



**Ontario Energy Board**

Commission de l'énergie de l'Ontario

# **The IESO Administered Markets November 2008 – April 2009**

**Market Surveillance Panel's**

**14<sup>th</sup> Monitoring Report**

*Stakeholder Advisory Committee Meeting*

*August 26, 2009*

# Agenda

- Summary of Key Findings / Highlights
- Recommendations
- Ongoing Monitoring of Exports to PJM
- OPG's New Payment Structure for Prescribed Assets
- Information Slides
  - Price Indicators
  - Demand Indicators
  - Supply Indicators
  - Hourly Market Uplifts
  - Trade Flow Indicators

# Winter of 2008/2009 – 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, with the possible exception of one matter that is still being assessed
- There were occasions where actions by market participants or the IESO led to inefficient market outcomes

# Highlights - Compared to Previous Winter Period - Prices

	Nov 2007 – Apr 2008	Nov 2008 – Apr 2009	% Change
HOEP - average (\$/MWh)	49.16	40.98	-17%
Richview Shadow Price - average (\$/MWh)	57.96	45.10	-22%
Gas Price - Henry Hub (\$/MMBtu)	8.35	6.07	-27%
Coal Price - Central Appalachian (\$/MMBtu)	2.92	4.03	+38%
Coal Price - Powder River (\$/MMBtu)	0.71	0.83	+17%
Average of Surrounding Markets (NY, PJM, MISO, NE) (C\$/MWh)	62.13	53.33	-14%

- Ontario is the lowest hourly price market in northeastern North America



# Highlights - Compared to Previous Winter Period (cont'd) – Anomalous Events

	Nov 2007 – Apr 2008	Nov 2008 – Apr 2009	% Change
High-Price Hours (>\$200/MWh)	2	8	+300%
Low-Price Hours (<\$20/MWh)	261	689	+164%
Negative-Price Hours	5	219	+4,280%
Anomalous Uplift	n/a*	5	n/a

\* Not reported in previous winter's Panel Report

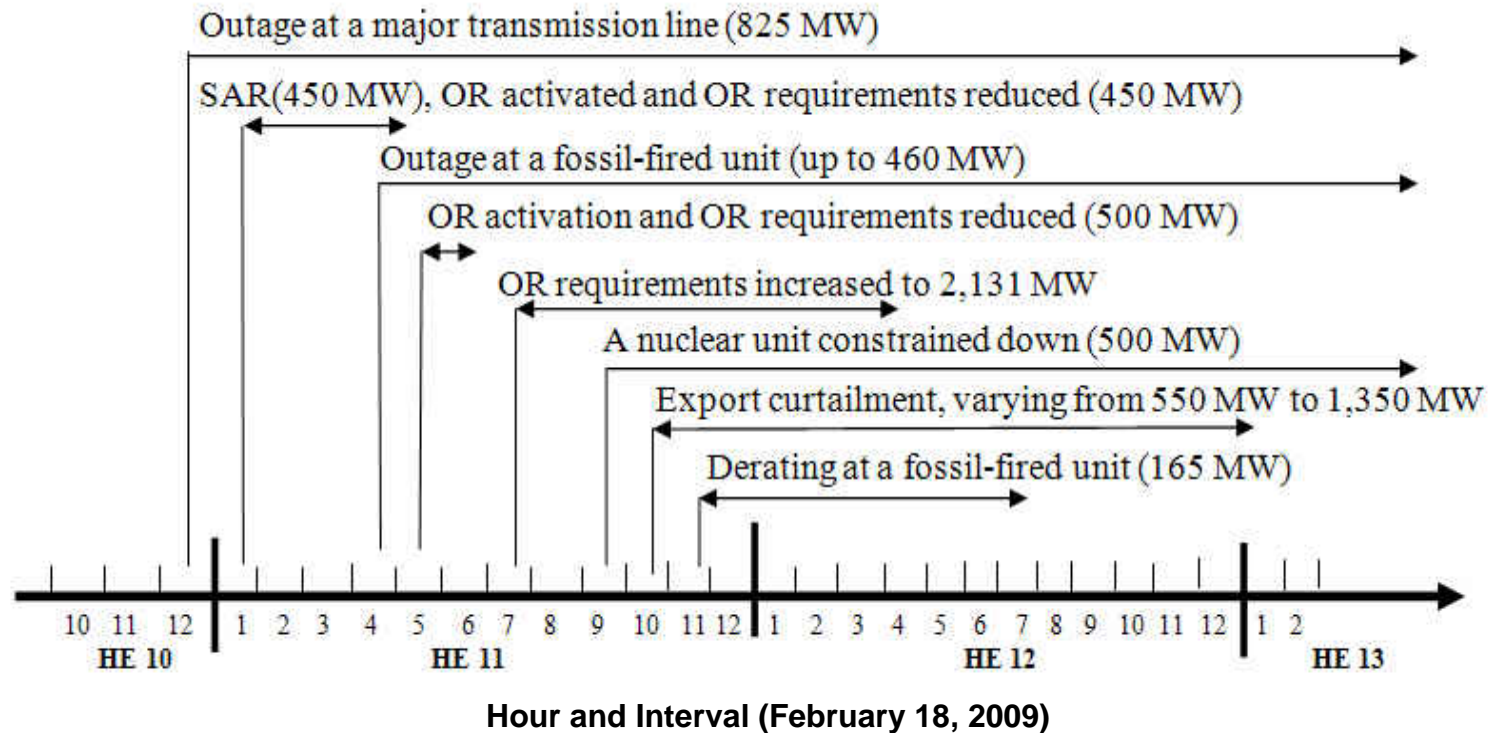
- Increase in lower-priced hours primarily caused by 5% drop in domestic and export demand



# Highlights - Highest HOEP since Market Opening

(February 18, HE12 at \$1,891.14/MWh)

- There were a series of major outages/deratings and IESO control actions prior to HE12 leading to the high HOEP
- MCP of \$1,999.99/MWh in 11 of 12 intervals



# Highlights - Highest HOEP since Market Opening (cont'd)

(February 18, HE12 at \$1,891.14/MWh)

- **MCP to \$1999.99/MWh after the OR Requirement increased**
  - From 1,437 MW to 2,131 MW due to a larger first contingency (2 nuclear units)
- **Large negative CMSC payments to exports**
  - Up to 1,350 MW of exports constrained-off in HE12 (\$2.7 million)
  - Negative CMSC as a result of HOEP exceeding the exporter's bid price
  - Had ADQh source code been used instead of TLRi, exporters would not have been charged through the negative CMSC
  - Choice of action codes can have a significant impact on uplift payments
- **Shorter lead time for offers and/or 15-minute dispatch could increase import and export responsiveness to changing internal conditions**
  - Simulation results estimate an efficiency gain of \$247,000 in HE12 with 15-minute scheduling at the interties



# Highlights - Lowest HOEP since Market Opening

(March 29, HE2 – HE4 at -\$51.00/MWh)

- Low prices reflected supply/demand conditions:
  - Abundant baseload supply
    - Constrained-down nuclear generation totaled over 1,400 MW during these hours
    - Some generation with OEFC or OPA contracts were on-line as they had little incentive to respond to market prices
  - Low demand
    - Ontario Demand slightly above 12,000 MW in HE2-HE4
    - Scheduled exports were limited due to transmission outages at the NYISO interties, which limited export capability at Michigan interties
      - Total hourly exports at NYISO and Michigan interties were 680 – 830 MW (versus typical levels exceeding 3,000 MW)



# Highlights - Lowest HOEP since Market Opening (cont'd)

(March 29, HE2 – HE4 at -\$51.00/MWh)

Day	Hour	Supply (MW)					Total Demand (MW)	Difference (Supply-Demand) (MW)
		Available Nuclear	Self-scheduling & Intermittent Generators	Baseload Hydro	Others	Total Supply		
Mar 29	2	10,410	1,460	1,597	901	14,368	13,039	1,329
	3	10,410	1,430	1,599	916	14,355	12,833	1,522
	4	10,410	1,392	1,599	918	14,319	12,801	1,518



# Highlights - Compared to Previous Winter Period (cont'd) – Uplift Payments

	Nov 2007 – Apr 2008	Nov 2008 – Apr 2009	% Change
HOEP - average (\$/MWh)	49.16	40.98	-17%
Load-weighted HOEP (\$/MWh)	51.09	43.31	-15%
Global Adjustment + OPG Rebate (\$/MWh)*	3.30	14.77	+348%
Effective Load-weighted HOEP (\$/MWh)	54.39	58.08	+7%
Total Hourly Uplift (\$/MWh)	2.56	2.32	-10%
Effective Load-weighted HOEP + Uplift (\$/MWh)	56.95	60.40	+6%

- Global adjustment is growing due to low prices and increased fixed portion of new OPA contracted supply and demand response and other conservation programs
- Hourly uplift decrease resulted from declines in IOG, CMSC, and Losses payments, which more than offset the increase in OR payments

# Highlights - Compared to Previous Winter Period (cont'd) – Operating Reserve

	Nov 2007 – Apr 2008	Nov 2008 – Apr 2009	% Change
10-minute Spinning Reserve Price (\$/MWh)	3.03	6.54	+116%
10-minute Non-spinning Reserve Price (\$/MWh)	2.52	6.04	+140%
30-minute Reserve Price (\$/MWh)	2.35	5.06	+115%
Average OR Requirement (MW)	1,371	1,523	+11%
Number of OR Activations	231	122	-47%

- Higher OR prices a result of:
  - Higher OR Requirement due to larger first contingency events
  - Fewer OR resources available
    - lower consumption by some dispatchable loads
    - withdrawal by some generation from the operating reserve market
    - IESO no longer accepting import operating reserve offers
    - fewer operating reserve offers available from coal-fired units

# Recommendations - Overview

- Panel has made 4 recommendations in this report:
  - Two relate to dispatch
  - One relates to price fidelity
  - One relates to reducing uplifts
- Two recommendations are addressed to IESO, one to OPG, and one to OPA/OEFC



# Recommendations on Dispatch – CO<sub>2</sub> Emissions

## **Recommendation 3-1**

- i. Ontario Power Generation (OPG) should discontinue the use of Not Offered but Available (NOBA) designations and CO<sub>2</sub> outages in excess of regular planned outages for the remainder of 2009 since they do not appear to be necessary to meet its 2009 CO<sub>2</sub> emission target.***
- ii. To the extent that OPG forecasts a need to reduce coal-fired generation in order to comply with its CO<sub>2</sub> emissions limit, the Panel recommends OPG should employ a strategy that utilizes an emissions adder alone as the most efficient way to offer an energy-limited resource into the market at the times when it has the most economic value.***

# Recommendations on Dispatch – CO<sub>2</sub> Emissions (cont'd)

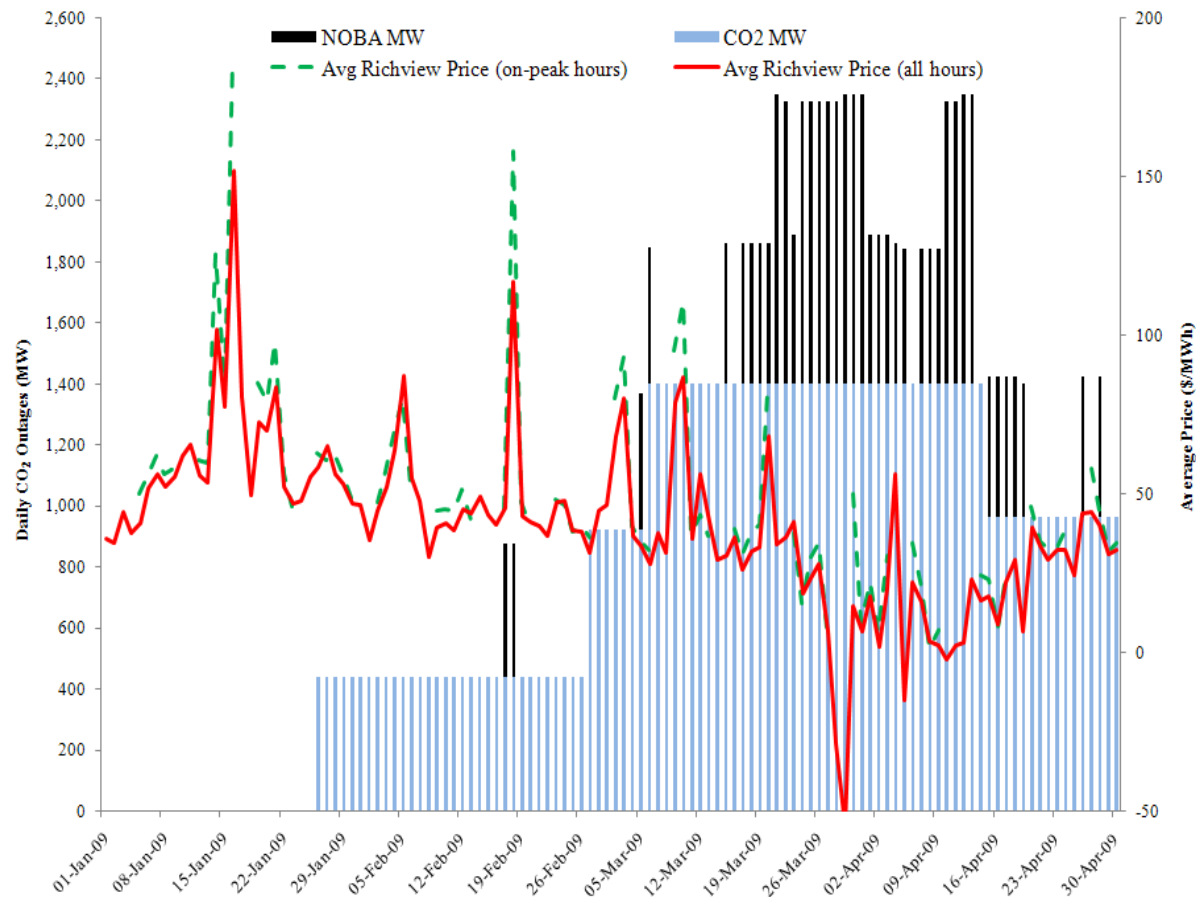
- This recommendation is an extension of a recommendation in the Panel's January 2009 Report:  
  
*“...that market participants' offers should reflect environmental costs flowing from the environmental standards established by the applicable regulatory authorities.”*
- Minister of Energy issued a declaration in May 2008 instructing OPG to reduce CO<sub>2</sub> emissions from its coal-fired units to 19.6 mmt in 2009 (roughly 19.6 TWh of coal-fired production)
- Panel's mandate includes monitoring market and efficiency implications of OPG's implementation of this directive

# Recommendations on Dispatch – CO<sub>2</sub> Emissions (cont'd)

- OPG *Implementation Strategy for 2009* has 3 elements:
  1. Emissions Cost Adder
    - Originally set at \$7.50/MWh but eliminated on March 17, 2009
  2. Designating Units as 'Not Offered But Available' (NOBA)
    - 53 NOBA's on 39 NOBA days during January - April
  3. Planned CO<sub>2</sub> Outages
    - 3 CO<sub>2</sub> outages during January – April
- Withholding of capacity beyond level needed to comply with CO<sub>2</sub> target will generate inefficiencies and increase prices paid by load

# Daily NOBA and CO<sub>2</sub> Outages and Average Richview Shadow Price

January 1 – April 30, 2009 (MW and \$/MWh)

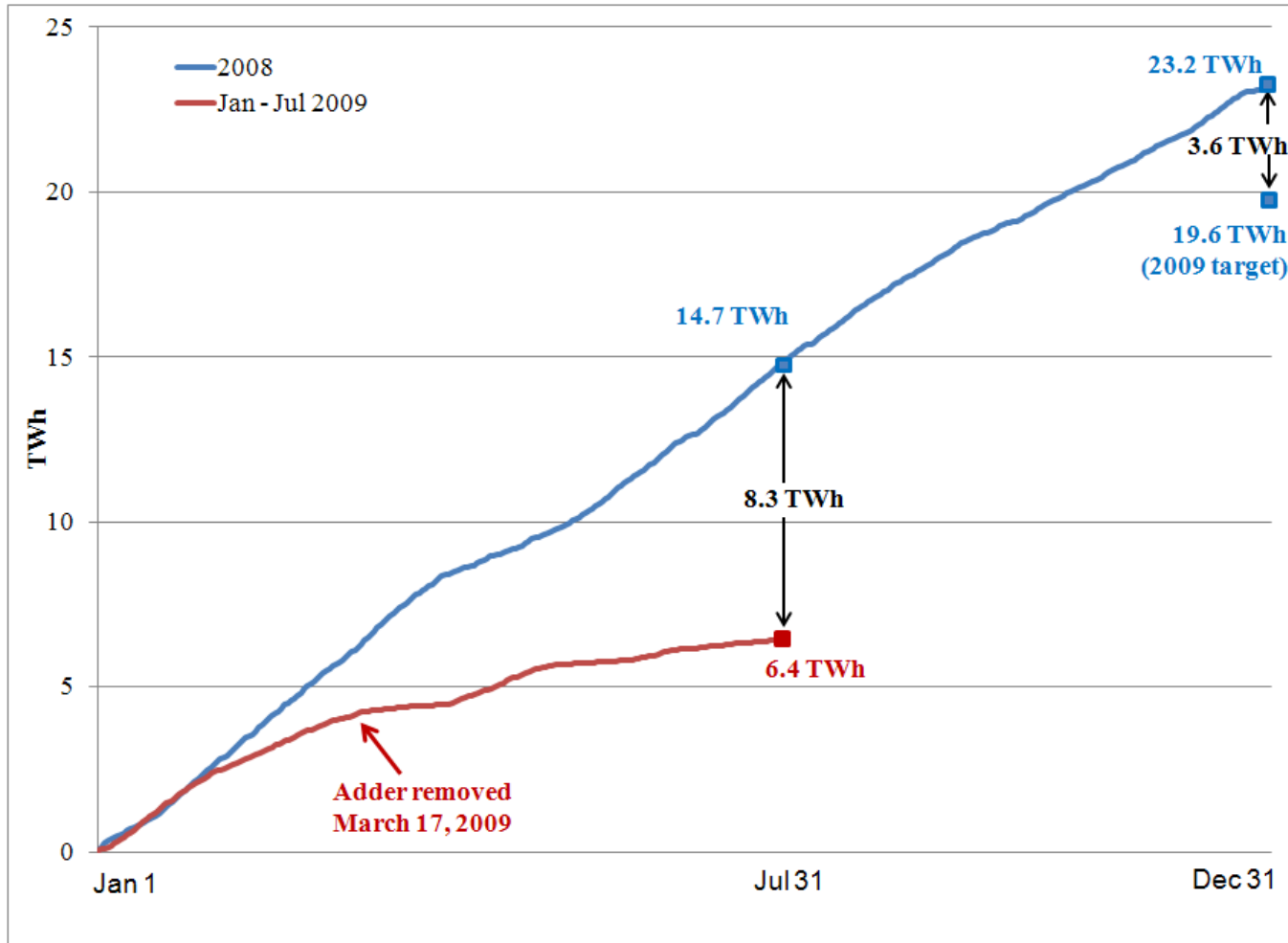


- 28 of the 39 NOBA days taken when Richview Price was in the lowest 33% (=28/120 days) of ranked days over the 4 month period.
- Of the 25 NOBA's taken during weekdays, 17 occurred when on-peak Richview Price was in the lowest 30% (=25/82 days) of ranked weekdays.
- NOBA units would have been economic on several days (eg. Feb 17-18, March 20, and April 4)



# Daily Energy Production from Coal-fired Generation

2008 and January – July 2009 (TWh)



- OPG unlikely to exceed CO<sub>2</sub> emissions target this year
- NOBA and CO<sub>2</sub> outages appear not to be necessary to comply with CO<sub>2</sub> target for 2009

## **Recommendation 3-4**

***In order to improve the price responsiveness of generation to low market price and Surplus Baseload Generation conditions, the Panel recommends that when Non-Utility Generation contracts are renewed and renewable energy (primarily wind-power) contracts are designed, the Ontario Power Authority and Ontario Electricity Financial Corporation should design the contracts in a way to motivate these generators to respond to the market price, at least when it is negative.***

# Increased Incidents of Surplus Baseload Generation (SBG)

- IESO's definition of an SBG condition
  - “when the amount of baseload generation (which may largely consist of a supply mix of high minimum load fossil, nuclear and run-of-the-river hydroelectric resources) exceeds the market demand”*
- Participants and the IESO must take manual actions to reduce supply
- SBG events typically coincide with low (and often negative) prices

# SBG and Negative Price Hours

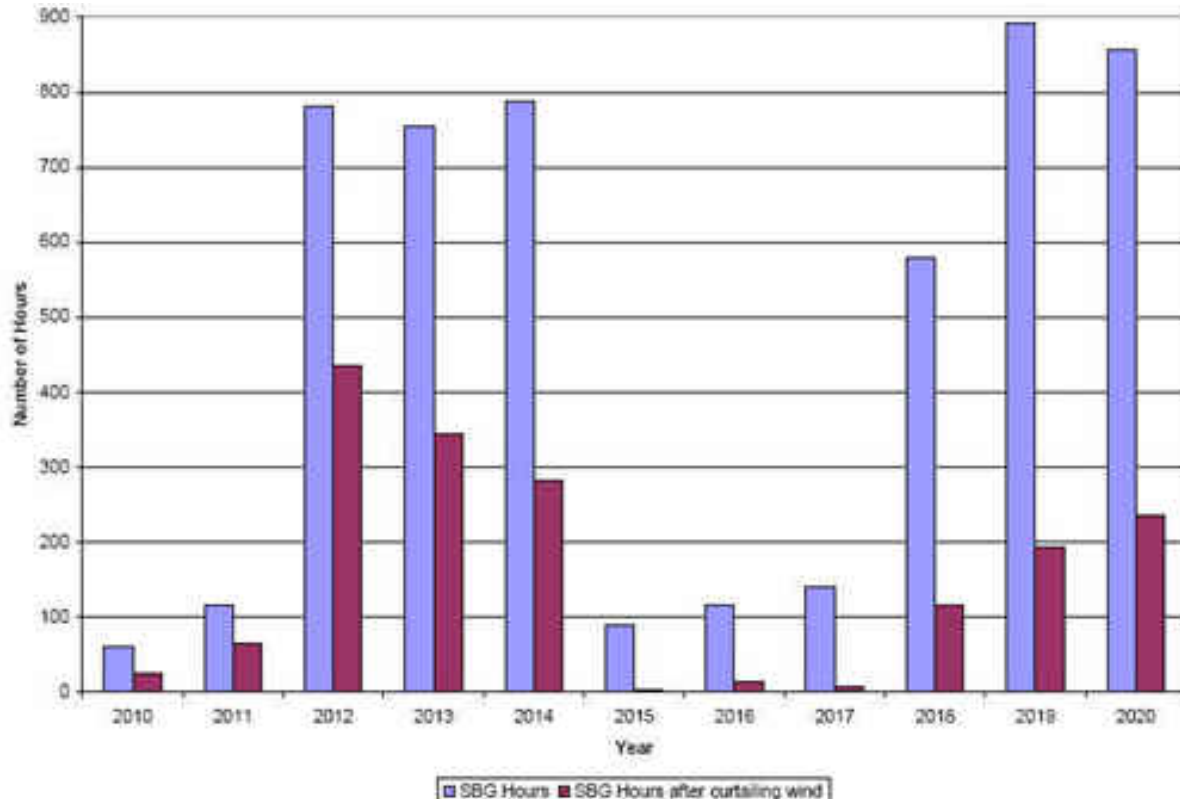
November – April 2007/2008 and 2008/2009 (Hours)

	<b>Nov – Apr 2007/2008</b>	<b>Nov – Apr 2008/2009</b>	<b>% Increase</b>
SBG Events	20	200	+900
Negative-Price Hours	5	219	+4,280

- 172 of the SBG events occurred in March/April 2009, when restrictions on exports to NYISO (and MISO) aggravated low domestic demand

# Projected Number of Hours with SBG

IESO's IPSP Submission for 2010-2020 (Hours)



- IESO projected significant SBG events pre-GEA
- SBG events are likely to increase above current levels with additional wind as well as nuclear capacity

# Average Hourly Production by Contract/Regulation Type during Negative-price Hours

November 2008 – April 2009 (MW and % of generation)

Payment Type	Resources	Output (MW)	(%)
Fixed Price Contract	OPG nuclear	5,485	38
	Bruce A	1,479	10
	NUG contracts	952	7
	OPA wind contracts	300	2
	<b>sub total</b>	<b>8,217</b>	<b>57</b>
Other OPG Regulated Generation	Prescribed hydroelectric	1,541	11
	Non-prescribed	1,465	10
	<b>sub total</b>	<b>3,006</b>	<b>21</b>
Market	Commissioning gas-fired units	365	3
	Early movers	142	1
	Bruce B*	2,704	19
	Fringe	85	1
	<b>sub total</b>	<b>3,295</b>	<b>23</b>
<b>Total</b>		<b>14,518</b>	<b>100</b>

- 57% of the production during negative-price hours was not exposed to market prices
- OPA contracts with wind generators and almost all NUG contracts are based on actual production, providing no incentive to respond to the negative prices

\* Bruce B has an annual average floor price, which could result in it being a fixed price rather than a market price resource in the future



# Recommendation to Enhance Price Fidelity

## – Daily Energy Limit

### **Recommendation 3-3**

***Given the frequency and impact on the market of incorrect Daily Energy Limit (DEL) submissions for hydroelectric generators, the Panel recommends that the IESO should discontinue the use of the DEL feature in the pre-dispatch schedules (including the Day-Ahead Commitment Process pre-dispatches) until an Enhanced Day-Ahead Commitment process is introduced which is specifically designed to optimize resources over 24 hours using accurate estimates of energy limits for hydroelectric resources. Alternatively, if the IESO considers that the DEL is currently useful for reliability reasons, the IESO should require submission of DELs from all hydroelectric generators, and strengthen the compliance provisions in the Market Rules to incent participants to submit more accurate forecasts of DEL.***

# Recommendation to Enhance Price Fidelity

## – Daily Energy Limit (cont'd)

- Daily Energy Limit (DEL) represents the maximum amount of energy that can be scheduled at a specified hydroelectric generation facility for a given day
  - Hydroelectric generators may submit but are not required to
  - DEL is applied in IESO's PD schedule but not in RT
- Submitted DEL below actual available energy can reduce efficiency
  - May lead to more imports, fewer exports, or the scheduling of slow-ramping generation (eg. coal)

# Frequency and Estimated Size of DEL Errors

January 2008 – April 2009 (Hours and MW)

Month	Schedule Difference (RT-PD) due to DEL (MWh)	Events (Number of Hours)	Average Difference (MWh/event)
Jan-08	22,203	278	80
Feb-08	45,913	419	110
Mar-08	31,809	287	111
Apr-08	19,991	190	105
May-08	4,100	57	72
Jun-08	7,535	86	88
Jul-08	10,109	145	70
Aug-08	7,610	122	62
Sep-08	4,667	77	61
Oct-08	4,673	66	71
Nov-08	8,110	91	89
Dec-08	5,341	86	62
Jan-09	9,733	146	67
Feb-09	11,737	219	54
Mar-09	21,618	163	133
Apr-09	18,423	190	97
<b>Total/ Average</b>	<b>233,572</b>	<b>2,622</b>	<b>89</b>

- Binding DEL occurred in 22 percent of all hours between January 2008 and April 2009
- Average increase in real-time supply was 89 MW for hours with binding DEL

# Recommendation on Uplifts – SGOL and DACP Cost Allocations

## **Recommendation 3-2**

***The IESO should improve the mechanisms for aligning submitted costs and associated revenue streams at combined cycle stations for its Spare Generation On-line and Day-Ahead Commitment Process generation cost guarantee programs, in the context of the other changes taking place to these programs. The preferred mechanism is to determine guarantee payments on an aggregate basis for all units at a station. Alternatively, the IESO should eliminate allocations that result in over-compensation (for example, by requiring allocation of submitted costs among units in proportion to the revenue they generate during the period associated with those costs).***

# Recommendation on Uplifts – SGOL and DACP Cost Allocations (cont'd)

- Generating units at combined cycle plants do not operate independently of each other
  - Waste heat from gas turbine(s) feeds steam turbine
- No market rules or IESO procedures indicate how costs should be distributed
- Different allocation methods can lead to different cost guarantee outcomes
  - Potential for excessive uplift payments

# Alternative Allocation Methods for SGOL and DACP Cost Guarantees at Multi-unit Generation Stations

	Allocation 1	Allocation 2	Allocation 3	Allocation 4	Allocation 5	Allocation 6 (Station-wide)
<b>GT 1:</b>						
Allocated Cost	\$90,000	\$90,000	\$60,000	\$0	\$65,000	
Revenue (Energy plus CMSC)	\$65,000	\$65,000	\$65,000	\$65,000	\$65,000	
SGOL	\$25,000	\$25,000	\$0	\$0	\$0	
Total Revenue	\$90,000	\$90,000	\$65,000	\$65,000	\$65,000	
<b>GT 2:</b>						
Allocated Cost	\$90,000	\$45,000	\$60,000	\$0	\$65,000	
Revenue (Energy plus CMSC)	\$65,000	\$65,000	\$65,000	\$65,000	\$65,000	
SGOL	\$25,000	\$0	\$0	\$0	\$0	
Total Revenue	\$90,000	\$65,000	\$65,000	\$65,000	\$65,000	
<b>ST:</b>						
Allocated Cost	\$0	\$45,000	\$60,000	\$180,000	\$50,000	
Revenue (Energy plus CMSC)	\$50,000	\$50,000	\$50,000	\$50,000	\$50,000	
SGOL	\$0	\$0	\$10,000	\$130,000	\$0	
Total Revenue	\$50,000	\$50,000	\$60,000	\$180,000	\$50,000	
<b>Station Total:</b>						
Revenue (Energy plus CMSC)	\$180,000	\$180,000	\$180,000	\$180,000	\$180,000	\$180,000
SGOL	\$50,000	\$25,000	\$10,000	\$130,000	\$0	\$0
<b>Total Revenue</b>	<b>\$230,000</b>	<b>\$205,000</b>	<b>\$190,000</b>	<b>\$310,000</b>	<b>\$180,000</b>	<b>\$180,000</b>
<b>Total Cost</b>	<b>\$180,000</b>	<b>\$180,000</b>	<b>\$180,000</b>	<b>\$180,000</b>	<b>\$180,000</b>	<b>\$180,000</b>

Allocation 1 – All costs allocated to unit that directly incurs cost

Allocation 2 - The cost of one gas turbine is split equally with the steam turbine

Allocation 3 – Total costs are pro-rated by MWh production

Allocation 4 – All costs are allocated to the steam turbine

Allocation 5 – Costs pro-rated according to unit revenue

Allocation 6 – Costs and revenue are aggregated on the plant basis

# Recommendation on Uplifts – SGOL and DACP Cost Allocations (cont'd)

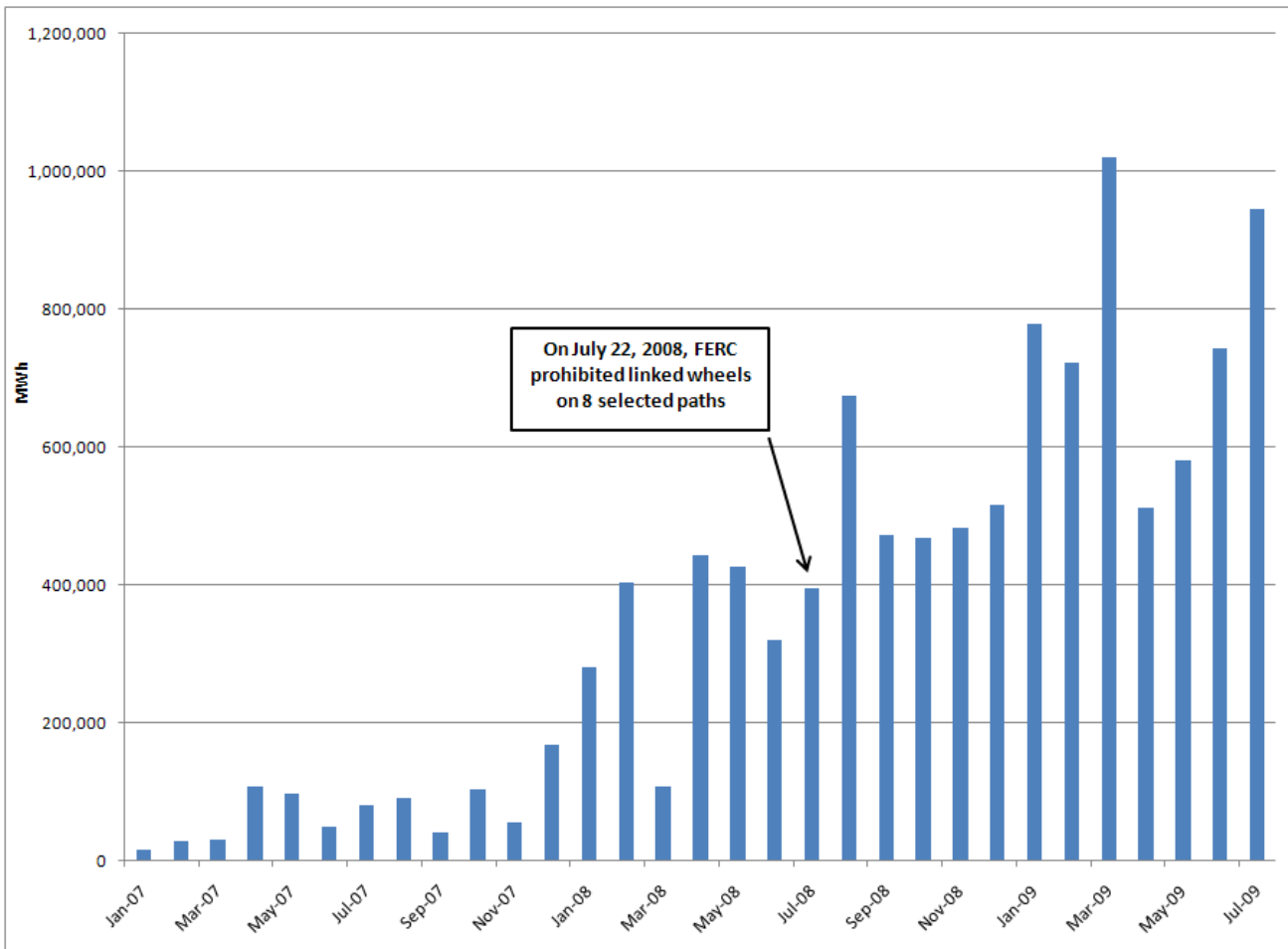
- A station-based guarantee approach was calculated for two combined-cycle generators for 2007 and 2008
  - SGOL payments reduced by 50%
  - DA-GCG payments reduced 20%
  - Combined total savings of almost \$8 million
- Guarantee payments that exceed station cost also create incentives for inefficient start-up decisions

# Ongoing Monitoring of Exports to PJM

- **Chronology of NY/Ont/MISO/PJM wheels:**
  - January 2008: MAU identifies NYISO/Ont/MISO/PJM linked-wheel trading patterns
  - July 22, 2008: FERC accepts NYISO application for urgent prohibition of this and 7 other circuitous transaction paths
  - January 2009: MSP reports on shift to Ont/MISO/PJM exports and concludes no problematic market effects to date in Ontario
  - July 16, 2009: FERC determines that traders did not engage in market manipulation and orders NYISO to negotiate design solutions with neighbouring markets

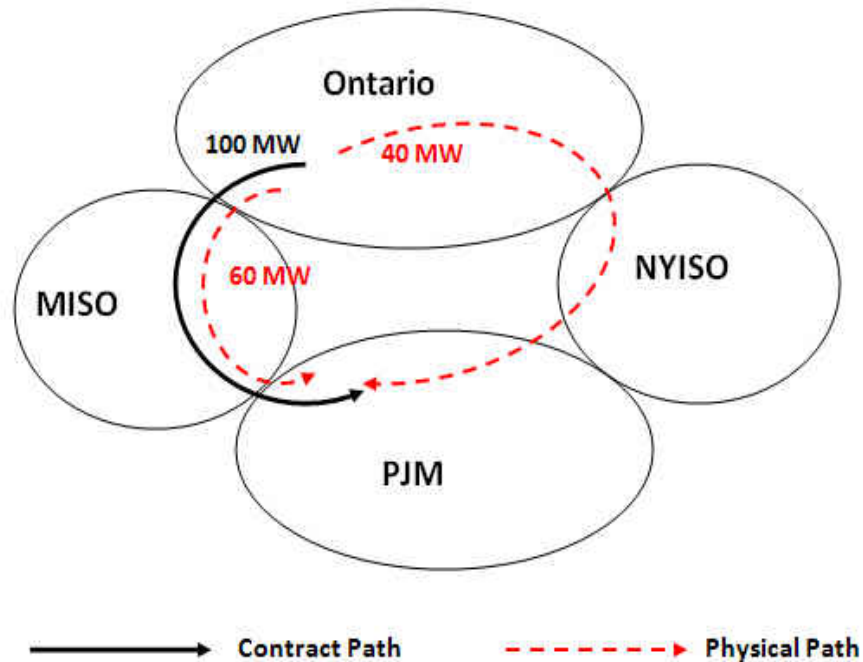
# Exports from Ontario to PJM

January 2007 – July 2009 (MWh)



- Exports from Ontario to PJM increased after FERC prohibited certain linked-wheel paths on July 22, 2008 (including the NY/Ont/MISO/PJM wheel)

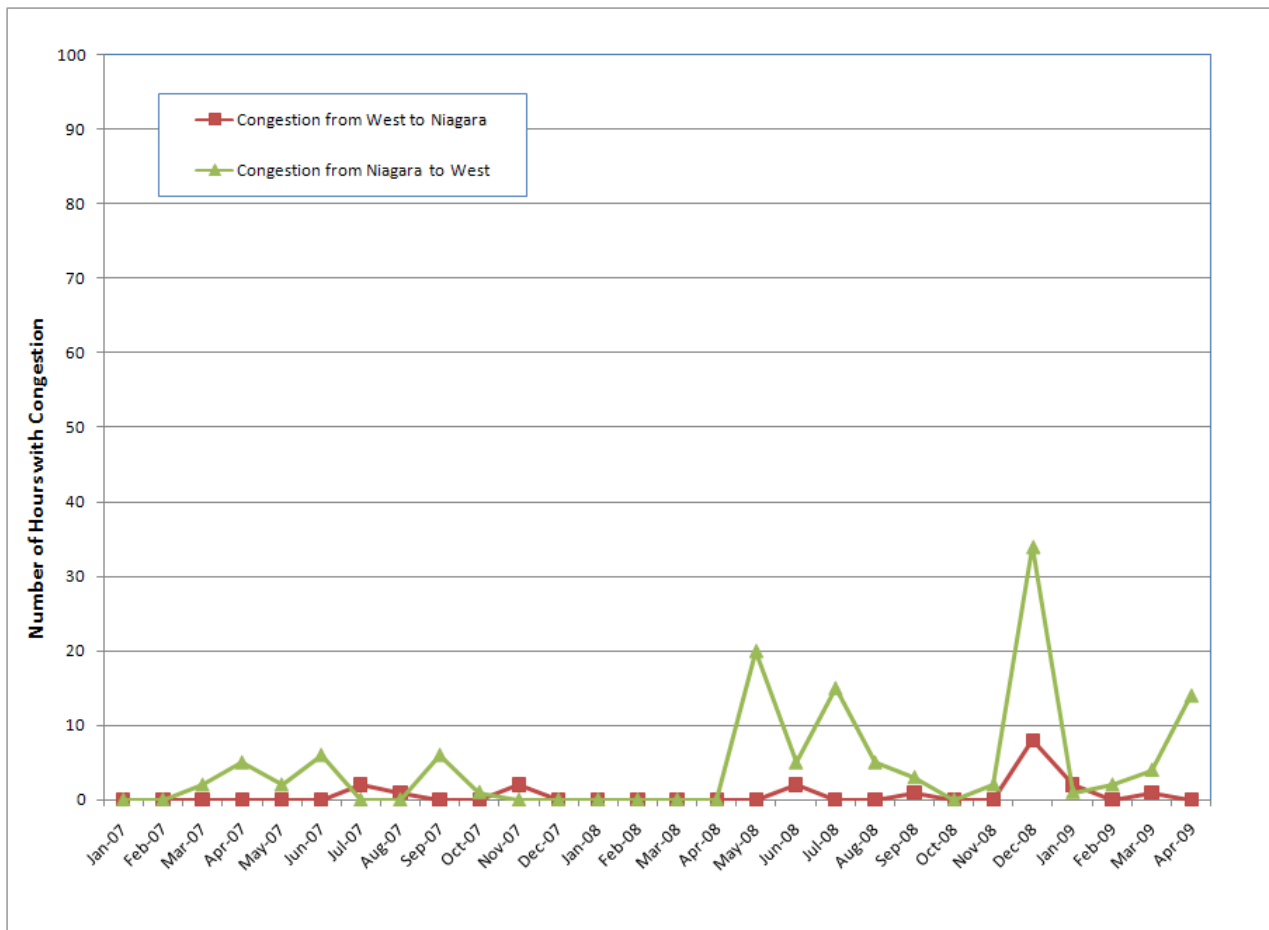
# Ongoing Monitoring of Exports to PJM (cont'd)



- Relationship between “physical path” pricing systems (used by PJM and MISO), “contract path” pricing systems (used by Ontario and NYISO), and Lake Erie Circulation (“LEC”, or “loop flow”) is complex
- NY-PJM linked wheels led to high congestion costs imposed on New York consumers as a result of increased west-to-east internal congestion in New York
- MSP/MAU have been examining whether Ontario is experiencing similar internal congestion issues as a result of ON to PJM exports

# Congestion between the West Zone & Niagara Zone

January 2007 to April 2009 (Number of Hours per Month)



- Internal congestion in Southern Ontario is infrequent
- Comparison of Niagara and West nodal prices indicates congestion in less than 1 percent of all hours between January 2007 and April 2009

# Ongoing Monitoring of Exports to PJM(cont'd)

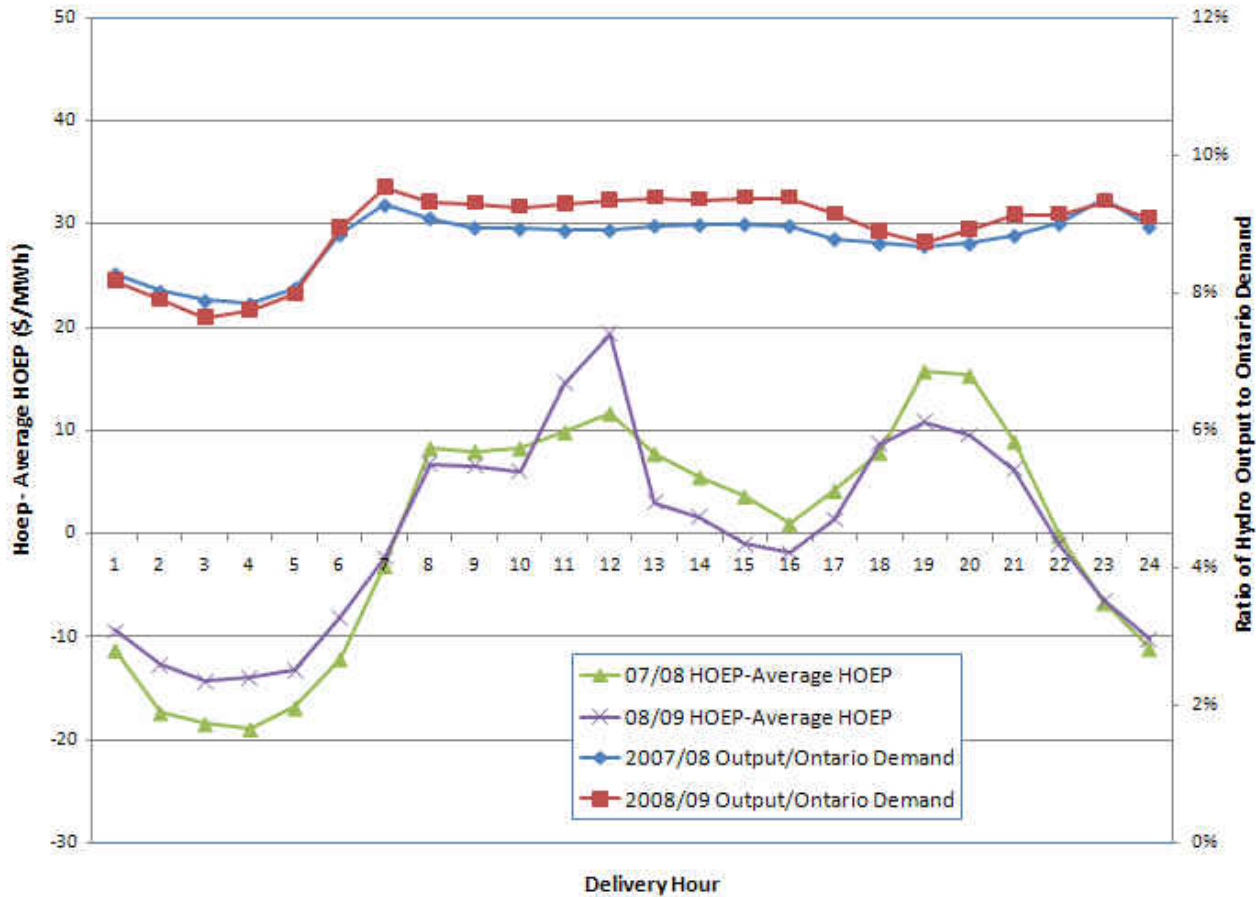
- MAU is undertaking further analyses which will assess whether the Ont-PJM exports through NY and/or MISO may be contributing to congestion at the Ontario-NY intertie
- MSP has also encouraged IESO to continue participating actively in NYISO's process for developing recommendations to FERC

# OPG's New Payment Structure for Prescribed Assets

- The Panel examined the market implications of the new payment structure for prescribed assets, which came into effect on December 1, 2008
- The new payment structure represents an improvement over previous structure
  - Should induce OPG to make more efficient production and pump-storage decisions for hydroelectric plant
  - OPG has shifted more energy from off-peak to on-peak
  - Incentives during negative-price hours are imperfect

# Average HOEP Difference and Ratio of Hydro Output\* to Ontario Demand

December to April 2007/2008 and 2008/2009 (\$/MWh and %)



- HOEP difference provides evidence that shifting of water occurred after new payment structure introduced
- Increased efficiency from water shifting estimated to be approximately \$1.5 million (December 2008 to April 2009)

\* Beck and Decew Falls Output



# Panel Semi-Annual Monitoring Reports

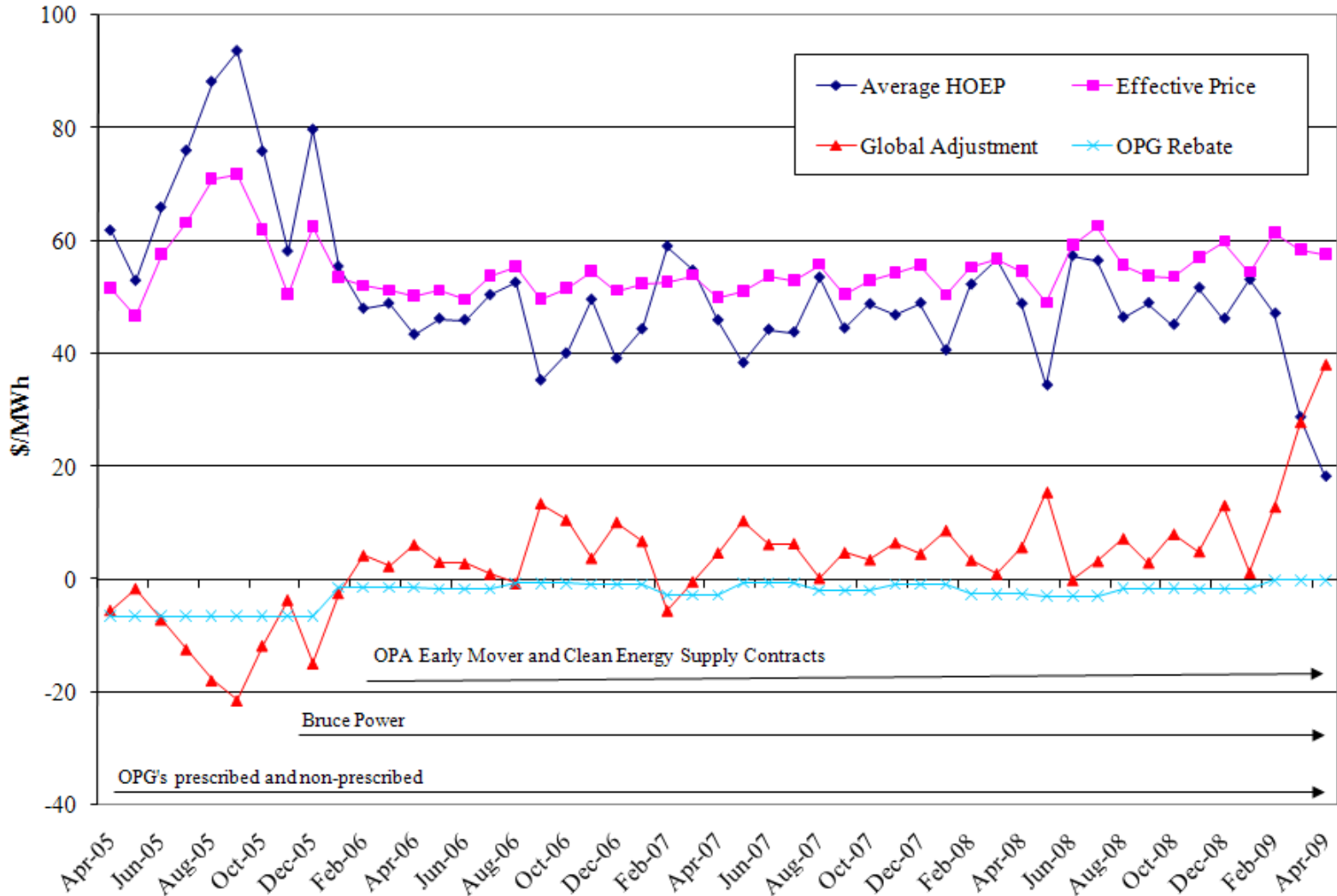
- Panel and MAU are reviewing report contents and frequency to ensure relevance and effective use of resources
- Stakeholder input would be welcome:
  - Areas for improvement
  - Items that can be downsized
  - Additional areas that should be covered

# Slides for Information Purposes



# Monthly HOEP versus Effective HOEP

April 2005 – April 2009 (\$/MWh)

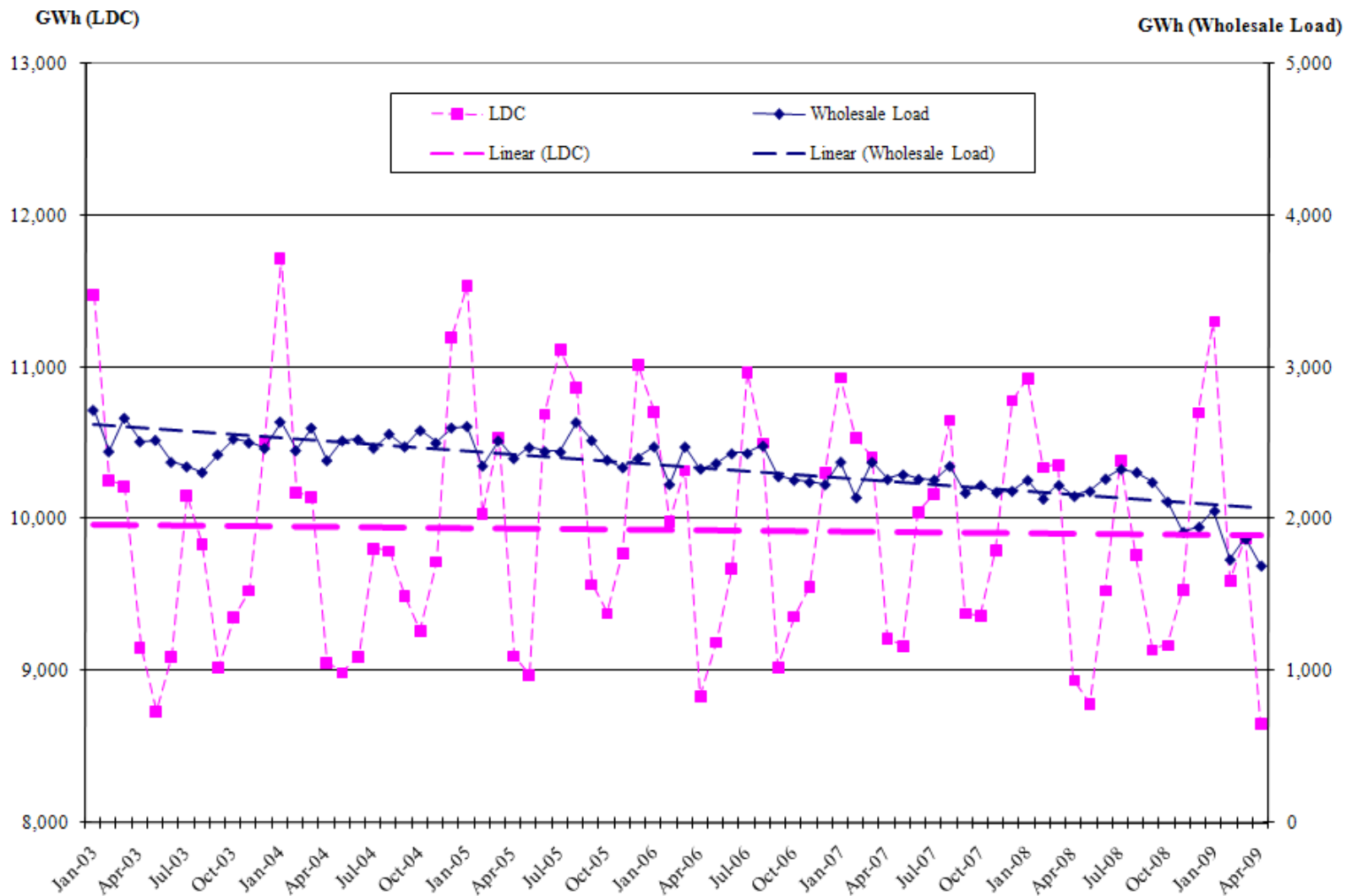


# Demand Indicators

- Ontario energy demand fell by 4.6% (3.55 TWh) in winter 2009 vs. 2008
  - Combination of wholesale load and LDC
- Total market demand (Ontario demand plus exports) declined by 4.5% (3.86 TWh)
  - Ontario was a net exporter in all months

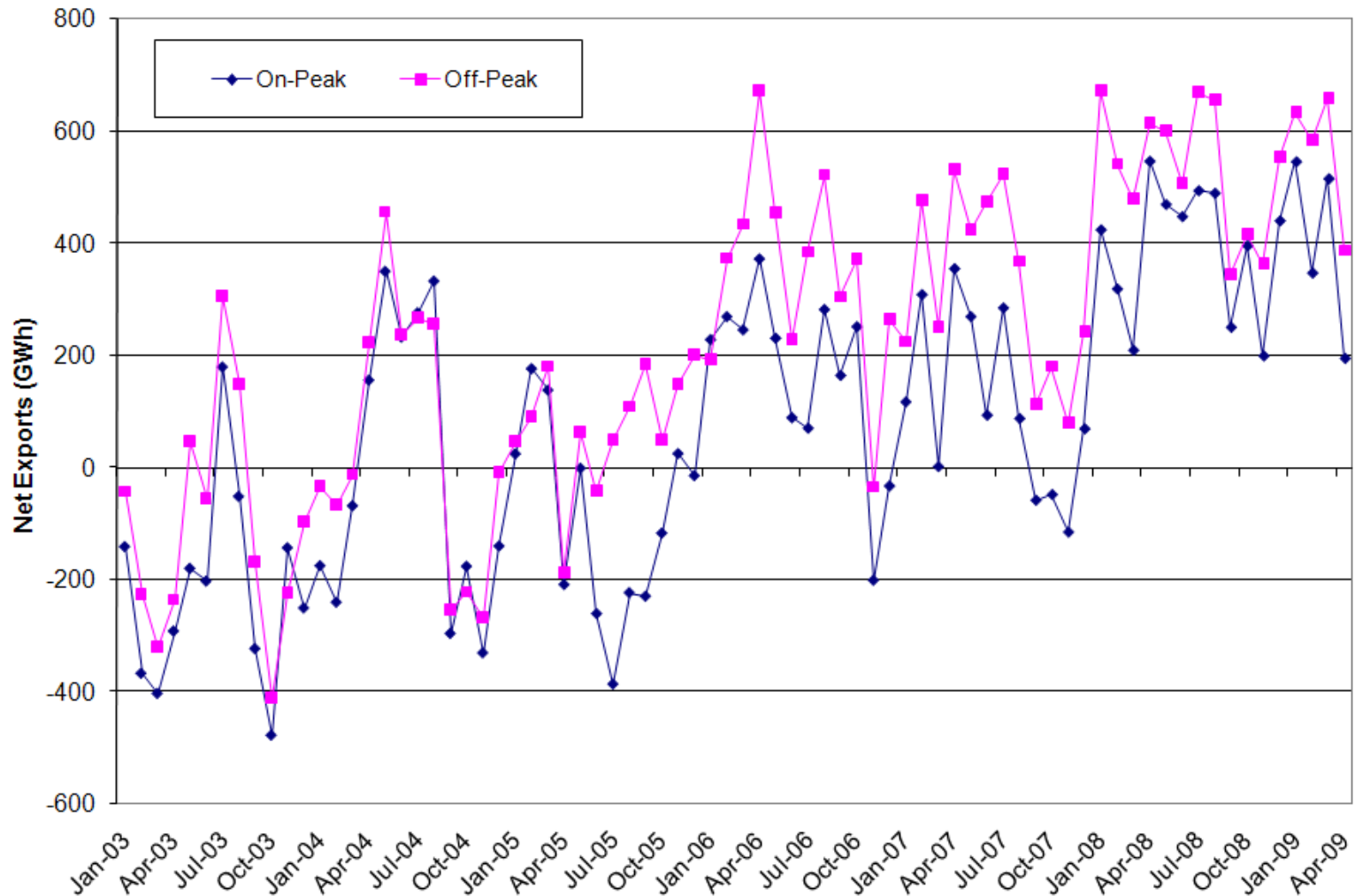
# LDC and Wholesale Load Declining

January 2003 – April 2009 (GWh)



# Net Exports Increasing

January 2003 – April 2009 (GWh)

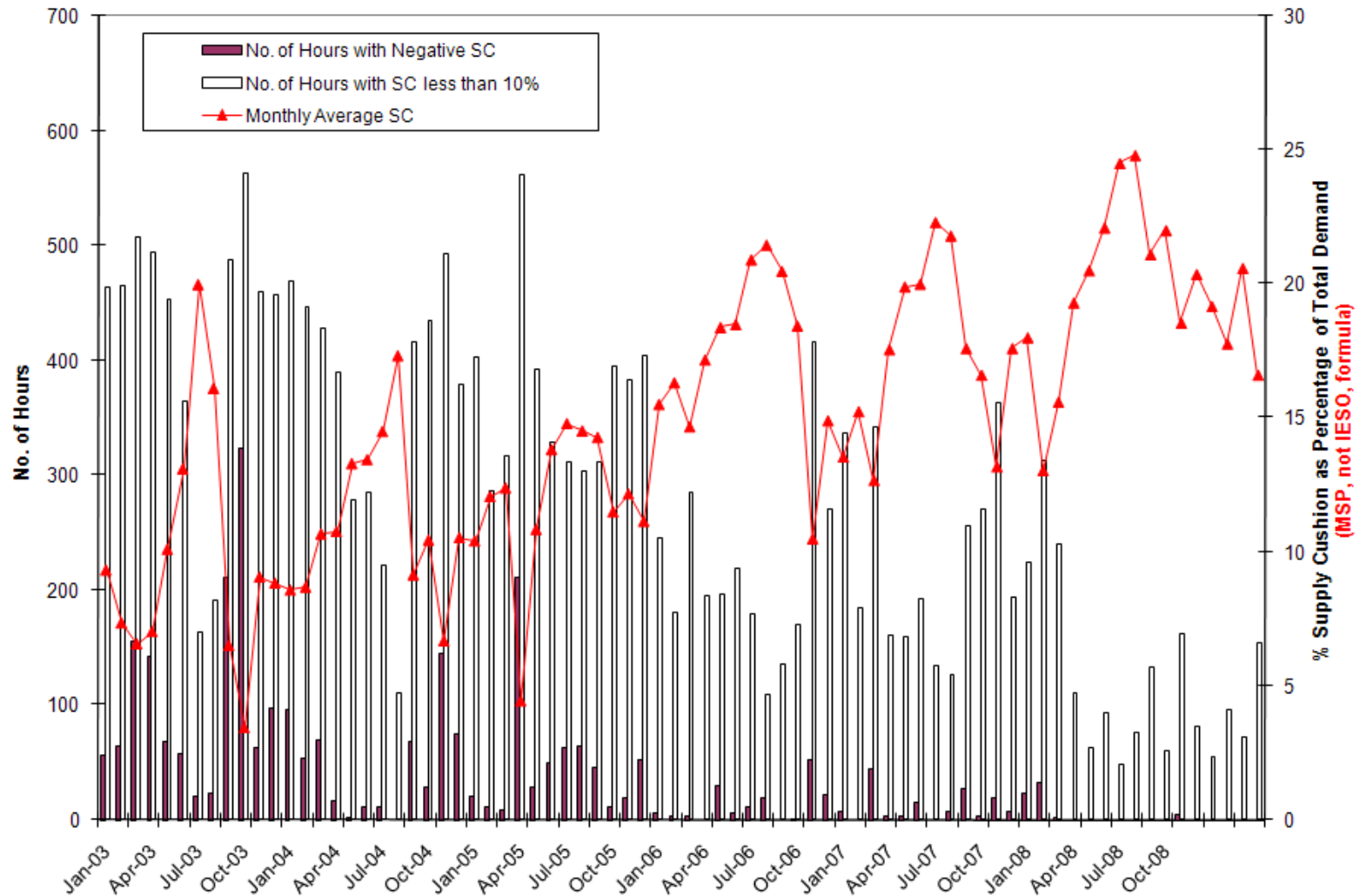


# Supply Indicators

- The real-time domestic supply cushion continues to improve as new generation becomes operational and demand falls
  - Average RT domestic supply cushion was 18.9% this winter, compared to 16.1% last winter
- Coal forced outage rate increased this winter
- Nuclear forced outage rates relatively low compared to previous periods
- Wind output increasing as new entrants become operational
  - MW of wind forecast error increasing

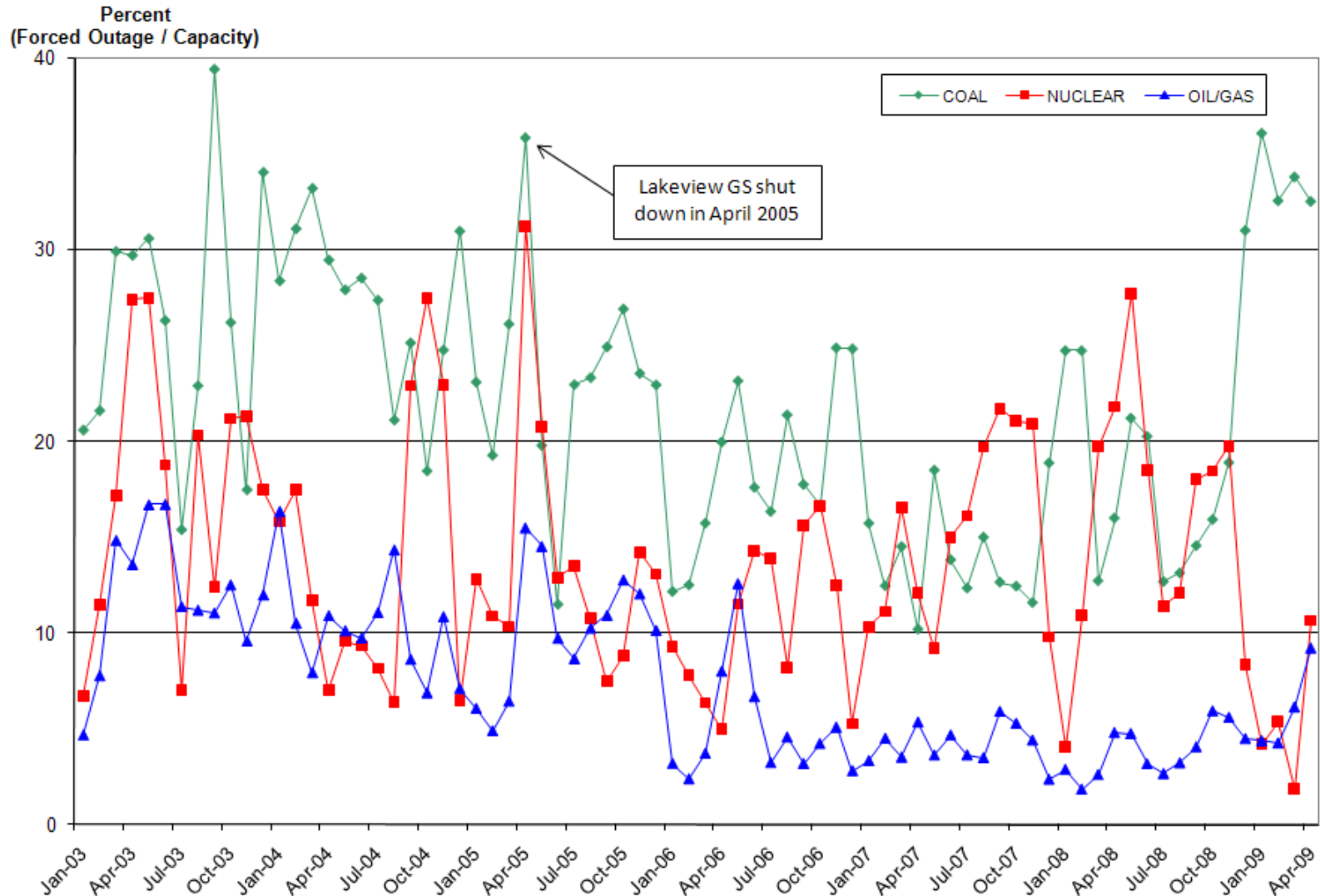
# Improved Real-time Supply Cushion Conditions

January 2003 – April 2009 (Hours and %)



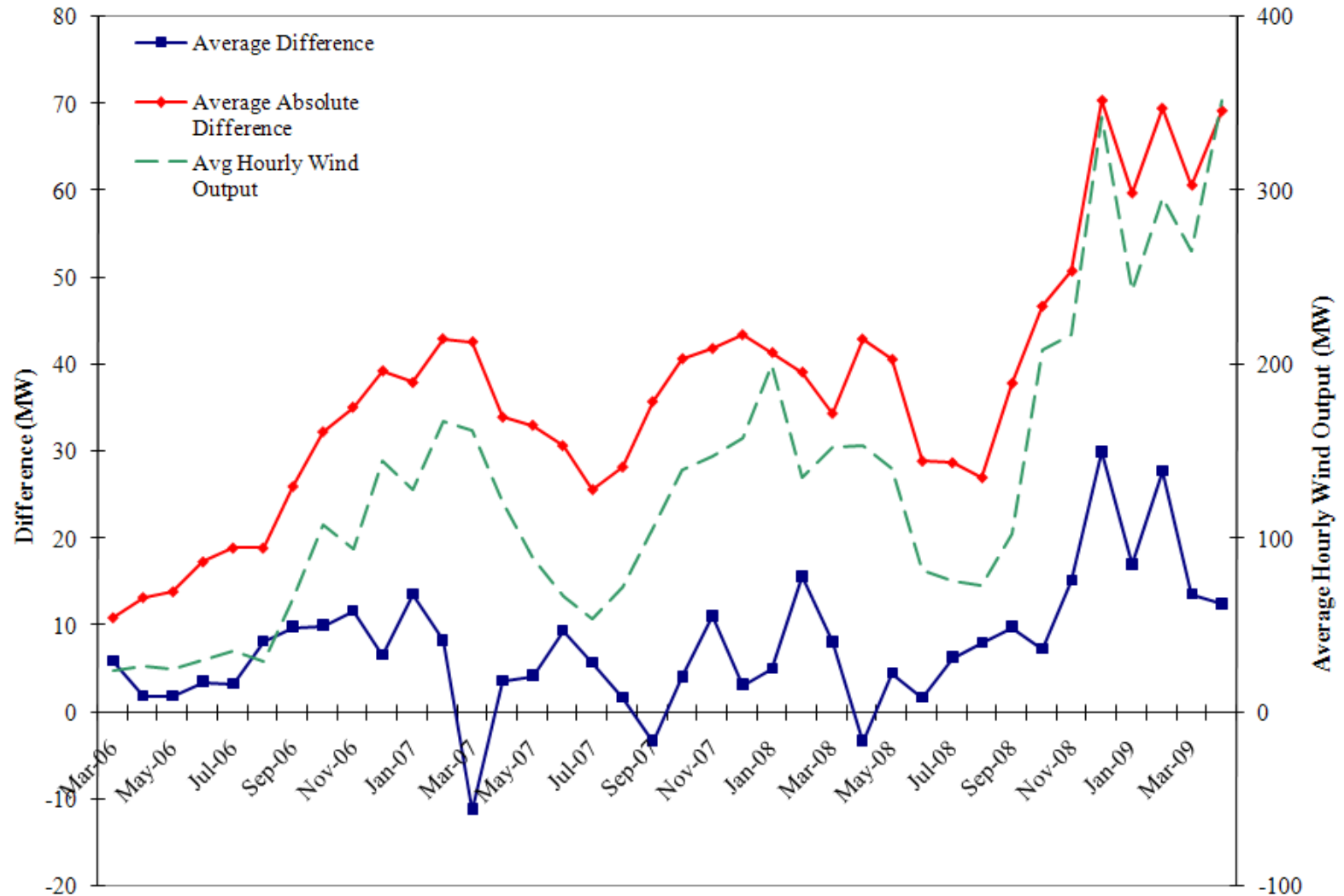
# Forced Outages Relative to Total Capacity by Fuel Type

January 2003 – April 2009 (%)



# Average and Absolute Average Difference between Wind Generator Forecasted and Delivered Energy and Average Hourly Wind Output

March 2006 – April 2009 (MW)

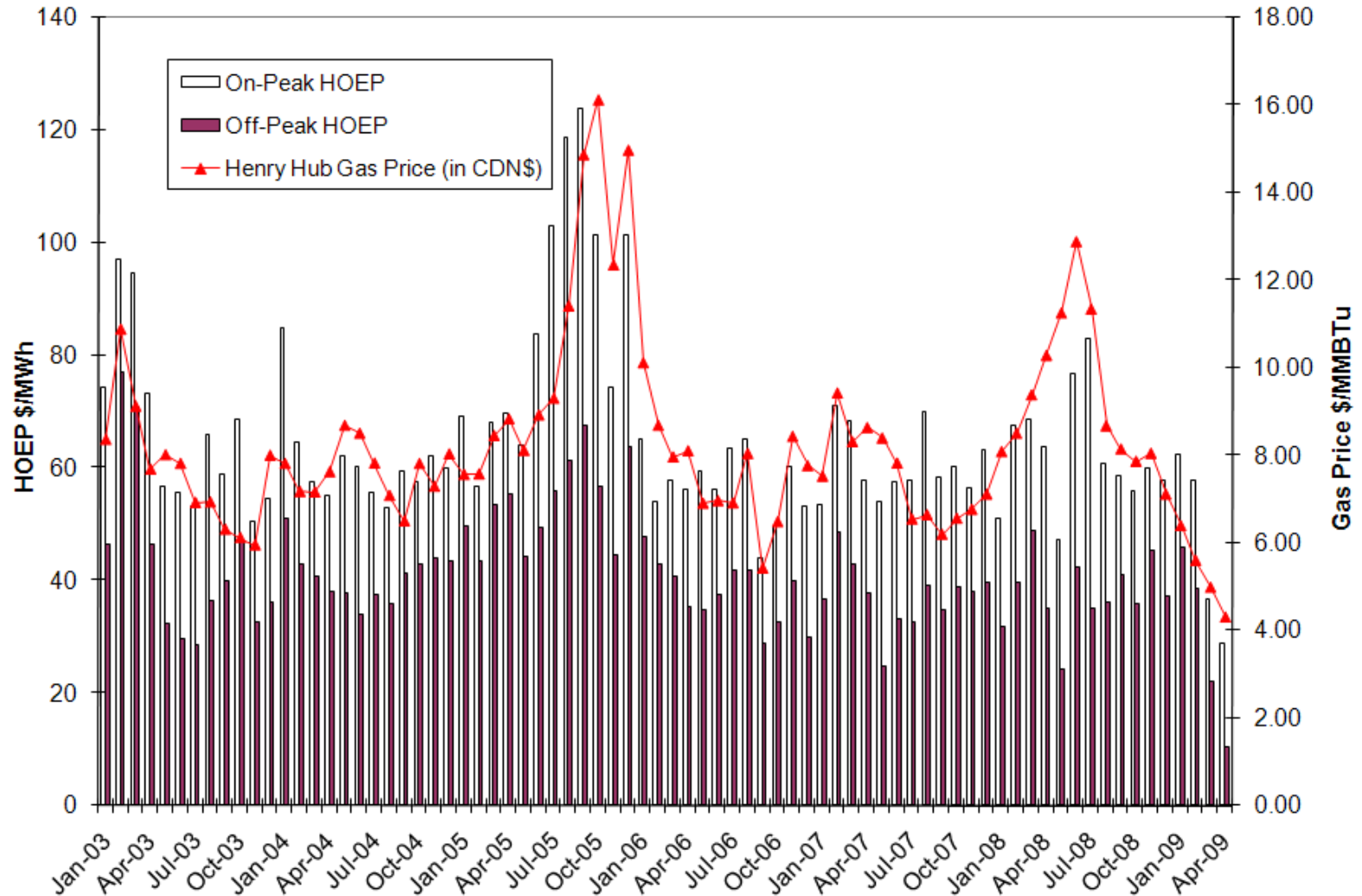


# Supply Indicators (cont'd) – Underlying Fuel Prices

- Average coal prices increased this winter relative to last winter while natural gas prices declined
- Central Appalachian Coal prices (used by Lambton) increased 38% while Powder River Basin coal prices (used by Nanticoke) increased 17%
- Natural Gas prices at Henry Hub declined by 27 percent

# Monthly Natural Gas Prices vs. HOEP

January 2003 – April 2009 (\$/MWh and \$/MMBtu)

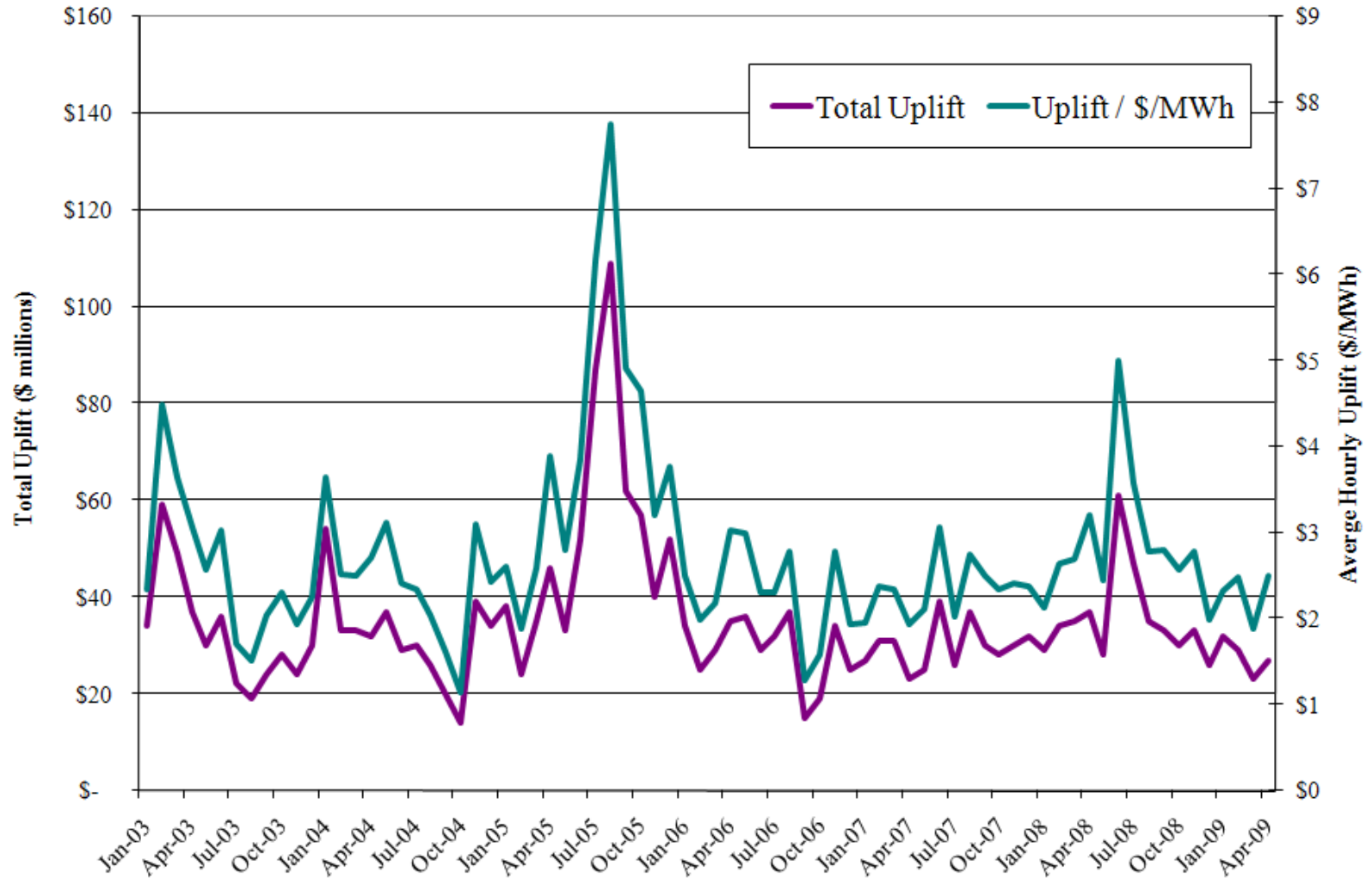


# Hourly Market Uplifts

- Hourly uplift declined 14%, from \$201 million in 2007/2008 to \$172 million in 2008/2009
  - Mostly the result of a \$20 million (74%) decline in IOG payments and a \$19 million (21%) decline in Losses (both primarily due to the HOEP decrease)
  - Operating reserve payments increased 136%, from \$13 million in 2007/2008 to \$31 million in 2008/2009 due to higher requirements and prices
- Northwest shadow prices averaged -\$272/MWh due to abundant hydro and low zonal demand
  - Generators receive payment equivalent to HOEP when constrained off (\$17.7 million in this period)
- Southern zonal prices all close to Richview

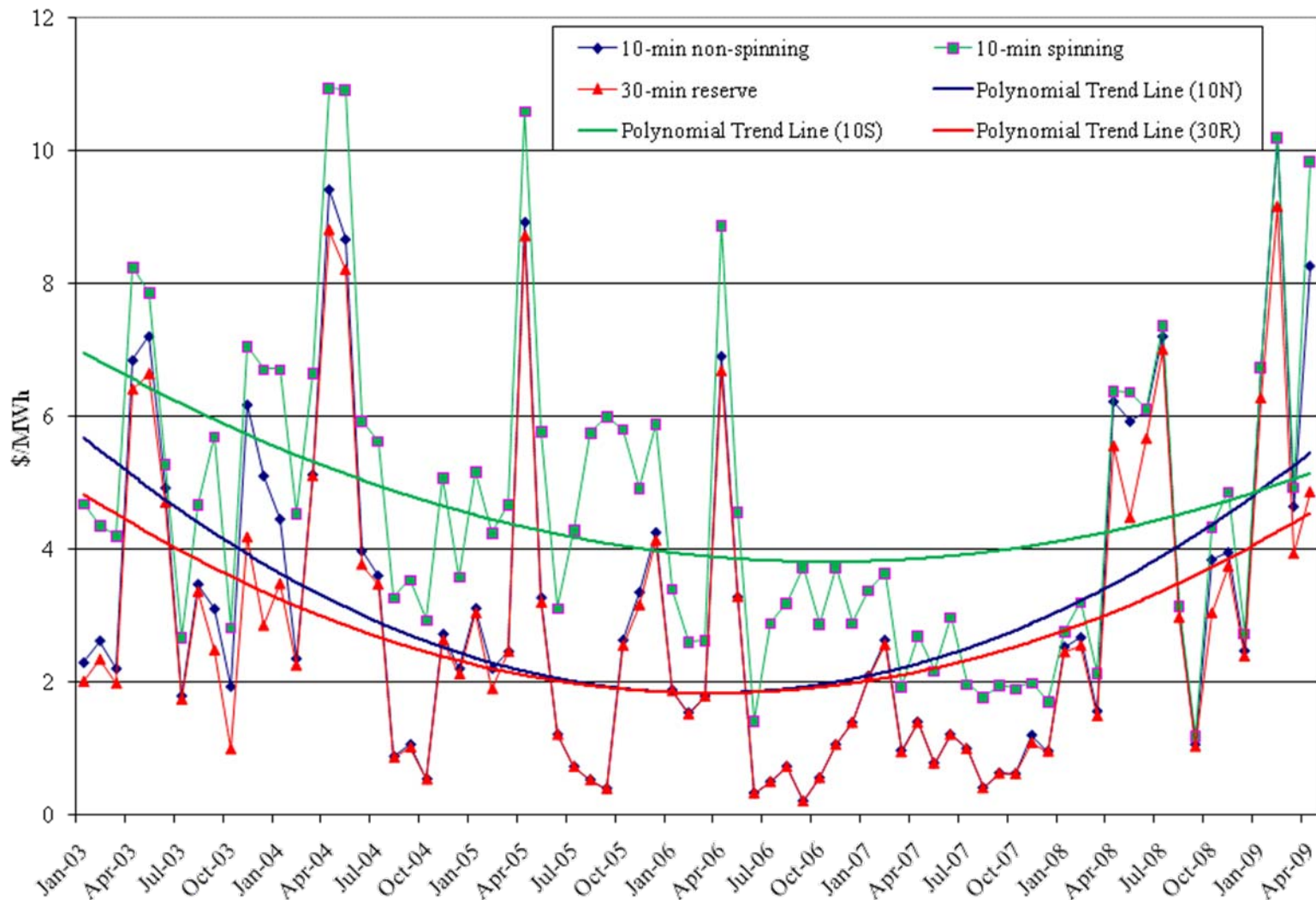
# Hourly Market Uplifts

January 2003 – April 2009 (\$ million and \$/MWh)



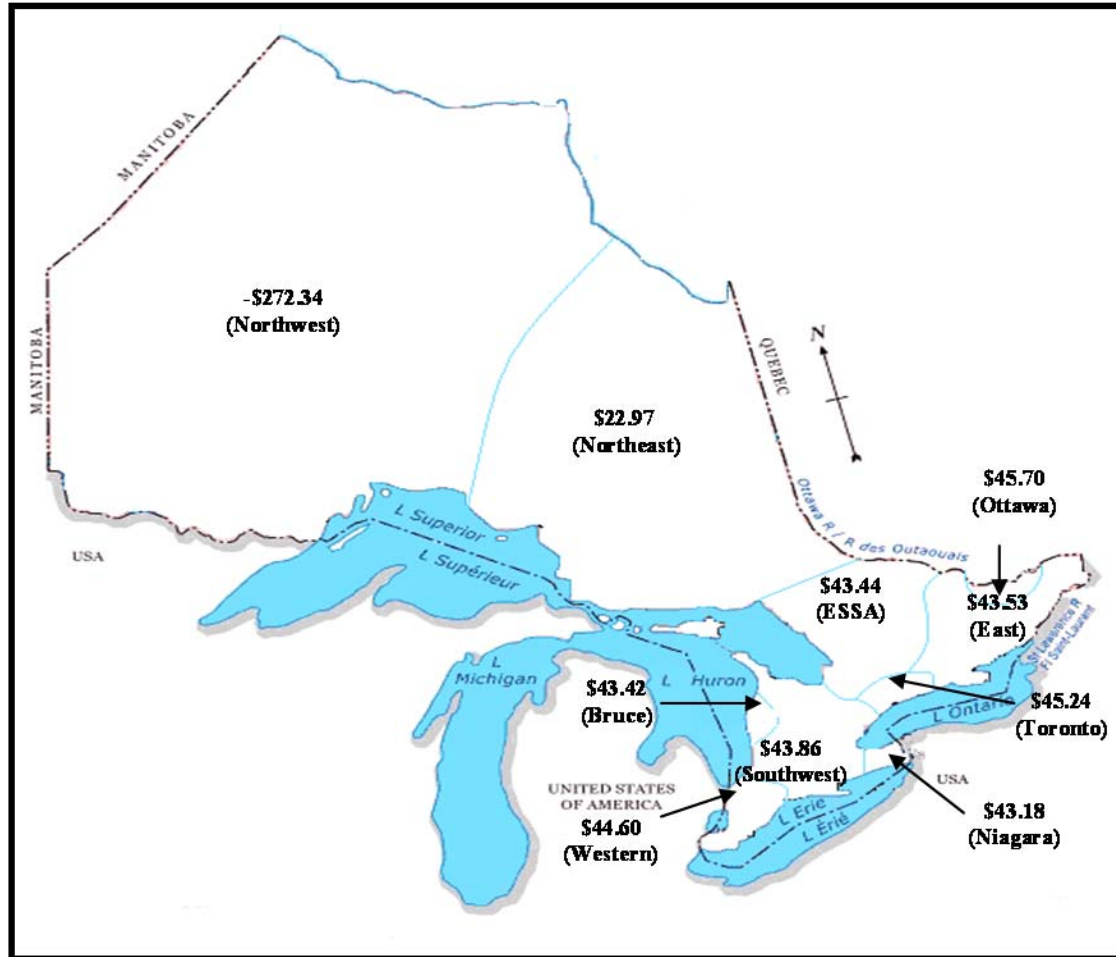
# Monthly Operating Reserve Prices by Class

January 2003 – April 2009 (\$/MWh)



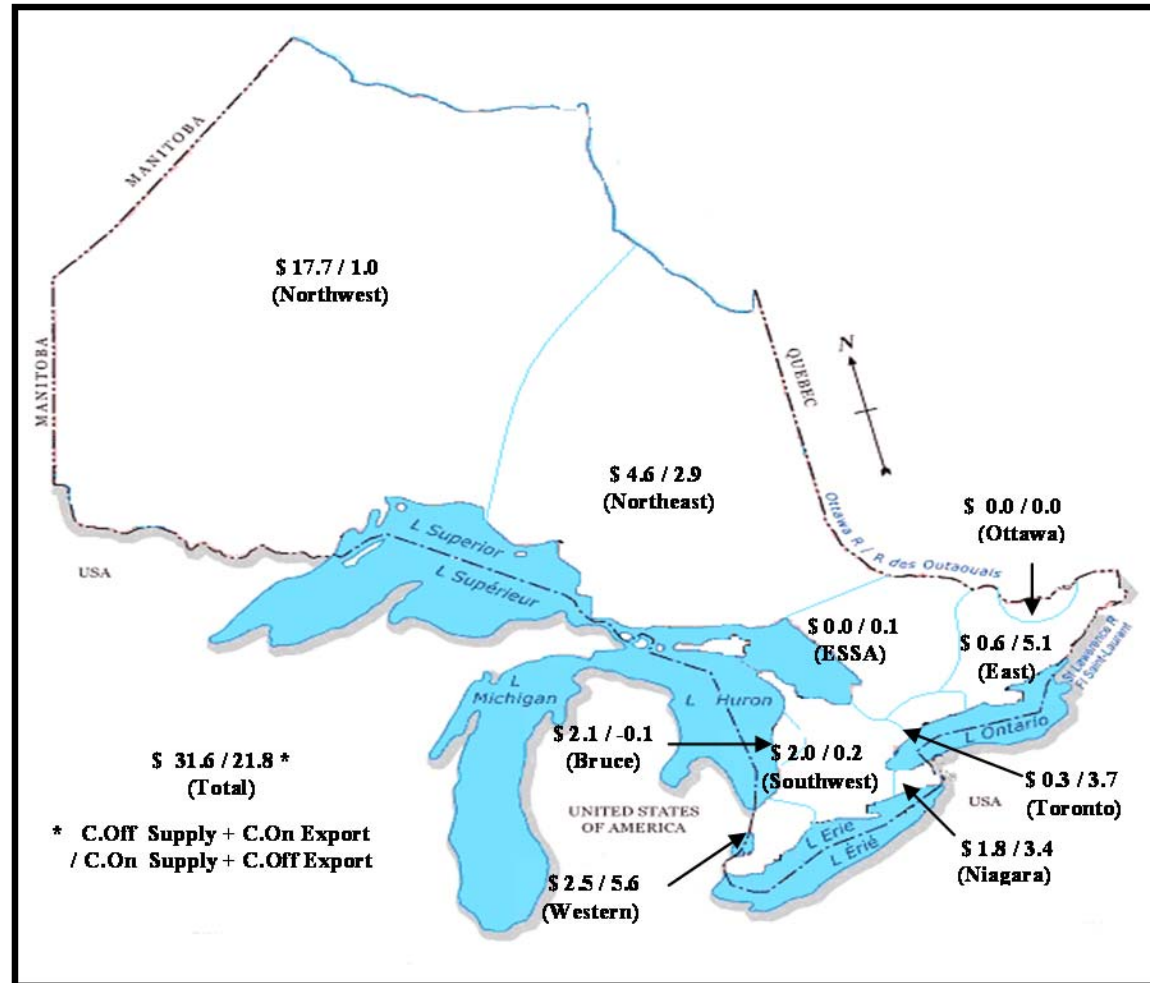
# Average Shadow Prices by Zone

November 2008 – April 2009 (\$/MWh)



# Total CMSC Payments by Zone

November 2008 – April 2009 (\$/MWh)



# Trade Flow Indicators

- Total export and import volumes declined this winter compared to last winter
  - Total exports fell 21% (3% excluding linked-wheels through Ontario)
  - Total imports fell 56% (37% excluding linked-wheels through Ontario)
  - Net exports increased 33%
- HOEP the lowest six-month hourly price compared to surrounding markets: NY, PJM, MISO and New England
  - \$1.81/MWh (4%) lower than the average MISO-ONT price
  - \$9.73/MWh (19%) lower than the average NYISO - Zone OH price



# Total Import and Export Volumes

November – April 2007/2008 and 2008/2009 (GWh)

	Total			Total Excluding Linked Wheels		
	2007/2008	2008/2009	% Change	2007/2008	2008/2009	% Change
Exports	10,305	8,178	(20.6)	8,446	8,162	(3.4)
Imports	6,222	2,755	(55.7)	4,368	2,737	(37.3)
Net Exports	4,083	5,423	+32.8			



# Average HOEP Relative to Neighbouring Market Prices

## November–April 2007/2008 & 2008/2009 (C\$/MWh)

	All Hours			On-peak Hours			Off-peak Hours		
	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change	2007/ 2008	2008/ 2009	% Change
<b>Ontario - HOEP</b>	49.16	40.98	(16.6)	61.65	50.50	(18.1)	38.72	33.10	(14.5)
<b>MISO – ONT</b>	52.48	42.79	(18.5)	67.73	50.50	(25.4)	39.75	36.34	(8.6)
<b>NYISO – Zone OH</b>	53.58	50.71	(5.4)	64.56	56.28	(12.8)	44.56	46.32	4.0
<b>PJM – IMO</b>	61.93	54.89	(11.4)	74.32	62.33	(16.1)	51.53	48.99	(4.9)
<b>New England – Internal Hub</b>	80.52	64.94	(19.4)	89.59	70.40	(21.4)	72.98	60.35	(17.3)
<b>Average</b>	59.54	50.86	(14.6)	71.57	58.00	(19.0)	49.51	45.02	(9.1)

# High Price Hours

- 8 hours with HOEP > \$200/MWh
  - Highest HOEP since market opening on February 18, HE12 at \$1,891.14/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

- 689 low price hours where  $HOEP < \$20/MWh$
- 219 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

