumption level. The market schedule is not updated where a load deviates from its submitted quantity bids, and the dispatch schedule will not move the load toward its submitted quantity bid where the load consumes at a level that is higher than its Dispatch Envelope.[220] This creates an opportunity for dispatchable loads to trigger self-induced constrained-on CMSC payments that are not subject to clawback. [221]

Between April 7 and August 19, 2010, the Fort Frances Facility often consumed significantly more energy than the quantity it bid at extremely negative prices, thereby pulling the dispatch

[220] The dispatch algorithm determines the dispatch schedule by taking a load's actual consumption over the last 10 minutes and calculating the range within which it can dispatch the load, based on the load's submitted ramp rates. This Dispatch Envelope indicates a load's physical capacity to move in any given direction within a five-minute interval, and the dispatch algorithm cannot dispatch a load outside the Dispatch Envelope.

[221] The *Market Rules* provide for recovery of constrained-off CMSC payments where dispatch deviation has occurred, (Business Rule 3 describes the specific circumstances in which the IESO would recover constrained-off CMSC payments where there has been dispatch deviation, pursuant to *Market Rules* Chapter 9, Section 3.5.1A). However, this was not expected to be needed for constrained-on situations and neither the *Market Rules* nor the Business Rules provide for the recovery of constrained-on CMSC payments when a load is deviating from dispatch.

schedule above the market schedule and making it appear that the Facility was constrained on to consume more electricity than its bid quantity. Abitibi received constrained-on CMSC payments in 2,457 intervals where the Nodal Price was greater than Abitibi's bid price (indicating Abitibi was consuming more MWs than the constrained schedule was directing). For example, as shown in Figure 8-2 Abitibi received dispatch instructions to consume roughly ● MW between HE 7 and HE 14, yet it was consuming in the neighbourhood of ● MW.[222] According to Abitibi's bids, it was only willing to consume between ● MW and ● MW if it was paid $●/MWh to do so (*i.e.* a bid of -$●/MWh). During this period the Nodal Price was in the $20/MWh to $70/MWh range, indicating it was not economic for the Fort Frances Facility to be consuming at the level that it was. The constrained-on quantities (*i.e.* the differences between the constrained on schedule and the market schedule) in each interval attracted a CMSC payment equal to the difference between the MCP (which was in the range of $30/MWh to $50/MWh in these hours) and the -$●/MWh bid. During these eight hours, such CMSC payments totaled approximately $150,000.

**Finding # 31 (Constrained-On Dispatch Deviations):**

*Abitibi deviated from the Fort Frances Facility's dispatch instructions on numerous occasions that resulted in the Facility appearing to be constrained on and receiving CMSC payments when its bids indicated it did not want to consume.*

As noted in Section 8.5.1, Abitibi has admitted that the constrained-on CMSC payments arising from its consumption deviations while bidding at -$●/MWh were "non-legit" and it made a voluntary repayment of 95% of the amount in question. There is no justification for Abitibi to retain the approximately $100,000 of similar CMSC payments, especially those payments that it received after it had conceded that CMSC payments of this type were non-legitimate.

[222] During this period Abitibi had bid ● MW at $2,000/MWh (making this quantity non-dispatchable), ● MW at $●/MWh and ● MW at -$●/MWh.

## 8.6 Profits or Benefits to the Market Participant

As the Panel observed in Section 7.5, a market participant will profit or benefit from CMSC payments when those payments exceed the reduction in the participant's operating profits caused by its adherence to an IESO dispatch instruction to consume less or more electricity than its quantity in the market schedule. The Panel has analyzed (separately for constrained-off and constrained-on CMSC payments) data relating to prices, differences between the unconstrained and constrained schedules and the reasons for those differences, the operating and bidding behaviours of Abitibi that resulted, as well as the associated CMSC payments.

### 8.6.1 Constrained-off CMSC Payments

As indicated in Section 8.4, the Panel has found that Abitibi submitted bid prices in excess of its Marginal Benefit of Consumption, and has also engaged in frequent ramping and ramping faster than submitted ramp rates. Each of these behaviours triggered constrained-off CMSC payments that more than compensated for operating profit reductions. With the exception of occasional failures to ramp and dispatch deviations in non-ramping hours, almost all of Abitibi's constrained-off CMSC payments was the result of exploiting market defects (Findings #1) through using a high bid price (Finding #19)[223], ramping faster than submitted ramp rates (Finding #23)[224] and frequent ramping (Finding #24)[225]. The Panel has determined that Abitibi profited by $7.5 million from the CMSC payments it received.

From January 1 to August 28, 2010, Abitibi received approximately $7.8 million in net constrained-off CMSC payments. The vast majority of these payments were earned during ramp-down and ramp-up hours. As was detailed in Section 8.2.4, the CMSC payments received were substantially greater than the energy charges (including applicable Global Adjustment and Uplift amounts) during ramping hours. This resulted in Abitibi actually being paid to consume while implementing its self-induced ramps. For example, during the Relevant Period Abitibi received

[223] The Panel estimates a CMSC impact of $5.9 million.
[224] The incremental CMSC impact is subsumed in Finding #19.
[225] The Panel estimates an incremental CMSC impact of $1.6 million.

self-induced constrained-off CMSC payments in 986 hours by changing its maximum quantity bid. During these hours Abitibi earned $6.7 million in net CMSC payments but paid only $1.2 million for the electricity it consumed (including applicable Global Adjustment and Uplift charges). Abitibi has not identified any costs or other reductions in operating profits resulting from its self-induced ramps. It is clear that Abitibi profited significantly from the constrained-off self-induced ramping of the Fort Frances Facility.

**Finding #32 (Profit or Benefit to Abitibi from Constrained-Off CMSC):**

*Abitibi profited $7.5 million from the constrained-off CMSC payments received as a result of the behaviours set out in Findings #19, 23 and 24*, *which exploited the market defects set out in Finding #1.*

### 8.6.2 Constrained-on CMSC Payments

In Section 8.5 the Panel has found that, at various times, Abitibi submitted -$●/MWh bid prices that substantially understated its Marginal Benefit of Consumption and also consumed at levels which deviated from its dispatch instructions. These behaviours were used to obtain constrained-on CMSC payments that more than compensated for operating profit reductions. Abitibi has claimed that such deviations were an "oversight".[226] However, the evidence presented in Section 8.5 shows that the deviations were frequent and the strategy was intentional.

From January 1, 2010 to August 28, 2010, Abitibi received approximately $3.7 million in constrained-on CMSC payments at the Fort Frances Facility. As discussed in Section 8.2.5, the constrained-on CMSC payments arose in two different situations:

- During constrained-on consumption (Scenario #1) Abitibi received CMSC payments when the Nodal Price fell below the net load's submitted bid price

[226] Responses to RFI B.11.5.

of -$●/MWh and the load was constrained on. Abitibi received approximately $1.769 million in self-induced constrained-on CMSC payments in such situations.

- During consumption deviation (Scenario #2) Abitibi received self-induced CMSC payments when it deviated from its dispatch and therefore appeared to be constrained on. Abitibi received approximately $1.923 million in constrained-on CMSC payments in these situations. Abitibi paid back $1.825 million but retained approximately $100,000 of net constrained-on CMSC payments related to consumption deviation. The voluntary repayment after being contacted by the MAU does not negate the fact that, at the time the behaviours occurred, Abitibi was profiting from them.

Abitibi's internal correspondence and actual consumption patterns clearly indicate that it was intending to consume electricity regardless of whether or not it was constrained on while bidding at -$●/MWh, and that the highly negative bid price did not reflect the financial impact of Abitibi being constrained on to consume. The resulting constrained-on CMSC payments did not compensate Abitibi for reductions in operating profits resulting from responding to dispatch instructions caused by Grid Conditions; rather, they provided Abitibi with incremental operating profits. It is therefore clear that Abitibi's constrained-on CMSC payments were the result of exploiting market defects (Findings #1 and #16) through using low bid prices (Findings #30 and #31). [227] The Panel has determined that Abitibi profited by $1.9 million from the constrained-on CMSC payments generated by the negative-price bidding strategy.

[227] The Panel estimates an incremental CMSC impact of $1.9 million.

***Finding #33 (Profit or Benefit to Abitibi from Constrained-on CMSC):***

*Abitibi profited $1.9 million from the constrained-on CMSC payments received as a result of the behaviours set out in Findings #30 and 31, which exploited the market defects set out in Findings #1 and #16.*

## 8.7 Expense or Disadvantage to the Market

The Panel has already noted in Section 7.6 that net CMSC payments (that is, payments after the IESO's clawback procedures and voluntary repayments are applied) are charged to all Ontario wholesale market customers as part of Uplift charges. This is the case for constrained-on as well as constrained-off CMSC payments. As a result, when one market participant exploits market defects in the CMSC system and profits from its behaviour, this imposes an expense and disadvantage throughout the market. All customers bear the cost by paying higher Uplift charges than would otherwise have been incurred.

Between January and August 2010, Abitibi received $9.7 million in net CMSC payments (net of clawbacks and voluntary repayments). The Panel estimates that $ 9.4 million of that total was self-induced and increased Uplift charges by $0.09/MWh.[228] With the exception of occasional failures to ramp and dispatch deviations in non-ramping hours, almost all of the self-induced CMSC payments were the result of exploiting market defects (Findings #1 and #16) through using a high bid price (Finding #19)[229], ramping faster than submitted ramp rates (Finding #23)[230], frequent ramping (Finding #24)[231], and using low bid prices (Findings #30 and #31).[232]

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[228] Total Ontario Market Demand from January to August 2010 was 105 TWh.
[229] The Panel estimates a CMSC impact of $5.9 million.
[230] The incremental CMSC impact is subsumed in Finding #19.
[231] The Panel estimates an incremental CMSC impact of $1.6 million.
[232] The Panel estimates an incremental CMSC impact of $1.9 million.

**Finding #34 (Expense or Disadvantage to the Market):**

*All customers in the wholesale energy market were disadvantaged by paying additional Uplift charges of $0.09/MWh as a result of Abitibi's behaviours.*

## 8.8 Conclusion

Abitibi is a large and sophisticated market participant. The exploitative behaviours identified above were engaged in with the knowledge of many personnel including senior management at Abitibi and its ultimate parent company, ABI. Abitibi repeatedly and deliberately engaged in multiple behaviours to exploit market defects in a manner which triggered substantial CMSC payments for Abitibi at the expense of wholesale loads who pay Uplift charges in the Ontario market.

The Panel concludes that, during the Relevant Period, five behaviours giving rise to $9.4 million in CMSC payments to Abitibi were intentional and that the behaviours constituted gaming: using bid prices well above the Marginal Benefit of Consumption (or generator marginal costs) during self-induced ramps; ramping down faster than submitted ramp rates (including in certain situations using the fast ramping capability of the generator for ramping of the net load when load ramp rates were submitted); frequent ramping; the use of a -$●/MWh bid price lamination in certain hours; and deviating from the dispatch schedule so that the facility would appear to be constrained on. The latter two behaviours are particularly glaring given that the market defect in question had been publicly identified as such by the Panel and was being addressed by the IESO.

The Panel did not find the infrequent occasions where Abitibi failed to ramp or deviated from dispatch in non-ramping hours and received constrained-off CMSC payments to be exploitative. Nevertheless, such CMSC payments were unwarranted and should have been clawed back. In Section 9 the Panel examines the need for further improvements in the *Market Rules* and IESO procedures to prevent unwarranted CMSC payments in the future.

**Finding #35 (Finding of Gaming):**

*Abitibi exploited market defects. In so doing, Abitibi received $9.4 million in CMSC payments during the Relevant Period, and there was a corresponding disadvantage or expense to the market. Abitibi's conduct constitutes gaming.*

# 9. REVIEW OF CONTINUING CMSC PAYMENTS AND RECENT DEVELOPMENTS REGARDING REMEDIAL ACTION FOR GAMING

## 9.1 Constrained-Off CMSC Payments

On August 27, 2010, the IESO Board of Directors enacted an Urgent Market Rule Amendment which suspended all CMSC payments to constrained-off dispatchable loads in light of the fact that significant CMSC payments had been made to two dispatchable loads which the IESO believed to be inconsistent with the intent of the CMSC regime.[233]

On December 3, 2010 the Urgent Market Rule Amendment was rescinded and the *Market Rules* were amended to permanently eliminate constrained-off CMSC payments made to dispatchable load facilities associated with self-induced ramping. In the introduction to the amendment, the IESO stated:

> It is proposed that dispatchable loads will not be entitled to constrained-off CMSC payments related to ramping, where such payments are caused by conditions and/or actions at the load facility, and not by conditions on the IESO-controlled grid.[234]

To implement this amendment to the *Market Rules*, the IESO made a change to its settlement procedures. If a dispatchable load changes either element of its P/Q Pair from one hour to the next, and this change triggers ramping, any CMSC payments made for the hour are to be clawed back.[235] Accordingly, dispatchable loads no longer receive constrained-off CMSC payments for self-induced ramping. The amendment does not prevent CMSC payments from being calculated or being paid on a gross basis. Instead, it introduces a new clawback mechanism so that, net of automated clawbacks, the dispatchable loads do not receive ramp-related CMSC payments.

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[233] See MR-00373, online: http://www.ieso.ca/Documents/mr/MR_00373-R00.pdf.

[234] See MR-00374, online: http://www.ieso.ca/Documents/Amend/mr2010/MR-00374-R00-BA.pdf, p. 2.

[235] IESO, *Market Manual 5, Part 5.5: Physical Markets Settlement Statements*, s. 1.6.9.3.

### 9.2 Constrained-On CMSC Payments

On November 11, 2010, the IESO implemented an amendment to the *Market Rules* which largely eliminated deviation-induced constrained-on CMSC payments.[236] The amendment established a replacement bid price of -$50/MWh to cap the amount of the constrained-on CMSC payments to dispatchable loads and -$125/MWh for constrained-on CMSC payments to exporters. The replacement bid price for dispatchable loads was revised upwards to -$15/MWh in March 2012 because they were no longer being charged the Global Adjustment for each MWh of consumption.[237]

This amendment substantially reduced, but has not eliminated, constrained-on CMSC payments for dispatchable loads. For example, if a dispatchable load bids a quantity of 10 MW at -$1,999/MWh and it is constrained on in an hour when the MCP is $20/MWh, it will receive a CMSC payment of $35 ($20 – (-$15) *10MW) (considerably less than the $20,190 ($20 – (-$1,999) *10MW) than would have been received before the amendment took effect).

### 9.3 Continuing CMSC Payments

Table 9-1 summarizes the CMSC payments to all dispatchable loads in 2011 to 2013, with 2009 and 2010 provided for comparison. The data indicates that the vast majority of CMSC payments to Bowater and Abitibi from 2011 to 2013 were clawed back, although they still collectively received over $1.25 million in 2011, $1.75 million in 2012 and $1.00 million in 2013. In aggregate there was in excess of $5 million per year in net CMSC payments being made to dispatchable loads in 2011 and again in 2012, reflecting the fact that only about 61% of the gross CMSC payments were clawed back. In 2013 there was a significant increase in net CMSC payments being made to dispatchable loads, in excess of $13 million, and only about 50% of the gross CMSC payments were clawed back. The sharp rise in net CMSC payments in 2013 is of some concern to the Panel.

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[236] For further details, see MR-00370, online: http://www.ieso.ca/Documents/Amend/mr2010/MR-00370-R00-BA.pdf.

[237] See IESO, *Market Manual 5: Settlements. Part 5.5: Physical Markets Settlements Statements,* p. vi, online: http://www.ieso.ca/imoweb/pubs/settlements/se_RTEStatements.pdf.

***Table 9-1: Gross and Net CMSC for the Thunder Bay Facility, the Fort Frances Facility and All Other Dispatchable Loads 2008 – 2013 ($000)***

| Year | Bowater (Thunder Bay Facility) | | | Abitibi (Fort Frances Facility) | | | All Other Dispatchable Loads | | |
|---|---|---|---|---|---|---|---|---|---|
| | Gross CMSC | Claw-back | Net CMSC | Gross CMSC | Claw-back | Net CMSC | Gross CMSC | Claw-back | Net CMSC |
| **2008** | Not Dispatchable | | | 9,487 | 7,587 | 1,899 | 8,942 | 6,415 | 2,527 |
| **2009** | | | | 20,527 | 14,220 | 6,307 | 7,111 | 5,282 | 1,829 |
| **2010** | 22,312 | 9,946 | 12,366 | 27,814 | 18,097 | 9,717 | 11,327 | 9,953 | 1,374 |
| **2011** | 11,979 | 11,033 | 946 | 16,603 | 16,271 | 332 | 11,359 | 6,071 | 5,288 |
| **2012** | 12,435 | 11,705 | 731 | 15,660 | 14,611 | 1,049 | 15,500 | 10,365 | 5,136 |
| **2013*** | 9 | 8 | 1* | 14,559 | 13,536 | 1,023** | 26,725 | 13,255 | 13,299 |

* On December 10, 2012 Bowater stopped bidding into the market, with the exception of 18 hours over March 3 and March 4, 2013, which designates the facility as non-dispatchable and ineligible for CMSC.
**On September 12, 2013 Abitibi stopped bidding into the market, which designates the facility as non-dispatchable and ineligible for CMSC.

The Panel considers that the continuing magnitude of net CMSC payments under the current *Market Rules* and IESO Business Rules, which equated to incremental Uplift charges payable by all Ontario wholesale market customers of $0.04/MWh in 2011 and 2012, and $0.09/MWh in 2013,[238] is significant enough to warrant further analysis. During the stakeholder consultation with dispatchable loads in October 2010 that reinstated constrained-on CMSC payments, the IESO proposed to review “the broader issue of CMSC” in the longer term.[239] In the Panel’s view, such a review is appropriate today.

When the IESO first automated the clawback of CMSC payments in 2007 it reported 6% less clawback by the automated process compared to the former manual process.[240] While substantial improvements have been made, automated clawbacks are inherently limited in their ability to

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[238] Based on total wholesale demand of 154 TWh in 2011, 156 TWh in 2012 and 155TWh in 2013.

[239] See SE-89 Session Notes from October 14, 2010, available online at: http://www.ieso.ca/Documents/consult/se89/se89-20101014-notes.pdf.

[240] IESO Powerpoint Presentation: Dispatchable Load CMSC Clawback, December 12, 2006, online http://www.ieso.ca/imoweb/pubs/consult/dlwg/dlwg-20061212-DL_CMSC%20clawback.pdf p.22

claw back unwarranted CMSC payments because they fail to consider all possible ways in which CMSC payments can be triggered. It may be the case that unwarranted CMSC payments are still being made in part due to limitations in the IESO's automated clawback rules.

The Panel therefore believes that it would be prudent for the IESO to review the remaining sources of CMSC payments with a view to determining which, if any, are unwarranted and should therefore be eliminated.[241] It may also be useful to consider, as an alternative to further clawback refinements, a revised approach in which CMSC payments are made only where they are demonstrated to be warranted (*i.e.* linked to Grid Conditions) rather than relying on an after-the-fact clawback mechanism.

***Recommendation (Review of Continuing CMSC Payments):***

*a) The IESO should review the CMSC payments being made to dispatchable loads since the November/December 2010 amendments to the Market Rules in order to determine whether there are significant amounts that continue to be unwarranted (i.e., paid as a result of market participant actions rather than to compensate for operating profit reductions arising from responding to dispatch instructions caused by Grid Conditions).*

*b) If necessary, the IESO should make further amendments to the Market Rules to eliminate unwarranted CMSC payments to dispatchable loads.*

### 9.4 Recent Developments Regarding Remedial Action for Gaming

As set out in Section 5.1, the Panel's responsibilities include monitoring, investigations and reporting.[242] The Panel submits its investigation reports to the OEB and the IESO. The Panel's

[241] The Panel also noted that it would be useful to undertake such a review in its *Monitoring Report on the IESO-Electricity Markets for the period from May 2011 – October 2011*, online : http://www.ontarioenergyboard.ca/OEB/_Documents/MSP/MSP_Report_20120427.pdf, pp. 47 and 48.

[242] See *Electricity Act, 1998*, section 37 and OEB *By-law*, Articles 4, 5 and 7.

investigation reports may include recommendations, including recommendations regarding *Market Rule* amendments. However, the Panel does not have the legislative mandate to impose sanctions or remedies when it finds that gaming has occurred. While a compliance and enforcement regime exists in relation to breaches of the *Market Rules,* gaming does not necessarily constitute a breach of the *Market Rules.* At present, there is no provision in the *Market Rules* that addresses gaming as a separate and distinct activity, although as noted below a "general conduct rule" is currently under development by the IESO.

The Panel regards gaming as a serious concern because of the potential negative impact on the operation of the wholesale market, the harm to market participants (and ultimately to all electricity consumers in Ontario) who bear the cost of it, and the undermining of public confidence in the market. The Panel therefore believes that remedial action should be available in appropriate cases, whether that action be in the form of penalties, the recovery of gains made by the market participant, or some other sanction. In addition to remedying conduct that has occurred, the prospect of meaningful remedial action would help to deter gaming and contribute to the integrity of the electricity market.

The IESO is currently engaging in stakeholder consultations regarding the introduction of a "general conduct rule" into the *Market Rules* that could encompass gaming (among other matters).[243] The Panel supports this initiative, and encourages the IESO to proceed expeditiously with its consultations and to ensure that any rule that it implements captures the kinds of conduct that are the subject of this Report or that have been discussed in other Panel reports.

[243] Details of the consultation, referred to as Stakeholder Engagement SE-112, are available at http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/SE-112.aspx.

# 10. SUMMARY OF FINDINGS AND RECOMMENDATION

## 10.1 Findings – Bowater

The Panel's findings with respect to its investigation of Bowater are as follows:

***Table 10-1: Summary of Findings Related to Bowater and the Thunder Bay Facility***

| No. | Subject | Finding | Page |
|---|---|---|---|
| 1 | **Market Defects Related to Constrained-off CMSC** | The CMSC rules, formulas and clawback procedures that existed during the Relevant Period allowed a dispatchable load to receive constrained-off CMSC payments that exceeded the amount required to compensate for reductions in operating profits arising from responses to dispatch instructions caused by Grid Conditions. | 52 |
| 2 | **CMSC Ramping Strategy** | Bowater developed strategies to self-induce CMSC payments at the Thunder Bay Facility, and these were known to senior management. | 61 |
| 3 | **Knowledge of CMSC Compensation Principles** | Bowater was aware that the CMSC regime assumed that dispatchable loads would bid based on their Marginal Benefit of Consumption and that CMSC payments were designed to compensate a dispatchable load for operating profit reductions when it was directed by the IESO to follow a dispatch different from its market schedule. | 64 |

| No. | Subject | Finding | Page |
|---|---|---|---|
| 4 | **Operating Profit Impact of Being Constrained Off** | a) During periods when Bowater was not operating the Thunder Bay Facility at capacity, there would be virtually no reduction in operating profits as a result of being constrained off during a ramping hour because production could be made up in a subsequent hour.<br>b) Even in situations where the Thunder Bay Facility was capacity constrained, Bowater's bid prices between February and August 2010 substantially exceeded its Marginal Benefit of Consumption and the reduction in operating profits that would result from the Thunder Bay Facility being constrained off during ramping hours.<br>c) Based on data provided by Bowater, the difference between Bowater's February - June 2010 bid price of $●/MWh and its Marginal Benefit of Consumption when ramping down was at least $1,644/MWh on weekdays and $1,934/MWh on weekends.<br>d) Based on data provided by Bowater, the difference between Bowater's February - June 2010 bid price of $●/MWh and its Marginal Benefit of Consumption when ramping up was at least $1,589/MWh on weekdays and $1,924/MWh on weekends.<br>e) Based on data provided by Bowater, the difference between Bowater's July - August 2010 bid price of $●/MWh and its Marginal Benefit of Consumption when ramping down was at least $445/MWh on weekdays and $735/MWh on weekends.<br>f) Based on data provided by Bowater, the difference between Bowater's July - August 2010 bid price of $●/MWh and its Marginal Benefit of Consumption when ramping up was at least $390/MWh on weekdays and $725/MWh on weekends.<br>g) Bowater's high bid prices were used to obtain CMSC payments that more than compensated Bowater for operating profit reductions by at least $10.3 million. | 72 |

| No. | Subject | Finding | Page |
|---|---|---|---|
| **5** | **Risk of Being Constrained Off** | The risk of being constrained off during self-induced ramping hours did not justify Bowater's use of a bid price of $●/MWh or $●/MWh, or any other level above the Marginal Benefit of Consumption of the Thunder Bay Facility. | 78 |
| **6** | **Risk of Being Activated for Operating Reserve** | The risk of being activated to provide operating reserve during self-induced ramping hours did not justify Bowater's use of an energy market bid price of $●/MWh or $●/MWh, or any other level above the Marginal Benefit of Consumption of the Thunder Bay Facility. | 81 |
| **7** | **High Bid Prices by Other Loads** | The historical use of high bid prices by other dispatchable loads does not provide a justification for Bowater's high bid prices during self-induced ramping hours. | 81 |
| **8** | **Maximum Bid Quantity** | a) Bowater's change in its maximum bid quantity from ● MW to ● MW from February 19 to May 11, 2010 was undertaken to, and did, increase constrained–off CMSC payments.<br><br>b) The estimated amount of incremental CMSC payments derived from Bowater's use of a ● MW maximum bid quantity at the prices Bowater was bidding was $330,000. | 84 |
| **9** | **Ramp Down Timing** | a) Bowater used a ramp down pattern for its auxiliaries that triggered increased CMSC payments during the Relevant Period when there was a known alternative ramping pattern that would have generated significantly lower CMSC payments and that was compatible with the Thunder Bay Facility's operational requirements (having been used before and considered for use after the Relevant Period).<br><br>b) The estimated amount of incremental CMSC payments derived from Bowater's ramp down pattern was $3.9 million at the prices Bowater was bidding. | 91 |

| No. | Subject | Finding | Page |
|---|---|---|---|
| **10** | **Ramping Down Faster than Submitted Rates** | a) Bowater's Thunder Bay Facility was able to, and frequently did, ramp down faster than its submitted ramp rates during the Relevant Period, indicating that its submitted ramp rates were lower than the Facility's operational capabilities.<br><br>b) The submission of ramp down rates that were lower than the Facility's operational capabilities increased the magnitude of constrained-off CMSC payments to Bowater.<br><br>c) The ramping down of the Facility faster than the submitted ramp rates increased the magnitude of constrained-off CMSC payments to Bowater. | 97 |
| **11** | **Failure to Ramp** | The occasions during the Relevant Period where the Thunder Bay Facility failed to ramp after bidding to do so were infrequent. While the resulting CMSC payments were self-induced and should have been clawed back, the available evidence does not indicate that the failures to ramp were intentional attempts by Bowater to exploit a market defect. | 99 |
| **12** | **Constrained-off Dispatch Deviations in Non-Ramping Hours** | Instances of dispatch deviation in non-ramping hours by the Thunder Bay Facility during the Relevant Period were infrequent. While the resulting CMSC payments were self-induced and should have been clawed back, the available evidence does not indicate that these deviations were intentional attempts by Bowater to exploit a market defect. | 101 |
| **13** | **Profit or Benefit to Bowater** | Bowater profited $11.0 million from the CMSC payments received as a result of the behaviours set out in Findings #4 and #8 – 10, which exploited the market defects set out in Finding #1. | 102 |
| **14** | **Expense or Disadvantage to the Market** | All customers in the wholesale energy market were disadvantaged by paying additional Uplift charges of $0.12/MWh as a result of Bowater's behaviours. | 103 |
| **15** | **Finding of Gaming** | Bowater exploited market defects. In so doing, Bowater received $11.0 million in CMSC payments during the Relevant Period, and there was a corresponding disadvantage or expense to the market. Bowater's conduct constitutes gaming. | 104 |

## 10.2 Findings – Abitibi

The Panel's findings with respect to its investigation of Abitibi are as follows:

***Table 10-2: Summary of Findings Related to Abitibi and the Fort Frances Facility***

| No. | Subject | Finding | Page |
|---|---|---|---|
| **1** | **Market Defects Related to Constrained-off CMSC** | The CMSC rules, formulas and clawback procedures that existed during the Relevant Period allowed a dispatchable load to receive constrained-off CMSC payments that exceeded the amount required to compensate for reductions in operating profits arising from responses to dispatch instructions caused by Grid Conditions. | 118 |
| **16** | **Market Defects Related to Constrained-on CMSC** | The CMSC rules, formulas and clawback procedures that existed during the Relevant Period allowed a dispatchable load to receive constrained-on CMSC payments that exceeded the amount required to compensate for reductions in operating profits arising from responses to dispatch instructions caused by Grid Conditions. | 118 |
| **17** | **CMSC Ramping Strategy** | Abitibi developed strategies to self-induce CMSC payments at the Fort Frances Facility, and these were known to senior management. | 123 |
| **18** | **Knowledge of CMSC Compensation Principles** | Abitibi was aware that the CMSC regime assumed that dispatchable loads would bid based on their Marginal Benefit of Consumption and that CMSC payments were designed to compensate a dispatchable load for operating profit reductions when it was directed by the IESO to follow a dispatch different from its market schedule. | 124 |

| No. | Subject | Finding | Page |
|---|---|---|---|
| 19 | **Operating Profit Impact of Being Constrained Off** | a) During periods when Abitibi was not operating the Fort Frances Facility at capacity, there would be virtually no reduction in operating profits as a result of being constrained off during a ramping hour because production could be made up in a subsequent hour.<br><br>b) Even in situations where the Fort Frances Facility was capacity constrained, Abitibi's bid prices during the Relevant Period substantially exceeded its Marginal Benefit of Consumption and the reduction in operating profits that would result from the net load at the Fort Frances Facility being constrained off during ramping hours.<br><br>c) Based on data provided by Abitibi and the Facility's electricity consumption pattern, the difference between Abitibi's bid price of \$●/MWh (or \$●/MWh) and its Marginal Benefit of Consumption when ramping (up or down) was at least \$1,418/MWh (or \$1,369/MWh).<br><br>*d)* Abitibi's high bid prices were used to obtain CMSC payments that more than compensated Abitibi for operating profit reductions by at least \$5.9 million. | 129 |
| 20 | **Risk of Being Constrained Off** | The risk of being constrained off during self-induced ramping hours did not justify Abitibi's use of a bid price of \$●/MWh or \$●/MWh, or any other level above the Marginal Benefit of Consumption of the Fort Frances Facility. | 132 |
| 21 | **Risk of Being Activated for Operating Reserve** | The risk of being activated to provide operating reserve during self-induced ramping hours did not justify Abitibi's use of an energy market bid price of \$●/MWh or \$●/MWh, or any other level above the Marginal Benefit of Consumption of the Fort Frances Facility. | 133 |
| 22 | **High Bid Prices by Other Loads** | The historical use of high bid prices by Abitibi or any other dispatchable loads does not provide a justification for Abitibi's high bid prices during self-induced ramping hours. | 134 |

| No. | Subject | Finding | Page |
|---|---|---|---|
| 23 | **Ramping Down Faster than Submitted Rates** | a) Abitibi's Fort Frances Facility was able to, and frequently did, ramp down the net load faster than its submitted ramp rates, indicating that its ramp rates were lower than its operational capabilities.<br>b) The submission of ramp rates that were lower than the Fort Frances Facility's operational capabilities increased the magnitude of constrained-off CMSC payments to Abitibi.<br>c) The ramping down of the Fort Frances Facility faster than the submitted ramp rates increased the magnitude of constrained-off CMSC payments to Abitibi. | 137 |
| 24 | **Frequent Ramping** | Abitibi increased its CMSC payments through frequent ramping of the Fort Frances Facility during the Relevant Period by at least $5.8 million. | 143 |
| 25 | **Bid Prices When Using Generator to Alter Net Consumptio n** | When Abitibi used the generator to implement self-induced changes to the net load at the Fort Frances Facility, the bid prices it submitted did not reflect the marginal cost of the generating facility, resulting in CMSC payments that substantially exceeded the amount needed to compensate Abitibi for any operating profit reductions, but was not a deliberate attempt to exploit a market defect. | 146 |
| 26 | **Ramp Rates When Using Generator to Alter Net Consumptio n** | When Abitibi used the generator to implement self-induced changes to the net load at the Fort Frances Facility, the ramp rates it submitted did not reflect the actual ramping capabilities of the generator, resulting in CMSC payments that substantially exceeded the amount needed to compensate Abitibi for any operating profit reductions, but was not a deliberate attempt to exploit a market defect. | 147 |
| 27 | **Failure to Ramp** | The occasions during the Relevant Period where the Fort Frances Facility failed to ramp after bidding to do so were infrequent. While the resulting CMSC payments were self-induced and should have been clawed back, the available evidence does not indicate that these failures to ramp were attempts by Abitibi to exploit a market defect. | 149 |

| No. | Subject | Finding | Page |
|---|---|---|---|
| **28** | **Constrained-Off Dispatch Deviations in Non-Ramping Hours** | Instances of dispatch deviation in non-ramping hours by the Fort Frances Facility were infrequent. While the CMSC payments were self-induced and should have been clawed back, the available evidence does not indicate that these deviations were attempts by Abitibi to exploit a market defect. | 151 |
| **29** | **Constrained-On CMSC Payment Strategy** | Abitibi's adoption of a negative-price bidding strategy between April and August 2010, which was known to senior management, was a deliberate attempt to exploit a market defect in the CMSC regime that had been publicly identified as such by the Panel and was in the process of being rectified by the IESO. | 161 |
| **30** | **Negative Bid Prices** | *a)* Abitibi's -$●/MWh bid price was well below its Marginal Benefit of Consumption during the hours in which such bids were submitted for the net load at the Fort Frances Facility.<br>*b)* Abitibi's low bid price was used to obtain CMSC payments that more than compensated Abitibi for operating profit reductions by at least $1.8 million. | 163 |
| **31** | **Constrained-On Dispatch Deviations** | Abitibi deviated from the Fort Frances Facility's dispatch instructions on numerous occasions that resulted in the Facility appearing to be constrained on and receiving CMSC payments when its bids indicated it did not want to consume. | 164 |
| **32** | **Profit or Benefit to Abitibi from Constrained-off CMSC** | Abitibi profited $7.5 million from the constrained-off CMSC payments received as a result of the behaviours set out in Findings #19, 23 and 24**,** which exploited the market defects set out in Finding #1. | 166 |
| **33** | **Profit or Benefit to Abitibi from Constrained-on CMSC** | Abitibi profited $1.9 million from the constrained-on CMSC payments received as a result of the behaviours set out in Findings #30 and 31, which exploited the market defects set out in Findings #1 and #16. | 168 |

| No. | Subject | Finding | Page |
|---|---|---|---|
| **34** | **Expense or Disadvantage to the Market** | All customers in the wholesale energy market were disadvantaged by paying additional Uplift charges of $0.09/MWh as a result of Abitibi's behaviours. | 169 |
| **35** | **Finding of Gaming** | Abitibi exploited market defects. In so doing, Abitibi received $9.4 million in CMSC payments during the Relevant Period, and there was a corresponding disadvantage or expense to the market. Abitibi's conduct constitutes gaming. | 170 |

### 10.3 Recommendation

The Panel makes the following recommendation to the IESO:

a) *The IESO should review the CMSC payments being made to dispatchable loads since the November/December 2010 amendments to the Market Rules in order to determine whether there are significant amounts that continue to be unwarranted (i.e., paid as a result of market participant actions rather than to compensate for operating profit reductions arising from responding to dispatch instructions caused by Grid Conditions).*

b) *If necessary, the IESO should make further amendments to the Market Rules to eliminate unwarranted CMSC payments to dispatchable loads.*

## Appendix A Glossary

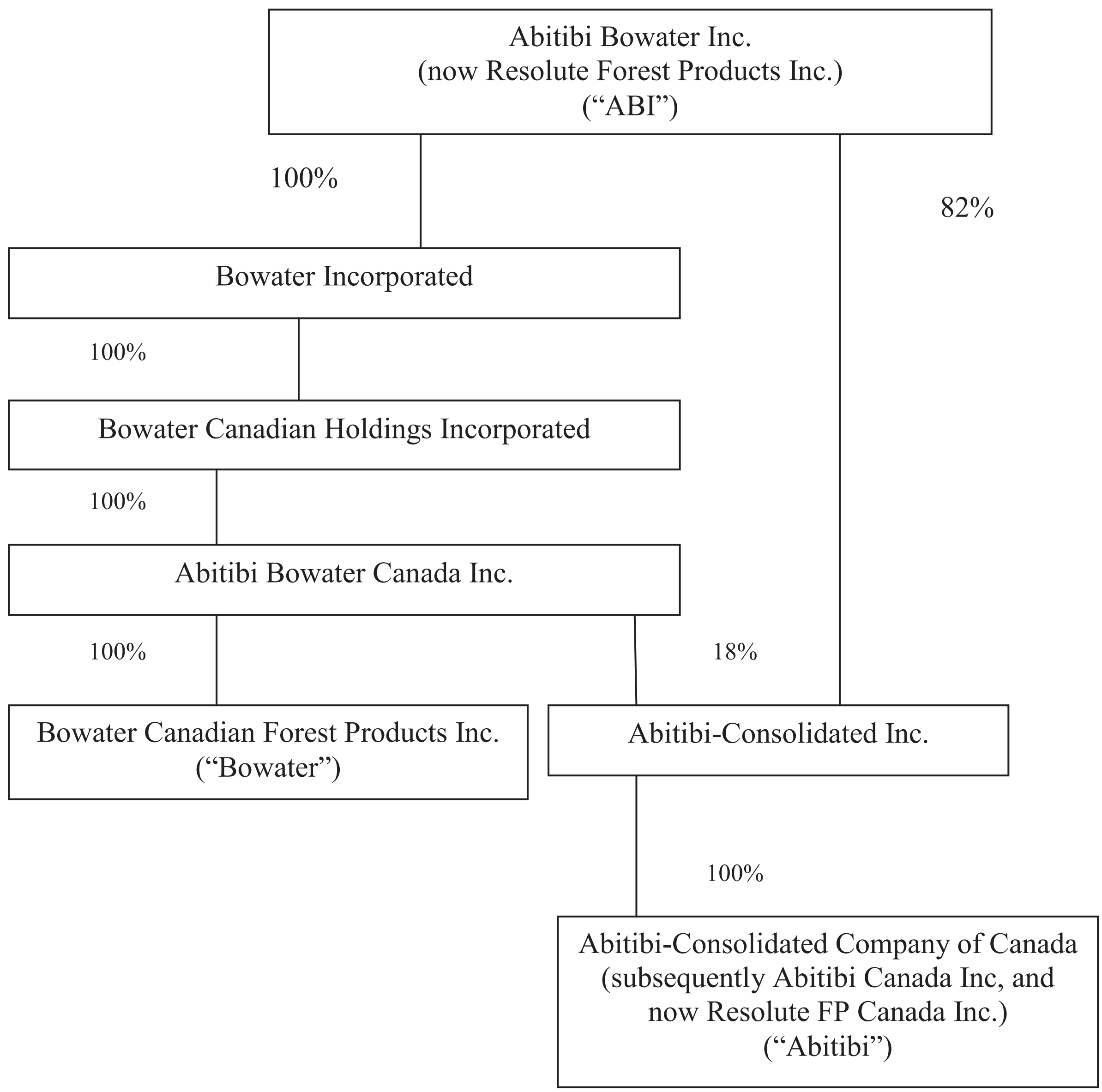
| Term/ Abbreviation | Definition | Page |
|---|---|---|
| **Act** | *Electricity Act, 1998* | 23 |
| **ABI** | AbitibiBowater Inc. (ultimate parent company of Abitibi and Bowater) | 18 |
| **Abitibi** | Abitibi-Consolidated Company of Canada, owner and operator of the Fort Frances Facility | 17 |
| **Bowater** | Bowater Canadian Forest Products Inc., owner and operator of the Thunder Bay Facility | 17 |
| **Business Rules** | The IESO initially relied on manual processes to identify CMSC payments that should be recovered. In 2007, the IESO introduced an automated approach to CMSC recovery, and documented the procedures used to calculate the amount of participant-induced CMSC that may be clawed back under the *Market Rules* in four Business Rules (see overview in Appendix H) | 40 |
| **CCAA** | *Companies' Creditors Arrangements Act* | 18 |
| **CMSC** | Congestion Management Settlement Credit | 9 |
| **Compliance Deadband** | The allowable range of variation in actual consumption relative to the IESO's dispatch instructions. (The Compliance Deadband for a resource with the characteristics of the Thunder Bay Facility or the Fort Frances Facility is 15 MW above or below its dispatch instruction.) | 83 |
| **Constrained Schedule** | Energy injections and withdrawals for dispatchable facilities that can actually happen within the physical constraints of the system | 32 |
| **Dispatch Envelope** | The range between the maximum and minimum dispatch instruction based on the load's current consumption level and submitted ramp rates | 98 |
| **Dispatch Schedule** | See Constrained Schedule | 31 |

| Term/ Abbreviation | Definition | Page |
|---|---|---|
| **DR2 Agreement** | A 2009 agreement between Bowater and the Ontario Power Authority which preceded the reopening of the Thunder Bay Facility | 43 |
| **Fort Frances Facility** | Abitibi's facility in Fort Frances, Ontario includes three paper machines (two of which were active), one kraft mill, and a biomass and natural gas boiler/generator | 19 |
| **Grid Conditions** | All physical limitations on the grid, including transmission constraints and transmission line losses | 31 |
| **h** | one hour | 46 |
| **h+1** | the following hour | 46 |
| **HOEP** | Hourly Ontario Energy Price | 29 |
| **IESO** | Independent Electricity System Operator | 17 |
| **Lamination** | One component of a dispatchable load's bid for electricity consumption, consisting of a P/Q Pair. A bid may have up to 20 laminations. | 30 |
| **MAU** | The IESO's Market Assessment Unit | 23 |
| **Marginal Benefit of Consumption** | The Marginal Benefit of Consumption is the incremental net revenue expected to result from increasing production by consuming an additional MW of electricity. "Net revenue" is the revenue expected to result from selling the additional output less variable costs of production other than electricity. A firm normally would not be prepared to pay more than the Marginal Benefit of Consumption. If it did so, the cost of the extra MW would exceed the incremental net revenue from increasing output (*i.e.,* its operating profits would be reduced). The Marginal Benefit of Consumption may also be used to measure the lost net revenues (again, before considering electricity costs) when a firm consumes one less MW of electricity. A firm normally would not reduce its consumption if the Marginal Benefit of Consumption exceeded the price of electricity | 37 |

| Term/ Abbreviation | Definition | Page |
|---|---|---|
| **Market defect** | A defect in the market design, poorly specified rules or procedures or a gap in the *Market Rules* or procedures | 27 |
| **Market Schedule** | See Unconstrained Schedule | 24 |
| **MCP** | Market Clearing Price | 29 |
| **MMCP** | Maximum Market Clearing Price ($2,000/MWh) | 30 |
| **MSP** | Market Surveillance Panel | 17 |
| **MSP By-Law** | OEB By-Law #3 – Market Surveillance Panel | 23 |
| **Nodal Price** | The system marginal cost of supply at a point on the grid | 33 |
| **OR** | Operating Reserve | 78 |
| **Operating Profit** | For each MW of consumption, the difference between a dispatchable load's Marginal Benefit of Consumption for the MW and the price paid for consuming the MW. | 62 |
| **Panel** | Market Surveillance Panel | 17 |
| **P/Q Pair** | One lamination of a bid by a dispatchable load, consisting of a bid price ("P") and the corresponding quantity ("Q") that the load is prepared to consume at that price. | 45 |
| **Protocol** | Protocol between the Ontario Energy Board and the Independent Electricity System Operator Related to Market Surveillance Panel | 23 |
| **Ramp Rate** | How quickly a load (or generator) can change (upwards or downwards) the amount of energy it is consuming (or producing), expressed in MW/minute | 33 |
| **Relevant Period** | January 2010 to August 2010 | 17 |
| **Responses to RFI** | Responses from Bowater and Abitibi to the Panel's requests for information. | 26 |

| Term/ Abbreviation | Definition | Page |
|---|---|---|
| **Thunder Bay Facility** | Bowater's facility in Thunder Bay, Ontario includes a thermo-mechanical pulpmill with two mainline refiners, a rejects refiner, auxiliaries, and a recycle mill | 18 |
| **TMP** | Thermo-mechanical pulpmill | 18 |
| **Unconstrained Schedule** | The amount of energy that dispatchable facilities would be prepared to inject or withdraw if there were no constraints on the system | 33 |
| **Uplift** | CMSC payments are charged pro rata to all wholesale loads (including exports) through hourly uplift charges | 11 |

## Appendix B Abitibi Bowater Inc. Corporate Chart



## Appendix C Selected Bowater and Abitibi Personnel who Prepared or Received Communications and Documents Referred to in this Report

| Name | Position | Company |
|---|---|---|
| ● | ● | Bowater<br>Thunder Bay Operations |
| ● | ● | Abitibi<br>Fort Frances Operations |
| ● | ● | Abitibi<br>Fort Frances Operations |
| ● | ● | AbitibiBowater Inc.<br>Montreal Operations |
| ● | ● | Bowater<br>Thunder Bay Operations |
| ● | ● | AbitibiBowater Inc.<br>Montreal Operations |
| ● | ● | Abitibi<br>Fort Frances Operations |
| ● | ● | Bowater<br>Thunder Bay Operations |
| ● | ● | Abitibi<br>Fort Frances Operations |
| ● | ● | AbitibiBowater Inc.<br>Montreal Operations |
| ● | ● | Bowater<br>Thunder Bay Operations |
| ● | ● | Bowater<br>Thunder Bay Operations |
| ● | ● | AbitibiBowater Inc.<br>Thunder Bay Operations |

| Name | Position | Company |
|---|---|---|
| ● | ● | AbitibiBowater Inc.Montreal Operations |
| ● | ● | AbitibiBowater Inc.<br>Montreal Operations and Sales |
| ● | ● | Abitibi<br>Fort Frances Operations |
| ● | ● | AbitibiBowater Inc.<br>Montreal Operations |
| ● | ● | Bowater<br>Thunder Bay Operations |
| ● | ● | Bowater<br>Thunder Bay Operations |

# Appendix D The Unconstrained Mode and Schedule

## D.1 Determining the Market Clearing Price and Market Schedules

The Market Clearing Price (MCP) is the price at which the supply of electricity is equal to the demand for electricity. This is the point where a downward sloping demand curve intersects with an upwards sloping supply curve. Conceptually, the MCP is established by stacking all offers of supply from the lowest to the highest offer price until the total quantity offered equals the amount of electric power demanded.[244]

The MCP is calculated for each five-minute interval and the MCPs are averaged to calculate the HOEP. Subject to various adjustments, all wholesale market suppliers are remunerated on the basis of the MCP or HOEP, even if they offered the energy at a lower price, and all wholesale market customers pay the MCP or HOEP, even if their bid indicated a willingness to consume at a higher price.[245]

There are three particularly important characteristics which distinguish the unconstrained mode from the constrained mode: absence of physical constraints; a ramp-rate-multiplier; and single-interval optimization. Each of these characteristics cause the quantities determined in the unconstrained schedule to differ from those in the constrained schedule.

## D.2 Absence of Physical Constraints

The unconstrained mode basically ignores transmission constraints inside Ontario. This allows the calculation of a five-minute MCP (or HOEP) that is the same for all energy market participants in Ontario because it does not consider line losses, transmission congestion, and other system constraints that would otherwise cause supply/demand conditions and prices to differ from location to location on the grid.

[244] Electric power demanded is the sum total of fixed electric power demanded from non-dispatchable loads and exports plus the amount of variable electric power demanded from dispatchable loads that are priced higher than any offers of supply that remain after the demand from non-dispatchable load and exports has been satisfied.

[245] Dispatchable generators receive, and dispatchable loads pay, the five-minute MCP. Non-dispatchable generators and loads are settled using HOEP (as are importers and exporters, subject to localized congestion price adjustments).

### D.3 Ramp-Rate-Multiplier

The unconstrained mode unrealistically assumes dispatchable facilities can ramp up or down three times faster than the ramp rates they submit to the IESO. The original Ontario market design did not include such an assumption. However, in market testing before the market opening in May 2002, the IESO discovered that market prices could be volatile during periods when the whole system was ramping up or down. The *Market Rules* were amended just before market opening to require that the unconstrained mode use ramp rates that were 12 times faster than the ramp rates submitted by market participants.[246] This assumption was changed to a three-times ramp-rate-multiplier in September 2007 after a proceeding before the OEB.[247] The ramp-rate-multiplier means that market schedules for dispatchable facilities will, in periods where the facility is ramping up or down, include quantities that the facility could never generate or consume.

### D.4 Single-Interval Optimization

In the unconstrained mode, the dispatch algorithm looks backwards to the interval that just ended as a starting point to determine the MCP and market schedule quantities for the current interval. The results for each interval are calculated in isolation from all other intervals (*i.e.*, the dispatch algorithm optimizes the market schedule for a single interval without consideration of any future intervals). As a result, the market schedule can change significantly from one interval to the next as the dispatch algorithm reacts to changes in generator and importer (supply) offers, dispatchable load and exporter (demand) bids, and estimated demand from non-dispatchable loads. Typically, such changes are largest "across-the-hour" as the unconstrained mode considers a set of hourly offers and bids in interval 1 of the new hour that may be significantly different from those applicable during the prior hour.

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[246] IESO, Market Rule Amendment MR-00189, April 18, 2002, online (as an attachment to Market Pricing Working Group Memorandum): http://www.ieso.ca/imoweb/pubs/consult/mep2/MP_WG-200708023-Memo_Action_Item_43-1.pdf, p. 3.

[247] IESO, Market Rule Amendment MR-00331, September 12, 2007, online: http://www.ieso.ca/Documents/Amend/mr2007/MR-00331-R00-BA.pdf; and OEB, Decision Order, EB-2007-0040, April 12, 2007, online: http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0040/dec_order_revised_ampco_20070412.pdf, p. 26.

## D.5 The Market Schedule

The unconstrained mode determines the market schedule for each dispatchable market participant based on the absence of physical constraints, the ramp-rate-multiplier and single-interval optimization. The quantities shown in market schedules are not used to calculate the basic energy payments or charges to market participants: they get paid or charged based on actual injection or withdrawal quantities. However, the MCPs are used as the starting point for settlement calculations and the quantities in the market schedules are used for determining CMSC payments (see Appendix F).

# Appendix E The Constrained Mode and Schedule

## E.1 Determining Dispatch Instructions and Nodal Prices

While the unconstrained mode focuses solely on economics, the constrained mode considers both economics and system limitations. There are three particularly important characteristics that are taken into account during the constrained mode: physical constraints; actual ramp rates; and multi-interval optimization. Each of these characteristics cause the quantities determined in the constrained schedule to differ from the unconstrained schedule.

The constrained mode of the dispatch algorithm also calculates Nodal Prices at each physical location on the transmission system where energy is injected by generators or withdrawn by loads. If suppliers' offers reflect their marginal cost of supplying electricity, and customers' bids reflect the marginal value they place on consumption, then the Nodal Prices will represent the locational value of the energy (including the cost of any line losses, and the impact of congestion) at each node.

## E.2 Physical Constraints

Initially, the constrained mode stacks offers and bids economically. It then determines whether or not it can dispatch the facilities in economic order and still respect system limitations such as line losses and transmission limitations applicable to each of the injection and withdrawal locations on the grid.

Physical dispatch instructions for a facility are based on the relationship of the facility's offers or bids to the Nodal Price determined for its node. For example, the constrained schedule for a dispatchable load will not schedule any energy withdrawals where the load's bid price (which applies throughout the hour) is less than the relevant five-minute interval Nodal Price (even though the load's bid price may be well above the five-minute uniform MCP and the unconstrained mode has included the load as consuming in the market schedule, in which case a CMSC payment would be calculated).

### E.3 Actual Ramp Rates

The constrained mode uses the actual ramp rates submitted by market participants, not the three-times faster ramp-rate-multiplier used in the unconstrained schedule (see Appendix D).

### E.4 Multi-Interval Optimization

In the constrained mode, the dispatch algorithm determines dispatch instructions for the next five-minute interval having regard to expected future system conditions. This multi-interval optimization (MIO) process considers both economics and system limitations over a number of intervals, rather than the singleinterval retrospective approach used in the unconstrained schedule (see Appendix D). With the benefit of foresight, the dispatch algorithm produces a more efficient dispatch pattern because it recognizes ramp rate limitations, expected changes in non-dispatchable demand and across-the-hour offer or bid changes in future intervals (based on hourly pre-dispatch offer and bid submissions). For example, it may ramp slower-moving but lower-cost dispatchable facilities in advance of the intervals when they are most needed (instead of more expensive resources with faster ramping capability).[248]

### E.5 The Constrained Schedule

The constrained mode produces a dispatch schedule which identifies the expected supply or consumption by each dispatchable facility for each five-minute interval. However, the quantities and the Nodal Prices in the dispatch schedule, are not used as the basis for settlement calculations (except to the extent that they affect CMSC calculations (see Appendix F)).

[248] For more detail, see IESO, *Quick Takes 13: Multi-Interval Optimization: An IESO Marketplace Training Publication*, online: http://www.ieso.ca/imoweb/pubs/training/QT13_MIO.pdf.

## Appendix F Calculation of Constrained-Off and Constrained-On CMSC Payments

The CMSC payment for a dispatchable load in any five-minute interval is effectively calculated as the difference between the bid price and MCP, multiplied by the difference between unconstrained schedule and the constrained schedule (or in certain circumstances the load's actual consumption). More precisely:[249]

Constrained-off CMSC = [Bid price – MCP] x [MQSW – max (DQSW, AQEW)]

Constrained-on CMSC = [MCP – Bid price] x [min (DQSW, AQEW) – MQSW]

Where:

MQSW is the quantity in the load's market (unconstrained) schedule,

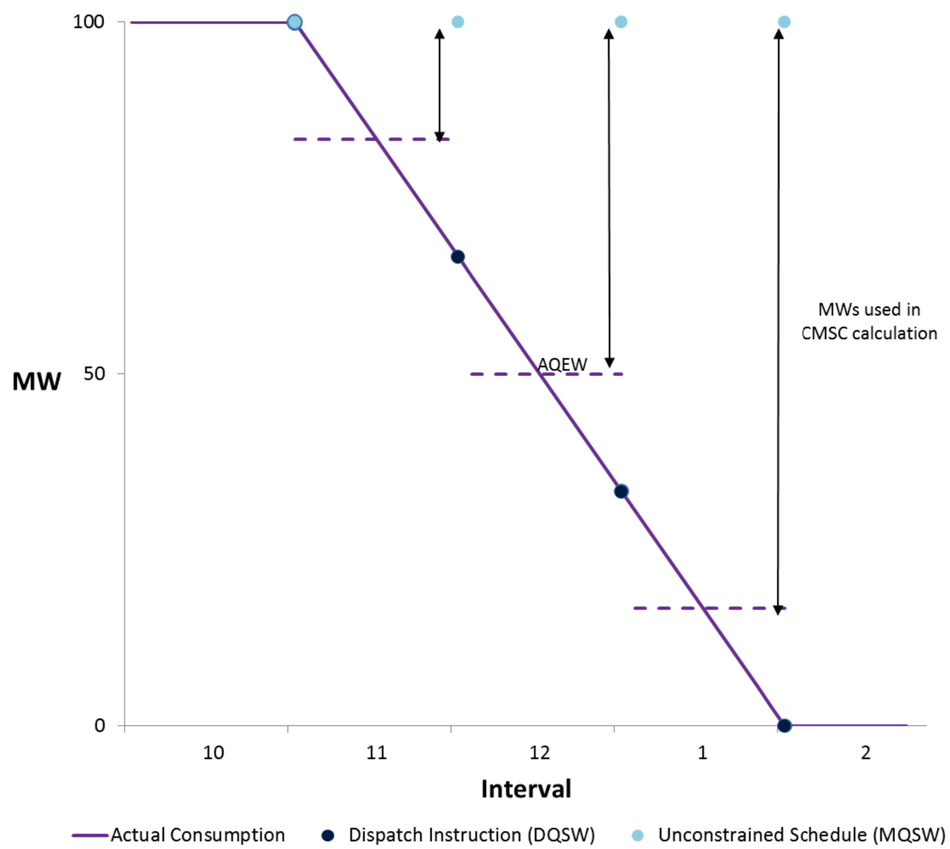
DQSW is the quantity in the load's dispatch (constrained) schedule, and

AQEW is the quantity actually consumed by the load during the interval.

There is an important distinction between DQSW and AQEW. DQSW is a MW quantity that the IESO instructs a dispatchable facility to meet by the end of the next five-minute interval. AQEW is the actual energy withdrawn by the load over the entire five-minute interval as measured by the facility's revenue meter. Where the load varies its consumption over the course of an interval, the reported AQEW value will be an average value. Figure F-1 shows how the DQSW and AQEW differ when a load receives a series of decreasing dispatch instructions during a ramp down and it fully complies with dispatch instructions.

[249] The last parts of these simplified equations are expressed as either a maximum or minimum of two quantities. This is necessary to ensure CMSC will not be paid when a load does not fully adjust its consumption to the level required by the IESO's dispatch instructions. See *Market Rules*, ch. 9, s. 3.5 for the precise CMSC equations.

***Figure F-1: Illustration of How CMSC is Calculated Using the Maximum of AQEW and DQSW During a Ramp Down***



## Appendix G CMSC Payments Arising from Self-Induced Ramping

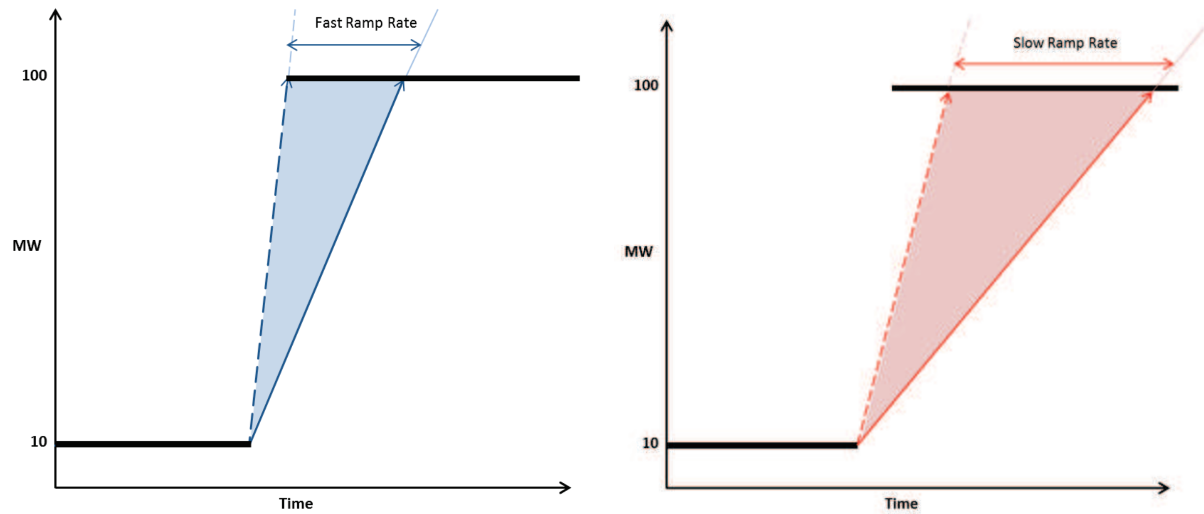
Ramping decisions made by a market participant may result in self-induced CMSC payments. More specifically, changes in the bid (or offer) quantities and/or prices of a market participant can self-induce ramping of a facility and give rise to CMSC payments that are not caused by IESO actions related to transmission or security limitations and that may overcompensate a load (or generator).

### G.1 Ramp-Rate-Multiplier on Ramp Ups

The three-times ramp-rate-multiplier that is built into a load's unconstrained schedule can contribute to CMSC payment through differences between the market and dispatch schedules whenever a load takes more than one interval to ramp up or down to a desired level of consumption. Depending on the load's ramp rates, the quantities in the unconstrained and constrained schedules may deviate during several intervals. All else being equal, the slower a load's ramp rate, the greater the deviation between the unconstrained and constrained schedules, and the higher the CMSC payments will be. This type of CMSC arises on ramps induced by a change in a facility's bids, as well as dispatches arising from changes in market supply/demand conditions.

Figure G-1 illustrates how a load's ramp rates affect schedule quantity differences (and hence the amount of CMSC) when the load is ramping. Assume the facility is ramped up from 10 MW to 100 MW. The solid lines represent the ramp in the constrained sequence: the blue line indicates a fast ramp rate and the red line, a slower ramp rate. The solid lines represent the fast or slow ramps in the constrained schedule and the dashed diagonal lines represent the unconstrained schedule (based on the three-times ramp-rate-multiplier). The quantity difference (and hence CMSC payment) is relatively small where the load ramps up quickly (blue shaded area). However, where the load ramps up slowly, a larger quantity difference (and CMSC payment) is generated (red shaded area).

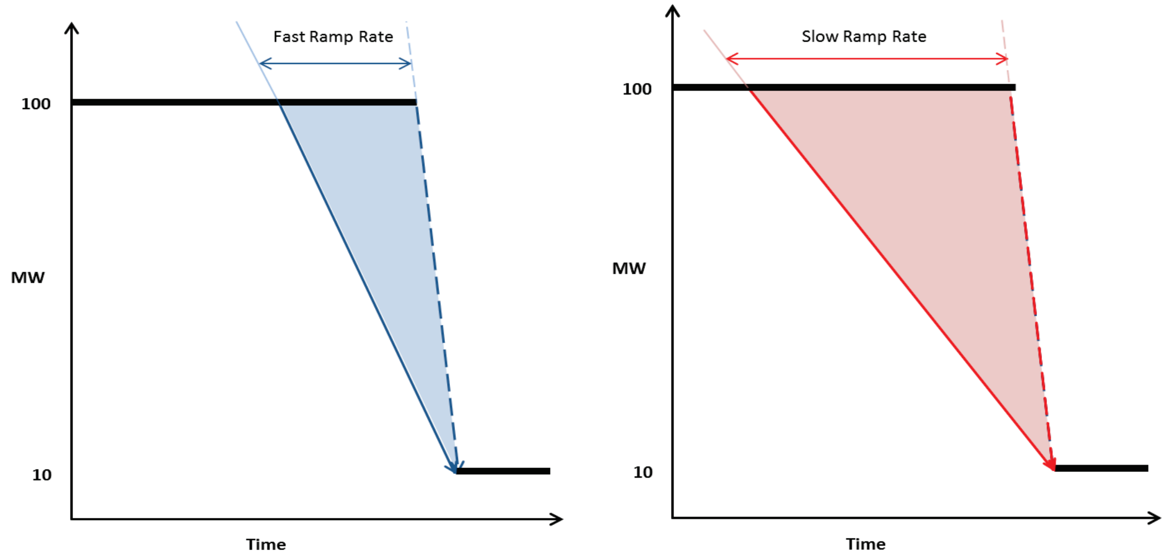
***Figure G-1: Illustration of How CMSC May be Increased Using a Lower Ramp Rate During Self-Induced Ramp Up***




## G.2 Ramp-Rate-Multiplier on Ramp Downs

Figure G-2 illustrates how a load's ramp rates affect schedule quantity differences (and hence the amount of CMSC) when the load self-induces a ramp down. Assume the facility is ramped down from 100 MW to 10 MW. The quantity difference (and hence CMSC payment) is relatively small where the load ramps down quickly (blue shaded area). However, where the load ramps down slowly, a larger quantity difference (and CMSC payment) is generated (red shaded area).

***Figure G-2: Illustration of How CMSC May be Increased Using a Lower Ramp Rate During Self-Induced Ramp Down***




## G.3 Single and Multi-Interval Optimization

Single versus multi-interval optimization causes similar variations between constrained and unconstrained schedules, again leading to CMSC payments. Under MIO, the constrained schedule is set on a "looking forward" basis, whereas the unconstrained schedule looks backward. When MIO looks forward for an upcoming hour 'h+1'and sees that the quantity bid has been reduced, the IESO dispatch tool begins ramping down the constrained schedule in advance of the next hour to ensure the facility is consuming no more than its quantity bid by interval 1 of hour 'h+1'. In contrast, the unconstrained schedule does not look ahead to hour 'h+1', it only sees the full quantity bid in the current hour (*i.e.* it does not consider that the bid quantity has dropped in hour 'h+1' until the beginning of hour 'h+1' when the schedule starts ramping down). As the load ramps down in advance of hour 'h+1' the market and dispatch schedules will diverge. As such, the load appears to be constrained off and receives CMSC, even though the facility was being dispatched in accordance with its quantity bids and was consuming no more and no less than it desired.

# Appendix H IESO "Business Rules" for Clawback of Constrained-Off CMSC Payments

In 2007, the IESO introduced an automated approach to CMSC recovery. It also documented the procedures used that would be to calculate the amount of participant-induced CMSC that may be clawed back under the *Market Rules*. The four criteria — referred to as "Business Rules" — which are applied by the IESO to recover constrained-off CMSC from dispatchable load, are summarized below:[250]

## H.1 Business Rule 1 – Materiality

Constrained-off CMSC is allowed for an interval if the total amount of CMSC paid during that trading day to that dispatchable load is less than $4,000.

## H.2 Business Rule 2 – Non-Dispatchable Portion of Load

Constrained-off CMSC is not allowed for an interval if it is paid for portions of the schedule where the load has bid at +MMCP (*i.e.* $2,000/MWh), indicating that it is non-dispatchable in that quantity range.

## H.3 Business Rule 3 – Dispatch Deviation

Constrained-off CMSC is not allowed for an interval if the current 5-minute constrained schedule exceeds the revenue meter value (*i.e.*, actual consumption) in the previous interval plus 2.5 minutes of ramping. However, this rule does not apply in various circumstances, including: when the load is constrained-off economically; when the load is ramping; and when the load is manually dispatched down for reliability.

[250] IESO, Market Manual 5, Part 5.5: Physical Markets Settlement Statements, s. 1.6.9. The *Market Rules* and IESO procedures do not address recovery of constrained-on CMSC.

### H.4 Business Rule 4 – Facility Off-Line or Unable to Follow Dispatch

Constrained-off CMSC is not allowed for an interval if the constrained schedule is 0 MW and consumption is less than 1 MW, or if consumption is 0 MW. However, this rule does not apply in various circumstances, including: when the load is constrained-off economically; and when the load is manually dispatched down for reliability.

### H.5 Intervals

There are over 100,000 five-minute intervals in a year, and there will be differences in many of those intervals between the constrained and unconstrained schedules for dispatchable loads and generators. It is a tall order to search out and clawback all inappropriate CMSC payments when, as described in Section 6 and Appendix D through Appendix G, there are various reasons why the quantity schedules can differ.

## Appendix I Five Largest CMSC Payment Days for Bowater's Thunder Bay Facility

Table I-1 below shows the five days on which Bowater received the highest CMSC payments for the Thunder Bay Facility in 2010. On each of these days the CMSC payments received far exceeded the charges incurred for the energy consumed.

***Table I-1: Highest CMSC Daily Payments and Net Energy Cost for the Thunder Bay Facility January to August 2010 ($000)***

| Date | Energy Charges* | CMSC Payments** | Net Energy Costs (Revenue) |
|---|---|---|---|
| April 11, 2010 (Sunday) | 35 | 215 | (180) |
| March 05, 2010 (Friday) | 89 | 179 | (90) |
| February 21, 2010 (Sunday) | 133 | 153 | (20) |
| May 16, 2010 (Sunday) | 127 | 128 | (1) |
| April 26, 2010 (Monday) | 88 | 123 | (35) |
| **Total Top Five** | **$471** | **$798** | **$(326)** |

* Includes Global Adjustment and Uplift charges.
** All amounts are net constrained-off CMSC payments after clawback of certain types of CMSC (charge type 105 less charge type 1050).

Figures I-1 to I-5 below show the hourly constrained and unconstrained schedules, as well as actual consumption and CMSC payments, on each of the five days listed above.

***Figure I-1: Schedules and CMSC Payments for the Thunder Bay Facility April 11, 2010 ($ and MW)***

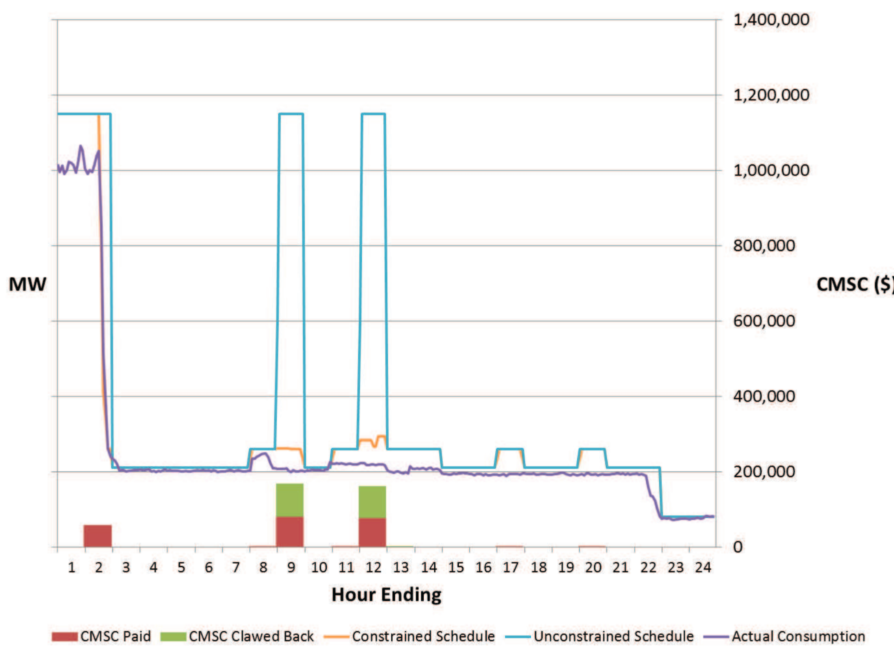



***Figure I-2: Schedules and CMSC Payments for the Thunder Bay Facility March 5, 2010 ($ and MW)***

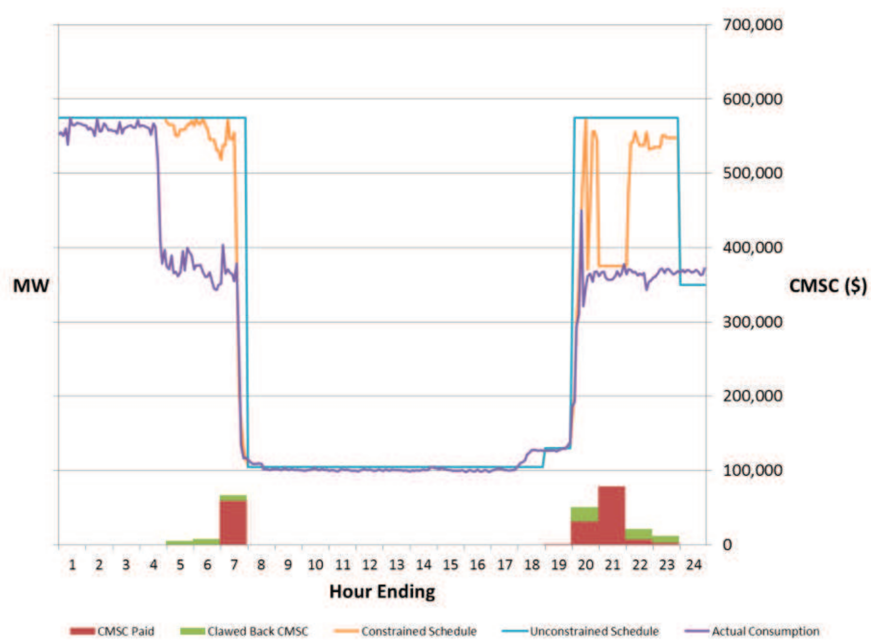


***Figure I-3: Schedules and CMSC Payments for the Thunder Bay Facility February 21, 2010 ($ and MW)***

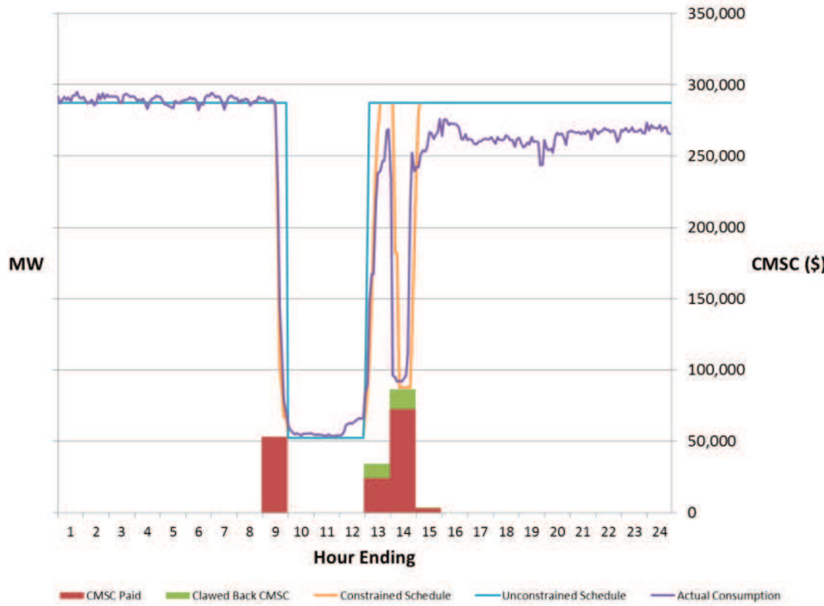



***Figure I-4: Schedules and CMSC Payments for the Thunder Bay Facility May 16, 2010 ($ and MW)***

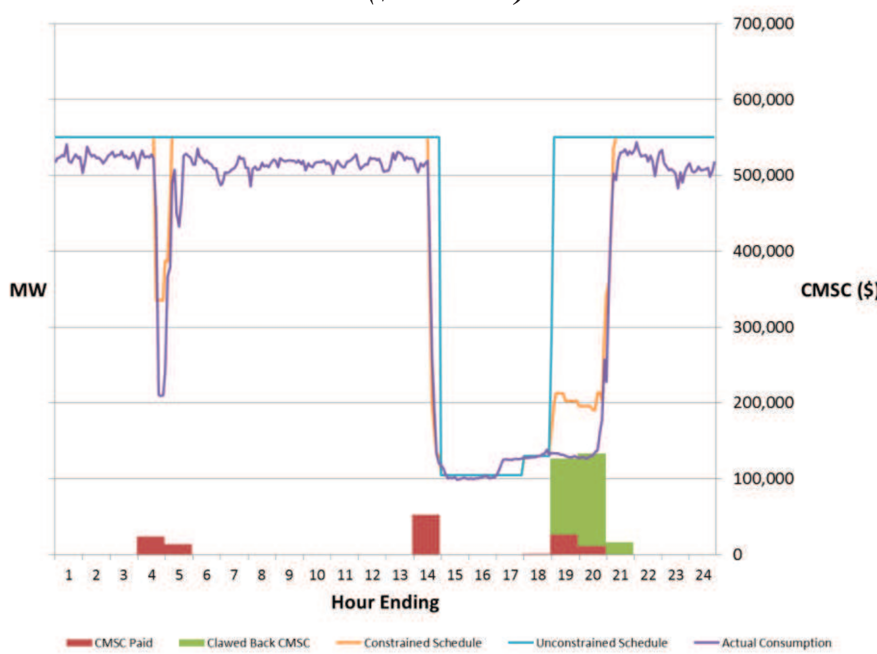
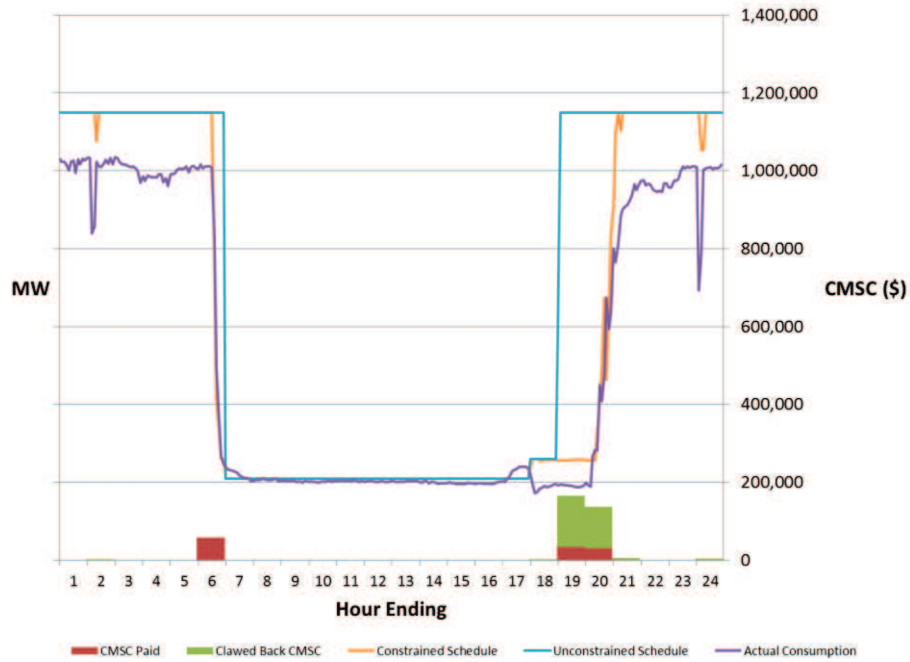


***Figure I-5: Schedules and CMSC Payments for the Thunder Bay Facility April 26, 2010 ($ and MW)***



## Appendix J AbitibiBowater Canada Inc. Presentation Slides Discussing CMSC and Operating Reserve

An internal PowerPoint presentation prepared by [Senior Bowater Personnel #2] for Abitibi Bowater's Vice Presidents, entitled "Thunder Bay 2010 Power Cost – October 1st, 2009", provided a summary of various financial programs, including CMSC and Operating Reserve.[251] Four slides from the presentation which discuss CMSC and Operating Reserve are reproduced below.

**Slide Redacted – Contains Confidential Information**

[251] Responses to RFI, B.3.6.

**Slide Redacted – Contains Confidential Information**

**Slide Redacted – Contains Confidential Information**

**Slide Redacted – Contains Confidential Information**

## Appendix K Sample Bowater Calculations for the Thunder Bay Facility Relating to Ramping Down Faster than Submitted Ramp Rates

Below is a spreadsheet prepared by personnel at the Thunder Bay Facility which shows how Bowater planned and forecasted their "Optimized CMSC Payment (actual load < constrained schedule)", which entails ramping faster than submitted ramp rates.[252]

**Spreadsheet Redacted – Contains Confidential Information**

[252] Attachment titled "TMP Shutdown & Stat Up Sequence re Dispatchable.xls" in email from [Senior Bowater Personnel #5] to [Senior AbitibiBowater Inc Personnel #2] and [Senior Abitibi Personnel #2], January 22, 2010. Responses to RFI, B.2.25.

## Appendix L Sample Bowater Analysis of CMSC During Ramp Down

Below is a chart prepared by personnel at the Thunder Bay Facility which shows Bowater understood that the CMSC calculation was based on the MW difference between the unconstrained schedule and the maximum of the constrained schedule or the actual energy withdrawn.[253] The chart and sample CMSC calculation shows the Thunder Bay Facility's consumption as greater than the constrained dispatch instruction during the first two ramp down intervals.

**Chart Redacted – Contains Confidential Information**

[253] Included in email from [Senior Bowater Personnel #5] to [Senior Bowater Personnel #3], September 25, 2009, Responses to RFI, B.3.5.

## Appendix M Five Largest CMSC Payment Days for Abitibi's Fort Frances Facility

Table M-1 below shows the five days with the highest CMSC payments for the Fort Frances Facility between January and August 2010. On each of these days the CMSC payments received far exceeded the charges incurred for the energy consumed by the net load.

***Table M-1: Highest CMSC Daily Payments and Net Energy Cost for the Fort Frances Facility January to August 2010 ($000)***

| Date | Energy Charges* | CMSC Payments* | | | | Net Energy Costs |
|---|---|---|---|---|---|---|
| | | Constrained-Off | Constrained-On Scenario #1 | Constrained-On Scenario #2 | Total | |
| June 1 (Tuesday) | 48 | 1 | 164 | 174 | 339 | (291) |
| July 21 (Wednesday) | 24 | 63 | 4 | 220 | 287 | (263) |
| July 22 (Thursday) | 27 | 5 | 42 | 222 | 269 | (242) |
| April 16 (Friday) | 27 | 52 | 210 | -3 | 259 | (231) |
| June 2 (Wednesday) | 40 | 50 | 98 | 84 | 233 | (193) |
| **Total Top Five** | **166** | **171** | **518** | **697** | **1,386** | **(1,220)** |

* Includes Global Adjustment and Uplift charges.
** All amounts are net CMSC payments after clawback of certain types of CMSC payments (charge type 105 less charge type 1050).

Figures M-1 to M-5 below show the hourly constrained and unconstrained schedules, as well as actual consumption and CMSC payments, on each of the five days listed above.

***Figure M-1: Schedules and CMSC Payments for the Net Load at the Fort Frances Facility June 1, 2010 (MW and $)***

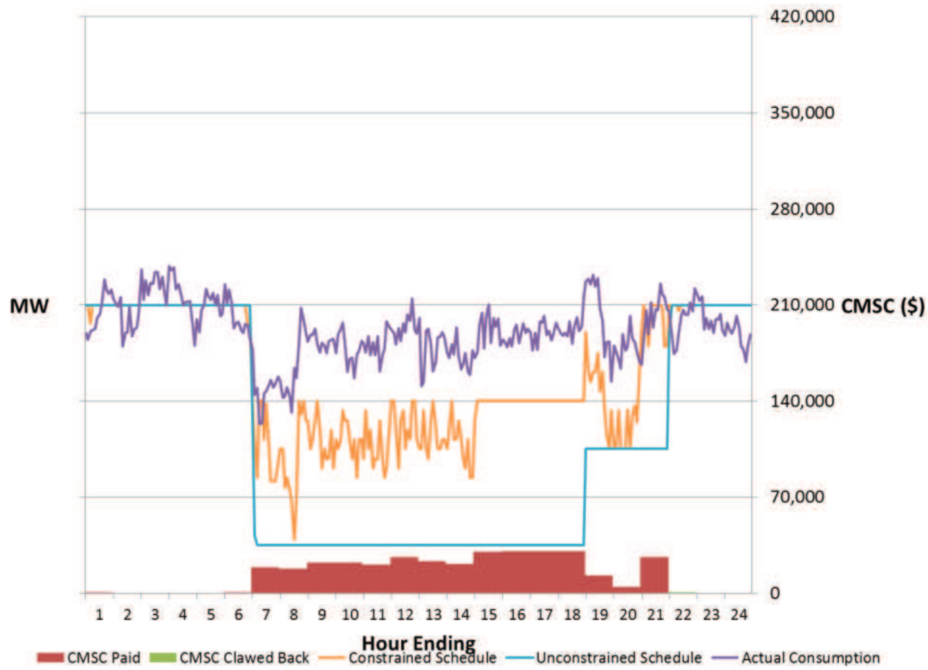



***Figure M-2: Schedules and CMSC Payments for the Net Load at the Fort Frances Facility July 21, 2010*** **(MW and $)**

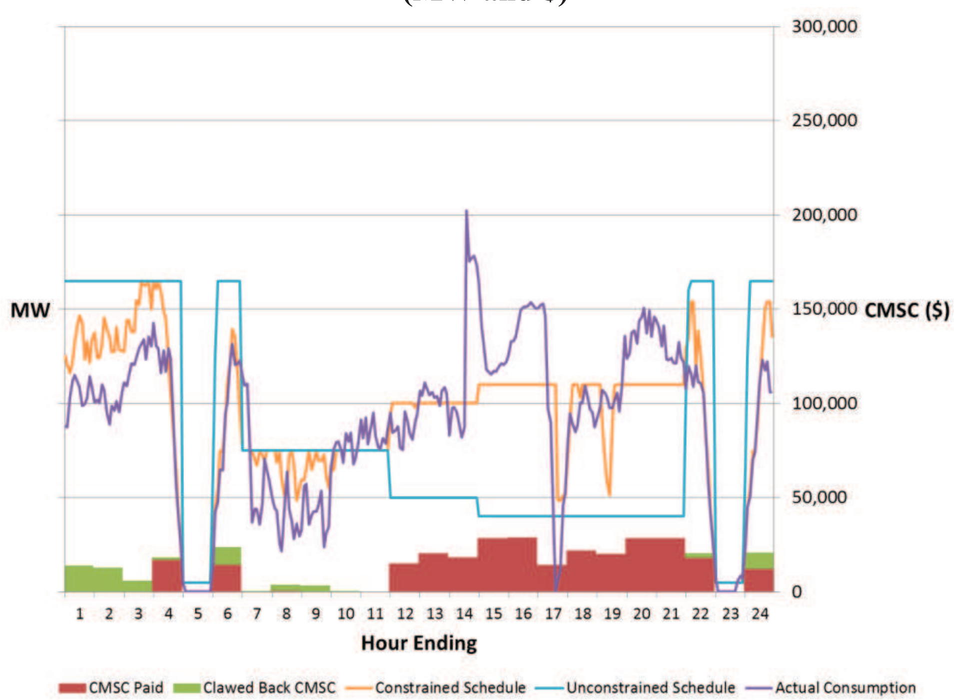


***Figure M-3: Schedules and CMSC Payments for the Net Load at the Fort Frances Facility July 22, 2010 (MW and $)***

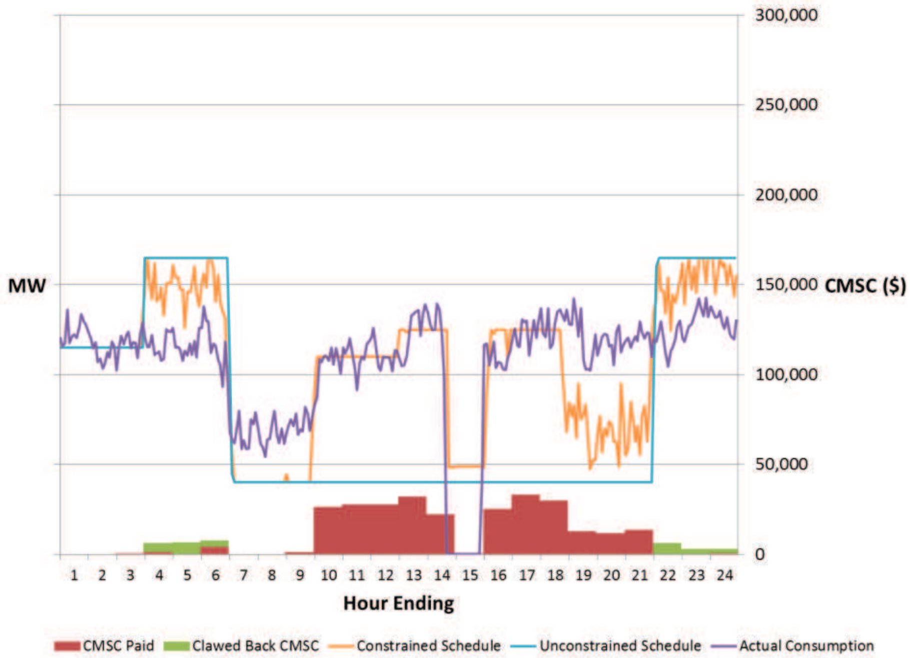



***Figure M-4: Schedules and CMSC Payments for the Net Load at the Fort Frances Facility April 16, 2010 (MW and $)***

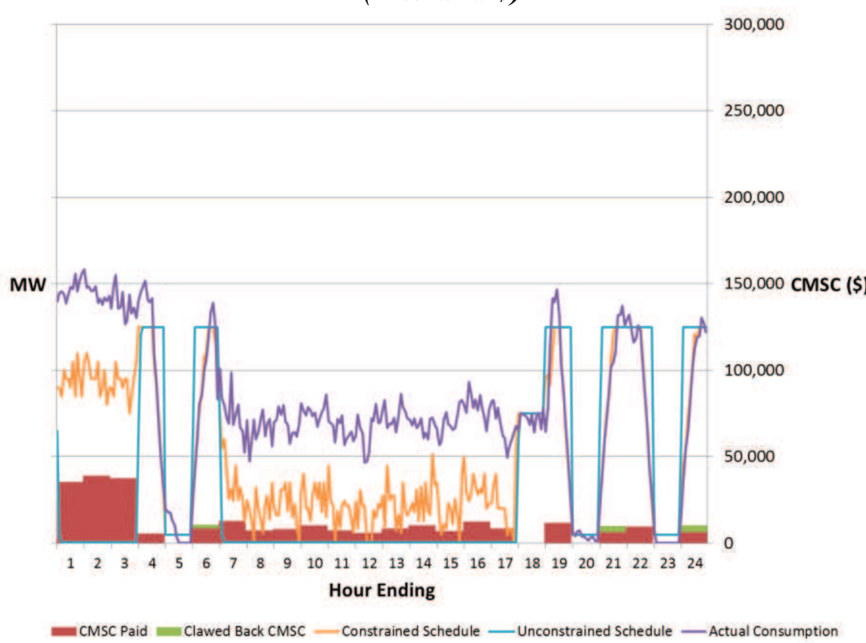
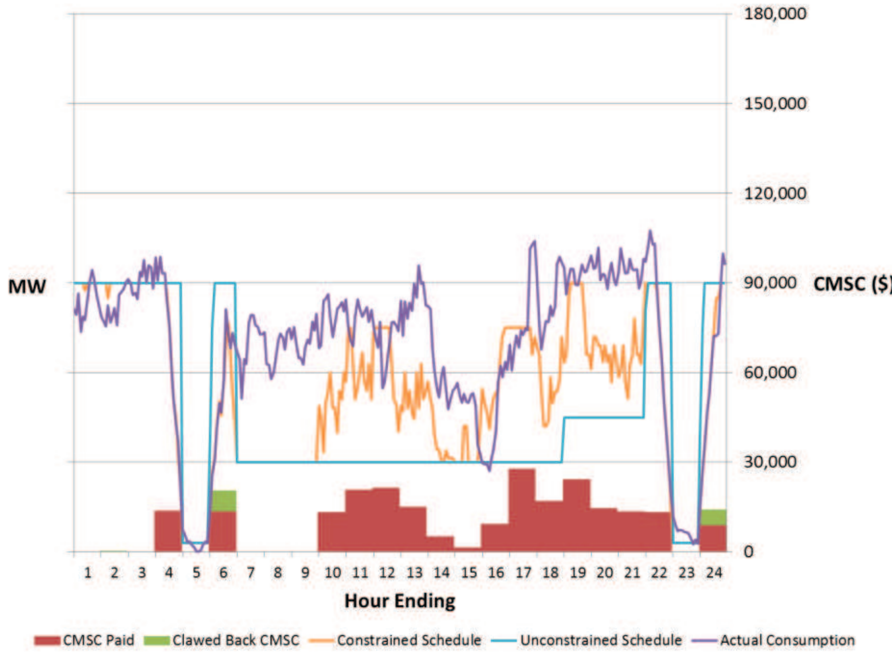


***Figure M-5: Schedules and CMSC Payments for the Net Load at the Fort Frances Facility June 2, 2010 (MW and $)***



## Appendix N Resolute's July 2, 2014 Response

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July 2, 2014

Martine Band
Associate General Counsel
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, Ontario M4P 1E4

Dear Ms. Band:

**Re: Resolute FP Canada Inc. ("Resolute")**
**Investigation by Market Surveillance Panel**

**Introduction and Summary**

We are counsel for Resolute FP Canada Inc. ("Resolute"), successor in interest to Abitibi-Consolidated Company of Canada ("ACCC") and Bowater Canadian Forest Products Inc. ("BCFPI") We are in receipt of the draft Report (the "Draft Report") of the Market Surveillance Panel (the "MSP") on an investigation into activities in respect of BCFPI's Thunder Bay facility and ACCC's Fort Frances facility (collectively, the "Facilities").

The Draft Report contains many allegations that Resolute engaged in gaming behaviour in the IESO-administered market during the period January 2010 to August, 2010 (the "Relevant Period."). For the reasons set out below, Resolute strongly disagrees that it has engaged in any inappropriate behaviour.

Much of the Draft Report addresses internal materials addressing the restart of the Thunder Bay Facility in February, 2010. As is described in greater detail below, the restart of the facility as a dispatchable load resulted in some "growing pains" as both the Facility operators and the IESO learned how to operate a paper mill as a dispatchable load. IESO staff was often very constructive in providing advice on various "work-arounds" to help meet the Facility's commercial and market participant obligations. Both parties experimented in trying to manage through a rigid set of IESO rules and practices that were clearly not designed with a paper mill's commercial operations in mind. Resolute is appreciative of IESO's staff's assistance.

At all times, Resolute attempted to operate appropriately in the IESO-administered market. Unfortunately, the market proved remarkably complex and difficult to operate in as a dispatchable load, leading to unanticipated and unpredictable outcomes. Resolute ultimately found that it could no longer participate in the market as a dispatchable load. The Thunder Bay Facility left the market in December, 2012 and the Fort Frances facility left the market in September, 2013.

Although Resolute may be accused of underestimating the complexity of operating as a dispatchable load, the MSP's allegations against it are totally unfounded. The Draft Report demonstrates no understanding of the way in which the market rules and administrative practices have adapted from the dated expectations for a "pure" energy market in light of the practical obligations of market participants. The MSP appears to be either unaware of how the IESO-administered market actually works or, if the MSP does understand how it works, then the Draft Report is deliberately misleading.

The Draft Report highlights the fact that the process by which serious allegations of misbehaviour are made is fundamentally unfair, allowing the MSP to make irresponsible and one-sided allegations without having to prove them before an independent and unbiased decision maker. The recently approved General Conduct Rule apparently represents a well justified transfer of the authority to investigate these issues from the MSP to the IESO. Further, the IESO, through its Market Assessment and Compliance Division ("MACD") will be required to prove its allegations before an independent tribunal. Hopefully, this will lead to an improved process for both investigating and enforcing these requirements.

The MSP's approach is particularly striking in light of its duty to fairness to Resolute and the individuals named in the Draft Report. The MSP's investigation and reporting function is similar to that of a commission of inquiry which owes "a high level of procedural fairness."[1] This duty is not met where, as here, there is a reasonable apprehension of bias. Indeed, given the mischaracterization and the selective treatment of materials provided to the MSP, any reasonable person would conclude that the MSP is biased in its analysis and conclusions.

[1] *Chretein v. Gomery,* [2009] 2 F.C.R. 417 at para. 61.

**The Allegations**

In summary, the Draft Report alleges three basic categories of what it considers to be gaming behaviour:

1. That the Facilities "self-induced" Congestion Management Settlement Credits ("CMSC") by failing to follow dispatch instructions (Findings 9 (for Thunder Bay), and 30 and 31 (for Fort Frances)). (Collectively, the "Self Induced CMSC Allegations");

2. That the Facilities took advantage of a defect in the market rules by bidding in order to avoid dispatch risk as opposed to bidding on the basis of their Marginal Operating Profits as that term is defined in the Draft Report. These are found in finding #1, which supports allegation 4 (against Thunder Bay) and 19 (against Fort Frances) (Collectively, the "Operating Profits Allegations"); and

3. That the Facilities engaged in a number of allegedly inappropriate behaviours (the "Miscellaneous Allegations"), namely, that the Thunder Bay facility:

    - changed its maximum bid quantity from 110 MW to 115 MW (finding 8);
    - used a ramp down pattern when there was a known alternative pattern that would not have resulted in CMSC (finding 9); and
    - submitted ramp rates that were lower than its operational capacities (finding 10).

    This category also claims that the Fort Frances facility:

    - submitted ramp rates that were lower than its operational capacities (finding 23); and
    - engaged in frequent ramping (finding 24).

Each of these categories will be address in turn. In summary, Resolute's response is as follows:

1. With respect to the Self-Induced CMSC Allegations, Resolute does not agree that it engaged in any gaming behaviour. The IESO's settlement system was expected to calculate and claw back such payments and Resolute assumed that it operated as expected. When the system failed to operate as expected, Resolute offered to voluntarily repay these amounts but, despite Resolute's requests, the IESO has failed to advise how much it claims to be owing. In other words, Resolute is in the situation where it has offered to voluntarily repay the IESO amounts which the IESO system failed to automatically collect if only the IESO would advise how much is owed. However, the IESO has failed to do so.

2. With respect to the Operating Profits Allegations, Resolute unequivocally denies that it engaged in any inappropriate behaviour. It is a well-known fact that offer and bidding

activity in the IESO administered market is driven by dispatch risk, not by the marginal costs or benefits of market participants. However, with respect to Resolute only, the MSP has changed this position and asserts that there was a positive obligation on Resolute to bid its opportunity costs. This has not been an obligation in the past on any market participant. It is therefore being applied on a retroactive and selective basis against Resolute. It is allegedly also supported by a deliberate mischaracterization of the materials provided to the MSP by Resolute.

3. With respect to the Miscellaneous Allegations, as a general matter, they either create obligations on a retroactive basis or create standards that are too vague to be operationalized by any market participant. They also involve inaccurate accounts of facts and flawed interpretations of the Market Rules. Each one of these allegations will be addressed separately.

Before addressing each of these allegations, it is helpful to provide some context respecting the return of the Thunder Bay Facility to commercial operations in February, 2010. This is necessary because the Draft Report quotes extensively from internal correspondence respecting the electricity strategy of that facility. Many of these quotations are taken out of context and display a fundamental misunderstanding of the realities of participating in the IESO-administered market as a dispatchable load. Not surprisingly, the restart of the facility as a dispatchable load led to challenges for both Resolute and IESO staff. IESO staff was often very constructive in providing advice on various "work-arounds" to help meet the Facility's commercial and market participant obligations while still respecting the requirements of the Market Rules. This required adaptation by both the IESO and Resolute. Again, resolute is appreciative of IESO's staff's assistance.

However, the MSP did not appreciate the complexities of this exercise. It had always, and continues to take an ideological position on how a hypothetically pure market should operate. This ideological purity was combined with a zeal to demonstrate that Resolute acted improperly. The MSP resisted any attempt to learn about the practical requirements of operating as a dispatchable load and preferred to make reckless allegations. This is reflected in its biased and selective quotations that are taken out of context in its draft report.

**Return of the Thunder Bay Facility to Commercial Operations**

In August of 2009 the corporation announced the indefinite idling of the Thunder Bay Paper Mill operations effective August 21, 2009. However the mill was provided an opportunity address to labour, power and fibre costs with the goal to design a viable operating platform that could result in the restart of Paper Machine #5 and the continued operation of the Kraft Mill. These issues were addressed and on December 17, 2009, the restart of Paper Machine #5 was announced. Addressing power costs was central to making the mill commercially viable. This is why there was so much correspondence on this matter.

The redesign of the paper mill had the Thunder Bay Facility operating completely off peak and the Recycle Mill operating only during on peak hours.[2]

Operating any of the Thunder Bay Facility's equipment under load during On Peak hours would also be detrimental to DR2 revenues. Fort Frances personnel were consulted as to what potential there may be for CMSC to reduce the Facility's power costs but at the same time meet our operating requirements.

Although the Thunder Bay had operated as a dispatchable load in a previous occasion (in 2006), it did not have to meet demand response obligations. As a result, ramp rates that were previously used by the Facility did not take the Facility completely out of service by the top of the hour as it would be required to do upon reopening. The solution was to provide additional laminations for the various loads that would allow for the same sequenced and orderly shutdown but be essentially be complete by the top of the hour.

A number of discussions with Fort Frances were held seeking clarification between the constrained and unconstrained schedules, how CMSC is determined, and the potential for negative CMSC.[3]

An estimate of CMSC for Thunder Bay was developed with the required ramp rates that would have all refiners shutdown by 7 am. Shut down of auxiliaries would extend into the following hour. This would create a concern for negative CMSC being generated.[4]

After further discussions with operations and the Fort Frances mill, the shut down sequence was finalized. The ramp rates were subsequently revised in attempt to get the auxiliary equipment down prior to 7 am or at least shortly after. This would be of less risk to DR2 payments as it takes additional load out of the on peak period, provides for an earlier start up of the Recycle plant and eliminate concerns for potential negative CMSC being generated. The ramp rates

[2] See RFI, B.2.10.
[3] See RFI, B.2.8.
[4] See RFI, B.2.10.

associated with the auxiliaries were set at [redacted] MW/min. These were slightly lower than those used in Fort Frances and as such it was expected that any CMSC generated in the last two intervals as a result could be clawed back per Market Rule 3.5.1A.

On January 25-26, 2010, a total of 33 operators, shift superintendents and support staff attended a one day on site Dispatchable Load training sessions led by [redacted] of the IESO, who was accompanied by Thunder Bay's Market Representative. Training material covered during these sessions confirmed the impact of using of very high energy bids to minimize the risks of being activated for OR.[5]

The Thunder Bay Facility entered the standing bids and offers during the week prior to going dispatchable with Q4B load. A phone call received from [redacted] and [redacted] of the IESO a day or two later commented on the energy bids and the low down ramp rates used in some of the laminations. It was explained that the ramp rates were designed to have an orderly shutdown and have the TMP plant completely down by 7 am. Considering the time the plant will be down it was essential to ensure there was adequate time allotted to purge the process, minimizing the potential plugged lines and equipment that would delay start-up. The IESO appeared satisfied with this response and there was no further communications from the IESO on this point until the Market Assessment Unit advised that it had conducted assessment of CMSC paid to Abitibi.

After several days of being dispatchable, performance of following the dispatches was reviewed. Unlike Fort Frances, where the dispatch signals automatically unload grinders, the Thunder Bay chip feed system to main line refiners must be manually shutoff, after which the refiners automatically unload due to lack of chips. This takes about [redacted] minutes. As the load has been reduced to the new target level by the end of the interval it is deemed to have met the dispatch target. The only way to get the load off faster is to anticipate the dispatch, which would be impractical and not necessary to meet the new target level by the end of the interval. When in full operation, the load had been at or slightly above the 110 MW target and may have to be adjusted as production rates in the TMP increase. This is necessary to fulfill the day ahead commitment process. Although there were discussions about changing bid practices and procedures, the bids and procedures were not revised.[6]

[5] See RFI, B.3.1.
[6] See RFI, B.2.16.

Due to the increased TMP production rates the energy target in the standing bids were increased from 110 MW to 115 MW in order to fulfill the day ahead commitment process.. This was later reduced back to 110 MW after the implementation of the Advanced Quality Control System, at a capital investment of $[redacted] that resulted in a significant reduction in specific energy [7]

In summary, ensuring control over power costs was crucial to justify the re-opening of the Thunder Bay Facility. It put a lot of effort into operating as a dispatchable load to avoid system peaks. This required designing bids to provide consistent orderly start-ups and shutdowns of the Thunder Bay Facility, maximizing its production while at the same time completely avoiding the on peak period between 7am and 7 pm prevailing eastern standard time.

While achieving this precision met with some challenges, Resolute did its best to meet them with the assistance of IESO Staff. Ultimately, the demands of dispatchability proved too much and Resolute exited from the market as a dispatchable load. However, at all times, Resolute complied with the market rules and ran the operation to the best of its ability.

## 1. Self-Induced CMSC Allegations

When the Facilities entered the market as dispatchable loads, Resolute was aware that self-induced CMSC was subject to "claw back" by the IESO in accordance with Chapter 9, s.3.5.1 of the Market Rules which provides as follows:

> "The dispatch instructions provided by the IESO to market participant 'k' will sometimes instruct k to deviate from its market schedule in ways that, based on market participant 'k's offers and bids, imply a change to market participant 'k's net operating profits relative to the operating profits implied by market participant 'k's market schedule. When this occurs and market participant 'k' responds to the IESO's dispatch instructions, market participant 'k' shall, subject to Appendix 7.6 of Chapter 7, receive as compensation a settlement credit equal to the change in implied operating profits resulting from such response, calculated in accordance with section 3.5.2. If market participant 'k' does not fully or accurately respond to its dispatch instructions from the IESO, the compensation paid to market participant 'k' shall be altered as set forth in this section 3.5, or as otherwise specified by the IESO."

[7] See RFI, B2.18-B.2.22.

Thus, Resolute understood that, if it did not "fully or accurately respond to its dispatch instructions from the IESO, "the compensation paid to" it would be "altered" by the IESO. Resolute therefore kept a "reserve" of self-induced CMSC payments in the expectation that these payments would be clawed back by the IESO.

For reasons unknown to Resolute, and certainly not caused by Resolute, the IESO's settlement system did not consistently claw back these payments. Resolute has always acknowledged that self-induced CMSC payments that the IESO has failed to "claw back" are owing to the IESO. It was always prepared to reimburse the IESO for these payments. However, the IESO proved to be incapable of identifying just how much CMSC was supposed to be returned.

Resolute's calculation of the amount of self-induced CMSC that should have been returned is approximately [redacted] million. Of this amount, Resolute has voluntarily repaid approximately $[redacted] million. As for the remaining, [redacted] million, Resolute has advised the IESO several years ago that it is prepared to repay that amount upon confirmation of Resolute's calculation of the amount owing.

Specifically, in a letter to the IESO dated September 28, 2010, Resolute quantified its calculation of the amount owing and provided its methodology to the IESO for verification. The letter notes that the IESO "expressed an unspecified concern with this estimate." However, the IESO did not identify any concrete concerns nor did it advise what amount it thought should have been clawed back. Resolute asked that [redacted] of the IESO advise of his specific concerns with the methodology and the amount and concluded by advising that Resolute

> "look[s] forward to obtaining your proposals for final settlement of constrained off CMSC payments to BCFI and ACC, as well as confirmation that the IESO continues to be agreeable to the methodology that ACC has used to calculate the payment of constrained on CMSC for the Fort Frances Facility."

That letter was never responded to.

To conclude on this category, Resolute agrees that it collected self-induced CMSC that the IESO should have clawed back. Resolute does not agree that it engaged in any gaming behaviour with respect to self-induced CMSC. The IESO's settlement system is supposed to calculate and claw back such payments. When the system failed to do so, Resolute offered to voluntarily repay these amounts but the IESO has failed to advise how much that is. In other words, Resolute is in the situation where it has offered to voluntarily repay the IESO amounts which the IESO system failed to automatically collect if only the IESO would advise how much owned. However, the IESO has failed to do so.

The MSP's Draft Report does not address any of these issues. Although one would have expected the MSP to provide an even handed account of these events, it has clearly failed to do so.

As is addressed below, the MSP's one-sided account of the second category of alleged gaming activity is even more blatant.

**2. Operating Profits Allegations**

The second category of alleged gaming activity relates to the Facilities' bidding behaviour. The Facilities bidding activity was aimed at avoiding dispatch risk. This allows the Facilities to be dispatched on when they need to generate commercial product and dispatched off to meet demand response obligations, to manage its operating reserve obligations and to avoid peak transmission rates. Bidding to address dispatch risk is common practice in the Ontario market and engaged in by virtually all market participants.

The MSP takes the position that the Facilities should have bid on the basis of their marginal benefit of consumption (defined below). This requirement is not imposed in any market rule or market manual and it is not imposed against any market participant other than Resolute. In fact, it amounts to the imposition of a *de facto* fixed bid price to Resolute, one that applies to no one else in the market place, and something that the MSP has no authority to require.

The MSP's allegations in this regard are the basis for its finding #1, which supports allegation 4 (against Thunder Bay) and 19 (against Fort Frances). It is also the basis for quantifying the alleged benefit to Resolute and the alleged harm to the market. It is therefore necessary to consider the basis for this allegation in greater detail.

In order to understand how the MSP constructs this allegation, it is necessary to address its framework for gaming investigations which the MSP sets out as follows:[8]

I. a defect in the market design, poorly specified rules or procedures or a gap in the *Market Rules* or procedures (collectively referred to as a "market defect");

[8] Draft Report, pp. 26 – 27.

II. exploitation of the market defect by the market participant;

III. profit or other benefit to the market participant; and

IV. expense or disadvantage to the market.

The MSP's application of s. (i) and (ii) of this framework to the Operating Profits Allegations is set out immediately below. Sections (iii) and (iv) are addressed at the end of this document.

**(i) The "Alleged" Defect in the Market Rules**

The Draft Report claims that there is a defect in the Market Rules which Resolute allegedly exploited, but is not entirely clear on what that defect is. The closest it comes to this is its assertion that "the *Market Rules* contain the assumption but not a requirement that bids will reflect the Marginal Benefit of Consumption."[9] Thus, according to this approach, the defect in the market rules is that they do not require loads or generators to bid their marginal benefit of consumption or production. The components of this assumption are elaborated below:

> "Net revenue" is the revenue expected to result from selling the additional output less variable costs of production (other than electricity). The change in operating profit is the incremental net revenue less the cost of electricity for the additional MW. A load normally would not be prepared to pay more for electricity than the Marginal Benefit of Consumption. If it did so, the cost of the extra MW would exceed the incremental net revenue from increasing output (*i.e.*, its operating profits would be reduced). The Marginal Benefit of Consumption may also be used to measure the lost net revenues (again, before considering electricity costs) when a load consumes one less MW of electricity. A load normally would not reduce its consumption if the Marginal Benefit of Consumption exceeded the price of electricity.

There are two obvious concerns with the characterization of this as a defect.

First, it assumes that market participants operate on the basis of a simplified model, making production decisions that take into account only revenues provided by the electricity market. The reality is quite different.

[9] Draft Report, pp. 48-49.

Specifically, paper mills such as the Fort Frances and Thunder Bay Facilities are in the business of providing products to their customers in accordance with their commercial obligations. Those are longer term obligations, not hourly decisions. In addition, the Facilities sought to avoid system peaks to meet their obligations under demand response contracts with the Ontario Power Authority and to reduce their exposure to being called on to provide operating reserve and to peak periods of transmission rates. In other words, it is not inappropriate for dispatchable loads to bid to address dispatch risk. A market participant may appropriately operate on the basis of being able to produce to meet its obligations and be dispatched on and off to accommodate contractual and rate incentives.

The Facilities therefore bid energy prices to manage their dispatch risk. The IESO was aware of the Facilities' bidding practice and even advised Resolute that such a practice would ensure being dispatched off when it was required to be.

Bidding to address dispatch risk is not unique to Resolute. To the contrary, it is the common practice of virtually all Ontario market participants. The sole authority relied upon by the IESO for the proposition that market participants must offer or bid at their marginal costs and benefits is a quotation from the Report of the Market Design Committee, which made recommendations on the design of the Ontario market prior to its establishment in 2002.

However, this abstract market model does not reflect the rules and practices in place during the Relevant Period. The fact that Ontario market participants bid to manage dispatch risk as opposed to marginal costs and benefits is well known to the government and agencies of Ontario. In fact, it was relied upon by the Governments of Canada and Ontario in their public representations. Thus, for example, in defending Ontario's practices to the World Trade Organization, the Government of Canada emphasized that participants in the Ontario wholesale market made offers and bids by reference to dispatch risks, and not marginal production or consumption costs. The WTO noted Canada's position as follows:[10]

> It follows from the above that the price offers attached to a generator's supply bids in the IESO-administered wholesale market are not motivated by the need to cover marginal costs of production (as would typically be the case in a competitive wholesale electricity market such as that which existed in Ontario in 2002), but rather by the need for each generator to be chosen to supply

[10] World Trade Organization, CANADA – CERTAIN MEASURES AFFECTING THE RENEWABLE ENERGY GENERATION SECTOR, CANADA – MEASURES RELATING TO THE FEED-IN TARIFF PROGRAM Reports of the Panels, December 19, 2012, paragraph 23 (emphasis added).

electricity into the Ontario grid in order to receive its contracted or regulated prices.

...

Thus, as Canada and Professor Hogan emphasize, the IESO-administered wholesale market clearing mechanism is perhaps best characterized as a tool for the IESO to make the dispatch decisions needed to balance physical supply and demand for electricity.

As appears from the above, the idealized version of the market envisioned by the Market Design Committee prior to market opening and apparently still idealized by the MSP may have been an aspiration prior to 2002, but it does not reflect the rules and practices of today's IESO administered markets. The MSP's theory of bidding behaviour that it is now seeking to impose is a remnant of an ideology that has been discarded several years ago. It is now seeking to resurrect that theory, ignoring the reality of today's market.

Of greater concern than the fact that the MSP is out of touch is the MSP's troubling attempt to apply its interpretation on a retroactive and selective basis. This is addressed below.

The second concern with the MSP's construct is that it identifies the lack of an obligation on market participants to bid at marginal cost is a *defect* of the market rules. However, the effect of the MSP's position is not to address a *defect* in the market rules. Rather, it would be to fundamentally change the market rules.

The Oxford English Dictionary defines the term defect as "a short coming, imperfection or lack".[11] That the market rules do not impose an obligation to bid on the basis of marginal benefit of consumption is not a "defect" of the market rules. It is a consciously arrived at characteristic of the market rules. Simply put, the IESO could have passed a market rule requiring market participants to bid their marginal costs. However, it has not done so.

For example, when the IESO was considering changing the rules respecting CMSC, it expressly considered whether it should require market participants to bid their marginal costs. It would do this by replacing a market participant's bid with a "replacement bid." However, after using this requirement on a temporary basis, the IESO declined to adopt it on a permanent basis.[12] It is worth noting in this regard that in some contexts, for example when a market

[11] *Oxford English Dictionary* (11th Edition).

[12] See: http://www.ieso.ca/Documents/consult/se89/se89-20100916-notes.pdf.

participant has market power, the IESO and other jurisdictions do require market participants to bid at their marginal costs.[13]

However, this approach is clearly the exception. There is no generic requirement in the Market Rules or any statement of the IESO that indicate that market participants should be bidding their marginal costs.

To the contrary, the IESO has explicitly observed that its dispatch mechanism works on the basis of bids and offers and when it uses the term "cost" it is referring to bid and offer prices, not specific costs of market participants:[14]

> "the term 'cost' refers to the as-bid and as-offered amounts to consume and produce energy in the market respectively. It does not represent the actual expenditure to maintain or generate an electricity-related product."

In fact the MSP itself has characterized the lack of prescribed bidding requirements as an "essential feature" of the Ontario Market. The MSP put it as follows in its *Market Power Framework*:[15]

> "An essential feature of the Ontario spot market is that it is a voluntary market. Participants are not compelled to offer. Nor is there any restriction on the prices at which supply may be offered (other than a maximum offer price of $2,000 and the closing of the bid window prior to real-time)."

It is simply not credible to say that this voluntary price market has somehow changed from being "an essential feature" of the market to a "defect" of the market. If the IESO were to propose a market rule change requiring market participants to offer and bid for electricity based on their opportunity costs, it would be a dramatic and fundamental reshaping of the rules and practices in Ontario and would require extensive stakeholdering and public participation. It is inappropriate for the MSP to seek to bring this result about outside of the rule making process by simply writing a report.

The MSP's sole reliance for its characterization that not bidding marginal cost is a defect of the Ontario market is its assertion that bidding on the basis of marginal cost is an "assumption" of the pre-dispatch model addressed in Chapter 9, s.3.5.1 of the Market Rules. That Market Rule (set out above) addressed the circumstances under which the IESO may claw back self-

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[13] See, for example: Market Rules, Appendix 7.5, Section 2.3.1 and PJM Manual 15: Cost Development Guidelines.

[14] See, for example, Market Manual 9.3, p. 8.

[15] MSP, *Market Power Framework Discussion Paper*, November, 2006, p. 3.

induced CMSC. Those circumstances arise where a market participant does not meet its dispatch instructions and gets CMSC payments. The CMSC payments are measured by reference to a "change in implied operating profits resulting from such response".

The term "operating profit" referred to in that section is not defined in the same way as the MSP has defined it above. It simply refers to the market participant's market schedule, i.e., their original offer or bid price. It is inconceivable that the use of this term in a calculation of CMSC claw back entitlements has the effect of setting aside what the MSP characterized as "an essential feature" of the Ontario market.

In summary, the MSP's approach is inappropriate because it is attempting to change the meaning of the rules on a retroactive and selective basis.

It is retroactive because these rules simply were not in place during the relevant period. If the IESO seeks to develop an obligation for market participants to offer and bid at marginal costs, it may seek to do so prospectively by changing the market rules. It can then follow the rule amendment process so that the proposed rule could be properly debated on its merits.

It is selective because these rules are being applied to Resolute only. To repeat the WTO's conclusions which were based on the representations of Canadian governments, "the price offers attached to a generator's supply bids in the IESO-administered wholesale market are not motivated by the need to cover marginal costs of production (as would typically be the case in a competitive wholesale electricity market such as that which existed in Ontario in 2002), but rather by the need for each generator to be chosen to supply electricity into the Ontario grid in order to receive its contracted or regulated prices." The MSP's Draft Report would change the rules by concluding that, although all market participants bid to manage dispatch risk, only Resolute should have bid on the basis of its operating profits.

The MSP's approach to this issue is made even more incredible in its characterization of Resolute's "intentions". This is addressed immediately below.

**(ii) Exploitation of the "Alleged" Market Defect by the Market Participant**

As indicated, the second component of the MSP's framework is that the MSP must demonstrate that a market participant intentionally exploited a defect in the Market Rules. As the Draft Report states, "The Panel considers that exploitation may exist where the market participant had some level of intention, knowledge or awareness of an opportunity arising from the market defect."[16]

To make its case that Resolute intentionally exploited the so-called defect of the market (i.e., the lack of an explicit obligation to bid at its opportunity cost), the Draft Report puts great emphasis on an internal power point presentation prepared when the Thunder Bay facility was being brought back into service.[17] The MSP characterizes the presentation in this way:

> "Another slide in the presentation correctly noted that '[t]he market rules assume that participants place bids and offers based on their marginal cost and benefit.' Despite Bowater's knowledge of what the Market Rules assumed, a further slide in the deck stated: '[b]id to run at $1,999.99 defines the [CMSC] compensation'.

This slide is referred to a number of times in the Draft Report for allegedly demonstrating that Resolute staff "knew that CMSC payments were intended to compensate for operating profit reductions resulting from being dispatched differently than the economics of bids in the market schedule."[18]

This is not a fair reading of the slide. The slide at RFI B.3.6 does not use the term "operating profit" in the way in which the MSP defined it above (see p. 10). Instead, the slide clearly adopts the formula in the market rules which uses the term "operating profit", i.e., as the difference between the pre-dispatch bid price and the market clearing price. The slide even explicitly defines this term as follows: "Operating Profit = (Bid Price – MCP) x Quantity"

The Draft Report deliberately ignores this statement in the middle of the slide from which it takes a quotation. Instead, it asserts that, by using the term "operating profit", Resolute was agreeing with the MSP's position that it was obliged to bid on the basis of its opportunity costs.

That this is clearly *not* the case is apparent from the remainder of the materials, which are largely ignored by the MSP. Examples of materials which were ignored, or worse, distorted by the MSP, are set out below.

First, the MSP states that the above mentioned slide demonstrates that "Bowater's CMSC projections involved increases in operating profits…" However, the slide clearly states that the

[16] Draft Report, p. 50.

[17] Responses to RFI, B.3.6.

[18] See, for example, Draft Report, at p. 60.

CMSC projection is not an attempt to inflate profits. It states: "The Congestion Management credit ($10.00) is a side benefit from participating in the OR market and from shutting down and starting up every day for DR2." This portion of the materials is completely ignored by the MSP.

Second, it is clear from the materials that when the Market Assessment Unit first questioned the author of the slide about his calculation of operating profits, the author was not familiar with this concept and investigated the practice at other Resolute and non-Resolute facilities. With respect to the former, the author asked, "Have you ever heard of basing your bid on the 'marginal lost opportunity' cost in your six years of bidding at FF?"[19] The question for unrelated facilities was the same: "Have they based their bid on the fact there supposed to bid by the 'marginal lost opportunity value" or have they just chosen a number for their bid? Have they ever heard of the 'marginal lost opportunity value' clause before?"[20]

It is clear from these internal notes that the author of the slide did not draft it on the assumption that bids were supposed to be based on "marginal opportunity value" that this concept originated with the MAU. This portion of the materials is completely ignored by the MSP.

Third, the MSP states that the fact that Resolute did not "book" all CMSC revenues demonstrates that its conduct was intentionally aimed at increasing CMSC. But the materials show that Resolute did not "book" CMSC revenues from self-induced CMSC because, as explained above, it expected that such revenues would be clawed back from the IESO. Accordingly, Resolute only booked "legitimate" CMSC, i.e., CMSC that was not self-induced. When the IESO failed to claw back self-induced CMSC, Resolute offered a voluntary repayment. Again, the IESO did not follow up and specify how much it claimed is owed. It still has not done so. This portion of the materials is completely ignored by the MSP.

Fourth, Resolute's understanding based on IESO instruction materials was that it was "trained on bidding high" to avoid dispatch risk. The MSP ignores Resolute's internal materials on this. Even though the IESO training manuals use the exact same price bid by Resolute to avoid being dispatched on, the MSP states that "this is merely an illustration using hypothetical prices."[21].. It does not explain why, if this is the case, the IESO would use a "hypothetical" example that, according to the MSP, is a deliberate exploitation of a defect in the market rules. More generally, the MSP reports that the MAU (which is employed by the IESO) interviewed

[19] RFI, B.13.32.
[20] RFI B.13.34.
[21] Draft Report, p. 76.

the IESO and, not surprisingly, took all of the IESO's statements at face value while discounting or even ignoring Resolute's contemporaneous notes.

Fifth, in determining and applying its interpretation of Resolute's opportunity costs, the MSP first makes much of the fact that Resolute acknowledged that its bid price did not reflect its operating profits and "lowered its bids to $[redacted]/MWh for ramping hours."[22] It infers from this an acknowledgment that Resolute always believed that it was expected to bid at its marginal benefit of consumption. However, as the MSP is aware, this lowered bid resulted from a negotiated solution between Resolute and the MAU. Resolute agreed to changing its bid price reluctantly, and only because of the pressure being put on it by the MAU. This was expressly addressed in correspondence with the MAU. For example, in an email to [redacted] of the MAU, Resolute confirmed that: the change in bids from $1999 to $[redacted]/MWh[23]

> "reflects opportunity costs lost during ramping and does not reflect dispatch risk. Once our internal back-office tools have been reconfigured to allow for this new combination of price/quantity pair structure, we will revert back to bidding $1999/MWh during the non-ramping hours to cover our risk aversion."

It is remarkable that the MSP would now point to this arrangement as supporting the MSP's position that Resolute always understood it to be obligated to bid on the basis of opportunity costs, not dispatch risk.

Sixth, when Resolute did acquiesce into bidding its marginal costs ($[redacted]/MWh during ramping periods), the MAU advised that "it represents a very positive step forward…and would appreciate if Abitibi could implement the proposed bid price on a go-forward basis."[24] However, the Draft Report rejects the agreed upon $[redacted]/MWh figure and instead uses the figure of $[redacted]/MWh. Its choice of this figure is typical of how the MSP has drafted its report.

The $[redacted]/MWh figure is referred to on only one occasion in the literally dozens of internal emails that Resolute provided to the MSP. The remainder of the materials use the $[redacted]/MWh figure. Further, as soon as the $[redacted] figure is raised in the internal correspondence, it is clearly identified as in error. Resolute's internal correspondence stated that this figure was "reviewed" with its source, involving an "explanation that doesn't exactly match his calculations". Following that review, Resolute confirmed internally that the [redacted]/MWh amount is the right one and, if

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[22] Draft Report, p. 60.

[23] RFI, B.13.59.

[24] RFI, B.13.36.

anything, "is very conservative."[25] The MSP's choice to use of [redacted]/MWh figure, which was clearly incorrect, to inflate what it claims was Resolute's unwarranted gains exemplifies the Draft Report's one-sided and misleading characterization of the materials provided to it.

To summarize on these points, Resolute does not agree with the MSP's characterization that there is a defect in the market rule or that Resolute intentionally exploited that defect. The so-called defect was previously characterized by the MSP as a "central feature" of the market rules pursuant to which market participants are not required to bid at a specific amount. The MSP provided no basis for its change in position.

As well, bidding to avoid dispatch risk is not an attempt to exploit that so-called "defect". To the contrary, it is the standard practice in Ontario. The MSP's attempt to rewrite the market rules by prohibiting that practice as against Resolute only is a retroactive and discriminatory attempt single out Resolute.

The MSP's approach also plagues its other allegations.

**3. Miscellaneous Allegations – that the Thunder Bay Facility Changed its Maximum Bid Quantity from 110 MW to 115 MW.**

Between February and May, 2010, the Thunder Bay facility increased its maximum bid quantity from 110 MW to 115 MW. The MSP alleges that this was done to increase CMSC payments. It bases this allegation on an internal e-mail which used the statement that "there is money to be had here."[26]

Like many of the allegations of the MSP, this interpretation is extremely strained and appears to be an intentional misrepresentation of the materials provided to it.

First, although the materials referred to by the MSP demonstrate that the normal range within which the Thunder Bay facility was intended to run was 110-115 MW; this assumed the installation of an Advanced Quality Control ("AQC") system which would reduce load.[27] The AQC system was eventually installed in May, 2010, with a capital cost of over [redacted]. Following that time, the facility's new full load amount was reduced back to 110 MW. This information was ignored by the MSP.

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[25] RFI, B.14.46.

[26] Draft Report, p. 79, referring to RFI, B.2.16.

[27] RFI, B.3.6.

Prior to the investment in the AQC system, an internal e-mail provides the reason for increasing the bid from 110 MW as being "made to better reflect the actual operating levels that we are seeing and to ensure that there is adequate energy amounts in the day ahead commitment process."[28] This material was ignored by the MSP.

Even the materials that the MSP do rely upon clearly demonstrate that the "Max. Consumption" of the facility was 117 MWh. [29] In fact, during the Relevant Period; the Thunder Bay facility had an average daily maximum of over 111 MW and reached a peak of 118 MW.[30]

Further, as a dispatchable load, Resolute was required to provide an Availability Declaration Envelope ("ADE") setting out the total energy bid on a day-ahead basis. Its ADE of 110 MW was exceeded and had to be adjusted to remain in compliance The MSP ignores emails submitted to it which are entitled "ADE Violation" and clearly speak to this matter. The MSP also ignores printouts which list withdrawn quantities of energy indicating that there were instances in which the Thunder Bay facility was consuming over 115 MWs during the Relevant Period.[31] It is remarkable that the MSP's Draft Report makes absolutely no mention of Resolute's understanding that in order to comply with its ADE obligation; it had to revise its bid to 115 MW, despite the materials submitted to it which demonstrate that this was Resolute's understanding.

As a result, the maximum bid amounts of the Thunder Bay Facility were entirely driven by the physical characteristics of the facility.

The MSP's assertion that the changes in the Thunder Bay Facilities' maximum energy bids are based on an attempt to generate CMSC is based on a skewed interpretation of the information provided by Resolute.

As indicated, the Draft Report notes that an email between Resolute personal stated that "there is money to be had here."[32] It takes that quotation out of context and wrongly attributes that quotation to the change in Thunder Bay's maximum energy bid.

The context for that quotation is as follows.

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[28] RFI, B.2.17.

[29] RFI, B.2.5.

[30] RFI, B.2.21.

[31] RFI, B.2.16.

[32] Draft Report, p. 79, referring to RFI, B.2.16.

When the Thunder Bay Facility resumed its operations as a dispatchable load in February, 2010, the facility was having challenges coordinating its operations with dispatch instructions, particularly respecting the speed at which the facility ramped down. The concern was that there was a time lag between the dispatch signal and the physical shutdown. Timing the physical shut down more closely would have involved "anticipating the dispatch"; this raised concerns about whether engaging in such conduct would create the perception of gaming. It was explained in an internal email as follows:[33]

> "The ramp rates are basically determined by the amount of energy we expect to drop by the end of the 5 minute interval (i.e. 1 refiner line is about [redacted] MW+[redacted]). Once the dispatch signal is received the operating stops feedings chips to the preheater. The refiners unload automatically (feedguard) as soon as there are no chips being delivered to the refiner and the load quickly from [redacted] MW to 0. It is analogous to grinding and completing what is already in the pocket. However with grinders it may be OK to unload the pockets and leave wood until you start back up, with TMP refiners you must run the chips out. The time lag is [redacted] minutes depending on the level of chips in the preheater. If your looking at the 5 minute averages in POMAX it will vary depending on the how long it took to run the chips out. <u>In order for us to be closer to the dispatch eng amount we would have to anticipate the dispatch signal and take the chips off earlier. Danger is that the load may come off before the dispatch.</u>"

The subsequent correspondence addressed whether this was permissible or whether the process should change. It is clear that, in this correspondence, and in the conclusion of this issue, Resolute decided to not anticipate the dispatch, <u>even though such an approach left "money to be had"</u>. In other words, the goal was to avoid gaming, not to participate in it.

Thus, following that email, there was discussion on whether it would be appropriate to anticipate the dispatch. In response to a proposed solution to this issue, the author of the above note repeated his concern: "wouldn't anticipating the dispatch be considered gaming"? The response was that this approach "was not gaming." This demonstrated a legitimate exchange of views about whether this behaviour was appropriate.

To resolve this issue, Resolute organized an internal conference call to address this issue. The purpose of the call was to produce "a collective decision...whether we want to go after the additional CMSC by taking action prior to the dispatch signal." The recommendation was that this approach <u>not</u> be taken: "I just want to be comfortable that we can defend the way we shutdown and CMSC is just a consequence." It was in response to that proposal that the

[33] RFI, B.2.16.

statement was made that such an approach left "money to be had." The internal debate thus had two legitimate perspectives and differences of opinion as to whether a change in approach (i.e., anticipating the dispatch) should be adopted. One consequence of not changing the approach is that some CMSC would be left behind. In any event the decision was made to not anticipate the dispatch. As Resolute advised the MSP, "Although there were discussions about changing bid practices and procedures, the bids and procedures were not revised."[34]

The MSP was thus fully aware that the quotation it relies so heavily upon was not about changing maximum bids and that the decision was made to avoid the potential appearance of gaming and thus not pursue additional CMSC. This fact is not referred to in the Draft Report.

**Miscellaneous Allegations – that the Thunder Bay Facility used a ramp down pattern when there was a known alternative pattern that would not have resulted in CMSC**

The MSP notes that, after a market rule change respecting CMSC, Resolute considered the possibility of changing its ramp down pattern such that the Facilities' auxiliaries would be ramped down in the hour after the refiners, as opposed to the same hour. The MSP's allegation is that Resolute engaged in gaming behaviour by not using this ramp down pattern. It therefore is proposing a definition of gaming which puts a positive obligation on market participants to structure their bidding activity to minimize CMSC. Again, Resolute is not aware of this standard being applied to other market participants. In Resolute's view, its ramp down pattern was an evolving practice that the IESO was fully aware of and did not express concerns with. The sequence of events on this point was provided to the MSP and is set out below.

The ramping for Thunder Bay was developed so that all refiners would shut down by 7 am. Shut down of auxiliaries would extend into the following hour. When this pattern was developed internal Resolute correspondence explicitly notes that it sought to avoid "negative CMSC."[35]

After further discussions with operations and the Fort Frances mill, the shutdown sequence was finalized. The ramp rates were subsequently revised in attempt to get the auxiliary equipment down prior to 7 am or at least shortly after. This would be of less risk to DR2 payments as it would take additional load out of the on peak period, provide for an earlier start-up of the Recycle plant and eliminate concerns regarding the possibility of generating negative CMSC. The ramp rates associated with the auxiliaries were set at [redacted] MW/min. These were slightly

[34] RFI, Response to B.2.

[35] See RFI B.2.10.

lower than those used in Fort Frances and it was expected that any CMSC generated in the last two intervals as a result could be clawed back per Market Rule 3.5.1A.[36]

Thunder Bay entered the standing bids and offers the week prior to going dispatchable with Q4B load. A phone call received from [redacted] and [redacted] of the IESO a day or two later commented on the energy bids and the low down ramp rates used in some of the laminations. It was explained that the ramp rates were designed to have an orderly shutdown and have the TMP plant completely down by 7 am. Considering the time the plant would be down it was essential to ensure there was adequate time allotted to purge the process, minimizing the potential plugged lines and equipment that would delay start-up. The IESO appeared satisfied with this response and there was no further communications from the IESO on this point until the MAU advised that it had conducted assessment of CMSC paid to the facility.[37]

All of this information was provided to the MSP, but none of it is referred to in the Draft Report.

**Miscellaneous Allegations – that the Thunder Bay Facility and the Fort Frances Facilities submitted ramp rates that were lower than their operational capacities** (findings 10 and 23).

The MSP's allegation here is that the Facilities ramped faster than their submitted ramp rates. The alleged consequence of this is that quantities used to calculate CMSC payments (pursuant to the applicable formulas) were increased, as was the length of ramping periods. The MSP also alleges that submitted ramp rates were lower than the facility's maximum capabilities and operating levels.

Resolute has a number of concerns with this allegation.

First of all, as "proof" that the Thunder Bay Facility ramped faster than its submitted ramp rates, the MSP alleges that the Thunder Bay Facility ramped down faster than its submitted ramp rate in at least one interval during 82% of its ramp downs during the Relevant Period.[38] Assuming

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[36] RFI B.2.

[37] RFI B.13.1.

[38] Draft report page 89.

that the data presented by the MSP is correct, the MSP is saying that because the facility ramped slightly faster at one or two of twelve intervals over the course of a ramping hour – in the example given by the MSP, down to 34 MWs instead of 35 MWs and then down to 23 MW instead of 27 MW[39] – the facility is guilty of ramping faster than submitted ramp rates. The MSP concludes that because the facility was 1 MW or 4 MWs off at the end of one or two of twelve intervals over the course of an hour, the Thunder Bay Facility ramped faster than its submitted ramp rates.

Similarly, as "proof" that the Fort Frances Facility ramped faster than its submitted ramp rates, the MSP alleges that the Fort Frances Facility ramped down faster than its submitted ramp rate in at least one interval during 68% of its ramp downs during the Relevant Period.[40] Assuming that the MSP's data is correct, the MSP is saying that because the facility ramped slightly faster at only one interval over the course of a ramp – in the example given by the MSP, down to 16 MWs instead of 19 MWs at interval 9 of a ramping hour[41] – the facility is guilty of ramping faster than submitted ramp rates. The MSP saying that because the facility was 3 MWs off at the end of one of twelve intervals over the course of an hour, the Fort Frances Facility ramped faster than its submitted ramp rates.

Resolute disagrees that the above analysis amounts to proof that the Facilities ramped faster than their submitted ramp rates. The MSP has applied no deadbands whatsoever, and has given no consideration of the inherent difficulties of ramping a load such as the Facilities. The IESO Market Rules recognize that there will not always be precision in respect of following dispatch instructions. This is recognized by the use of deadbands, such that if a facility operates within the compliance dead band, it is deemed to be compliant.[42] All the examples cited by the MSP here are instances where the quantum of the claimed departure from submitted ramp rates are within the deadband for dispatch deviations.

The MSP report then proceeds to reproduce excerpts of Resolute's internal correspondence in an inaccurate and misleading manner in order to demonstrate that Resolute personnel were aware of "the impact of ramping faster than submitted ramp rates" and that "ramping down

[39] Draft report page 92.
[40] Draft report page 129.
[41] Draft report page 129.
[42] See Market Rule interpretation bulletin, "Compliance with Dispatch Instructions Issued to Dispatchable Facilities."

faster than dispatch schedule could constitute gaming."[43] The excerpts re-produced by the MSP are taken from the same series of correspondence incorrectly excerpted by the MSP in respect of the allegation that the Thunder Bay Facility changed its maximum bid quantity from 110 MW to 115 MW. Once again, these emails are taken out of context and fail to recognize that the correspondence clearly indicates a legitimate discussion among Resolute personnel as to how to best be in compliance when ramping the Thunder Bay Facility. As explained above, when the Thunder Bay Facility resumed its operations as a dispatchable load in February, 2010, the facility was having challenges coordinating its operations with dispatch instructions, particularly respecting the speed at which the facility ramped down. The concern was that there was a time lag between the dispatch signal and the physical shutdown. Timing the physical shut down more closely would have involved "anticipating the dispatch"; this raised concerns about whether engaging in such conduct would create the perception of gaming. See page 20, above, for the full discussion of this context. As set out above at pages 20-21, the exchange of correspondence and subsequent internal decisions indicate that Resolute decided to <ins>not</ins> anticipate the dispatch. Read in its proper context, the exchange of correspondence does not support the MSP's allegation that there was an intention to ramp faster than submitted ramp rates. It would be a tremendous stretch to say that being aware of and discussing how CMSC is generated in and of itself constitutes gaming.

The Draft Report also quotes,[44] once again, a powerpoint slide prepared when the Thunder Bay Facility was being brought back into service.[45] This slide, however, simply provides an explanation to management about how CMSC works. It does not address an intention.

Finally, in respect of the allegation that submitted ramp rates were lower than the facility's maximum capabilities and operating levels, there is no requirement in the market rules or in any issuance of which Resolute is aware that requires ramp rates bid by a facility to reflect a facility's maximum ramp rate.

The relevant requirement in the Market Rules is that ramp rates must reflect a market participant's reasonable expectations of the current actual operational capabilities of the

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[43] Draft report page 89, see also page 129.
[44] Draft Report page 91.
[45] See discussion of this slide above at pages 15-16.

registered facility.[46] Ramp rates may be affected by operational considerations; the best ramp rate for a facility may very well not be its maximum ramp rate. Moreover, the best ramp rate for a facility may change due to physical and operational changes. Finally, the ramping up and down of industrial loads such as the Facilities plant is very different from the ramping of a generator which has the ability to ramp up and down on a linear ramp. Resolute notes that the applicable market rule, s. 2.1.2.3 of Chapter 7, contemplates that market participants require flexibility in respect of the dispatch data they submit, by stating that dispatch data shall be consistent with registration information and a market participant's reasonable expectations of the facility.

Resolute's ramp rates reflected its reasonable expectations of the current actual capabilities of the Facilities. In materials provided to the MSP,[47] Resolute sets out how the ramp rates it submitted were developed. The Draft Report ignores this information.

**Miscellaneous Allegations – that the Fort Frances Facility engaged in overly frequent ramping (finding 24)**

The MSP's allegation that the Fort Frances facility inappropriately engaged in frequent ramping and thereby increased its CMSC payments by $5.8 million ignores relevant facts and is plagued by the same flawed reasoning described above in relation to the Operating Profits Allegations.

The MSP begins this section of the Draft Report by correctly noting that in 2009, one of the paper machines at the Fort Frances facility was shut down, and that this resulted in the facility having excess pulp but limited capacity to store this pulp.[48] The rest of the section then proceeds to ignore this operational consideration as well as other operational considerations.

First, the MSP sets out emails which allegedly show that "the ramping strategy was closely connected to the impact on CMSC payments"[49]. From these emails, it is concluded that "Abitibi viewed CMSC payments as a financial flow that could be managed and forecasted. This is

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[46] Market Rules Ch. 7, s. 2.1.2.3.

[47] See responses provided to B.2 and B.6.

[48] Draft report page 131.

[49] Draft report page 131.

inconsistent with the design of the CMSC regime, which is to provide market participants with compensation for unexpected reductions in operating profits caused by unpredictable Grid Conditions."[50]

Once again, the MSP appears to be attempting to change the market rules on a retroactive basis. Resolute is not aware of a market rule which forbids participants from planning in order to manage and forecast CMSC. Once again, the MSP is imagining an idealized version of the market which was envisioned prior to market opening but does not reflect the rules and practices in today's electricity market in Ontario.

The MSP then cites an email in which the Fort Frances Energy Supervisor states "If there are not legitimate reasons to schedule an outage, this is considered gaming by the IESO...All ramps [need] to be justified..."[51] From this email, which in fact indicates that Resolute did not intend to operate its facility in a manner which could constitute gaming, the MSP concludes that "personnel were aware that frequent ramping could constitute gaming".[52]

The Draft Report then compares the amount of ramping at the Fort Frances facility during the Relevant Period to historical data and finds a percentage increase in ramping as compared to the previous year and the 2007-2009 average. Based solely on this percentage increase in ramping, the MSP alleges an "at least $5.8 million" benefit due to frequent ramping of the Fort Frances facility during the Relevant Period.

The MSP makes no attempt to consider the changes in operational realities at the Fort Frances facility, including the shutdown of one of the paper machines. In other words, the MSP ignores the very facts which it sets out at the beginning of the section on this allegation. The reality is that a number of operational factors affected ramping at the facility, including the frequency of ramping. These operational factors included internal generation capabilities (affected by water levels/ availability of fuel/availability of steam host), ground wood maintenance and cleanup, paper machine downtime, pulp tank levels (storage capacity), downtime to avoid 5 coincidental peak hours, and maintaining a predetermined level for network peak charges.

[50] Draft report page 134.
[51] Draft report page 134.
[52] Draft report page 134.

**Profit or Other Benefit to the Market Participant; and Expense or Disadvantage to the Market**

The MSP's quantification of benefits to Resolute and expense to the market is based on three faulty assumptions. First, that Resolute knew that it owed an obligation to bid at its marginal benefit of consumption and intentionally bid in a way that was inconsistent with that obligation; second, that Resolute's marginal benefit of consumption was $[redacted]/MWh; and third, that other market participants did in fact either offer at their marginal cost of production or marginal benefit of consumption. None of these assumptions are merited.

In fact, Resolute did not have such an obligation or believed that it had such an obligation; second, its marginal benefit of consumption was $[redacted]/MWh; and third, other market participants did not offer and bid on the basis of their marginal costs or benefits.

In order for the MSP to fairly quantify how Resolute's market revenues (including, but not limited to CMSC) should have worked under its proposal, the MSP would have to recreate an offer bid scenario where all market participants meet the same obligations, i.e., they either all offered and bid at their marginal cost or benefit or they all did so to manage dispatch risk. The MSP would then have to recalculate both a price and dispatch outcome that would have resulted from its idealized model. It would then have to compare the payments to all market participants under both the real world scenario that Resolute and other market participants operated in and the idealized market world of the MSP's model.

While it is not clear what the value would be of such an exercise, it is the only way in which to test the MSP's theory of what the benefits and costs to market participants would be if they all bid as the MSP now claims they should have. The great distance between the MSP's idealized outcome and the real world outcome of how market participants actually bid demonstrates both the unreasonableness of the MSP's position in this case and of its estimate of the benefits to Resolute and the cost to other market participants.

**Conclusion**

For the reasons set out above, Resolute strongly disagrees that it has engaged in any inappropriate behaviour. As has been shown, Resolute attempted to operate appropriately in the IESO-administered market at all times. Unfortunately, the market proved remarkably complex and difficult to operate in as a dispatchable load, leading to unanticipated and unpredictable outcomes. Resolute ultimately found that it could no longer participate in the market as a dispatchable load, and removed both Facilities from the market.

While Resolute may be accused of underestimating the complexity of operating as a dispatchable load, the MSP's allegations against it are completely unfounded. The Draft Report demonstrates no understanding of the way in which the market rules and administrative practices have adapted from the dated expectations for a "pure" energy market in light of the practical obligations of market participants. The MSP appears to be either unaware of how the IESO-administered market actually works or, if the MSP does understand how it works, then the Draft Report is deliberately misleading.

Contrary to the MSP's allegations, Resolute did not engage in inappropriate conduct. Specifically:

1. With respect to the Self-Induced CMSC Allegations, Resolute does not agree that it engaged in any gaming behaviour. The IESO's settlement system was expected to calculate and claw back such payments and Resolute assumed that it operated as expected. When the system failed to operate as expected, Resolute offered to voluntarily repay these amounts but, despite Resolute's requests, the IESO has failed to advise how much it claims to be owing. In other words, Resolute is in the situation where it has offered to voluntarily repay the IESO amounts which the IESO system failed to automatically collect if only the IESO would advise how much is owed. However, the IESO has failed to do so.

2. With respect to the Operating Profits Allegations, Resolute unequivocally denies that it engaged in any inappropriate behaviour. It is a well-known fact that offer and bidding activity in the IESO administered market is driven by dispatch risk, not by the marginal costs or benefits of market participants. However, with respect to Resolute only, the MSP has changed this position and asserts that there was a positive obligation on Resolute to bid its opportunity costs. This has not been an obligation in the past on any market participant. It is therefore being applied on a retroactive and selective basis against Resolute. It is allegedly also supported by a deliberate mischaracterization of the materials provided to the MSP by Resolute.

3. With respect to the Miscellaneous Allegations, as a general matter, they either create obligations on a retroactive basis or create standards that are too vague to be operationalized by any market participant. They also involve inaccurate accounts of

facts and flawed interpretations of the Market Rules. Each one of these allegations has been addressed separately above.

Sincerely,

George Vegh

## Appendix O The Panel's Comments on Resolute's July 2, 2014 Response and Update on Subsequent Correspondence and the General Conduct Rule

In accordance with section 7.2.2 of the MSP By-Law, the Panel provided a draft of this Report to the market participants on April 16, 2014, to provide them with an opportunity to discuss the findings with the Panel, to respond to the findings and to comment on matters of factual accuracy and confidentiality. The Panel offered to meet with the market participants, and identified the date by which any written response should be provided. Resolute delivered a written response to the Panel's draft report on July 2, 2014, which is reproduced in Appendix N. Appendix N as it appears in the public version of this Report was redacted by Resolute.

While Resolute's response directly addresses some of the Panel's findings, it more generally attacks the integrity of the Panel's process, including allegations that the Panel has acted in a manner that is biased and unfair. The Panel deals first with these latter issues, and then turns to Resolute's response on the substance of the Panel's findings.

### A. The Panel's Comments on Resolute's Claims regarding the Integrity of the Panel's Process and Similar Issues

*1. Claims of bias and unfair process*

Resolute's response alleges that the Panel is "biased in its analysis and conclusions." The Panel has carefully considered each claim made in Resolute's response to the effect that the Panel has not fairly considered or fairly characterized the materials before it, and believes those claims to be without substance.

Resolute provides six examples of materials that it alleges were "ignored" or "distorted" by the Panel (these are found at pages 15 through 17 of Resolute's response). Some of these examples are specifically addressed elsewhere below, and in the Panel's view none provide any real basis for Resolute's claims. To illustrate, the Panel refers to Resolute's sixth example, found at page 17 of its response, in which Resolute claims that the Panel's use of $●/MWh as the estimated Marginal Benefit of Consumption for the Thunder Bay Facility – as opposed to the $●/MWh advocated by Resolute – had as its purpose to inflate the magnitude of Resolute's unwarranted CMSC payments. Resolute also states that the $●/MWh was referred to on only one occasion in the e-mails provided to the Panel, and that "as soon as the $● is raised in the internal correspondence, it is clearly identified as an error."

The Panel's decision to use $●/MWh was made after careful review of both that figure and the $●/MWh figure advanced by Resolute, including all relevant materials provided by Resolute on this point. E-mails and associated e-mail attachments related to the internal correspondence referred to by Resolute regarding the erroneous identification of the $●/MWh figure indicate that additional fixed costs and downtime of the paper machine were added to derive the $●/MWh figure. As explained in section 7.4.2.2 of this Report, the Panel believes these costs to be inappropriate in calculating the marginal benefit. The Panel's conclusion is that, for the reasons discussed in sections 7.4.2.2 to 7.4.2.4 of this Report, $●/MWh overstates the marginal benefit. The Panel is not required to accept a market participant's own estimate of the marginal benefit, and is not precluded from using an alternative estimate in cases such as this where the materials before the Panel give it reason to do so. Although the Panel in fact believes that even the $●/MWh amount is too high, as noted in this Report the Panel has used that figure in the absence of any better information.

Resolute also complains that the Panel's process is "fundamentally unfair" because there is no requirement for the Panel to prove its allegations before an independent tribunal. In effect, Resolute takes the position that any investigation by the Panel will be unfair in the absence of an associated adjudicative process. The fact that there is no provision for adjudication in the context of the Panel's investigations is a decision of the legislature. The Panel's responsibility is to ensure that its process accords with its legislated mandate and with the MSP By-law, and the Panel has done so in this case. It is worth noting in this context that, while invited by the Panel to do so, Resolute made no attempt to meet with the Panel following receipt of the Panel's draft Report.

In reaching its conclusions in this case, the Panel acted carefully and fairly, and believes that its conclusions will withstand any level of serious scrutiny.

*2. Claims that the Panel does not understand the electricity market and is trying to redefine the rules*

Resolute alleges variously that the Panel is "out of touch", "appears to be… unaware of how the IESO-administered market actually works" and is "attempting to change the meaning of the rules on a retroactive and selective basis". The Panel includes in this general category of claims the claim that the market defect at issue is not entirely clear.

The Panel is well aware of how the Ontario electricity market works, and is confident that even a cursory reading of this Report will satisfy an objective reader that that is the case. With respect to bid prices, as discussed in further detail in section B below the Panel is in no way attempting to redefine the *Market Rules*.

Contrary to Resolute's assertion, the nature of the market defect at issue in this case is entirely clear from the Panel's Report. It is captured in the Panel's Finding #1, and relates exclusively to the rules and procedures relating to CMSC payments. Moreover, Resolute attributes to the Panel's analysis a market defect of its own creation that is not expressed anywhere in this Report; namely, the "lack of an obligation on market participants to bid at marginal cost." While the Panel accepts that an obligation to bid at marginal cost would go a long way towards eliminating the potential for gaming of CMSC payments given how these payments are calculated, the Panel has not identified the lack of such an obligation as a market defect, nor does it equate that with the market defect captured in its Finding #1, nor does it believe that its approach in essence has the effect of imposing such an obligation.

Resolute's response also makes it appear that the Panel is unacquainted with dispatch risk, that is, the risk that a dispatchable load's facilities could be dispatched down or off by the IESO if the Nodal Price at its location rises above its bid price, or the risk that the load could be activated to provide operating reserve. The Panel's extensive analyses of dispatch risk are described in sections 7.4.2.6, 7.4.2.7, 8.4.2.5, and 8.4.2.6 of this Report, and its conclusions are clear that neither the risk of being constrained off nor the risk of being activated for operating reserve justified the high bid prices used by Abitibi and Bowater.

Taken to their logical conclusion, Resolute's assertions would appear to preclude the Panel from scrutinizing the bids that underlie CMSC payments simply because the *Market Rules* do not require dispatchable loads to bid at their marginal benefit of consumption, even when there is evidence that the bids have been set at levels designed to maximize CMSC payments and are much higher than necessary to address any dispatch or other risks. The Panel has a very different view of this issue. Fundamentally, the Panel does not accept that gaming behaviour is outside of its purview because the conduct in question is not prohibited by the *Market Rules* or may be technically compliant with the *Market Rules*. That this is the Panel's view is illustrated by its Monitoring Document "Generator Prices Used to Signal an Intention to Come Offline", which makes it clear that offer prices that are allowable under the *Market Rules* (because they are no higher than the maximum market clearing price of $2,000/MWh) can nevertheless be the subject of a gaming investigation.

*3. Resolute's suggestion that its behavior was encouraged by IESO staff*

In its response, Resolute makes references to discussions or meetings with IESO staff. Through these references, it appears that Resolute is trying to create the impression that IESO staff condoned, if not encouraged, the behaviours that resulted in the substantial CMSC payments that are the subject of this Report.

The Panel makes two observations in this regard. First, the IESO staff members referred to by Resolute did not have authority to determine what conduct would or would not constitute gaming, a point that is made in section 8.5.2 of this Report. Second, even if the IESO staff members had such authority (which again they did not), there is no evidence that any advice that they might have provided to Abitibi or Bowater was provided with full knowledge of the specific underlying details of the market participants' conduct (for example, that the market participants' bid prices were much higher than required to deal with dispatch risk and would lead to substantial unwarranted CMSC payments). Merely stating the obvious, such as the fact that high bid prices lower the risk of being activated to provide operating reserve, is not the same as encouraging, or condoning, behavior that is undertaken to exploit a defect in the *Market Rules.*

Ultimately, market participants are responsible for their actions in or affecting the wholesale electricity market, including in respect of conduct that may be subject to review by the Panel for gaming. The actions of IESO staff referred to in Resolute's response do not justify or excuse the market participant behaviours addressed in this Report, any more than did the actions of [Senior IESO Personnel] as discussed in section 8.5.2 of this Report. In fact, as discussed in more detail in Section 9 of this Report and in section B below, when the IESO became aware of the situation, it moved immediately to change the *Market Rules* to prevent further CMSC payments of the kind obtained by Abitibi and Bowater through ramping behaviour.

## B. The Panel's Comments on Resolute's Response to the Substance of the Panel's Findings

In its response, Resolute groups the Panel's findings into three categories, and the Panel's comments are organized accordingly.

### *1. Category 1: "Self-Induced CMSC Allegations"*

In the first category, Resolute includes Finding #9 (which relates to Bowater's Thunder Bay Facility) and Findings #30 and #31 (which relate to Abitibi's Fort Frances Facility). Resolute characterizes these as "Self-Induced CMSC Allegations", and its discussion of them pertains almost exclusively to CMSC payments that are made in circumstances where a facility fails to follow dispatch instructions. Resolute makes the point that it has always acknowledged that such payments should be clawed back, and that by its estimation roughly $5.3 million should have been returned to the IESO. Of that amount, $1.825 million has been repaid, while the remainder has not been paid by reason of the IESO's failure to confirm the amount.

The Panel notes first that, to the extent that Resolute's descriptor for Findings #9, #30 and #31 ("Self-Induced CMSC Allegations") reflects a view that CMSC payments can be self-induced only when there is a failure to follow dispatch instructions, that view is not aligned with the Panel's approach. In the Panel's view, all of the CMSC payments that the Panel finds were obtained as a result of gaming as set out in this Report were self-induced.

In addition, Findings #9 and #30 do not relate to a failure to follow dispatch instructions. Rather, they relate to ramp down timing and negative bid prices, respectively. Moreover, Resolute's response with respect to Finding #9 is not consistent. On the one hand, Resolute includes Finding #9 in its discussion of the kinds of CMSC payments that it indicates it has been prepared to repay to the IESO. On the other hand, Resolute also includes that Finding in the third category in its response, where it defends the timing of the Thunder Bay Facility ramp down and does not offer to repay any CMSC amounts.

Resolute's calculation of the CMSC payments that should be repaid in relation to these three findings ($5.385 million, of which $1.825 has been repaid) differs from the amounts calculated by the Panel ($7.624 million). If, as Resolute states, the CMSC payments related to Findings #9, #30, and #31 should be repaid, the Panel encourages Resolute to do so.

*2. Category 2: "Operating Profit Allegations"*

The second category of Resolute's response concerns the Panel's Findings #1, #4 and #19. Resolute characterizes this category as "Operating Profit Allegations." The findings in question relate to unwarranted CMSC payments made to Resolute resulting from high bid prices during voluntary ramping activity.

Resolute states, and relies on the fact, that the basis for calculating CMSC payments is a market participant's offer or bid prices, not the participant's marginal cost of production or Marginal Benefit of Consumption (referred to below as "opportunity cost"). Resolute further states that it had no obligation under the *Market Rules* to bid its opportunity costs, and that the bids it submitted during ramping ($●/MWh) were intended to avoid dispatch risk rather than to exploit the market rules relating to the calculation of CMSC.

The Panel agrees that there is no section of the *Market Rules* that states that a market participant must bid its opportunity costs, but as noted above disagrees that its approach in essence has the effect of imposing such a requirement. Rather, the Panel's point is that CMSC payments are calculated based on the assumption that a market participant's bids or offers reflect their opportunity costs, and when this assumption does not hold true the market participant can obtain

CMSC payments that go beyond the intended compensatory purpose and that are not always subject to claw-back by the IESO. This is precisely the market defect identified by the Panel in Finding #1, and which the Panel concluded was exploited by the market participants in relation to Findings #4, and #19. Specifically, the Panel concluded that Abitibi and Bowater exploited this defect while engaged in ramping by consistently submitting an extremely high bid price. The Panel was not persuaded that these bid prices could be explained as bearing a relationship to the market participants' cost of doing business.

Resolute takes the position that its very high bid prices were intended to avoid dispatch risk. This explanation was also given during the course of the Panel's investigation. Contrary to the suggestion in Resolute's response that this explanation was disregarded by the Panel, the fact that the Panel considered it is clear from sections 7.4.2.6 and 8.4.2.5 of this Report.

At page 16 of its response, Resolute refers to a slide that it states clearly says that the CMSC payment projection in the slide is not an attempt to inflate profits, noting that the slide refers to a CMSC payment as "a side benefit from participating in the OR market and from shutting down and starting up every day for DR2." It is not clear to the Panel what difference this distinction makes, since the "side benefit" would have contributed to profitability in the same way as other revenue. Moreover, both the Market Design Committee and the Panel have explicitly stated in the past that *Market Rules* need to be developed or reformed to deter gaming of "side payments" of precisely the kind obtained by Resolute in this case.

At page 16 of its response, Resolute asserts that the Panel states that the fact that Bowater did not "book" all CMSC revenues demonstrates that Bowater's conduct was intentionally aimed at increasing CMSC payments. Resolute then claims that the Panel completely ignored materials that show that Resolute "did not book CMSC revenues from self-induced CMSC because…it expected that such revenues would be clawed back from the IESO." In section 7.4.1 of this Report, the Panel notes that Bowater did not "book" certain CMSC revenues. It does so to illustrate that Bowater and ABI senior management were aware of the accounting technique. Moreover, the Panel specifically acknowledges that this accounting treatment was used as a result of personnel at Bowater and its affiliates being aware that the IESO might seek to recover some of the CMSC payments obtained as a result of their ramping strategies, and that Bowater only booked what it considered to be "legitimate" CMSC payments.

Finally, the Panel considers it important to complete the record in relation to Resolute's description of actions taken and not taken by the IESO in 2010 (page 12 of Resolute's response). Resolute states, in the context of Resolute's argument that the lack of an obligation to bid at marginal cost is not a defect in the *Market Rules*, that the IESO expressly considered whether it should require market participants to bid their marginal costs by means of substituting a market participant's bid with a "replacement bid." Resolute then states that the IESO declined to adopt this approach on a permanent basis. These statements are made citing the IESO's Stakeholder Engagement SE-89, and are accurate. However, to the extent that Resolute invites any inference to be drawn from these statements, the Panel believes that it is important to note that the solution that the IESO did adopt – notably, the elimination of constrained-off CMSC payments to dispatchable loads related to ramping – made the replacement bid approach moot. As described in section 9.1 of this Report, after the Panel first reported on these issues in its August 2010 Monitoring Report, the IESO took immediate action to temporarily suspend constrained-off CMSC payments to dispatchable loads altogether in order to "eliminate CMSC payments that are not consistent with the intent of CMSC payments under the market rules." It is also clear that this measure was taken in specific response to CMSC payments that had been made to Bowater and Abitibi: the IESO noted at the time that "[f]or the period February 1 to July 31 2010, two market participants received approximately $22 million in CMSC payments associated with two dispatchable load facilities"; that "[t]hese two dispatchable load facilities represent 22% of Ontario's dispatchable load capability yet have received over 95% of the total constrained off CMSC paid to all dispatchable loads in Ontario"; and that "constrained off CMSC payments associated with these two facilities (totalling 190 MW) are also equivalent to approximately 75% of total constrained off CMSC payments made to all dispatchable generators in Ontario during the same period (approximately 35,000 MW )."[254] The IESO also noted that the main

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[254] See Urgent Market Rule Amendment Proposal MR-00373-R00, online: http://www.ieso.ca/Documents/mr/MR_00373-R00.pdf.

contributing factor was "frequent ramping up/down with a slow ramp rate and high bid price."[255] Stakeholder Engagement SE-89 was initiated to consider alternative solutions to the temporary suspension of constrained-off CMSC payments to dispatchable loads, and ultimately culminated in the *Market Rule* amendments that permanently eliminated constrained-off CMSC payments to dispatchable loads associated with self-induced ramping.

*3. Category 3: "Miscellaneous Allegations"*

This category of Resolute's response covers five of the Panel's findings.

a. <u>Finding #8 (increase in the maximum bid quantity for the Thunder Bay Facility)</u>

This finding relates to Bowater's decision to increase the bid quantity for the Thunder Bay Facility from ● MW to ● MW for the period February 19, 2010 through May 11, 2010.

Resolute claims that the normal range within which the Thunder Bay Facility was intended to operate was ● MW to ● MW, and that operating in that range depended on an Advanced Quality Control ("AQC") system being installed, which had not yet happened when the Thunder Bay Facility re-entered the market as a dispatchable load. The Panel has seen no documents that support that the normal operating range for the Thunder Bay Facility was ● MW to ● MW, nor does the e-mail cited by Resolute in its response suggest that such an operating range was dependent on installation of an AQC system. In fact, the Panel notes that the consumption level at the Thunder Bay Facility in off-peak hours averaged less than ● MW for April 2010, notwithstanding that the AQC system referred to in the response was not in place at that time (Resolute states that it was implemented in May 2010).

Resolute also claims that the increase in the bid quantity was implemented to avoid non-compliance with the IESO's rules concerning the Availability Dispatch Envelope (ADE) for dispatchable loads. The ADE is the hourly bid quantity made by dispatchable loads into the IESO's day-ahead commitment process. The *Market Rules* and applicable Market Manual

[255] *Ibid.*

require that a dispatchable load's bids into the real-time energy market not exceed 102% of its ADE. However, the Panel is not aware of any restriction (other than the IESO's 15 MW Compliance Deadband) on Thunder Bay consuming energy at a level above its bid quantity. Thus, in the Panel's view, the Thunder Bay Facility could have retained a ● MW bid in the real-time market for February 19 through May 11, 2010 and consumed at the level it actually did while remaining compliant with the ADE rules.

As Resolute notes in its response, consumption at the Thunder Bay Facility during some off-peak hours was not only higher than ● MW but was also higher than ● MW. The Panel has re-examined the data and agrees that actual consumption was often higher than ● MW (and at times much lower than ● MW) during the first month of the period in question (or from February 19 to roughly mid-March 2010). While the Panel has seen nothing that causes it to reconsider its finding that the increase in bid quantity was for the purpose of increasing CMSC payments, the Panel reduced its estimate of the amount of CMSC payments obtained through this conduct by counting payments made in the shorter period from March 16, 2010 to May 11, 2010, inclusive.

b. Finding #9 (ramp down pattern for the Thunder Bay Facility)

Resolute claims that ramping down the load at the Thunder Bay Facility in a single hour was developed to avoid negative CMSC payments. It cites a September 24, 2009 e-mail as support for that claim.[256] The Panel reviewed that e-mail when drafting this Report, and the Panel still sees nothing in the e-mail that connects the selected ramp down pattern with negative CMSC payments. No further records or explanation have been provided by Resolute to substantiate its stated concern.

Resolute also states that ramping the Thunder Bay Facility down in a single hour "would be of less risk to DR2 payments as it would take additional load out of the peak period." The Panel had already considered this argument but did not accept it as justification for the Facility's ramp

[256] Responses to RFI, B.2.10.

down pattern because [Senior Bowater Personnel #5]'s shut down instructions noted that it was acceptable to drag out the shutdown of auxiliaries into the hour after 7:00 am.[257]

Resolute's response to this Finding also states that, just before the Thunder Bay Facility re-entered the market as a dispatchable load, two IESO staff members "appeared satisfied" with the ramp rates Bowater proposed to use for the Facility. The Panel was already aware of this assertion, having read it in the material supplied in response to the Panel's Requests for Information.[258] However, Finding #9 does not address Bowater's ramp rates, but rather relates to the decision to ramp down the Thunder Bay facility in a single hour rather than delay the ramp down of auxiliaries to the next hour. Accordingly, the e-mail exchange in question does not appear to the Panel to be germane to this Finding. There is nothing in Resolute's response or its earlier responses to the Panel's Requests for Information that suggests that IESO staff was satisfied with the proposed ramping pattern for the Thunder Bay Facility. Even if IESO staff "appeared satisfied" with Bowater's decision to ramp down the Thunder Bay Facility in a single hour, as discussed in section A above the Panel does not consider that to justify or excuse the market participant behaviour described in this Report.

c. <u>Findings #10 (Thunder Bay Facility ramping down faster than submitted ramp rates) and #23 (Fort Frances Facility ramping down faster than submitted ramp rates)</u>

Resolute claims that ramping "slightly faster over one or two intervals over the course of a ramping hour" does not mean that Bowater and Abitibi were guilty of ramping down faster than submitted ramp rates. Resolute also notes that all of the instances of ramping down identified by the Panel were within the deadband for dispatch deviations, and further claims that the Panel has given no consideration to the inherent difficulties of ramping a load such as the Thunder Bay and Fort Frances Facilities. Resolute's response implies that a dispatchable load can be found to be

[257] Responses to RFI, B.2.28, referred to in section 7.4.4 of this Report.
[258] Responses to RFI, B.2.

ramping down faster than its submitted ramp rates only if its consumption during an interval falls below the constrained schedule by an amount greater than the IESO's Compliance Deadband.

The Panel accepts that precise compliance with dispatch instructions may not be possible in all situations. However, when a load consistently ramps down faster than its submitted ramp rates, which the Panel finds was the case here, the Panel has good reason to believe that this ramping behaviour is not tied exclusively to normal operational problems.

The Panel certainly accepts that the Compliance Deadbands established by the IESO for generators and loads are appropriate in the context of ensuring the reliable operation of the electricity system. However, the Panel does not accept that those Compliance Deadbands are dispositive when assessing whether a market participant is ramping down its facilities faster than its submitted ramp rates for the purpose of increasing CMSC payments.

Finally, the fact that the deviation between actual consumption and the constrained schedule during ramp down is small does not make it inherently trivial. As shown in section 7.4.5 of this Report, small deviations can have a significant impact on CMSC payments when a load is bidding at $●/MWh.

d. Finding #24 (frequent ramping at the Fort Frances Facility)

Resolute does not dispute that the Fort Frances Facility ramped up and down much more frequently in the first eight months of 2010 than it did in earlier periods.

Consistent with the information filed in response to the Panel's Requests for Information, the response attributes the increased ramping to various operational factors, including the operational implications of the shutdown of a paper machine in 2009. The response does not provide any additional information on how and why operational factors required an 85% increase in the number of self-induced ramps in the first 8 months of 2010 compared to 2009.

As in other parts of its response, Resolute accuses the Panel of attempting to change the *Market Rules* retroactively. It states that it "is not aware of a market rule which forbids participants from planning in order to manage and forecast CMSC." The Panel does not assert in this Report that such a *Market Rule* exists. But when "managing" CMSC extends to exploiting market defects for the benefit of the market participant and at significant cost to the market, then such behaviour can constitute gaming.

## C. Subsequent Correspondence

By letter dated August 22, 2014, the Panel notified Resolute that it had considered Resolute's July 2, 2014 response and altered one aspect of this Report (Finding #8) as a result. The Panel also advised of the process for finalization of this Report, including the Panel's intention to reproduce the entirety of Resolute's response as an Appendix and to include the Panel's comments on certain elements of that response as a separate Appendix. The Panel also identified the types of information that it agreed to redact from the public version of this Report, and invited Resolute to provide a redacted version of its July 2, 2014 response if Resolute wished to request confidential treatment of information contained in that response. Resolute did so and, as noted above, it is Resolute's redacted version of its response that appears as Appendix N in the public version of this Report.

A redacted version of Resolute's July 2, 2014 response was provided under cover of a letter dated September 2, 2014. In that letter, Resolute advised that, upon further review, there were some materials that fall within the scope of the Panel's October 2010 Requests for Information that were not discovered until several years after responding to those Requests for Information, and that it would advise the Panel when its review had been completed. Resolute also provided certain additional information to the Panel, including an analysis of data that in Resolute's view demonstrated that the majority of IESO data respecting dispatch was often inaccurate and could not be relied upon.

On September 30, 2014, the Panel notified Resolute that, of the supplementary materials provided on September 2, 2014 that appeared to the Panel to be potentially relevant to its investigation, the Panel assessment is that they are not inconsistent with the Panel's findings. The Panel also advised that the materials did not cause the Panel to change its view regarding the accuracy of the IESO data used to quantify the impact of the market participants' conduct.

However, the Panel allowed Resolute a further opportunity to identify, with precision, any specific factual errors in this Report and how the alleged inaccuracies affect the substance of the Panel's findings.  On October 14, 2014, Resolute advised the Panel that it had completed its review of the completeness of its responses to the Panel's Requests for Information to ensure that the information provided to the Panel was complete and accurate, and provided further information to the Panel.

**D. Update on the IESO's General Conduct Rule**

The Panel notes that amendments to the Market Rules to include the "general conduct rule" were approved by the IESO Board of Directors on June 12, 2014, and that those amendments have now come into force.