



Power to Ontario.  
On Demand.

# Pricing Events – November & December 2008

February 3<sup>rd</sup>, 2009  
MPWG



## 1. Overview

## 2. Discussion

- High-price hours
- Low-price hours
- Negative MCP
- Prices compared to uplifts
- MCP Volatility
- Operating reserve pricing and activations
- Demand response programs
- Administered pricing
- Emergency control actions

- Average Hourly Ontario Demand: 16,429 MW
  - Minimum: 11,881 MW
  - Maximum: 21,279 MW
- Total Ontario Demand: 11.829 TWh
- Average Net Exports: 762 MW
- Average HOEP: \$51.78 /MWh
  - Peak: \$ 59.98 /MWh
  - Off-peak: \$ 45.22 /MWh
- Average OR Prices
  - 10S: \$ 4.86 /MW/hr
  - 10N: \$ 3.84 /MW/hr
  - 30R: \$ 3.74 /MW/hr
- Wind Generation: 161.5 GWh
  - Output: 154.1 GWh (Capacity: 34.8%) from fully in-service projects

- Average Hourly Ontario Demand: 17,591 MW
  - Minimum: 11,992 MW
  - Maximum: 22,541 MW
- Total Ontario Demand: 13.1 TWh
- Average Net Exports: 1328 MW
- Average HOEP: \$46.34/MWh
  - Peak: \$57.67/MWh
  - Off-peak: \$37.02/MWh
- Average OR Prices
  - 10S: \$2.73/MW/hr
  - 10N: \$2.47/MW/hr
  - 30R: \$2.39/MW/hr
- Wind Generation: 238 GWh
  - Output: 237 GWh (Capacity: 45.2%) from fully in-service projects

- There were no instances of HOEP exceeding \$200 reported for the month of November.

Date	Hour	HOEP	Issue(s)
December 9 <sup>th</sup>	12	\$233.52	<ul style="list-style-type: none"> <li>• Under forecast of demand of 600 MW due to incorrect temperature estimate</li> <li>• Forced outage of approximately 500MW</li> </ul>
December 19 <sup>th</sup>	12	\$211.01	<ul style="list-style-type: none"> <li>• Under forecast of demand of 1000 MW</li> <li>• Extended planned outage increases required reserve 400MW</li> </ul>

- There were 31 hours in November where HOEP was less than \$20
  - Of these, none were negative HOEP.
- There were 62 hours in December where HOEP was less than \$20
  - Of these, there were 5 hours with negative HOEP

# Hours with HOEP < \$20

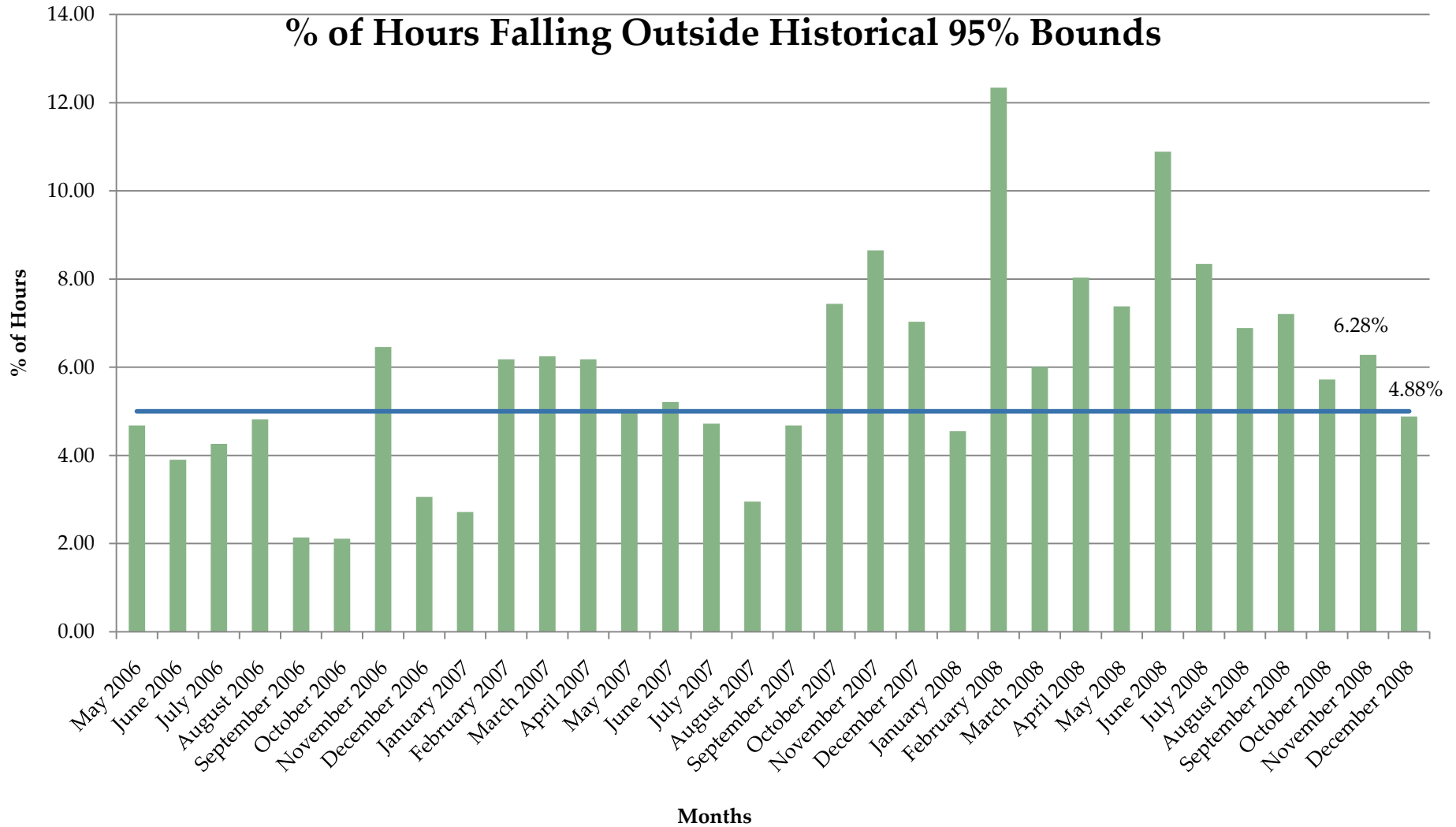
Day	Hour	HOEP
December 28 <sup>th</sup>	3	-\$20.14
December 28 <sup>th</sup>	4	-\$28.83
December 28 <sup>th</sup>	5	-\$33
December 28 <sup>th</sup>	6	-\$34
December 28 <sup>th</sup>	7	-\$32.67

- There were no instances of negative market clearing prices for the month of November.

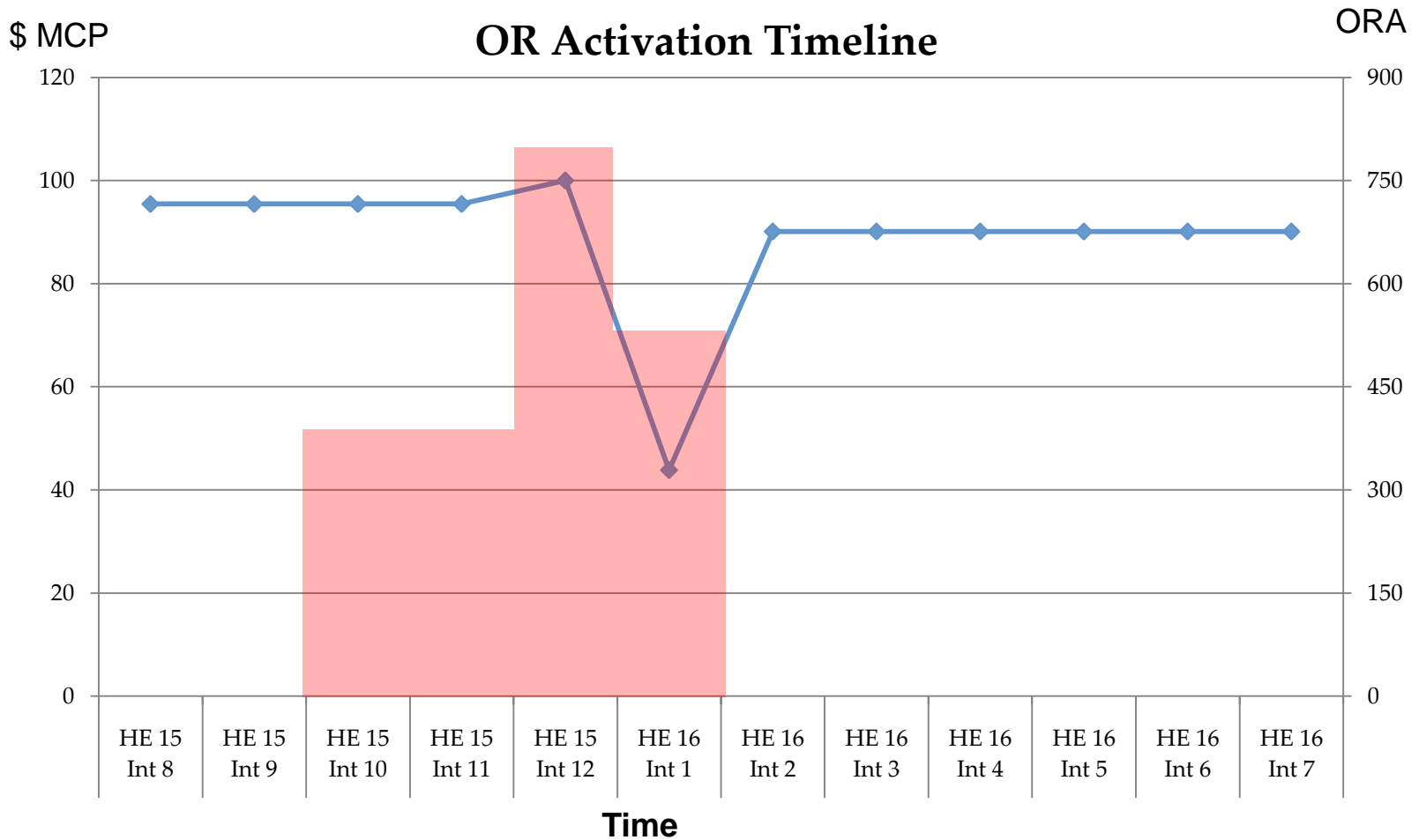
Date	Hour(s)	# Negative MCP's	Issue(s)
December 28 <sup>th</sup>	3, 4, 5, 6, 7	57	<ul style="list-style-type: none"><li>• Excess baseload generation</li><li>• Unusually high temperature, resulting in over-forecast of demand</li><li>• Failed exports</li></ul>

- NOTE: The Market Surveillance Panel has amended its standard for investigating anomalous pricing events.
  - \$500 000 CMSC or IOG payments in an hour
  - \$1 000 000 CMSC or IOG payments on an intertie in a day
  - \$100 000 OR payments in an hour
- There were no instances where IOG was greater than \$500,000 in an hour.
  - On Thursday, December 18<sup>th</sup> HE 9 total CMSC was \$516,804.
- There were no instances where CMSC or IOG payments on an intertie in a day were greater than \$1,000,000.
- There were no instances where OR payments exceeded \$100,000 in an hour.

- To measure MCP volatility we calculate the proportion of current period interval-to-interval price changes that exceed certain thresholds
  - Thresholds constructed using previous 4 years of monthly data
  - Capture 95% of historical interval-level price changes
- If current month's prices are equally volatile to the average of the same month in the 4 previous years, value will be 5%
  - Value will be higher if prices are more volatile than in previous years

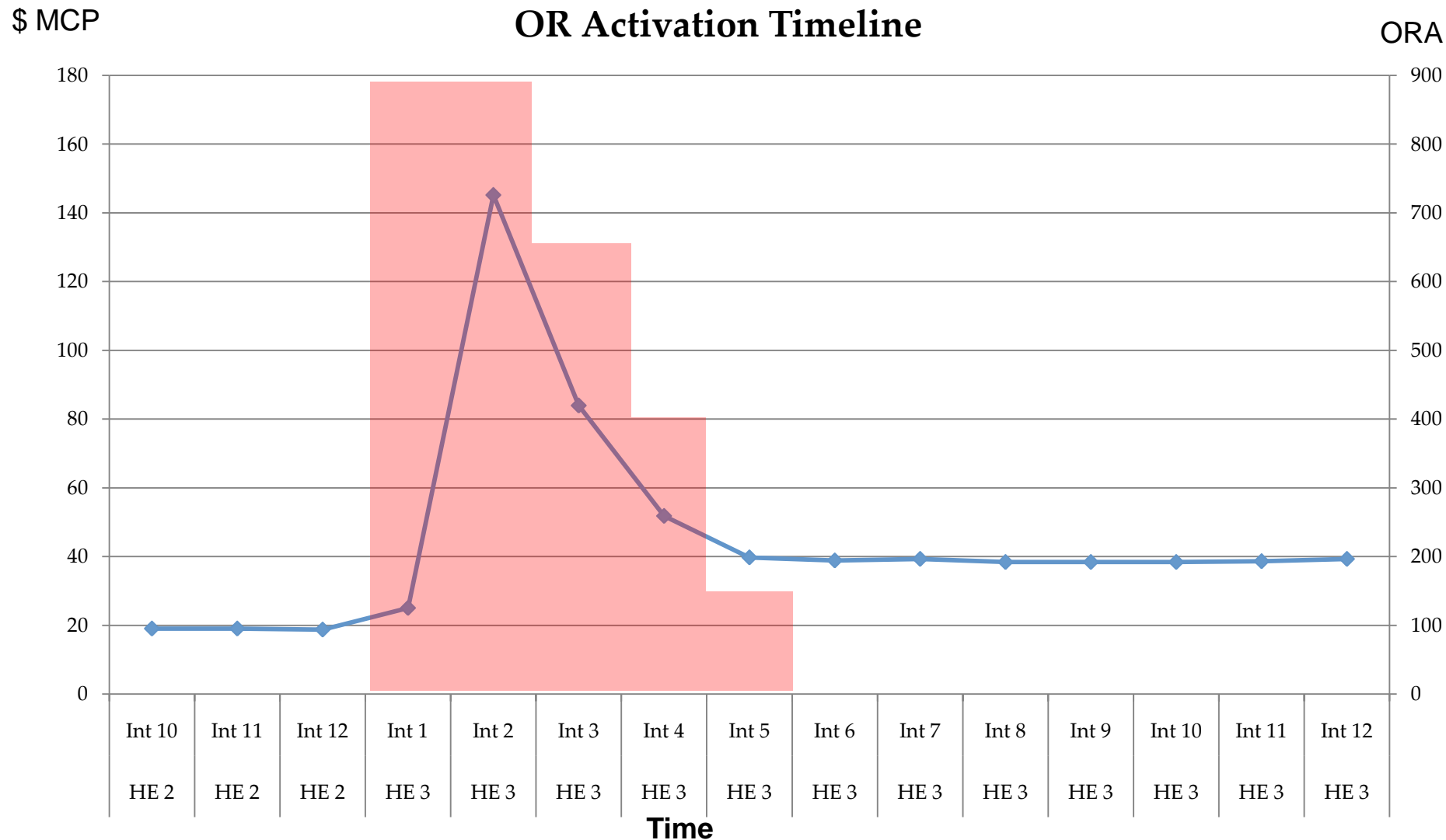


- 27 Hours with OR activations.
- Largest activation occurred on Monday 24 at 15:50.
  - 800 MW OR activated
  - Cause:
    - Under forecast of demand by 250 MW
    - 470 MW generation loss
  - Duration: 17 minutes



- 17 Hours with OR activations
- Largest activation occurred on Friday 26<sup>th</sup> at 2:08
  - 900 MW OR activated
  - Cause: 800MW generation loss
  - Duration: 27 minutes

## OR Activation Timeline



## November 2008

- 6 DR3 program activations
- 6 events required administered pricing
  - 9 intervals due to planned outages
  - 13 intervals due to input data problems
- There were no emergency control actions in November

December 2008

- One DR3 program activation
- 7 events required administered pricing
  - 9 intervals due to planned outages
  - 13 intervals due to input data problems
- There were no emergency action controls in December