Ontario Energy Board

Commission de l'énergie de l'Ontario

The IESO Administered Markets May – October 2008

Market Surveillance Panel's 13th Monitoring Report

February 4, 2009

Briefing for the Strategic Advisory Committee

Agenda

- Summary of Key Findings/Highlights
- Decisions and Recommendations
- Accounting for Environmental Constraints in the Market

- Information Slides
  - Update on Linked Wheels
  - Price Indicators
  - Demand Indicators
  - Supply Indicators
  - Hourly Market Uplifts

Summer of 2008 – Key Findings

- Market worked reasonably well according to its design
- Hourly prices generally reflected underlying supply and demand forces
- No abuse of market power or gaming identified
- There were occasions where actions by market participants or the IESO led to inefficient market outcomes

Highlights – Compared to previous summer

- Average HOEP higher by $2.59/MWh (5.7%)
- Effective load-weighted HOEP higher by $3.04/MWh (5.7%)
- HOEP the lowest six-month price compared to surrounding markets: NY, PJM, MISO and New England
  - $5.29/MWh (10%) lower than the contiguous MISO zone
- Fuel prices have increased:
  - Appalachian coal (Lambton generators) increased 146%
  - Powder River Basin coal (Nanticoke generators) increased 34%
  - Henry Hub natural gas increased 45%

Highlights – Compared to previous summer (cont'd)

- Hourly uplift payments increased by $49 million (27%)
  - IOG down $9 million
  - CMSC up $35 million mainly in NW
  - OR up $18 million
- HOEP more dispersed with:
  - 724 hours below $20/MWh (versus 331 hours last year) and 28 hours with a negative HOEP
  - 17 hours above $200/MWh (versus 4 hours last year)
- Total domestic demand fell by 1.9 TWh (2.5%)
- Total market demand (Ontario demand plus exports) increased by 1.0 TWh (1.2%)

Recommendations - Overview

Panel has made 8 recommendations in this report:

- Three relate to price fidelity
- Four relate to dispatch
- One relates to reducing uplifts
- The recommendations are summarized in priority order below

Recommendations to Enhance Price Fidelity

Recommendation 4-1 (Chapter 4, section 2)

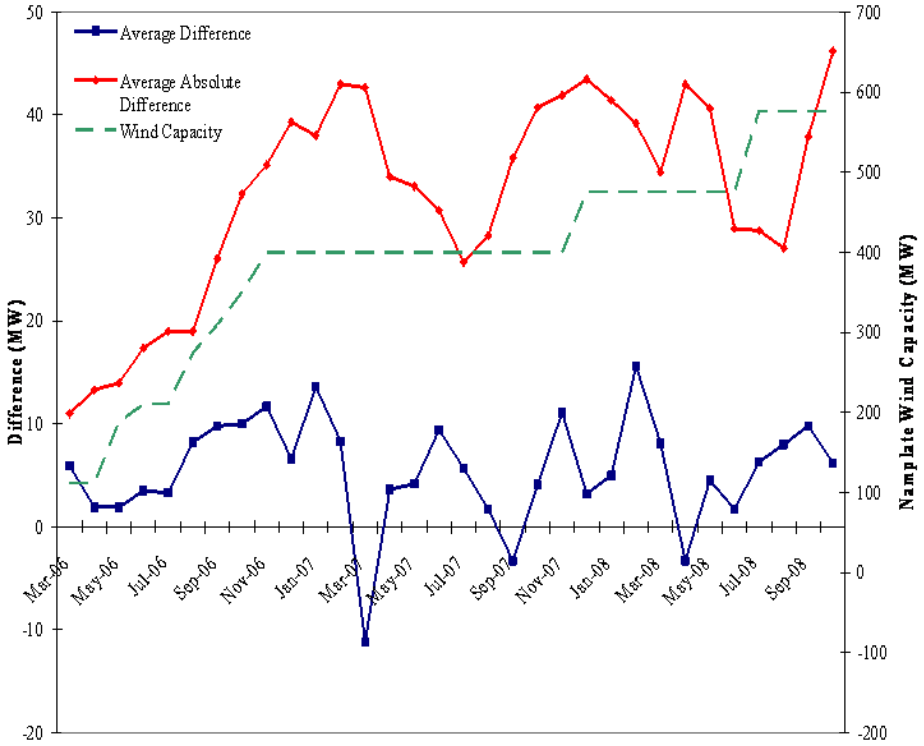
In an effort to efficiently accommodate greater levels of renewable resources in the Ontario Market:

1. **The Panel recommends the IESO consider centralised wind forecasting to reduce the forecast errors associated with directly connected and embedded wind generation in the pre-dispatch schedules;**

2. **The Panel also reiterates its December 2007 recommendation that the IESO investigate a 15-minute dispatch algorithm which should further reduce forecast errors and allow for more frequent rescheduling of imports and exports in response to the different output characteristics of renewable resources.**

Recommendations to Enhance Price Fidelity (cont'd)

Wind Forecast Error and Wind Capacity



- California obtained a 3-5% error reduction in their day-ahead wind forecast from centralised forecasting
- Ontario wind forecast error averaged 6.5% during the latest summer

Recommendations to Enhance Price Fidelity (cont'd)

Recommendation 2-2 (Chapter 2, section 2.1.11)

The Panel recommends that when an intertie trade fails in some intervals while not in others within the hour, the IESO should apply a failure code only for those intervals with the failure.

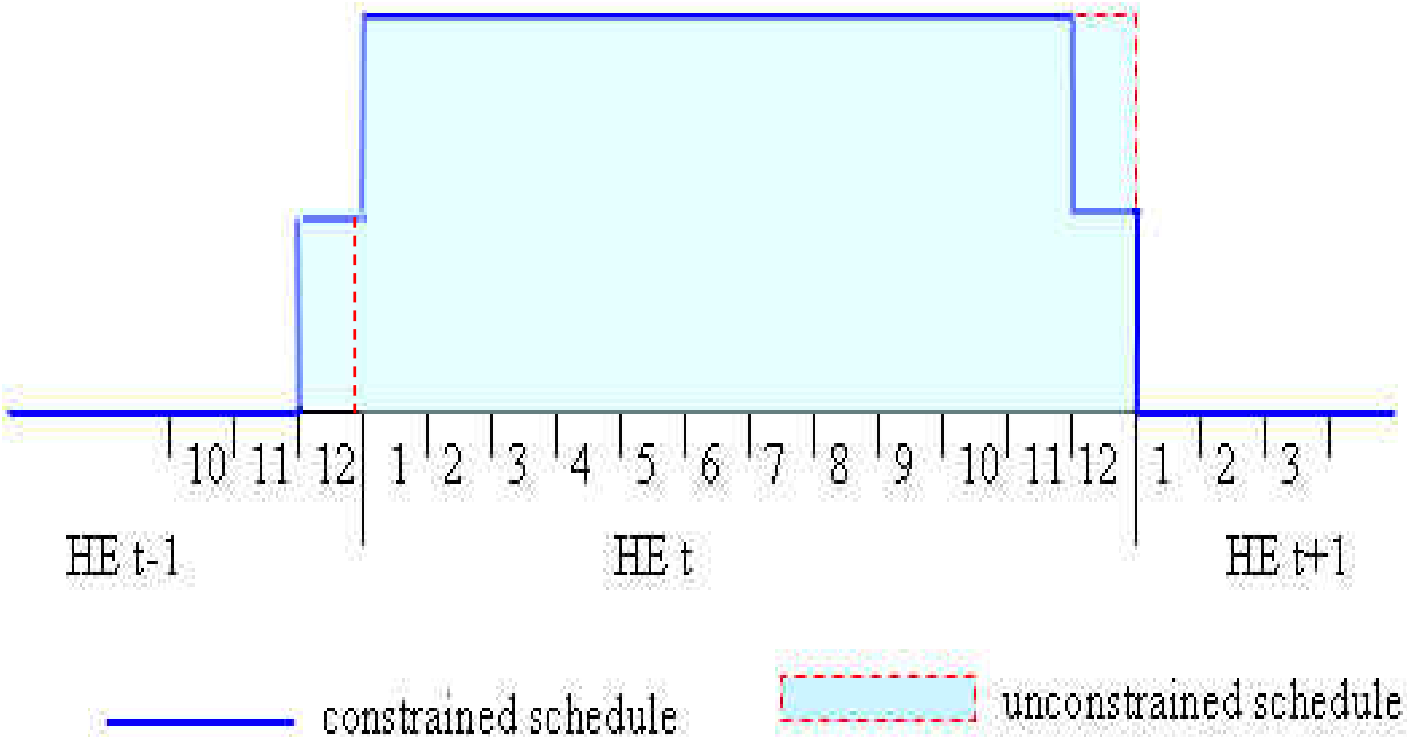
Recommendations to Enhance Price Fidelity (cont'd)

Recommendation 2-1 (Chapter 2, section 2.1.1)

The Panel recommends that the IESO's ramping of intertie schedules in the unconstrained process (the pricing algorithm) be consistent with actual intertie procedures and the treatment in the constrained scheduling process.

Recommendations to Enhance Price Fidelity (cont'd)

Inter-Tie Schedules used in the Constrained and Unconstrained Sequence



Recommendations to Enhance Price Fidelity (cont'd)

- ***Simulated Comparison of With and Without Ramp Scenarios,***
- ***September 12, 2007 to June 30, 2008***
- ***($/MWh)***

	"Actual" HOEP	HOEP with all intertie trades ramped
Average	$47.68	47.58

- Simulation found HOEP would have been $0.10 less on average with the correct intertie ramping formulation in the unconstrained sequence
- Differences in individual hours ranged from -$46.25/MWh to +$66.71/MWh

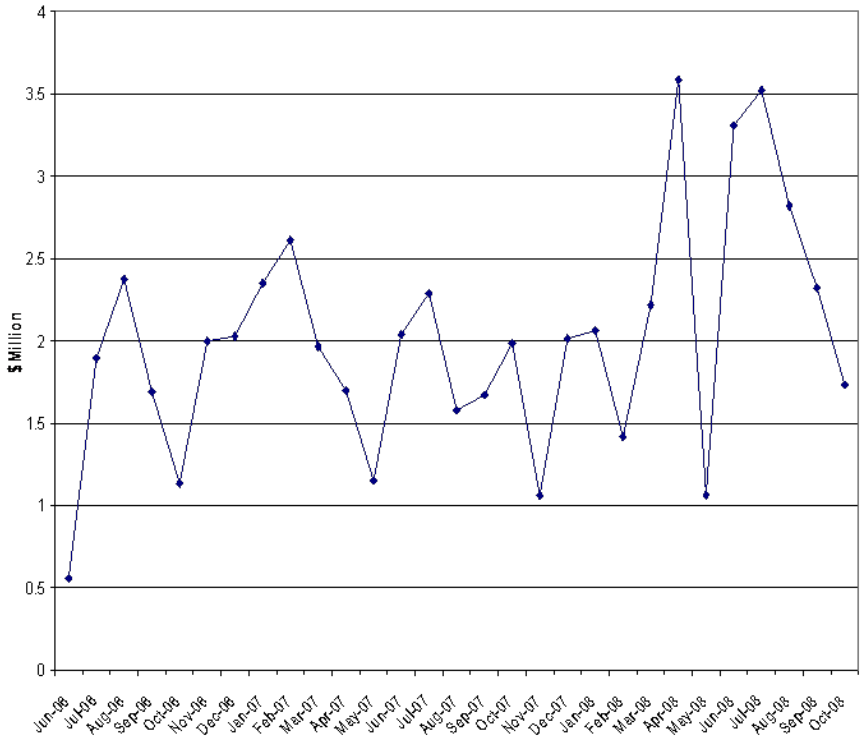
Recommendations on Dispatch

Recommendation 3-3 (Chapter 3, section 3.3)

In consideration of the length of time until the Panel's prior recommendation of an optimized Day Ahead Commitment Process (DACP) can be put in place (estimated to be 2011), the Panel recommends that the IESO consider basing the Generator Cost Guarantee on the offer submitted by the generator or other interim solutions that allow actual generation costs to be taken into account in DACP scheduling decisions.

Day-Ahead Generation-Cost-Guarantee (GCG) Payments

Monthly DA-GCG Payments
June 2006 through October 2008
($ million)



DA-GCG on Weekdays and Weekends,
June 2006 to October 2008
($ million)

	2006	2007	2008	Total
Weekdays	11.65	18.39	17.22	47.26
Weekends	1.74	3.93	5.11	10.89
Percentage of GCG on weekend	13	18	23	19

Recommendations on Dispatch (cont'd)

Recommendation 3-5 (Chapter 3, section 3.5)

The Panel recommends that market participants' offers should reflect environmental costs flowing from the environmental standards established by the applicable regulatory authorities.

- ***See further discussion below on Accounting for Environmental Constraints in the Market***

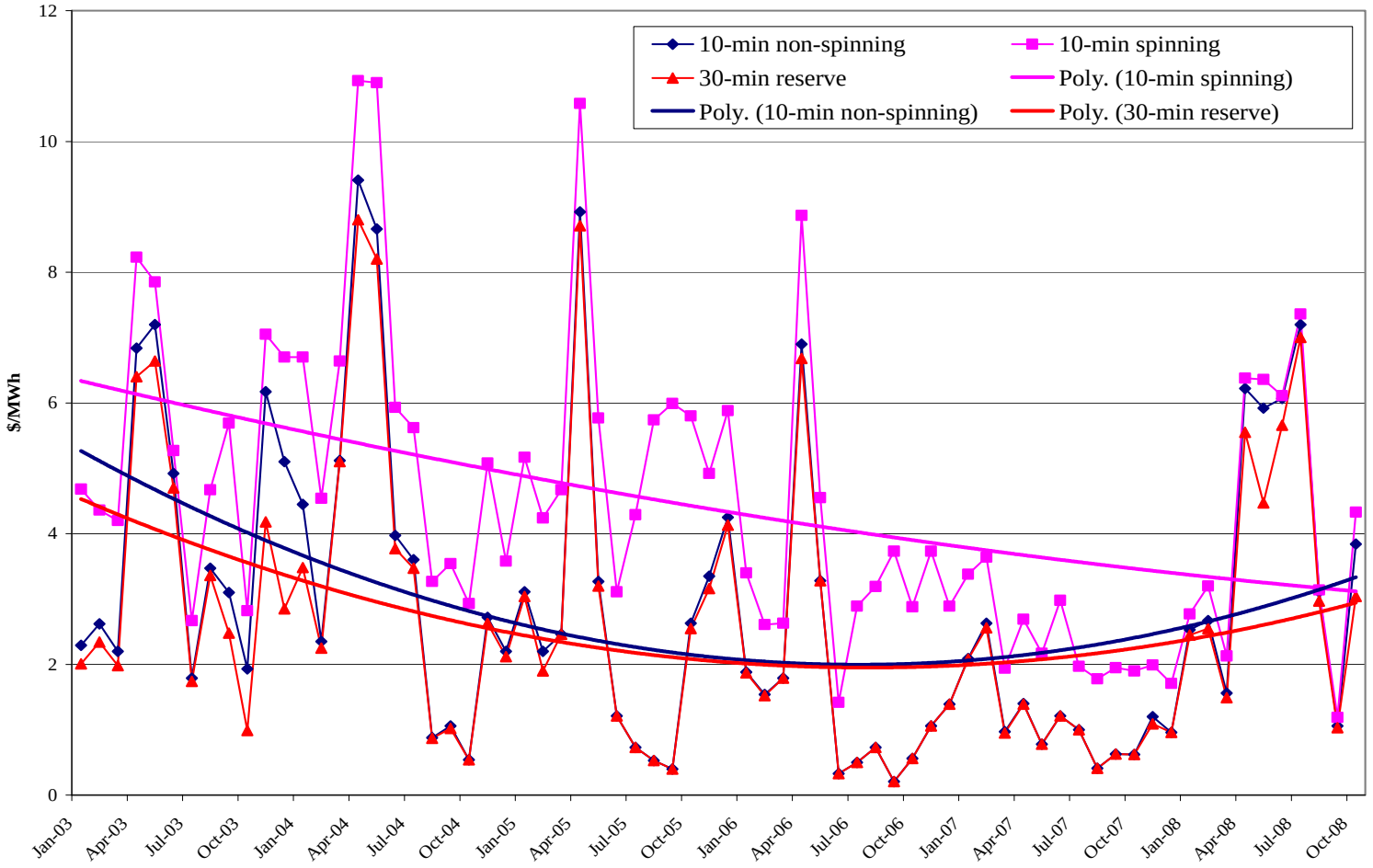
Recommendations on Dispatch (cont'd)

Recommendation 3-4 (Chapter 3, section 3.4)

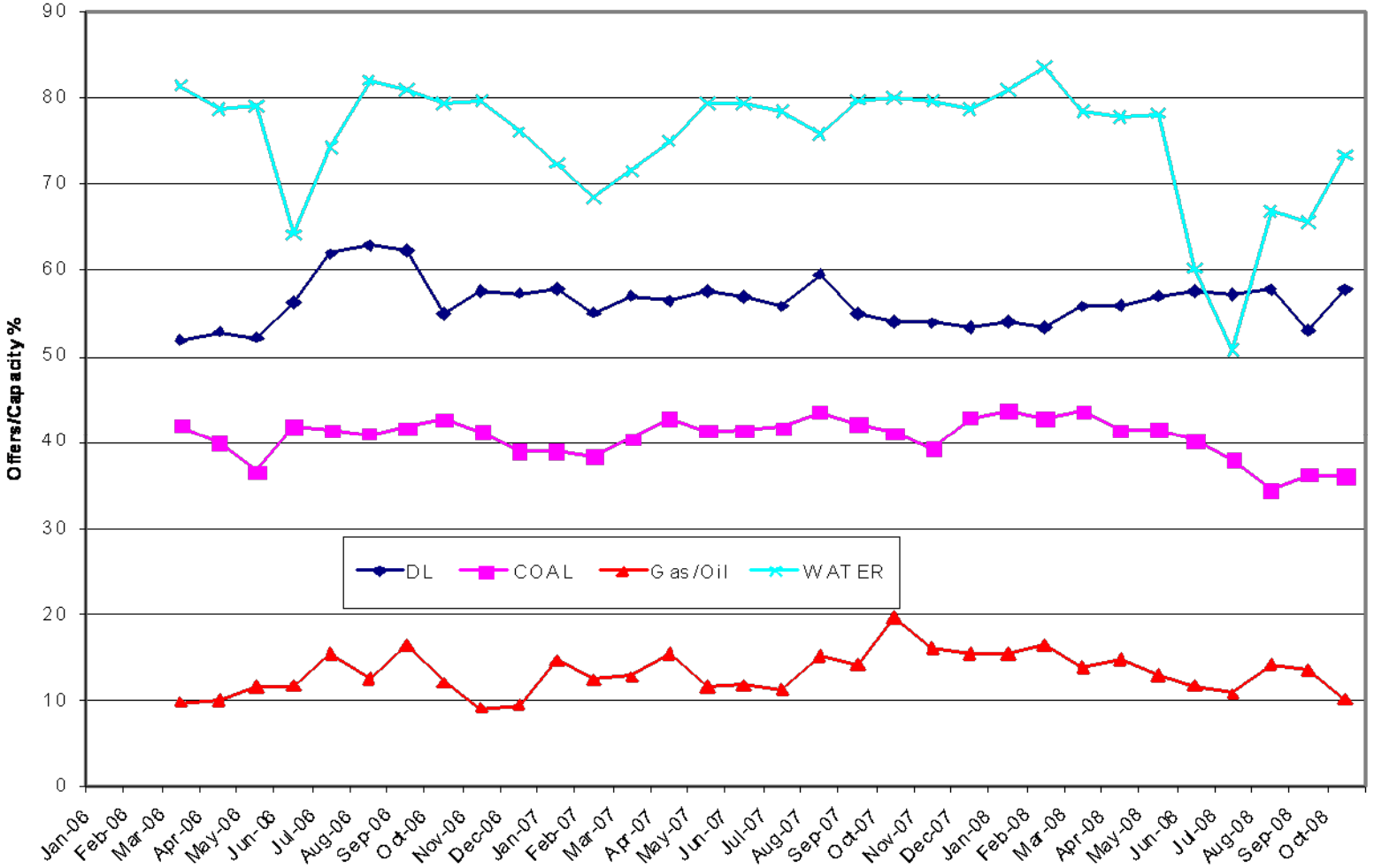
As coal-fired generators are eventually phased out, the market will require replacement for this source of Operating Reserve (OR). New gas-fired generators are generally not offering OR. The Panel recommends that the IESO and OPA explore alternatives for obtaining appropriate OR offers from recent and future gas-fired generation entrants.

Average OR Prices by Type
(January 2003 - October 2008)

- More supply with new generation but increasing OR prices



Total OR Offered Relative to Capacity by Resource Type
(January 2006 – October 2008)



Average OR by Type
(May - October 2008)

Average Sources of Operating Reserve On-Peak, May – October 2008

	Total OR	%
Hydro	622	45.9
Dispatchable Load	231	17.0
Coal	239	17.6
Oil/Gas	140	10.3
CAOR	73	5.4
Export	52	3.8

Recommendations on Dispatch (cont'd)

Recommendation 3-1 (Chapter 3, section 3.1)

1. **In light of the Panel's findings on the inefficiency of the Demand Response Phase 3 (DR3) program, the Ontario Power Authority (OPA) should review the effectiveness and efficiency of the program.**

2. **Until that review is completed, to improve short term dispatch efficiency:**

   i) the IESO, with input from the OPA, should improve the supply cushion calculation; and/or

   ii) the OPA should develop other triggers such as a pre-dispatch price threshold that could be better indicators of tight supply/demand conditions.

DR3 Programming is not Targeting Successfully

Hours when DR3 was Activated
(August - October 2008)

Date	Activation Hour	Highest Demand in the hours (MW)	Rank of the Highest Demand in Each Activation		Highest HOEP in the Hours ($/MWh)	Rank of the Highest HOEP in Each Activation	
			Aug - Oct 2008	All 2008		Aug - Oct 2008	All 2008
08/18/2008	15 - 18	22,477	9	58	100.12	78	477
09/02/2008	14 - 17	22,643	3	40	214.00	10	19
09/03/2008	14 - 17	23,016	1	23	105.87	57	371
09/04/2008	15 - 18	21,606	37	184	83.25	173	897
09/12/2008	14 - 17	18,921	268	1,965	78.53	206	1,085
09/17/2008	15 - 18	18,793	301	2,103	41.81	1,282	4,634
10/28/2008	17 - 20	19,320	172	1,521	83.85	169	871
10/29/2008	18 - 21	19,322	171	1,518	87.72	132	733

Targeted Successfully

DR3 Programming is not Targeting Successfully cont'd

IESO Supply Cushion vs MAU Supply cushion at 3 Hours Ahead (August - October 2008)

	IESO SC	MAU SC
18-Aug	32%	17%
02-Sep	29%	16%
03-Sep	27%	16%
04-Sep	35%	21%
12-Sep	42%	26%
17-Sep	37%	25%
28-Oct	36%	20%
29-Oct	42%	21%

What is the number below 16% in the period

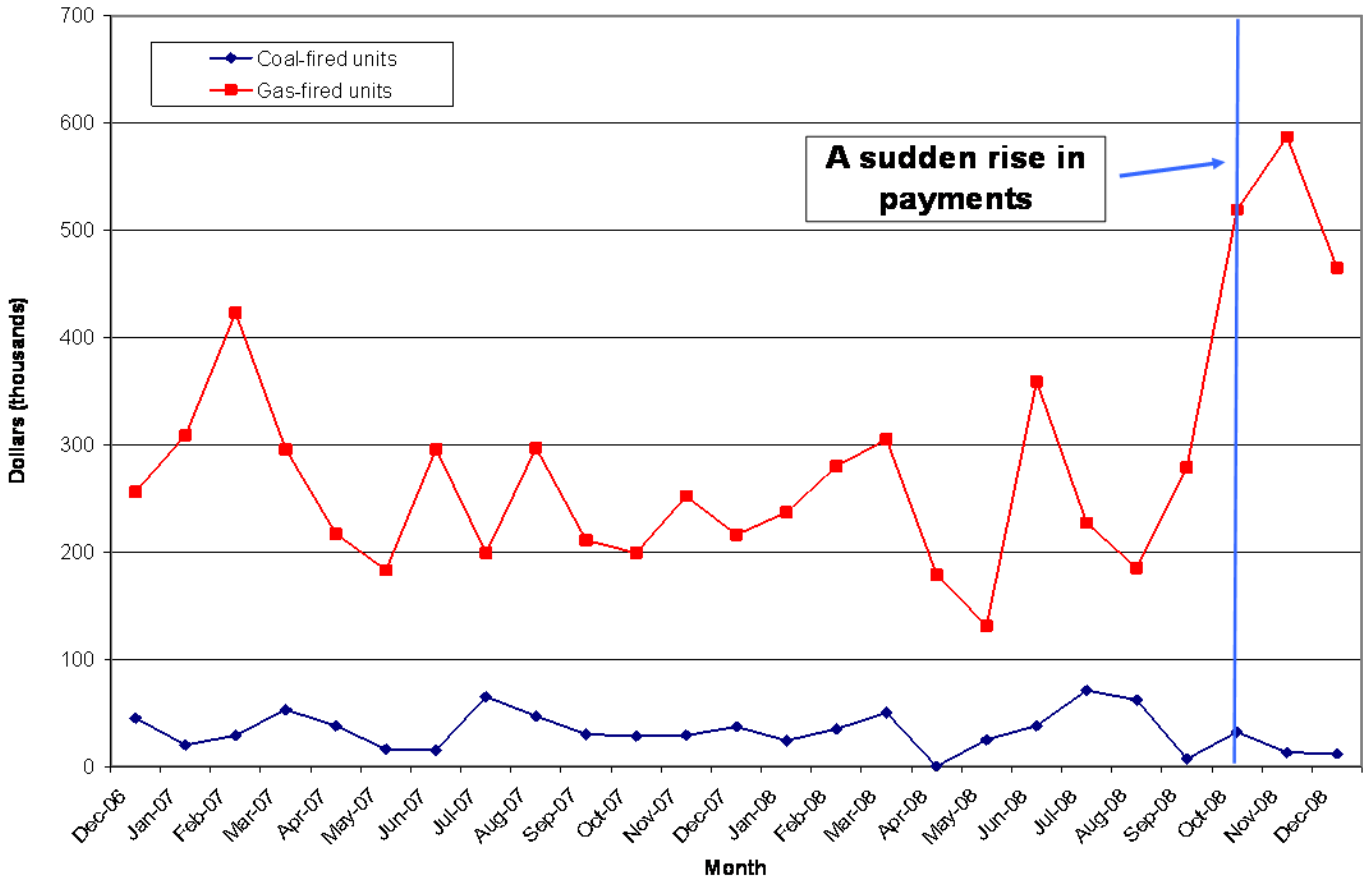
Recommendation on Uplifts

Recommendation 3-2 (Chapter 3, section 3.2)

In an earlier report, the Panel encouraged the IESO to limit self-induced congestion management settlement credit (CMSC) payments to generators when they are unable to follow dispatch for safety, legal, regulatory or environmental reasons. The Panel further recommends that the IESO take similar action to limit CMSC payments where these are induced by the generator strategically raising its offer price to signal the ramping down of its generation.

CMSC Payments for Shut-downs have been Escalating

Monthly Constrained-on Payments for Fossil-fired Generators (December 2006 to December 2008)



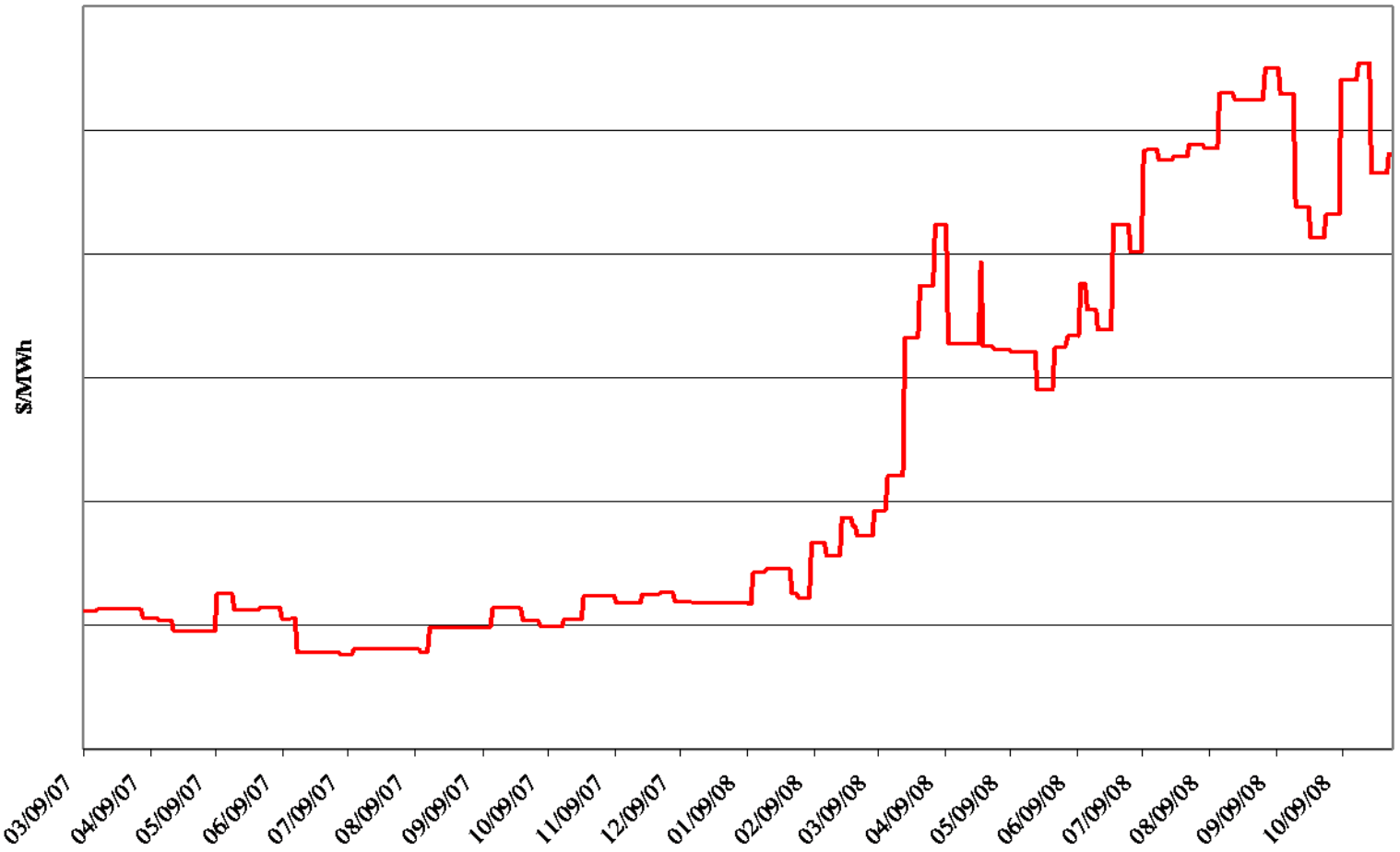
Accounting for Environmental Constraints in the Market – General Principles

- The Panel believes that market participants can comply with government environmental standards without compromising the efficiency of the IESO-administered markets
- Electricity offers should reflect the costs of complying with the environmental standards the government has established
- The manner in which environmental costs are taken into account, however, is crucial
- When environmental costs are properly taken into account, the resulting equilibrium in the Ontario electricity market is efficient in the broadest sense of the word

Accounting for Environmental Constraints in the Market – NO_x and SO_2 Emissions

- Emissions Caps have been set on NO_x and SO_2 emissions from Ontario (and other) power plants
  - Market Participant's fossil-fired units are below the Gov't emissions caps
  - MP can and does buy and sell credits as needed
- MP's fossil-fired units have different NO_x and SO_2 attributes.
  - Facility A have lower emissions but have been facing higher fuel costs than Facility B
- MP decided to change the merit order by offering lower emissions units below cost to be selected ahead of higher emissions generators
- MP had to offer the lower emitters at a "negative adder"

Negative Adder Applied to Offers at Facility A, (March 9, 2007 – October 31, 2008



Accounting for Environmental Constraints in the Market – NO_x and SO_2 Emissions

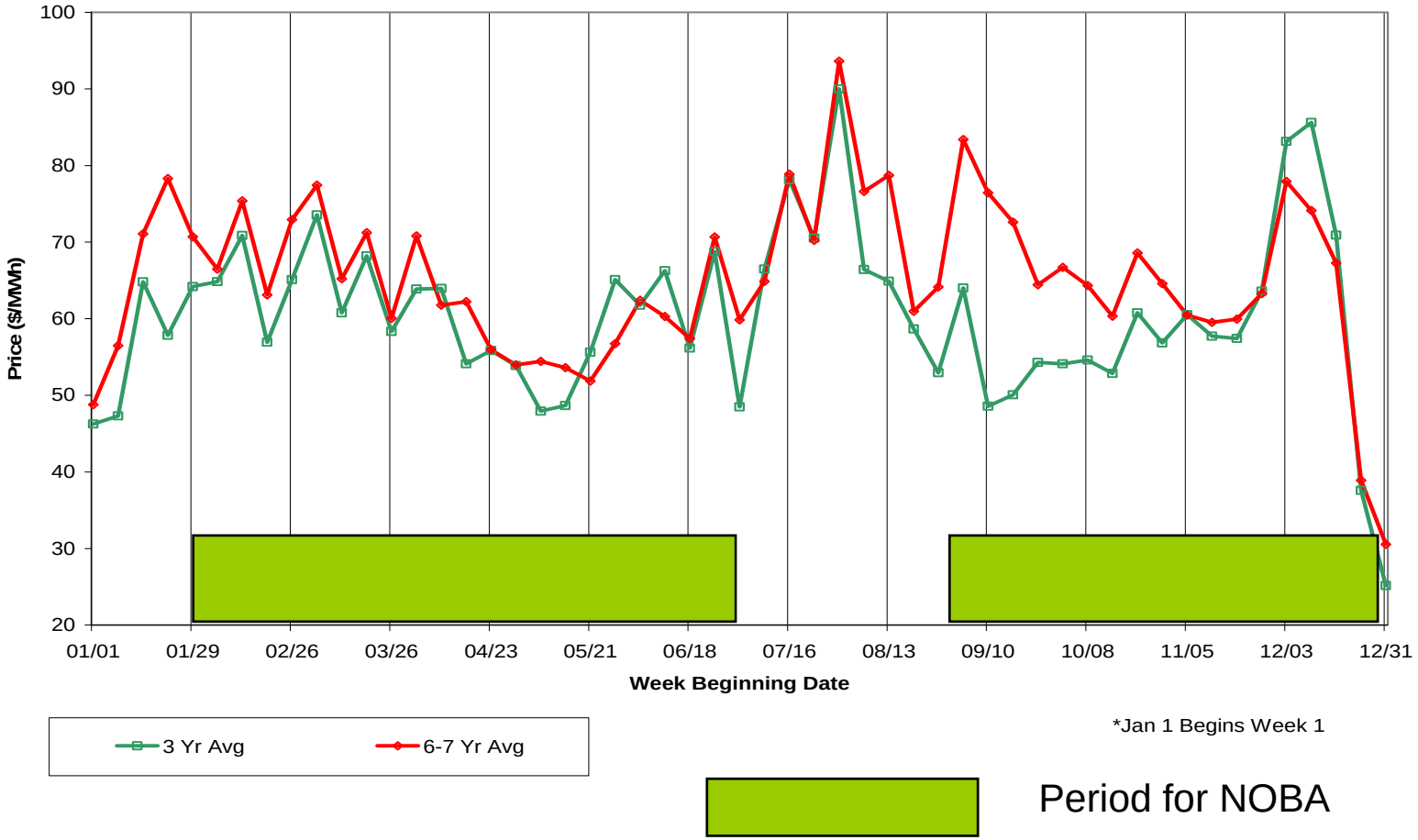
- Changing the merit order resulted in:
  - Estimated market inefficiencies in the order of $19 million from November 2007 to October 2008 ($16 million between May and October 2008)
  - Potentially lowering the HOEP by as much as $2/MWh on average, although export demand response would have an offsetting effect on the price suppression
- In part, MP was importing fuel and exporting the power made from it at a loss

Accounting for Environmental Constraints in the Market – CO_2 Emissions

- The Government has directed OPG to limit CO_2 output from coal-fired units in 2009 to 19.6 mmt (which translates into roughly 20 TWh of electricity production, a 15% decline from 2008)
- The Panel analyzes the market effect like any other energy-limited resource
- OPG has indicated that it will use an adder of $7.50/MWh on all offers as one component for achieving compliance with the target.
- OPG will also use two other components which involve removing capacity from the market
  - Extension of planned outages ("CO_2 outages")
  - Not Offered But Available Generators ("NOBA's")

Weekly Average On-Peak HOEP
(May 2002 - Nov 2008 and Dec 2005 - Nov 2008)

- NOBA parking planned in some high-priced weeks



Accounting for Environmental Constraints in the Market – CO_2

- In principle, an adder can reflect opportunity cost of an energy limited resource
  - If OPG relied solely on an appropriate adder, this would lead to efficient and transparent production and consumption responses in the market
- Capacity removals are likely to be less efficient
  - They are arbitrary and lumpy, which limits responsiveness to the highest-priced hours
- OPG indicates there will be cost savings from “parking” generators but magnitude is unclear
- The Panel will monitor the effect of OPG’s implementation strategies on the market during 2009

Slides for Information Purposes

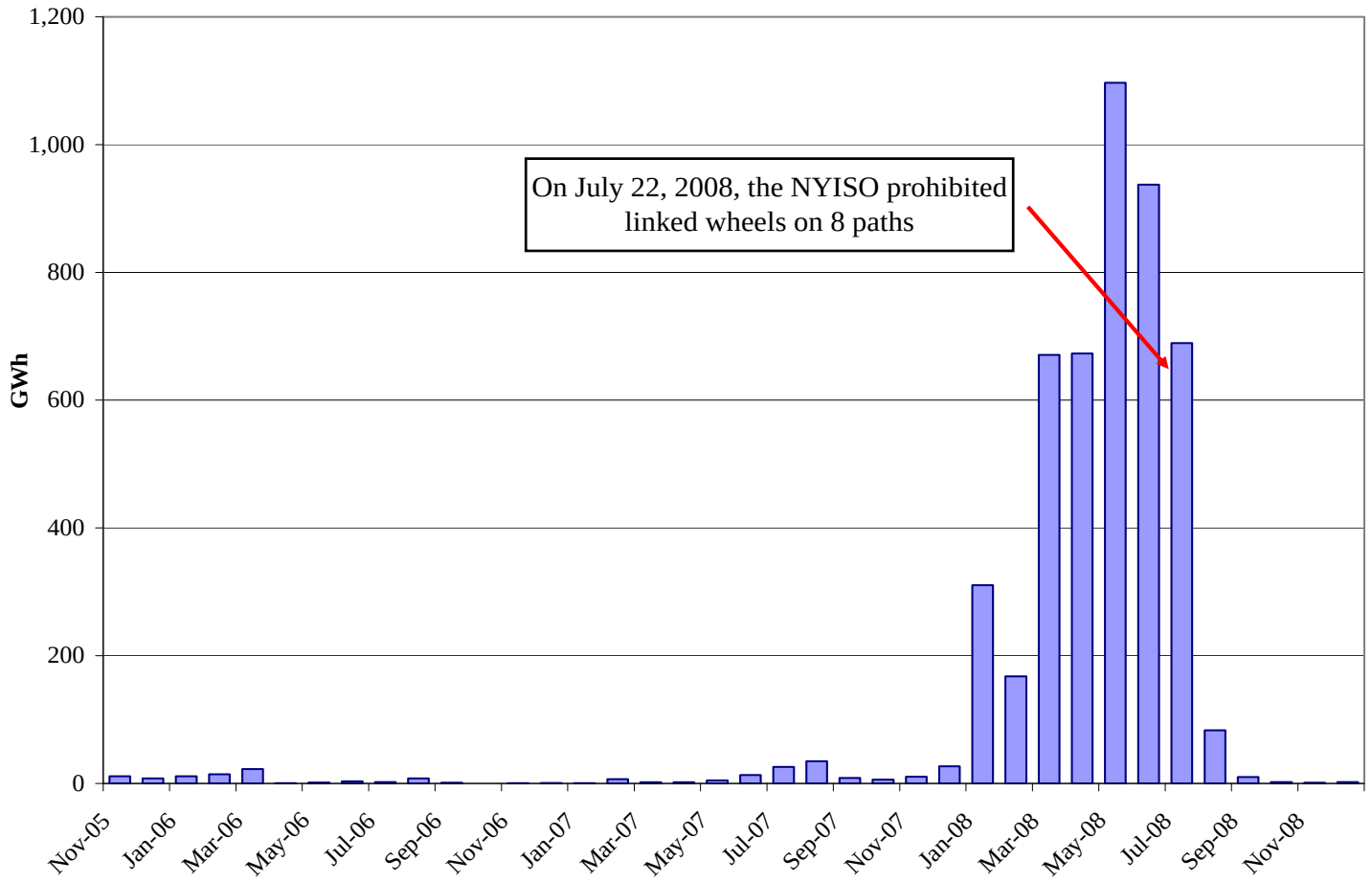
Update on Linked Wheels

- Panel has previously discussed linked wheels
  - The Market Assessment Unit identified this development in January 2008 and initiated discussions with its U.S. counterparts
  - NYISO initiated a tariff revision in July 2008 prohibiting certain indirect transmission paths that had caused congestion-related costs in NYISO. Separately, FERC's Office of Enforcement announced a non-public investigation into power flows in NYISO

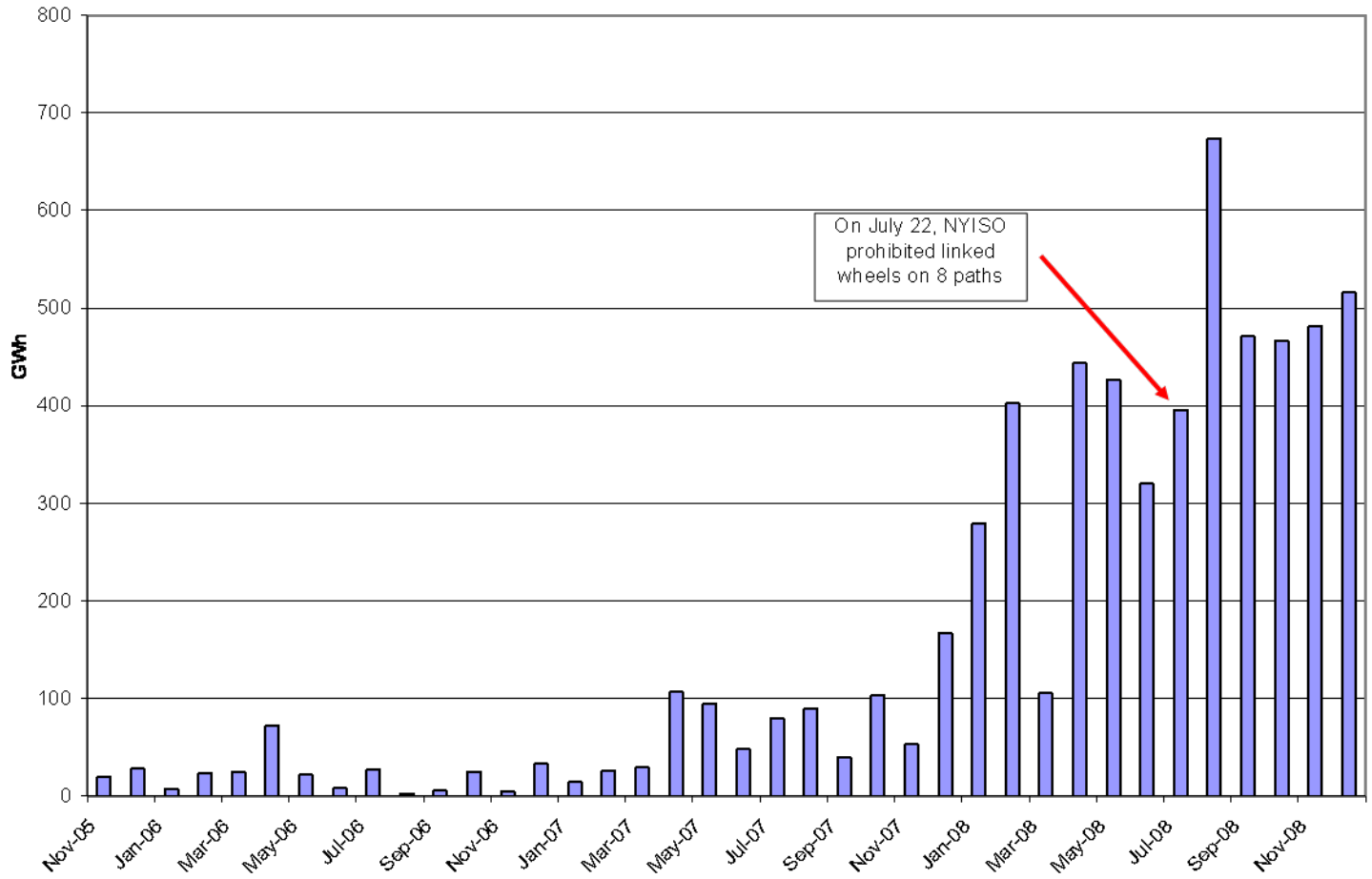
Update on Linked Wheels (cont'd)

- While wheels from New York to PJM through Ontario and MISO have been prohibited, wheels from Ontario to PJM through MISO remains available
- Both Ontario and New York use the same Market design for wheels (contract path rather than physical flow, which PJM and MISO use)
- To date inefficiencies in Ontario have not been observed
- The Panel has asked the MAU to continue monitoring and report back if inefficiencies in Ontario occur as a result of these wheels

Monthly Linked Wheels through Ontario
(November 2005 - December 2008 in GWh)



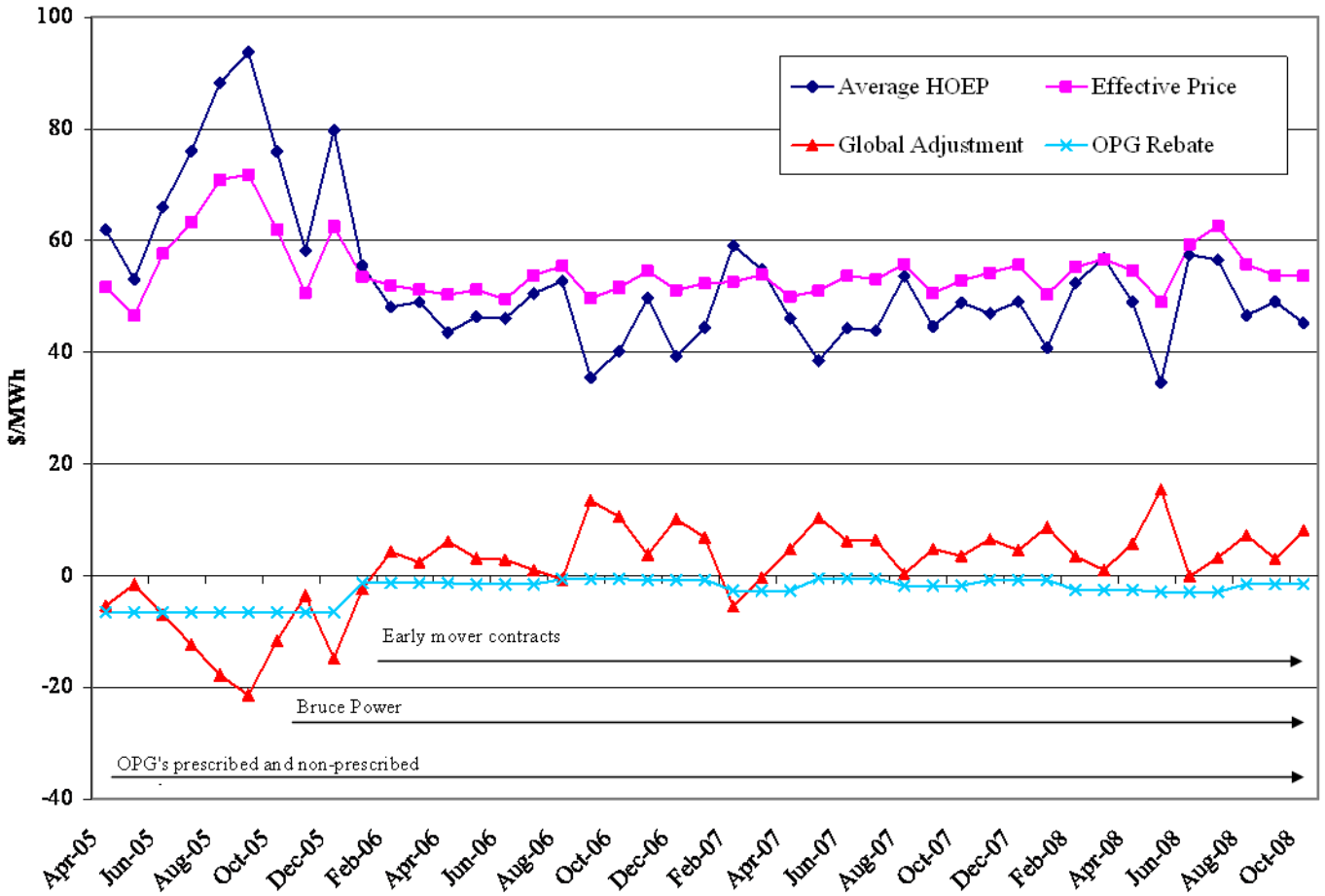
Scheduled Wheels From Ontario to PJM
(November 2005 - December 2008 in GWh)



Price Indicators

- Average HOEP higher by $2.59/MWh (5.7%)
- Effective load-weighted HOEP higher by $3.04/MWh (5.7%)
- HOEP the lowest six-month price compared to surrounding markets: NY, PJM, MISO and New England
    - $5.29/MWh (10%) lower than the contiguous MISO zone

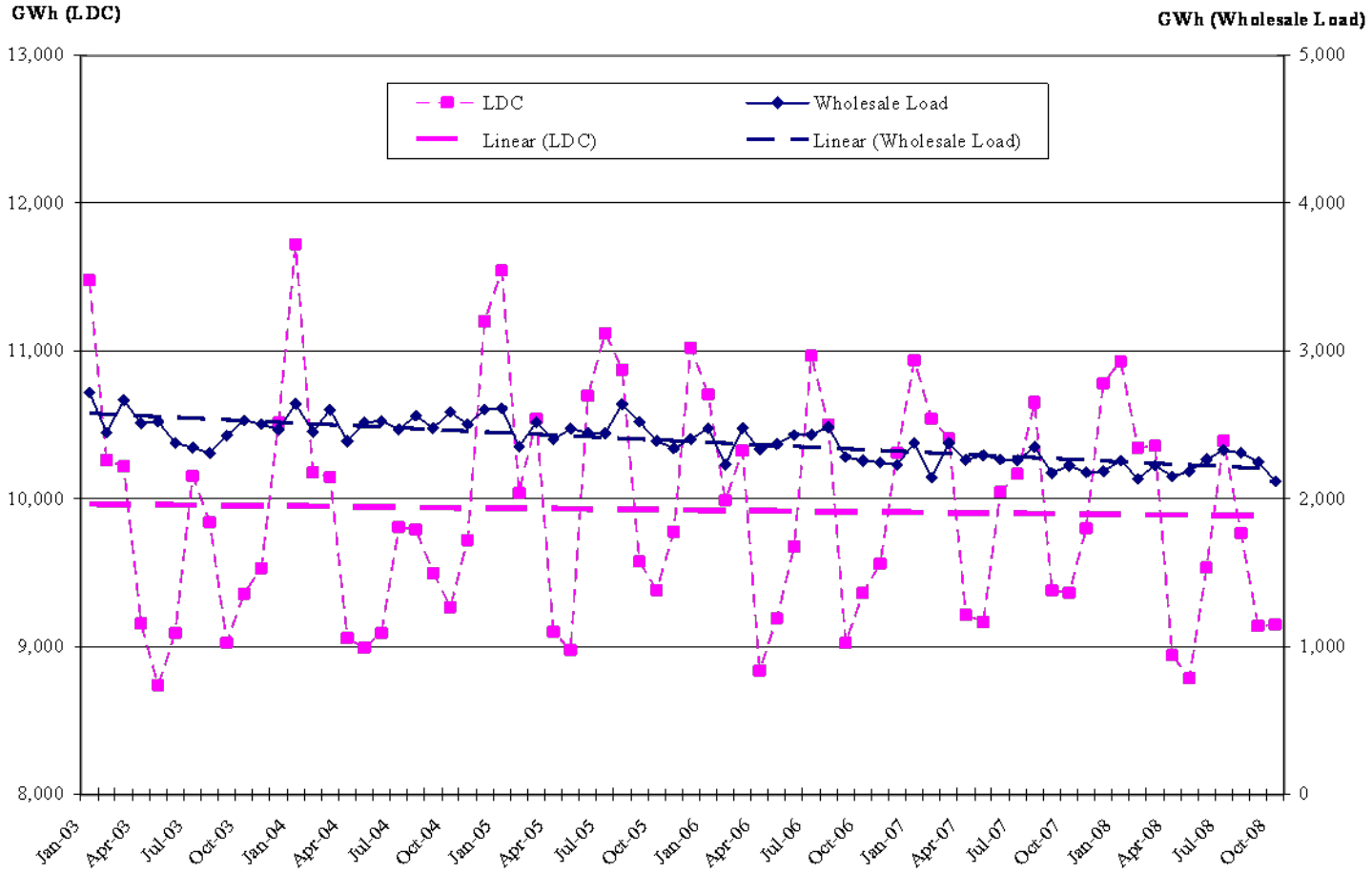
Monthly HOEP versus Effective HOEP
(April 2005 – October 2008)



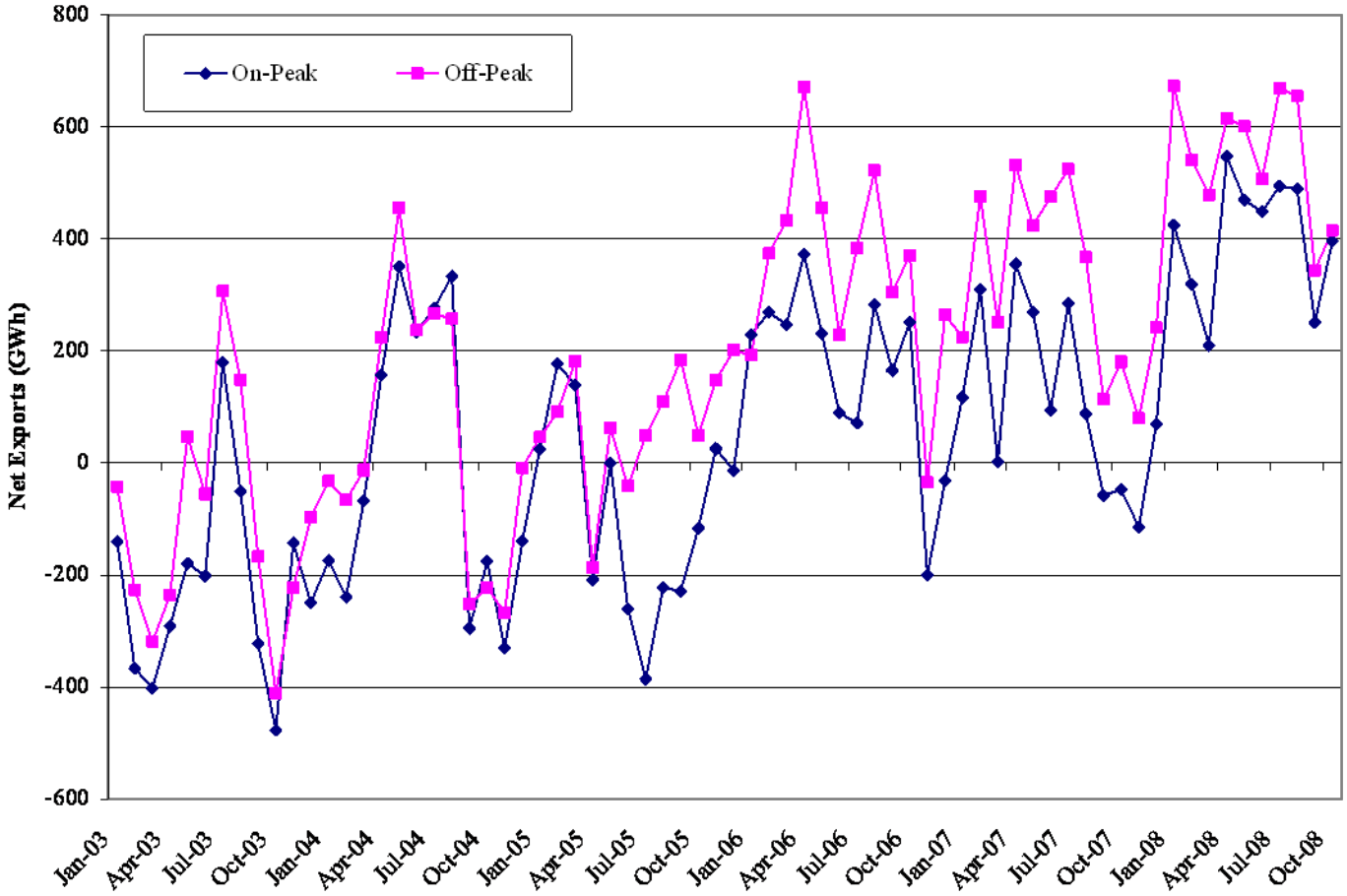
Demand Indicators

- Ontario energy demand fell by 2.5% (1.9 TWh)
- Total market demand (Ontario demand plus exports) increased by 1.2 (1.0 TWh)
  - Ontario was a net exporter in all months

LDC and Wholesale Load Declining
(January 2003 – October 2008)



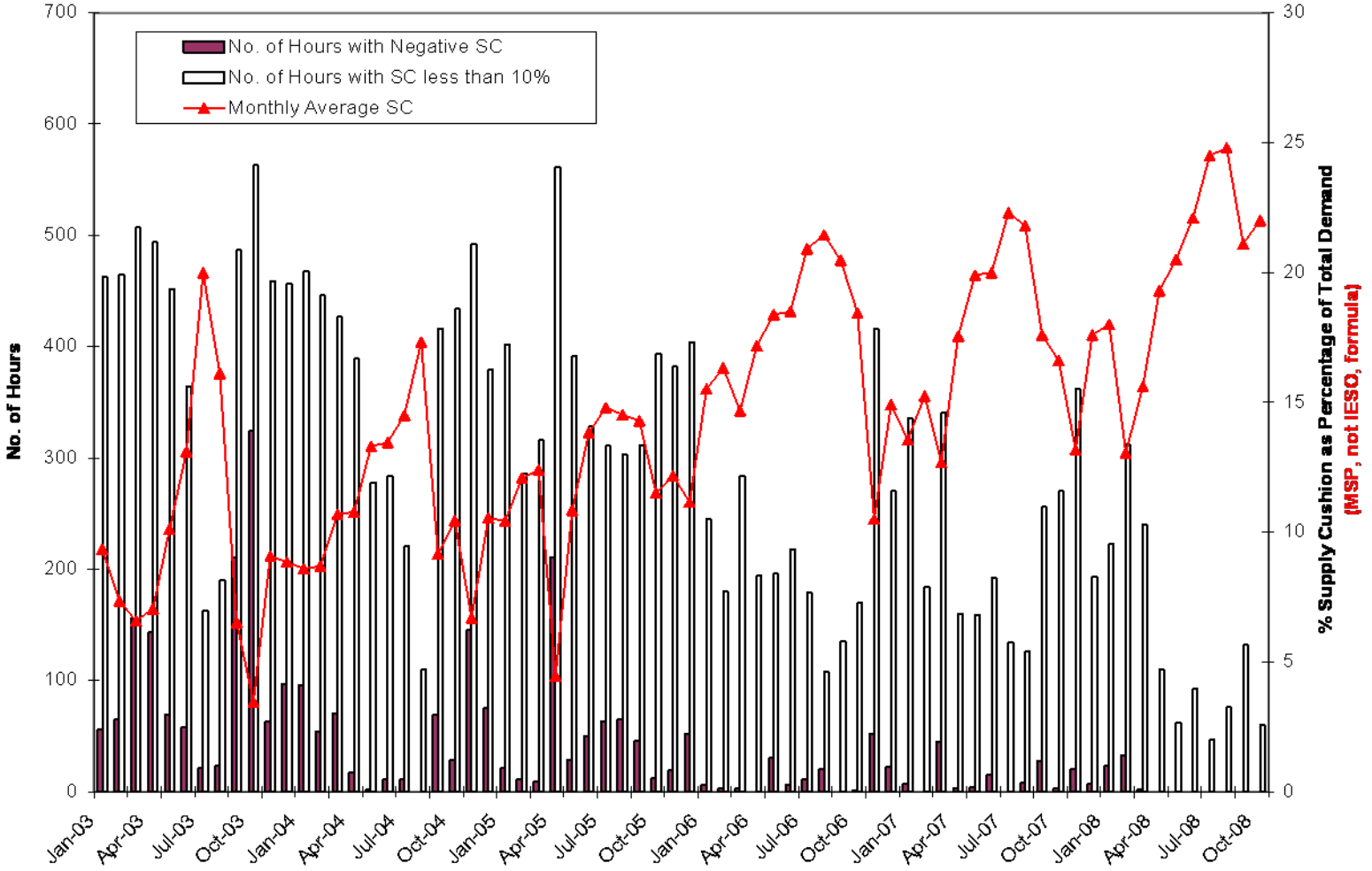
Net Exports Increasing
(January 2003 – October 2008)



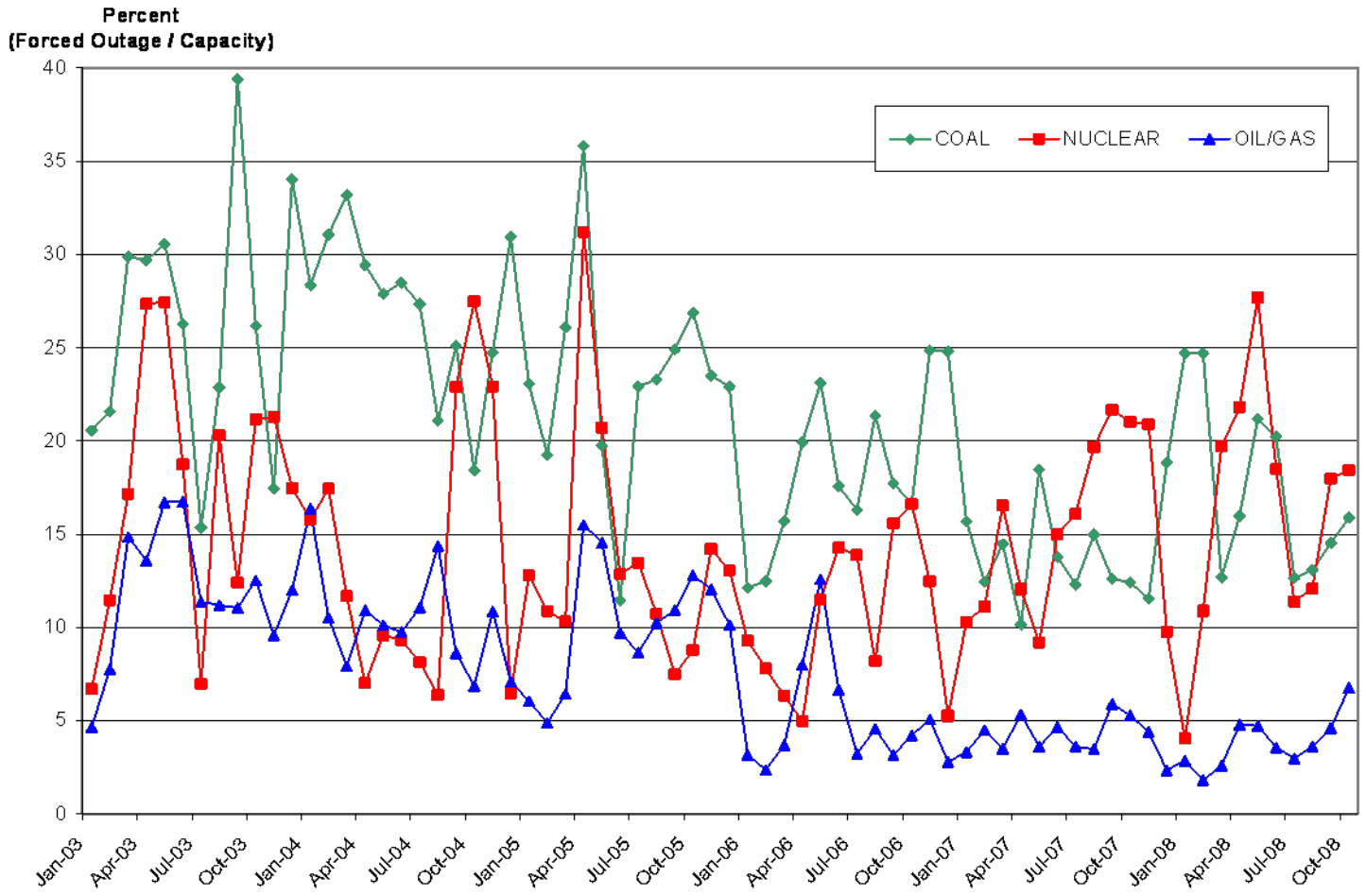
Supply Indicators

- Supply cushion has been progressively increasing since 2003 with both new generation and declining consumption
- Coal forced outage rates have declined continuously since 2003
- Nuclear forced outage rates have begun to increase recently
- Wind generation increasing, as is MW of forecast error

Improved Real-time Supply Cushion Conditions
(January 2003 to October 2008)



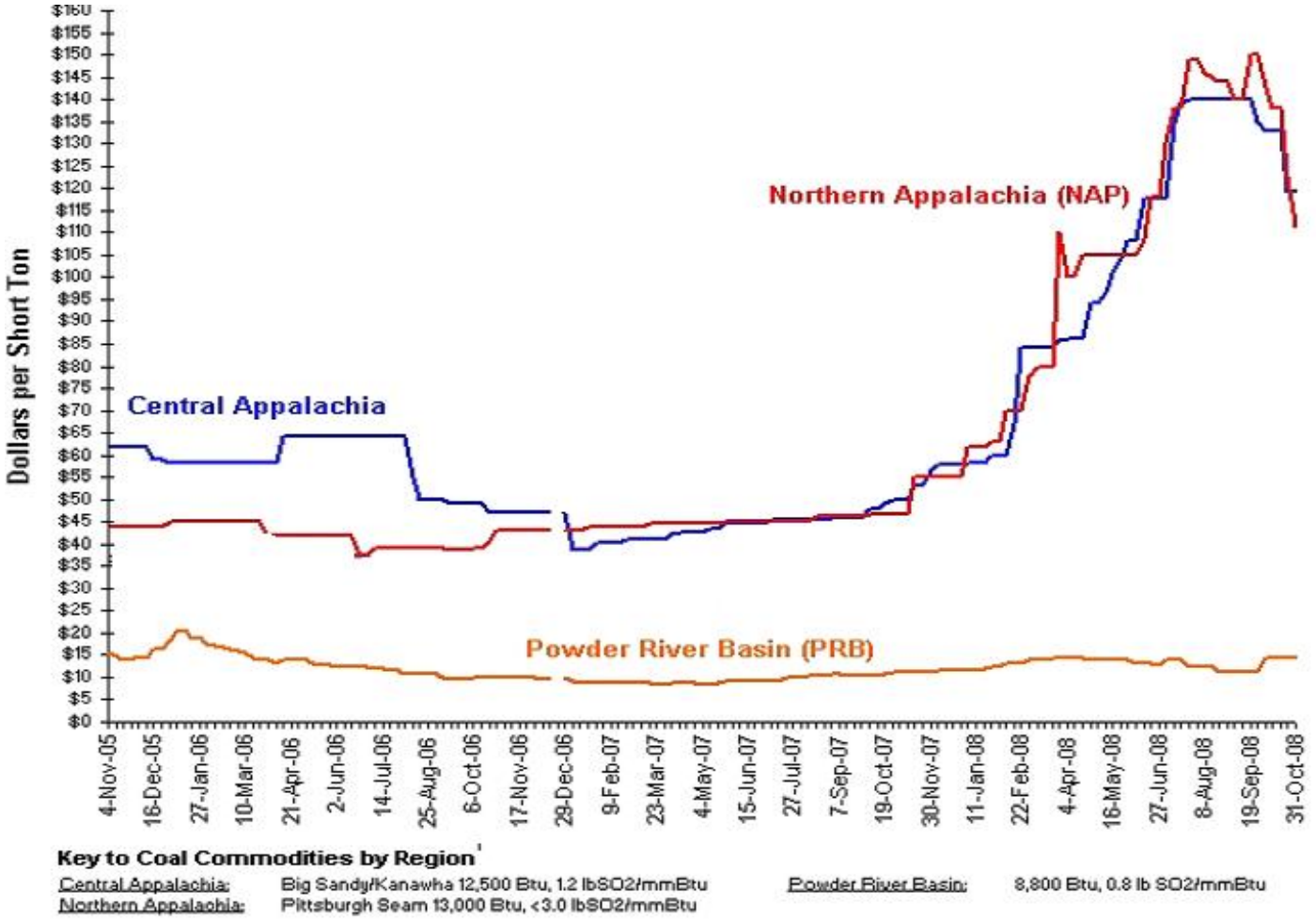
Forced Outages Relative to Total Capacity by Fuel Type (January 2003 – October 2008)



Supply Indicators (cont'd) – Underlying Fuel Prices

- Both coal and natural gas prices have increased from summer 2007 period
- Ontario coal-fired generators use both Eastern Coal (+146%) and Powder River Basin Coal (+34%)
- Natural gas prices at Henry Hub have risen 45%

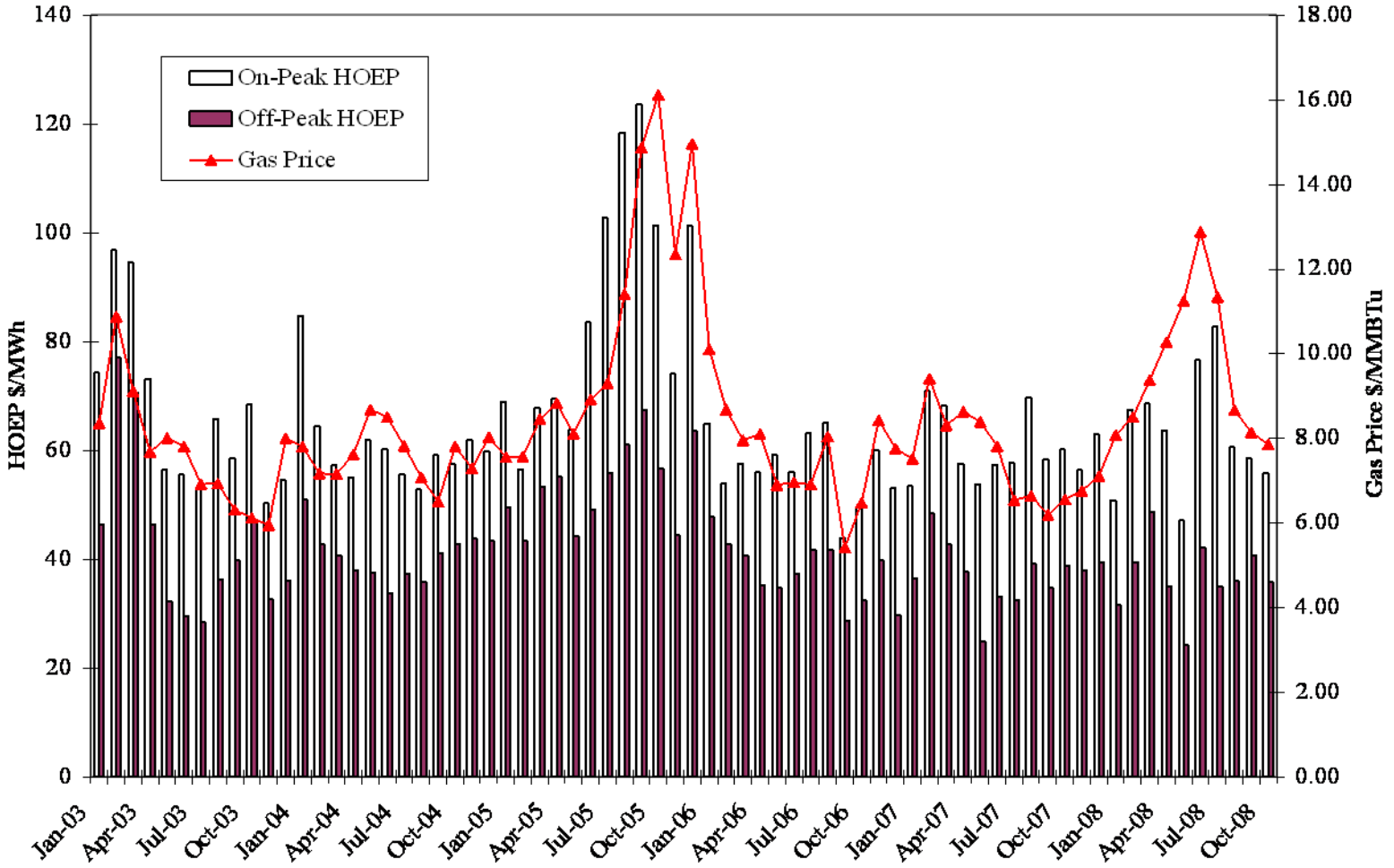
Coal Costs by Type
(November 2005 - October 2008)



Key to Coal Commodities by Region[1]

Central Appalachia:	Big Sandy/Kanawha 12,500 Btu, 1.2 lbSO2/mmBtu	Powder River Basin:	8,800 Btu, 0.8 lb SO2/mmBtu
Northern Appalachia:	Pittsburgh Seam 13,000 Btu, <3.0 lbSO2/mmBtu		

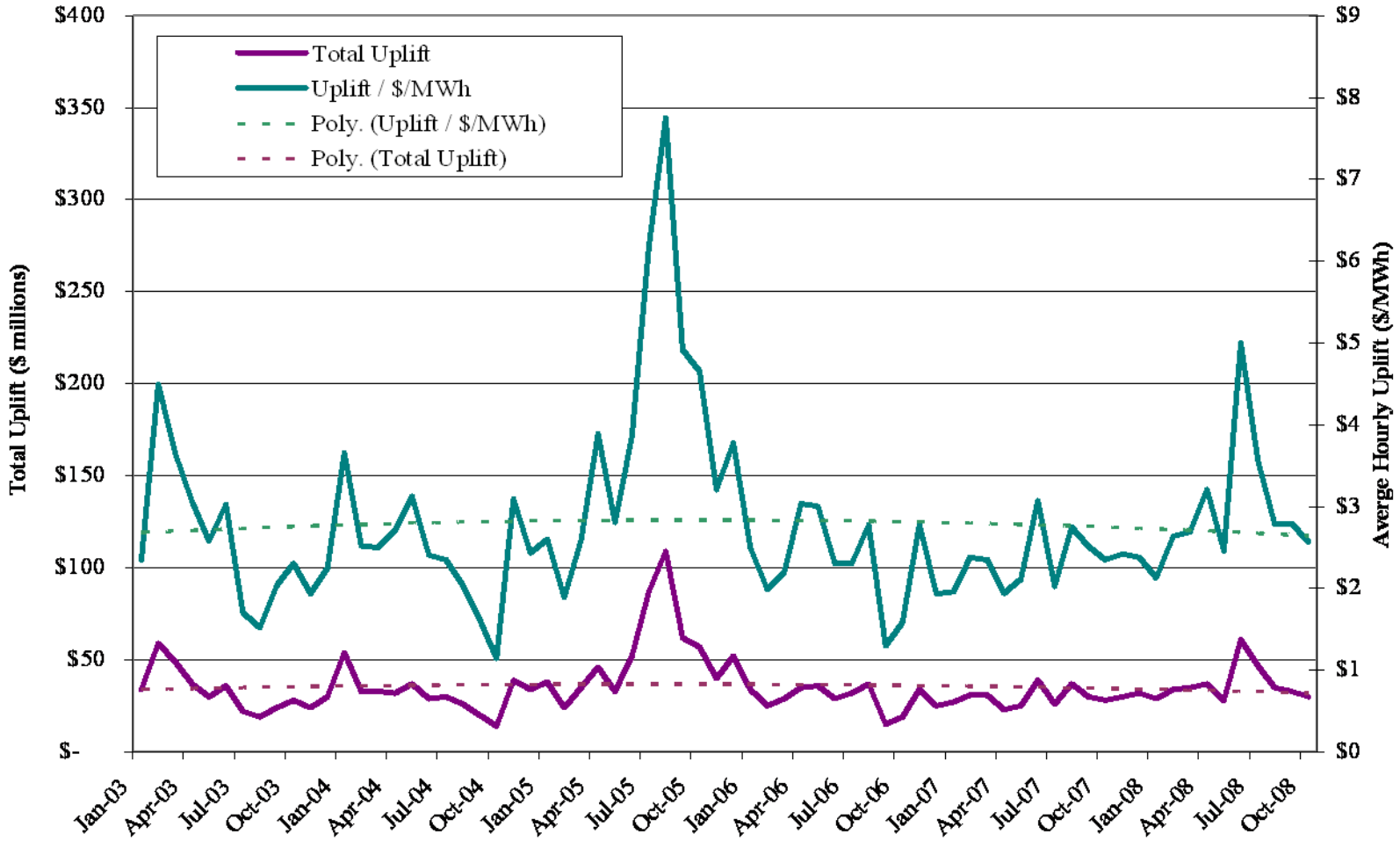
Monthly Natural Gas Prices vs. HOEP
(January 2003 – October 2008)



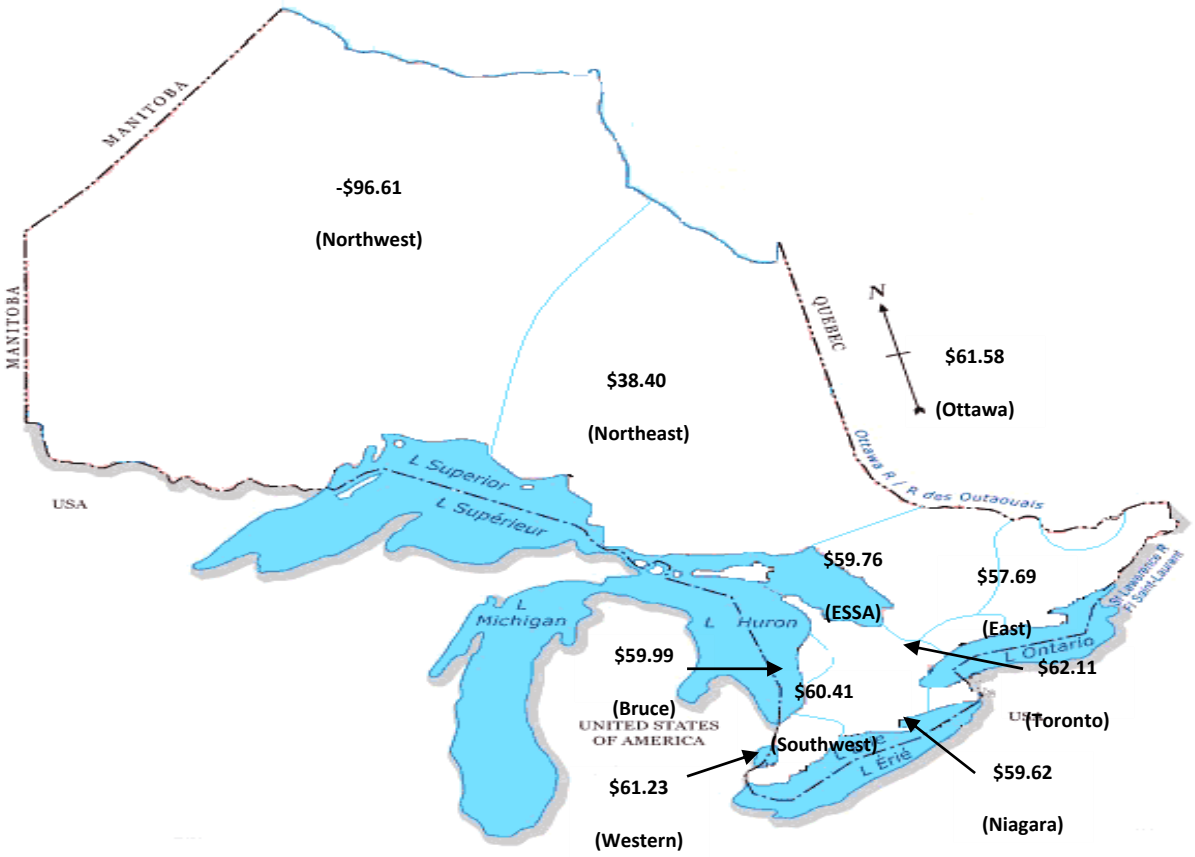
Hourly Market Uplifts

- Hourly uplift increased from $183 million in 2007 to $232 million in 2008 (27%)
  - Mostly the result of a $35 million increase in (CMSC) payments (45%)
  - Constrained off import payments in the North-West account for most of the increase in CMSC
  - Operating reserve payments increased from $6 million in 2007 to $24 million in 2008
- Shadow prices in the Northwest averaged -$96/MWh due to abundant hydroelectric energy and low Northwest demand
  - Generators receive payment equivalent to HOEP when constrained off

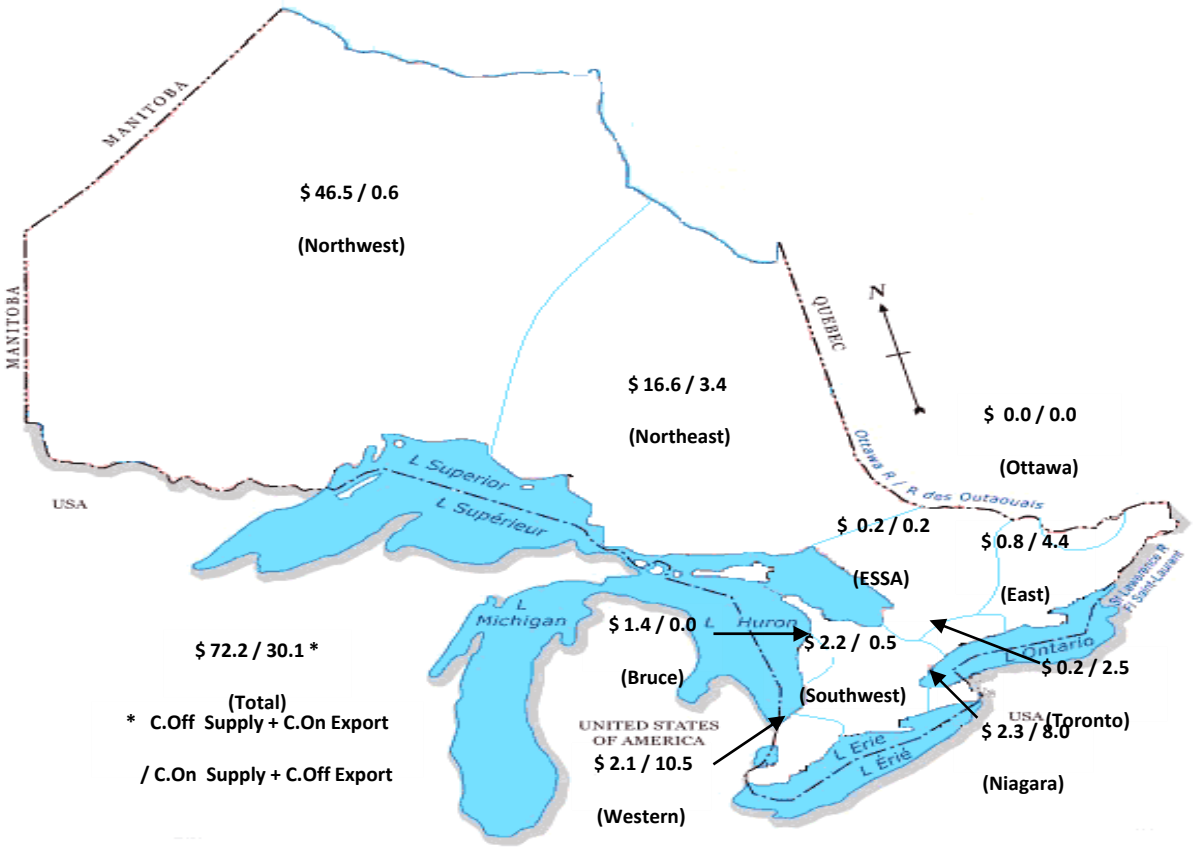
Hourly Market Uplifts
(January 2003 to October 2008)



Average Shadow Prices by Zone
(May – October 2008)



Total CMSC Payments by Zone
(May – October 2008)



High Price Hours

- 17 hours with HOEP > $200/MWh
- Factors previously identified by Panel continue to explain price spikes
  - Real-time demand higher than pre-dispatch forecast
  - Generating units available in pre-dispatch fail to deliver in real-time
  - Imports fail real-time delivery

Low Price Hours

- 724 low price hours where HOEP<$20/MWh
- 28 hours with negative prices
- Factors previously identified by Panel continue to explain low prices
  - Low market demand
  - Abundant base-load supply
  - Demand forecast errors
  - Failed exports

THE END