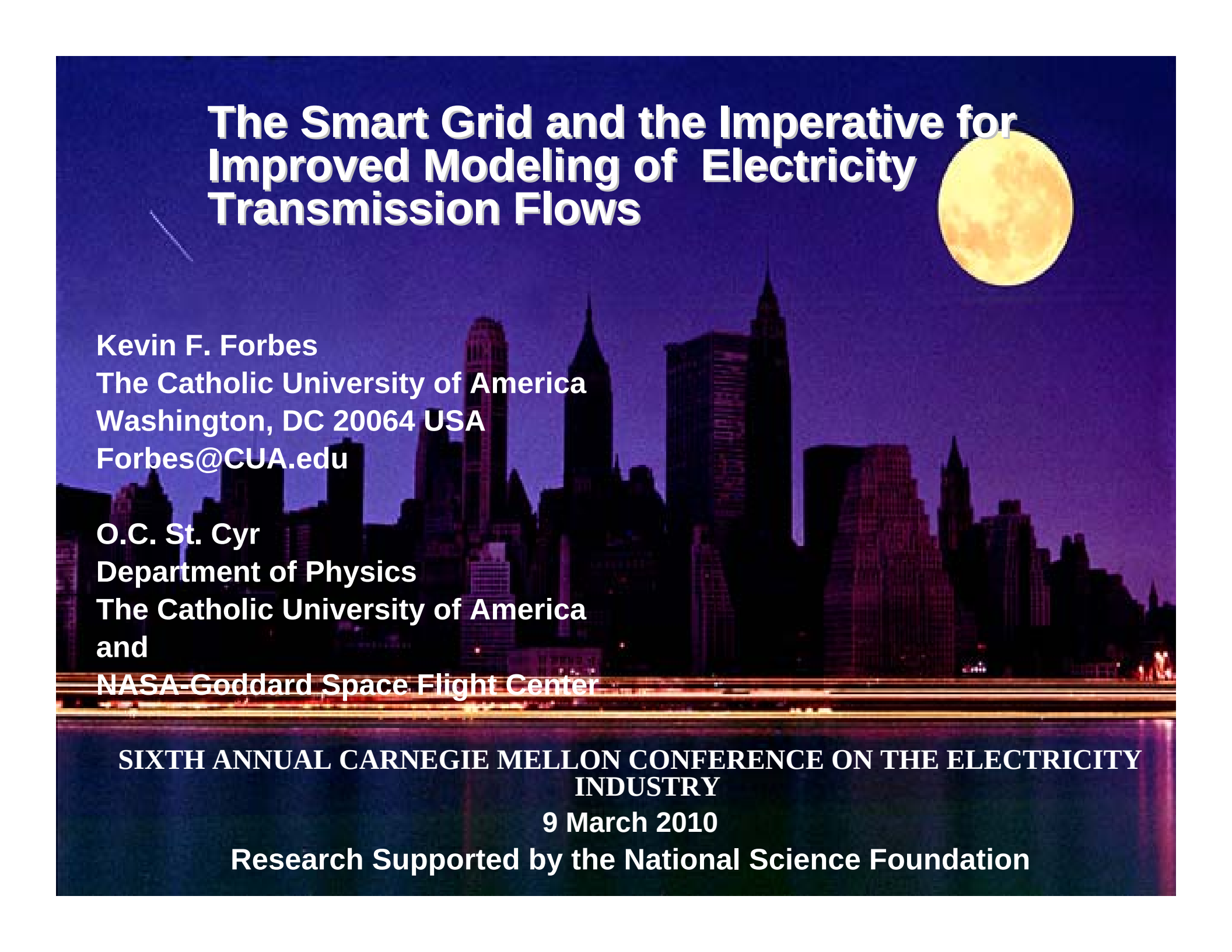


The Smart Grid and the Imperative for Improved Modeling of Electricity Transmission Flows

The background of the slide is a night photograph of a city skyline, likely New York City, with several skyscrapers visible. A large, bright full moon is in the upper right corner of the sky. The city lights are reflected in the water in the foreground.

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**SIXTH ANNUAL CARNEGIE MELLON CONFERENCE ON THE ELECTRICITY
INDUSTRY**

9 March 2010

Research Supported by the National Science Foundation

Back Ground

- Many markets are self-correcting. When a market is in disequilibrium in the sense that demand is not equal to supply, there are forces at work that will move the system to a new equilibrium.
- A decrease in the supply of, say, bananas could lead to a shortage of bananas but the shortage is likely to be short lived as the price of bananas changes and producers and consumers respond to the new price.
- In any event, a short-lived banana shortage is probably not a big deal.

Electricity is Different

- There are very large societal costs associated with blackouts.
- Avoiding these costs requires that system frequency be maintained at its setpoint value of 60 Hz (50 Mz in most of the rest of the world)
- Maintaining system frequency at its setpoint value requires that the demand for electricity match the supply. Specifically, the amount of power generation in a balancing area needs to match exactly, on a near-instantaneous basis, the system load, net of losses and interchange with other balancing areas.

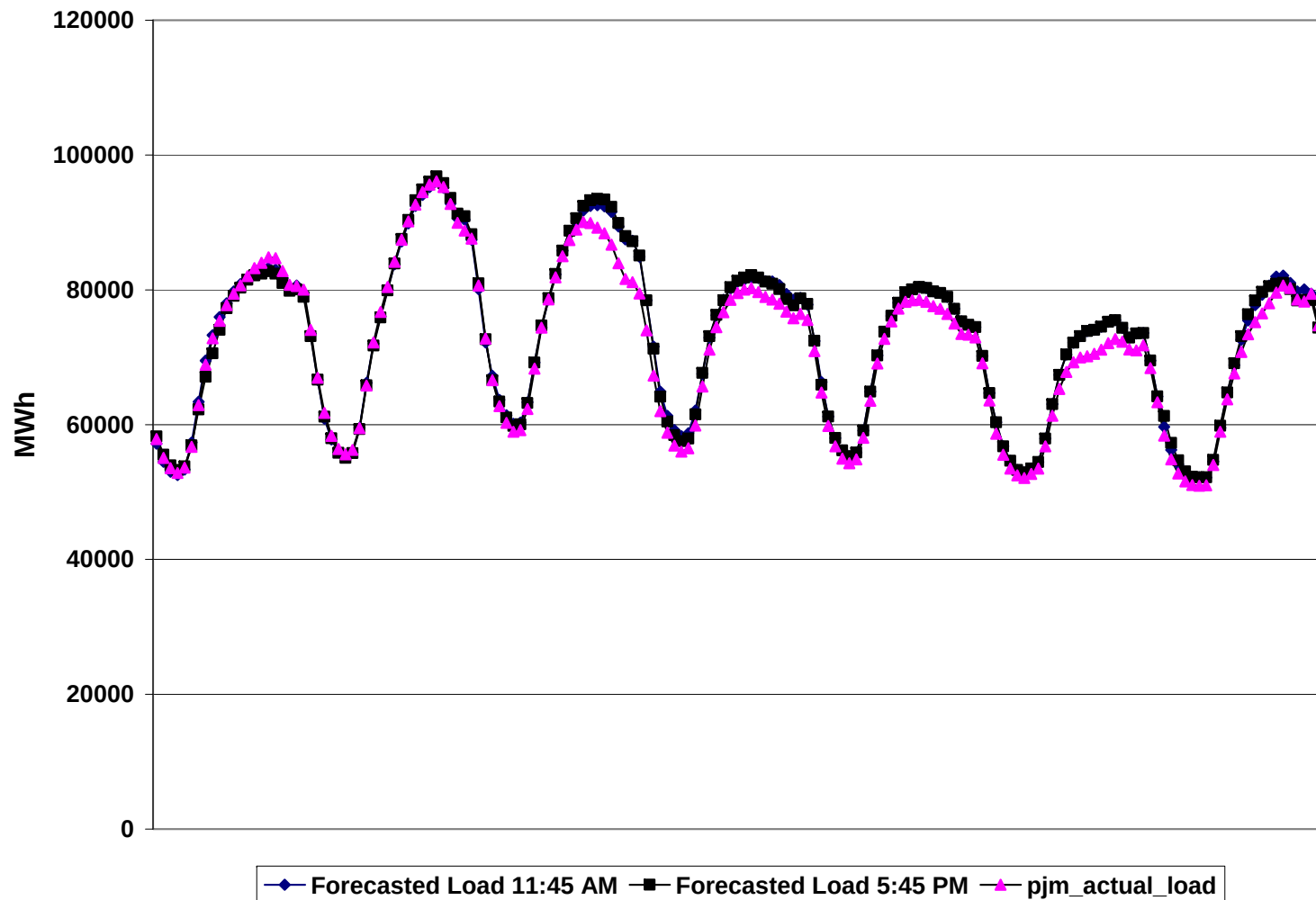
Challenges to Reliability

- **Load Forecasting Errors.**
- **Wind Forecasting Errors**
- **Issues with Conventional Generation**
- **Transmission Issues**

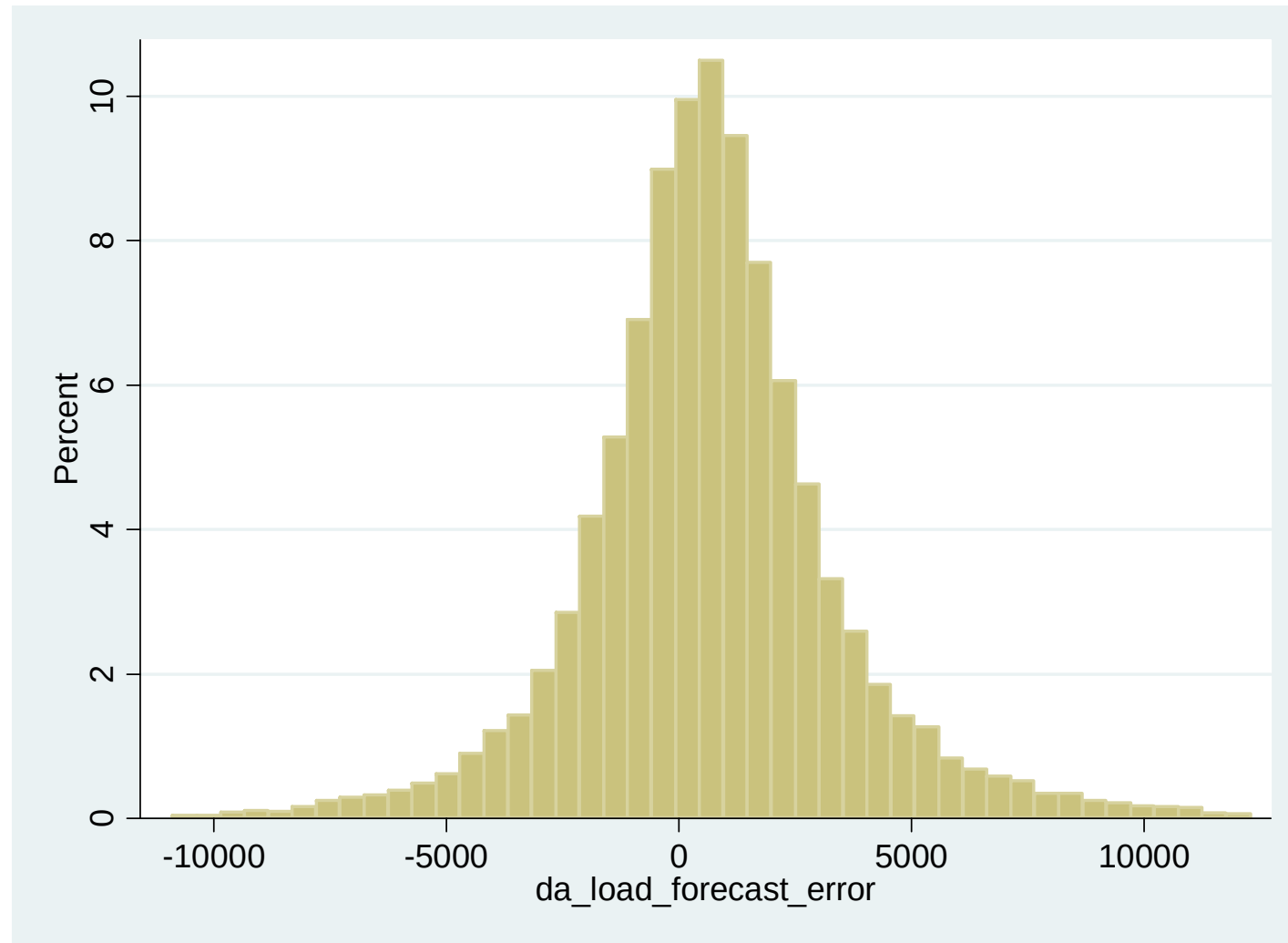
Challenges to Reliability

- **Load Forecasting Errors.** Depending on the system operator, the root-mean-squared errors of the day-ahead forecasts are usually between 3- 5 percent but can be as high as 10 percent.

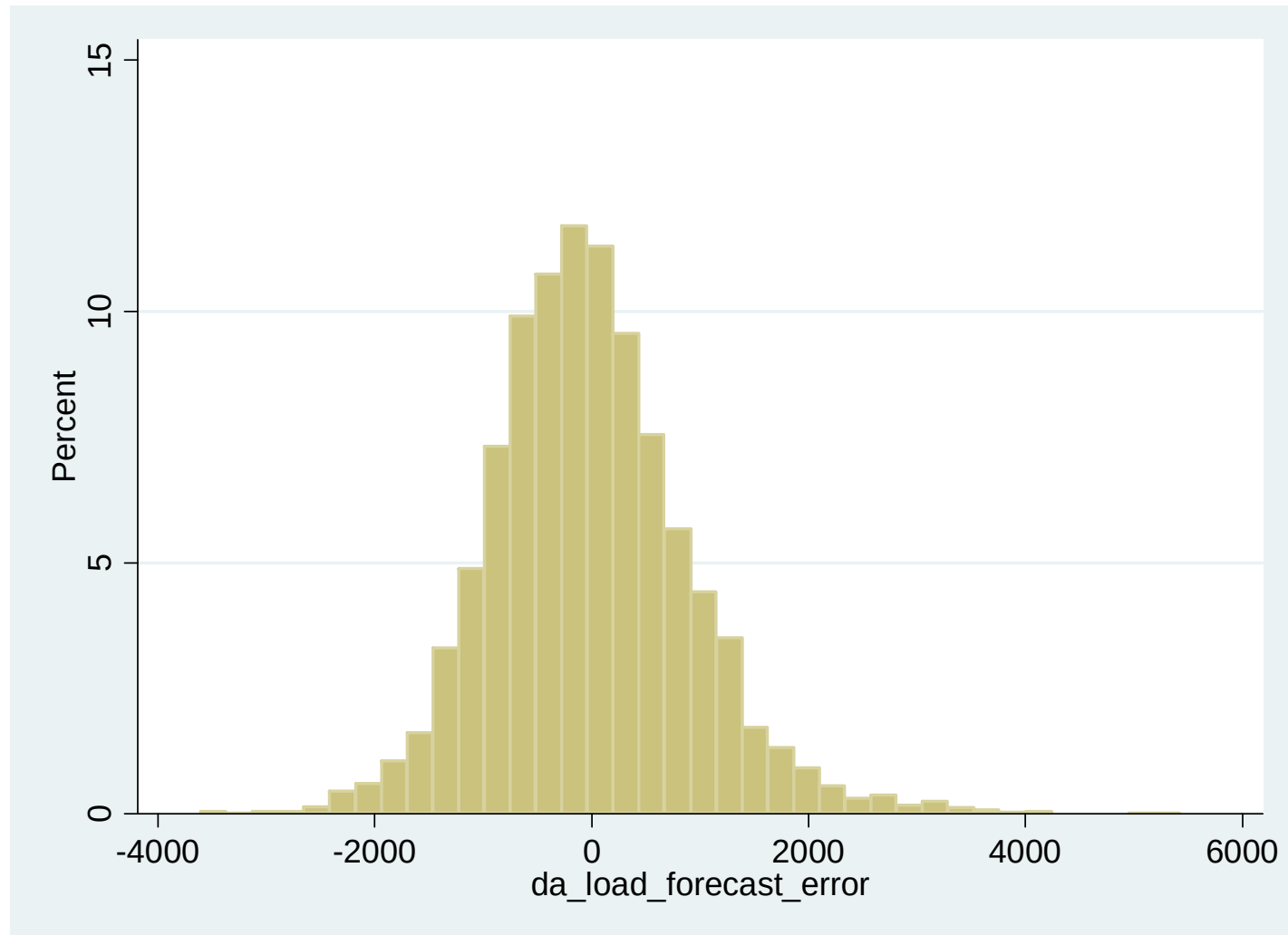
Actual and Day-Ahead Forecasted Load in PJM, 1 June – 7 June 2009



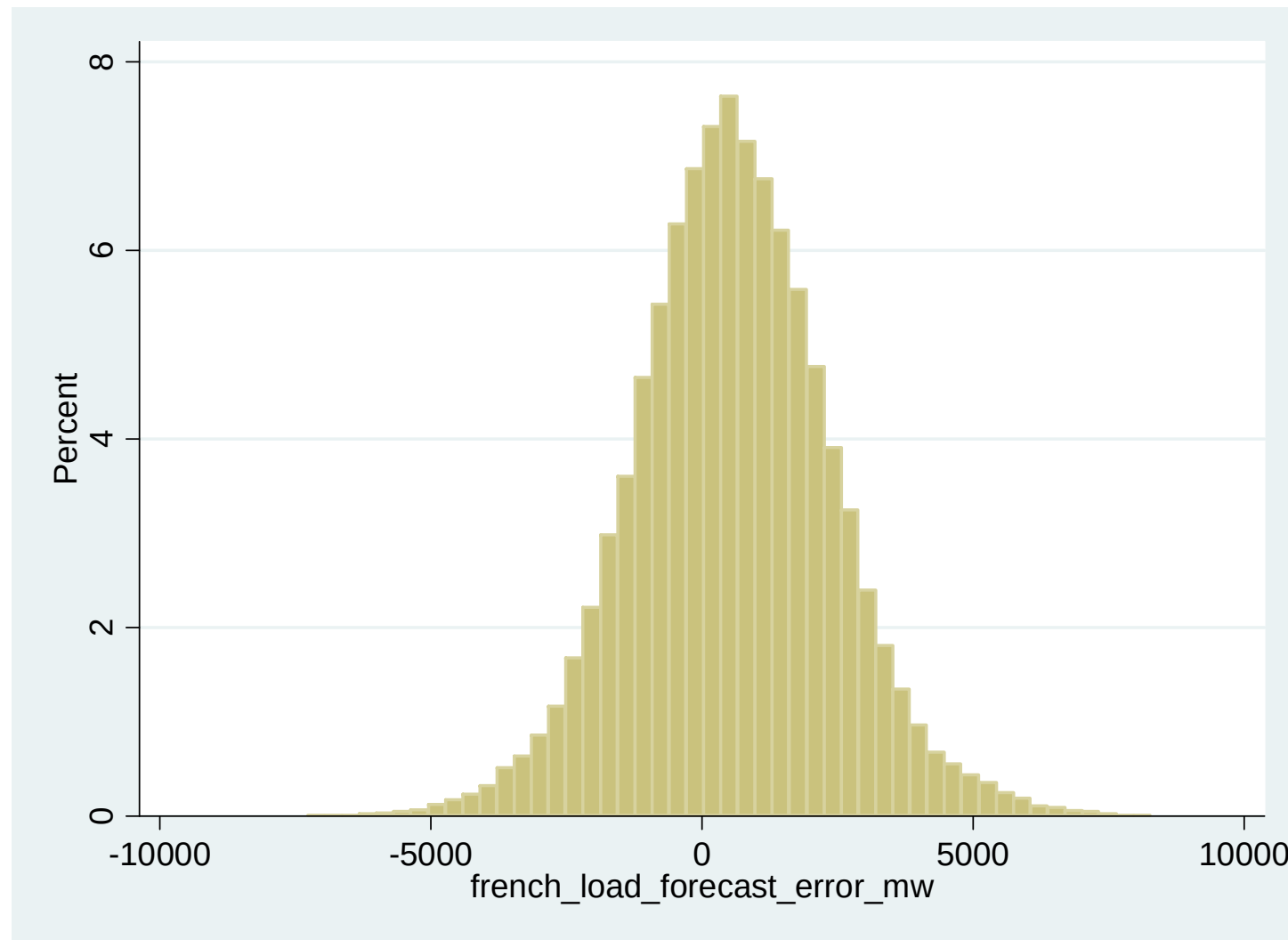
A Histogram of Day-Ahead Load Forecasting Errors by PJM, 1 May 2005 – 11 August 2009



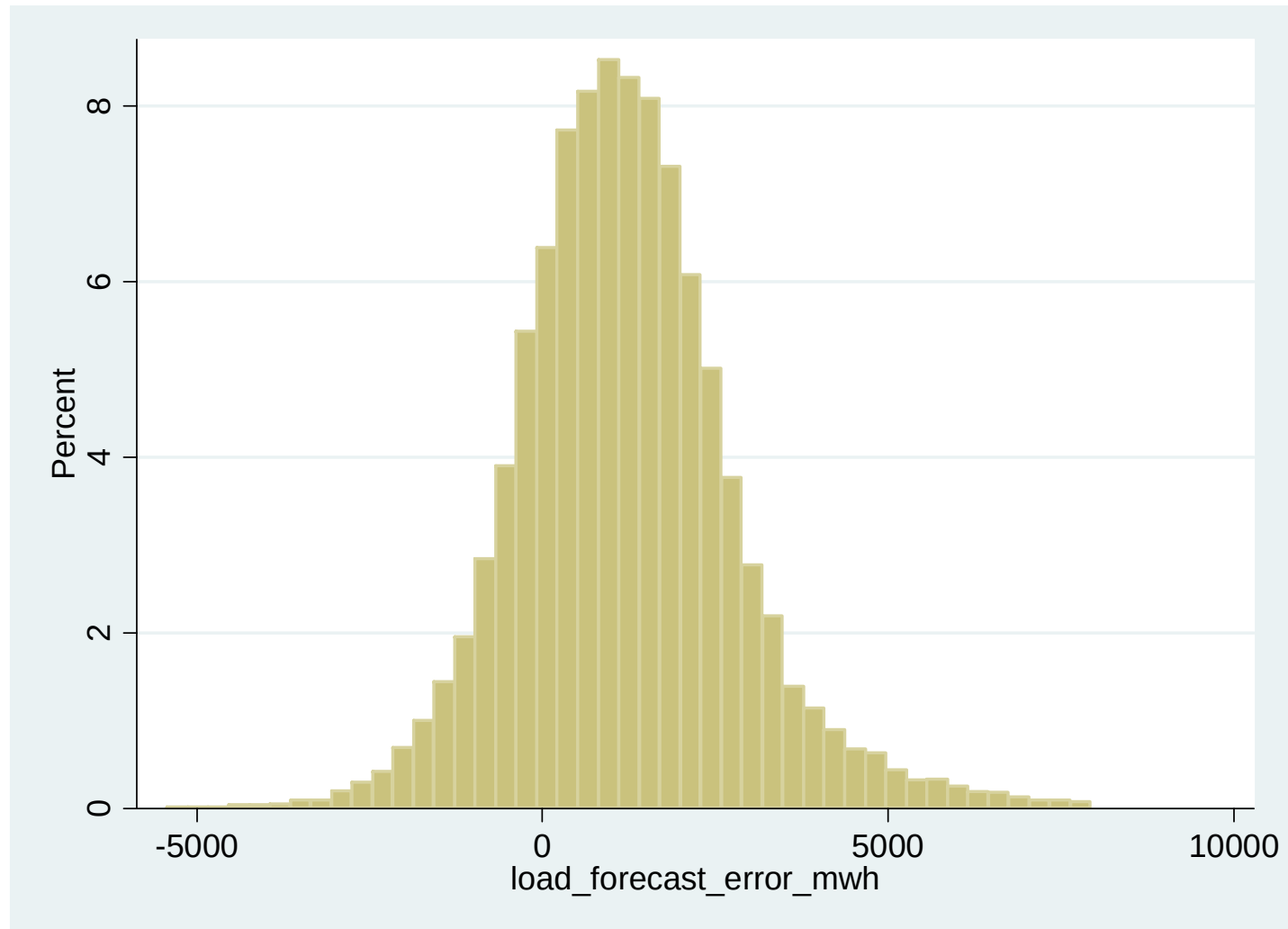
A Histogram of Day-Ahead Load Forecasting Errors by the California ISO, 1 April 2009 - 31 January 2010



A Histogram of Day-Ahead Load Forecasting Errors for France, 1 November 2003 – 31 December 2008



A Histogram of Day-Ahead Load Forecasting Errors for the Midwest ISO, 1 April 2005 – 31 December 2008



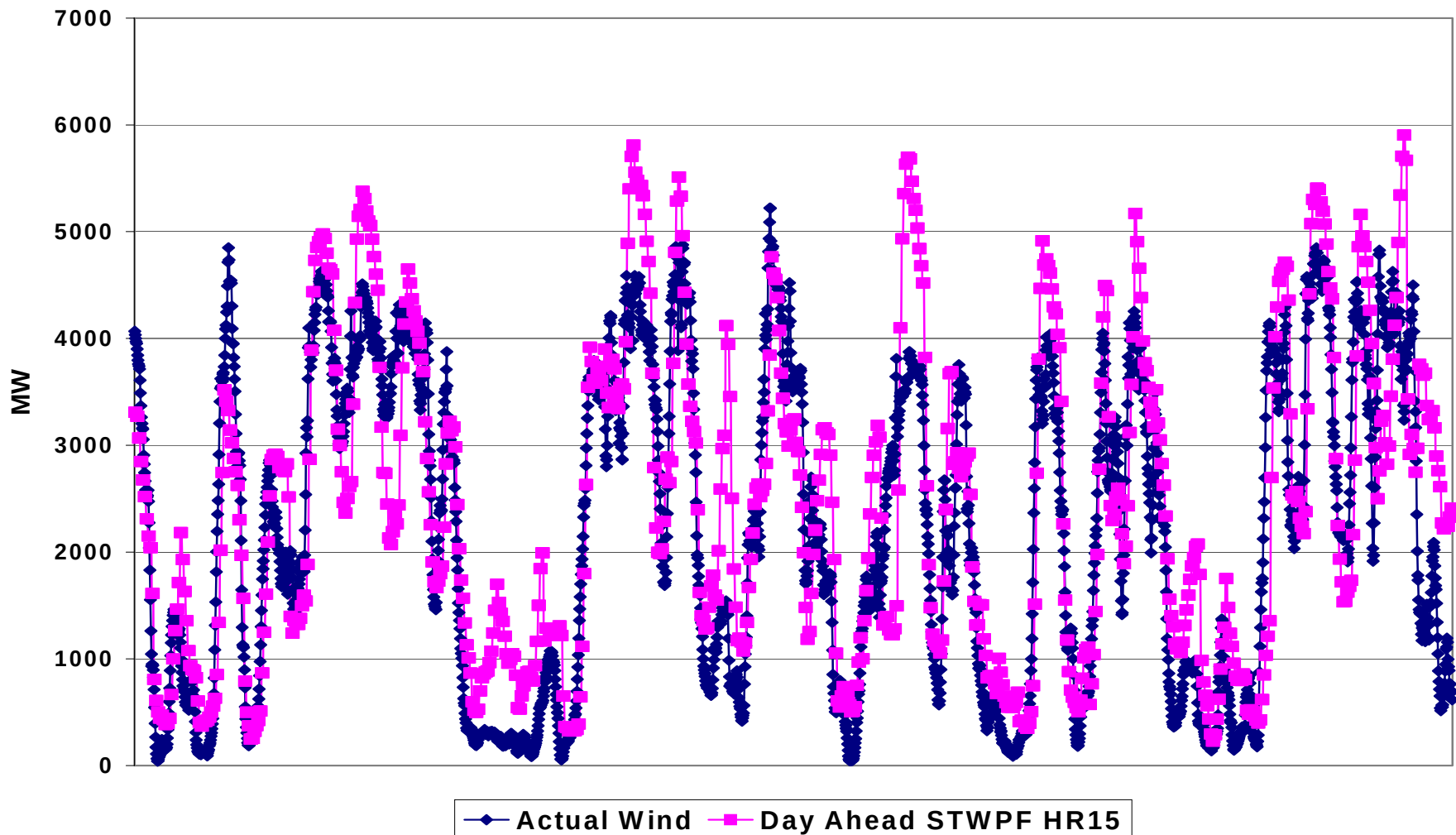
Load Forecasting Errors

- While the “average error” may seem small, there are a nontrivial number of days in which the errors are quite large
- There is preliminary evidence that a portion of the errors is systematic. This may make it possible to reduce the errors by modifying forecasts based on the systematic component of the errors

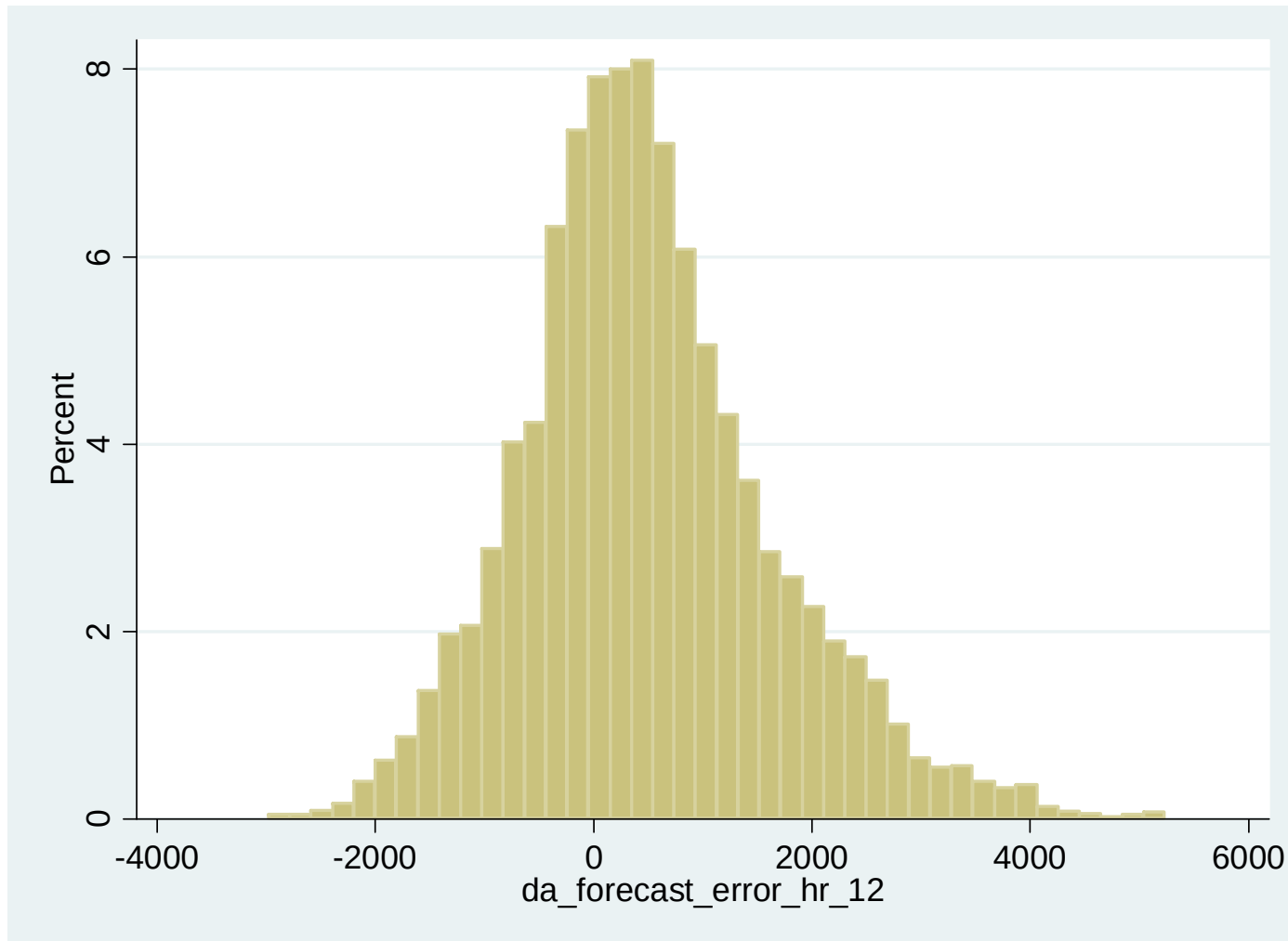
Challenges to Reliability

- **Wind Energy.** It is not uncommon for the root-mean-squared errors of the day-ahead wind energy forecasts to be larger than 30 percent of actual wind energy.

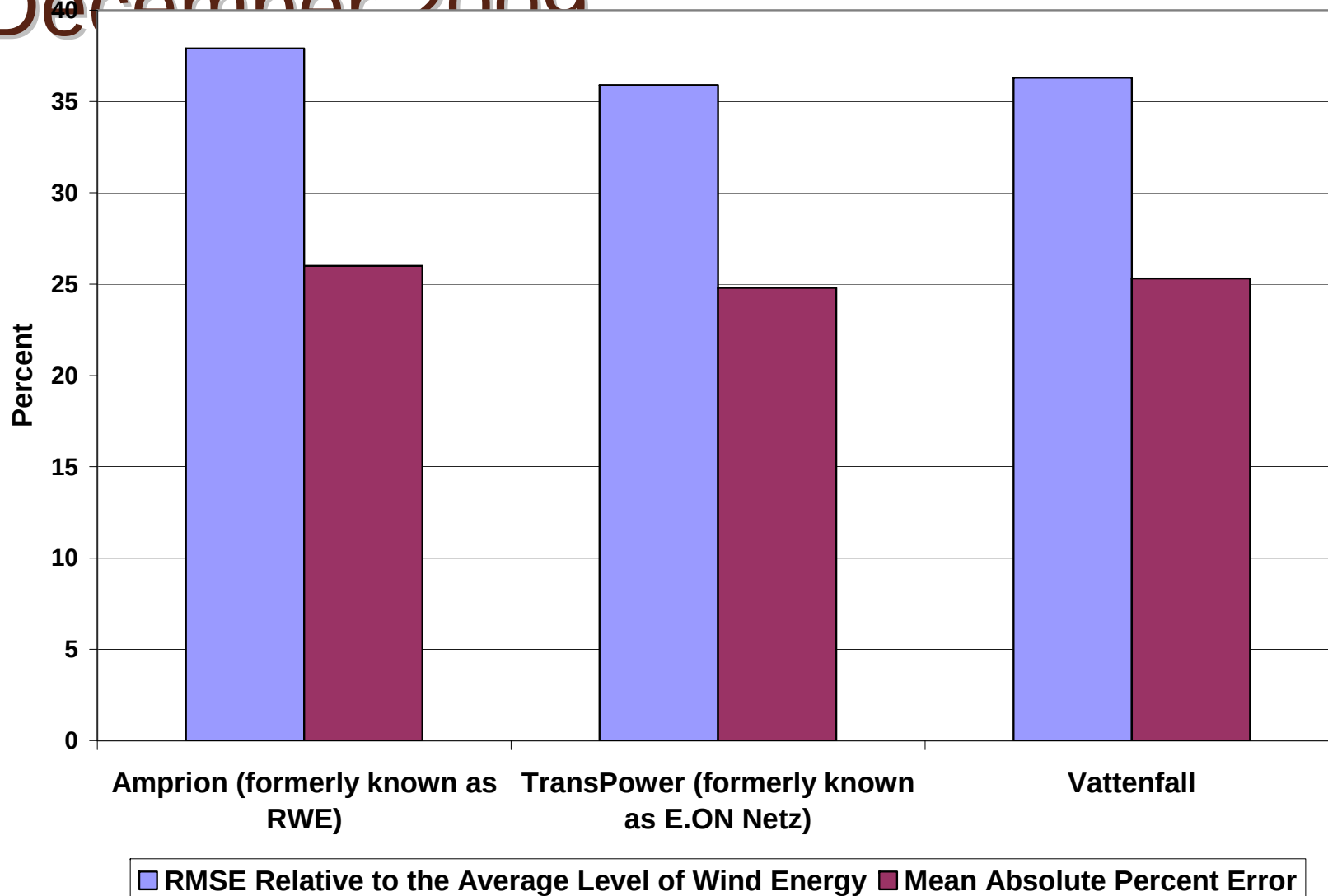
Actual vs Day-Ahead Forecasted Wind Energy in ERCOT, 2 November – 30 November 2009



A Histogram of Day-Ahead Wind Forecasting Errors in ERCOT, 13 June 2009 – 31 January 2010



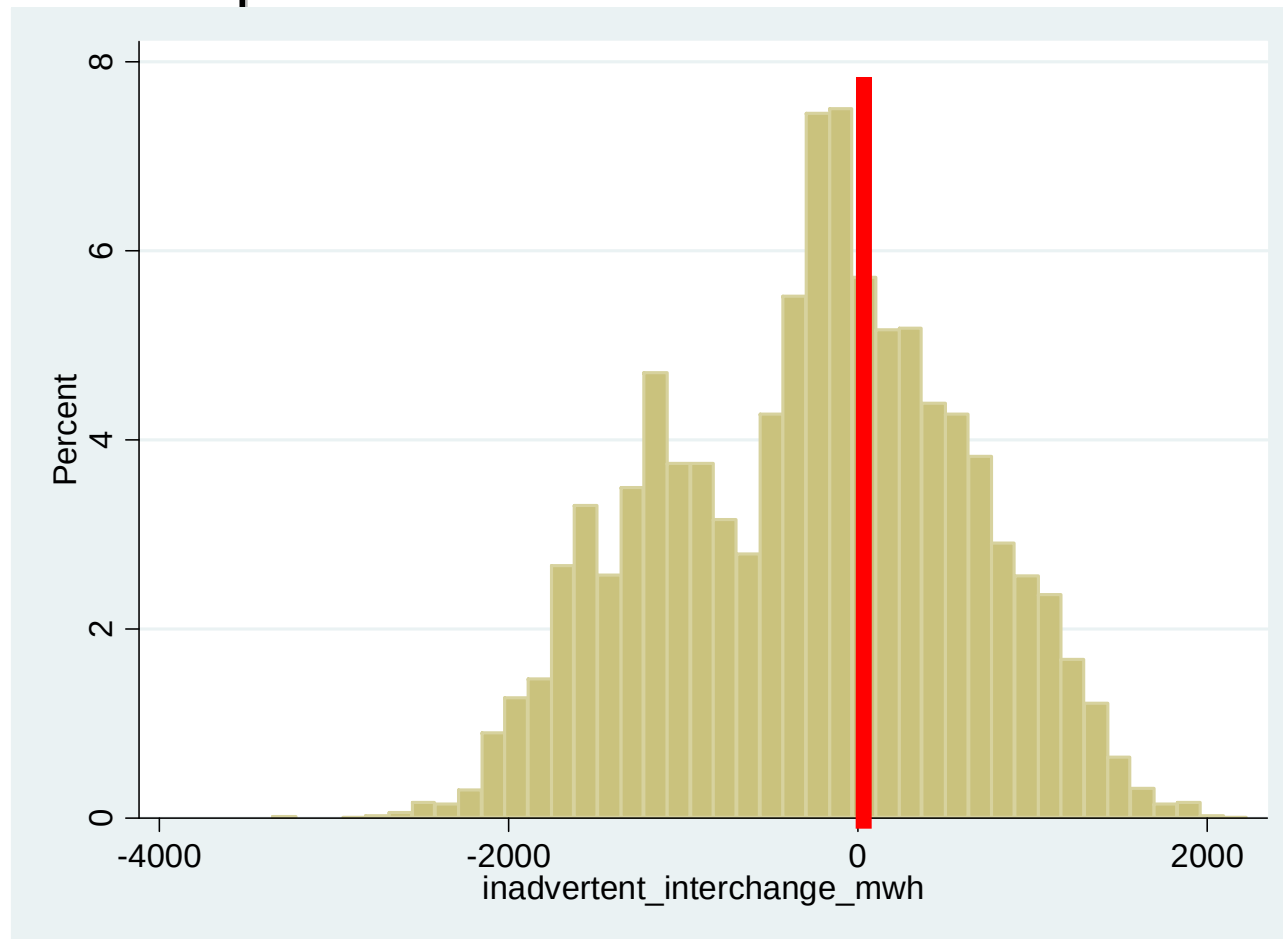
Day-Ahead Wind Forecasting Errors in Germany, 1 January -15 December 2009



Challenges to Reliability (Continued)

- **Unscheduled Electricity Flows (aka Loop Flows) between Control Areas.** It is not uncommon on alternating current transmission systems for the root-mean-squares of the unscheduled electricity flows between control areas to exceed 100 percent.
- System Operators have had difficulty modeling these flows.

Histogram of Inadvertent Interchange (the sum of the Loop Flow over all Interchanges) in the PJM Power Grid Over those Hours in Which PJM was a Scheduled Net Importer, 1April 2002-30 April 2004

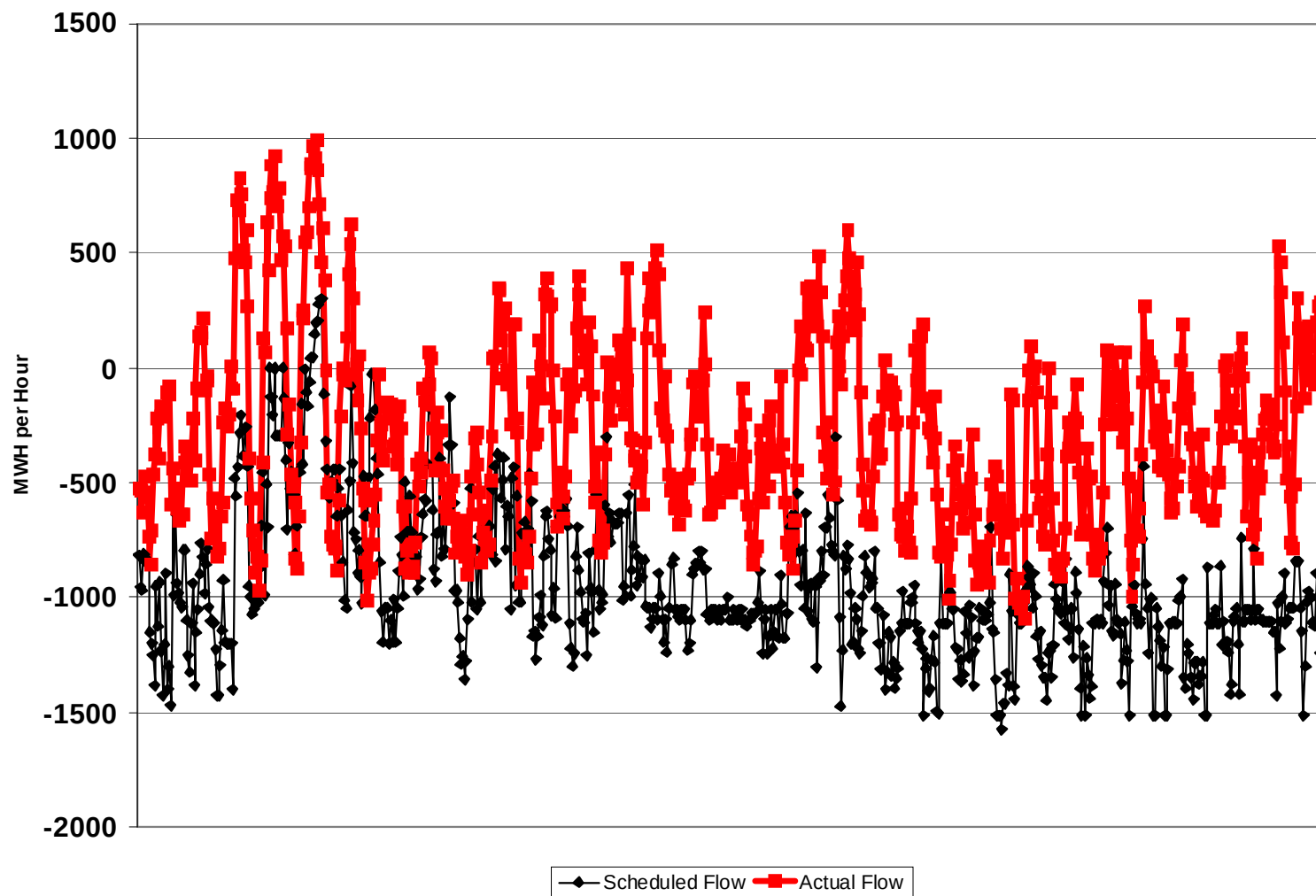


Note: the figure does not reflect dynamically scheduled flows

Actual Imports < Scheduled

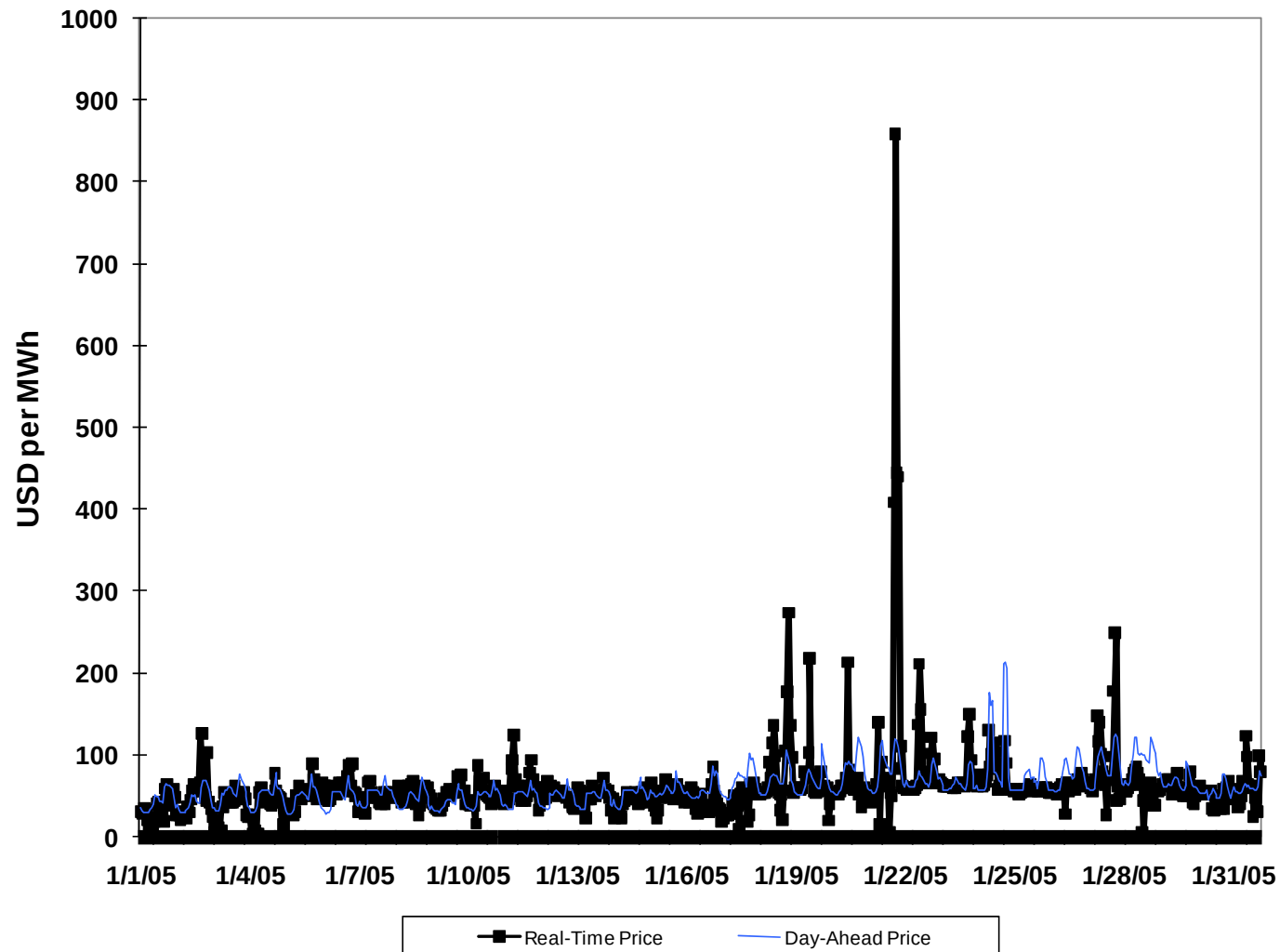
Actual Imports > Scheduled

Actual vs Scheduled Electricity Flows Between Ontario and Michigan, 1 Oct – 31 Oct 2005



Challenges to Reliability can Result in Price Spikes

The Day-Ahead and Real-Time Reference Price in the New York ISO, January 1-31 2005



Another Possible Outcome when Reliability is Challenged



**What is the Magnitude of the
Transmission Challenge?**

The Root Mean Squared Error of the Flows

$$RMSE = \sqrt{\frac{\sum (ActualFlow - ScheduledFlow)^2}{n}}$$

The Magnitude of the Challenge: 1 June 2007 – 31 December 2008

InterChange With PJM	InterChange Abbreviation	Absolute Value of Scheduled Trade (MWh per Hour)	Root-Mean- Square of the Inadvertent Flow Relative to Mean of the Absolute Value of the Scheduled Flow (in percent)	Simple Correlation between Actual and Scheduled Flow
Alliant East	PJM/ALTE	216	277 %	0.1080
Alliant West	PJM/ALTW	192	117 %	0.3766
Ameren	PJM/AMIL	139	659 %	0.2890
Cinergy	PJM/CIN	626	114 %	0.4561
Duke Energy	PJM/DUK	579	113 %	0.8549
First Energy	PJM/FE	329	361 %	0.0438

The Magnitude of the Challenge: 1

June 2007 – 31 December 2008

InterChange	InterChange	Absolute Value of Scheduled Trade (MWh per Hour)	Root-Mean-Square of the Inadvertent Flow Relative to Mean of the Absolute Value of the Scheduled	Simple Correlation between Actual and Scheduled Flow
Indianapolis Power and Light	PJM/IPL	217	273 %	0.2088
LG&E Energy	PJM/LGEE	180	117 %	0.3953
MidAmerican Energy	PJM/MEC	458	100 %	0.5654
Michigan Electric Coordinated	PJM/MECS	371	482 %	-0.0165
NEPTUNE	PJM/NEPT	599	0.2 %	1.00
Northern Indiana Public	PJM/NPIS	112	322 %	0.0789
New York ISO	PJM/NYIS	954	78 %	0.6174

The Magnitude of the Challenge: 1 June 2007 – 31 December 2008

InterChange	InterChange	Absolute Value of Scheduled Trade (MWh per Hour)	Root-Mean-Square of the Inadvertent Flow Relative to Mean of the Absolute Value of the Scheduled Flow (in	Simple Correlation between Actual and Scheduled Flow
Ohio Valley Electric Corporation	PJM/OVEC	1045	36 %	0.3947
Tennessee Valley Authority	PJM/TVA	484	125 %	0.6711
Wisconsin Energy Corporation	PJM/WEC	114	416 %	0.1446

Modeling Loop Flows

- Ambient temperature is probably an important factor. The relationship is probably nonlinear.
- Nonthermal transmission constraints that are terrestrial in origin are most likely also important
- “Network effects” are probably very important.

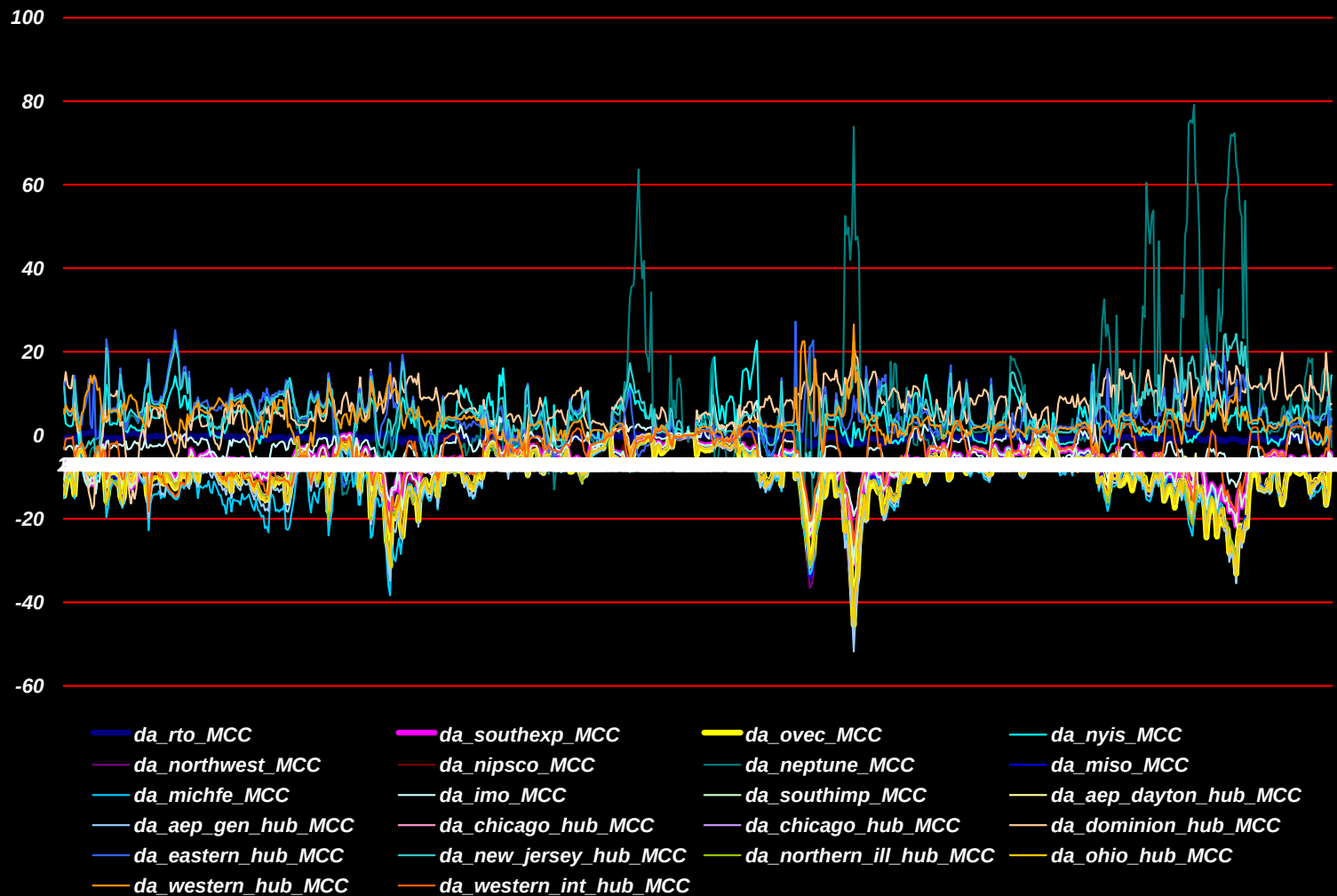
Proxies for the Expected Conductivity of the Power Grid

- PJM reports day-ahead electricity prices that are location specific.
- As of 1 June 2007, these prices have three components: a pure energy component, a congestion cost component, and a marginal transmission loss component.
- The congestion cost and transmission loss components reflect the expected conductivity of the transmission system
- We use 40 of these reported day-ahead measures as proxies for the conductivity of the power grid

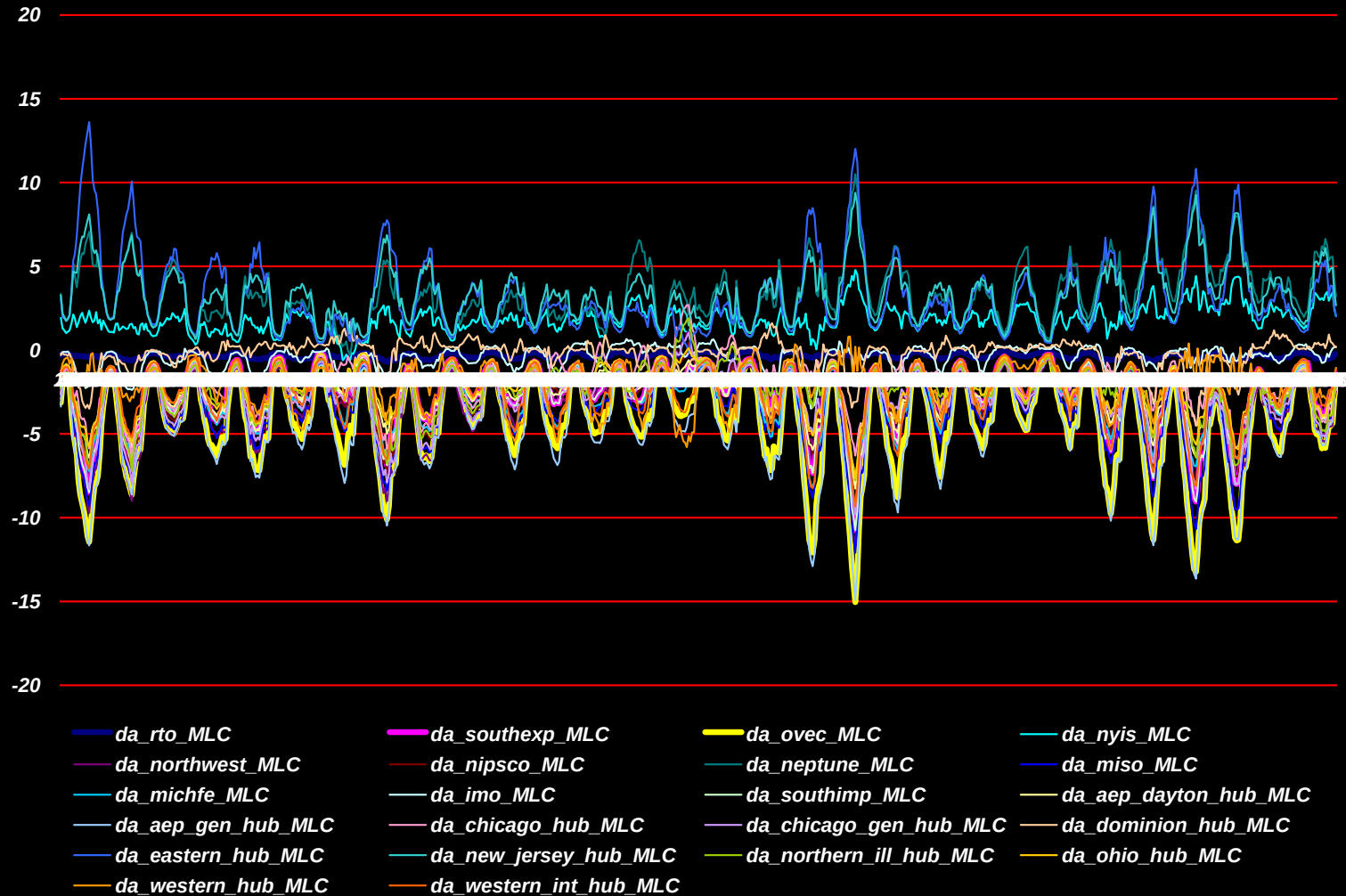
Examples of Proxies for the Expected Conductivity of the Power Grid

- Day-Ahead Congestion and Losses at Chicago Hub
- Day-Ahead Congestion and Losses at the PJM/New York Interface
- Day-Ahead Congestion and Losses at the AEP Dayton Hub
- Day-Ahead Congestion and Losses at the Interface with MISO

Day-Ahead Congestion Costs, June 2007



Day-Ahead Marginal Losses, June 2007



Geomagnetic Storms and Loop Flows

- Geomagnetic storms are disturbances in the Earth's magnetic field that are largely caused by explosions in the Sun's corona that spew out solar particles.

Solar Activity and the Earth's Magnetic Field



Source: NASA

Geomagnetic Storms and Loop Flows

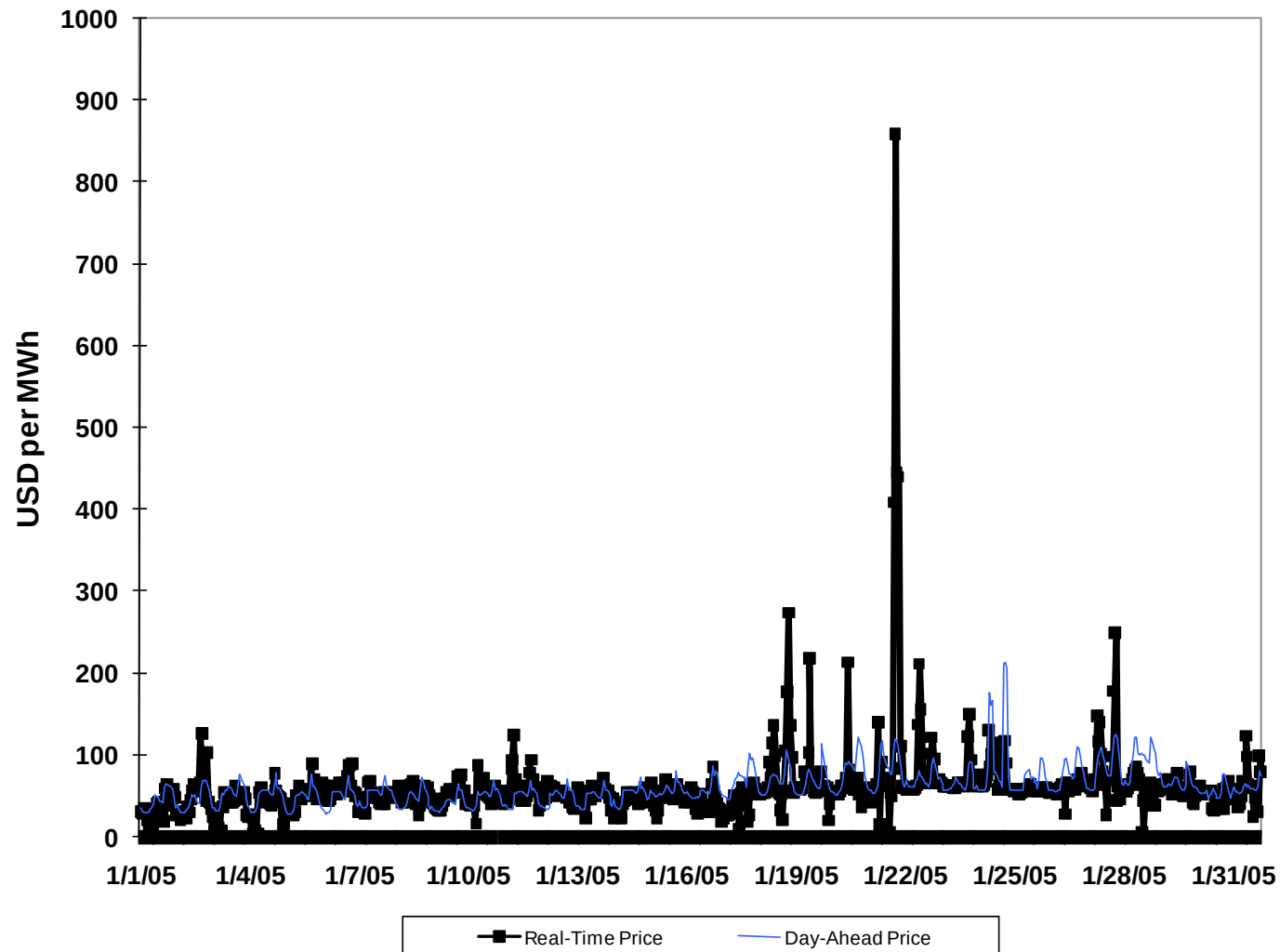
- **Power Grids are vulnerable to geomagnetic Storms because the power transmission grid acts as an “antenna” of sorts, picking up geomagnetically induced currents (GICs).**
- **These currents have the potential to induce transmission constraints which in turn can affect transmission flows.**

The Peer Reviewed Literature

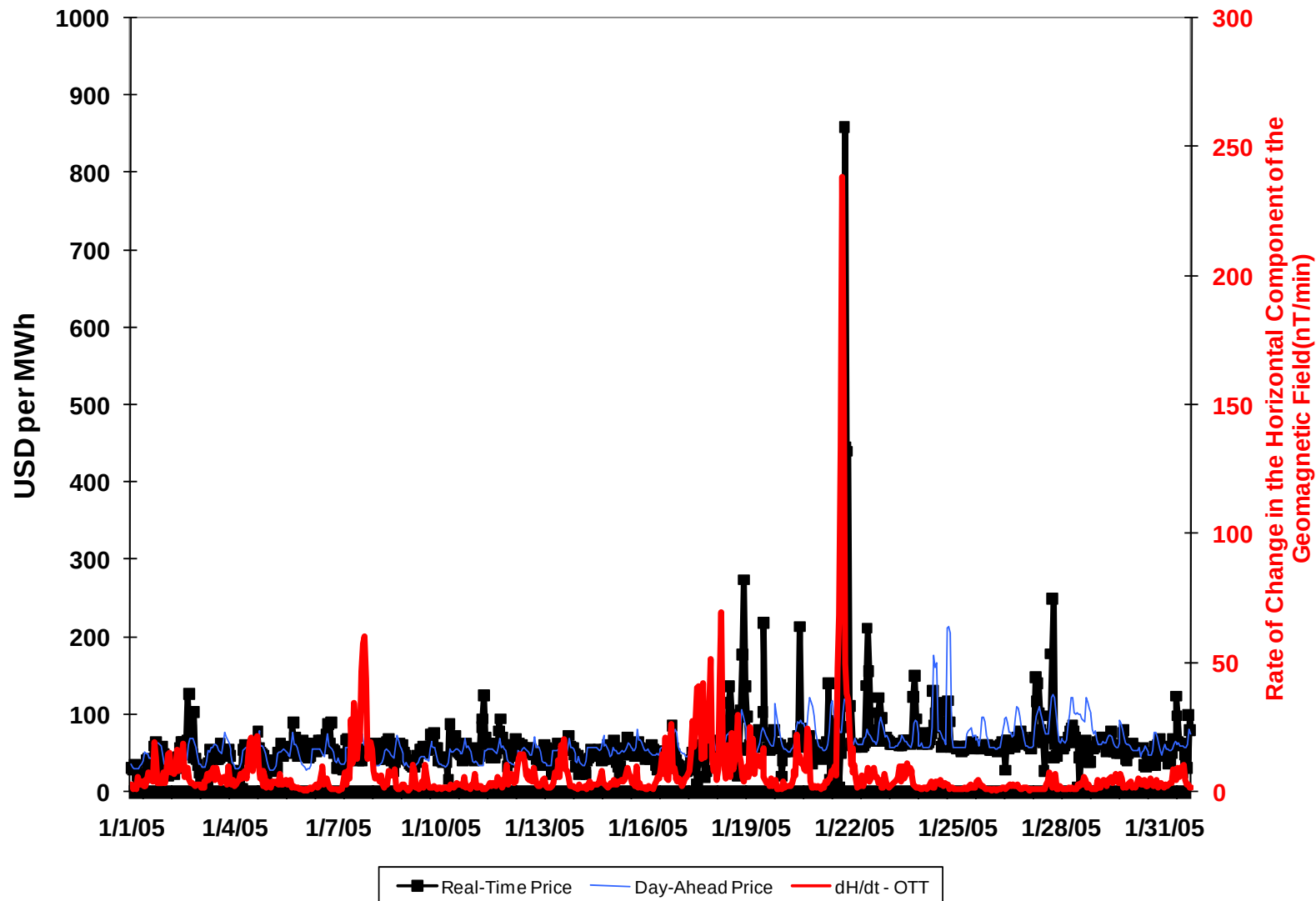
- GICs have been found to be statistically related with various measures of real-time operations in 12 power grids including PJM, NYISO, New England, England and Wales, New Zealand, Australia, Ireland, and the Netherlands.
- Many individuals openly scoff at these findings

Yet, the relationship is fairly robust:

The Day-Ahead and Real-Time Reference Price in the New York ISO, January 1-31 2005



The Rate of Change in the Geomagnetic Field and the Real-Time Reference Price in the New York ISO, January 1-31 2005



The Model and Sample Period

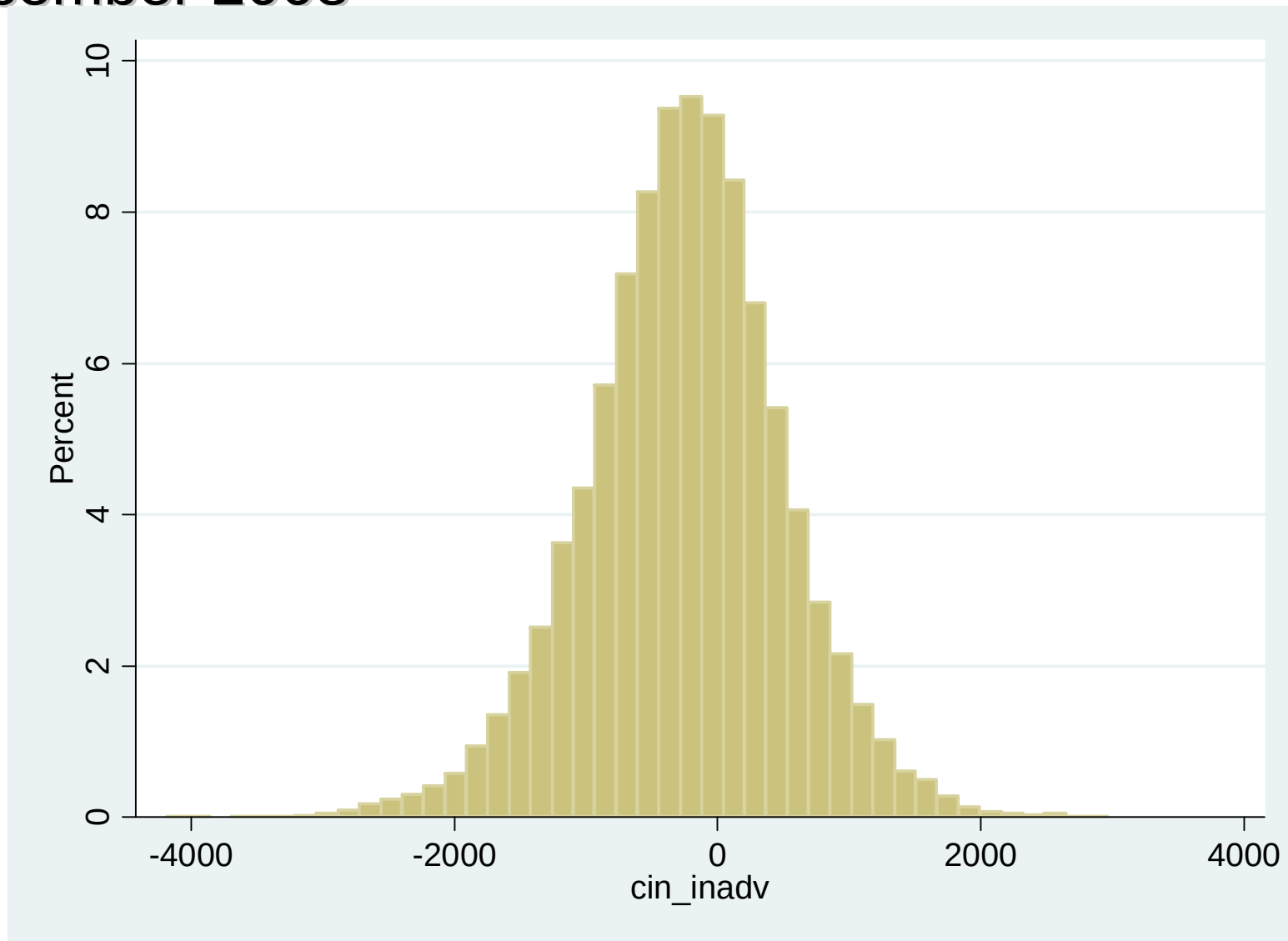
The model was estimated for five interfaces over the period 1 June 2007 – 31 December 2008 using hourly data. There are 12,956 observations

The model includes 113 explanatory variables

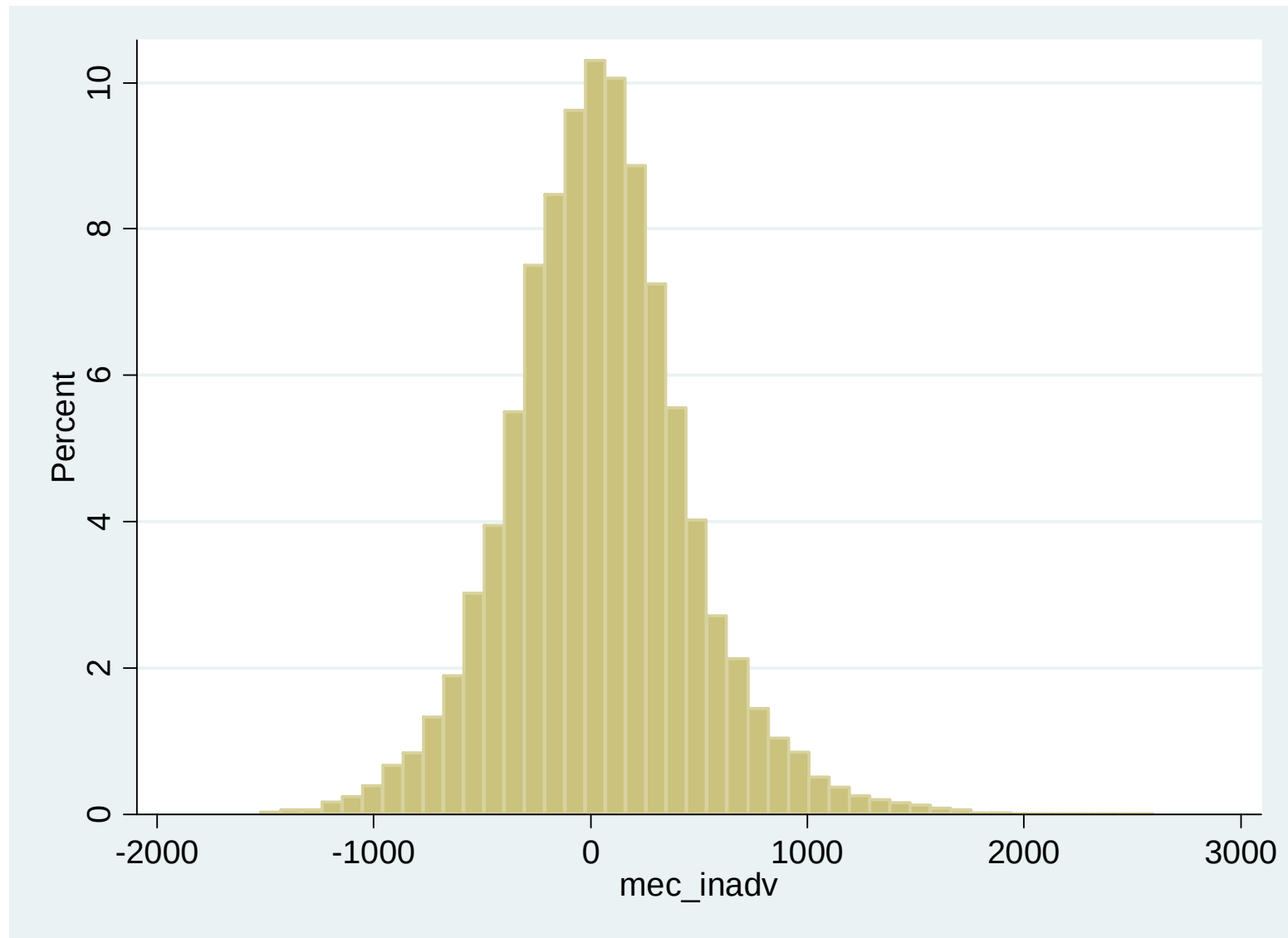
The Modeled Interfaces

- Cinergy (CIN)
- MidAmerican Energy (MEC)
- Michigan Electric Coordinated System(MECS)
- New York(NY)
- Tennessee Valley Authority (TVA)

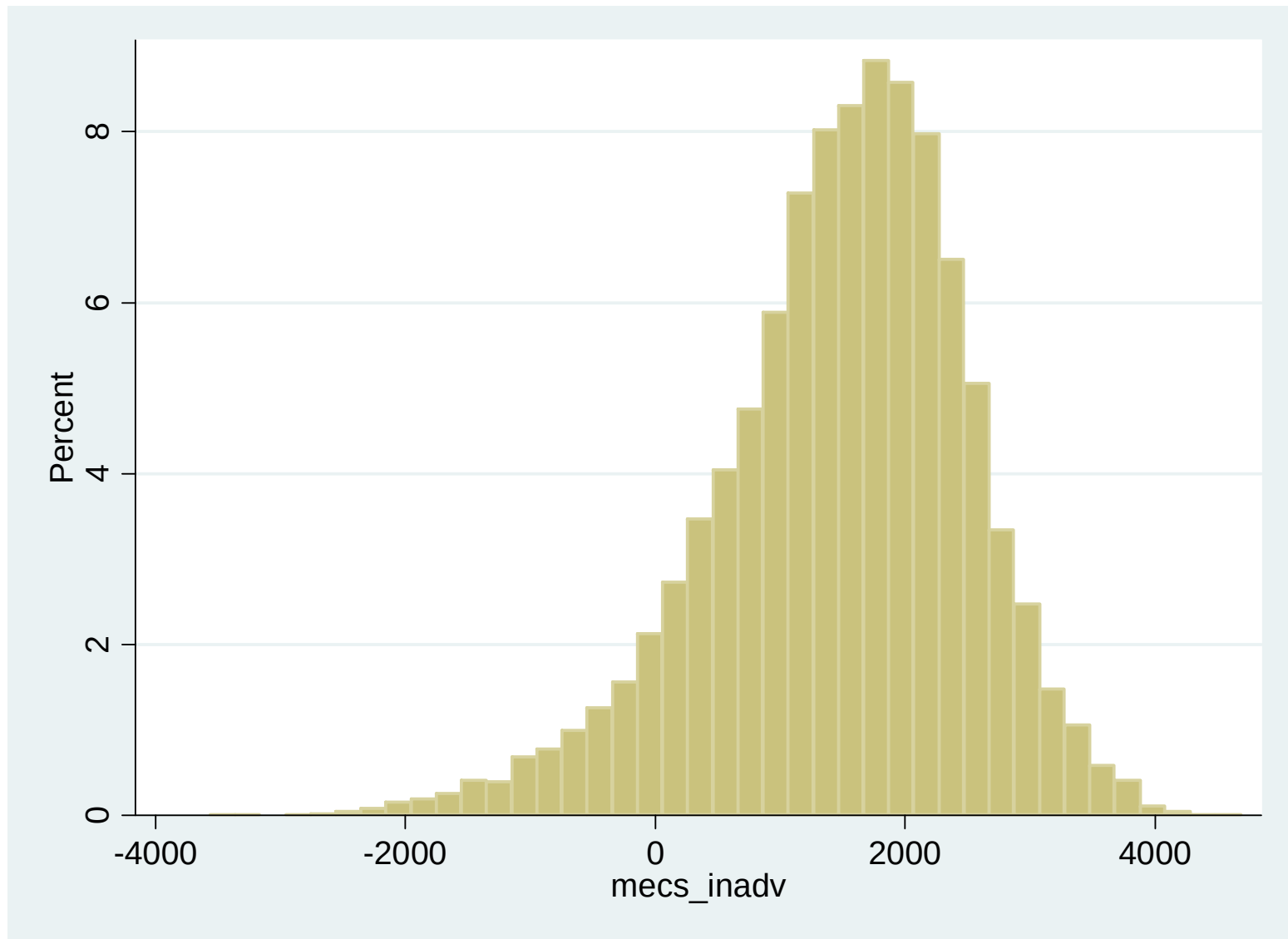
A Histogram of the Inadvertent Electricity Flow Between PJM and Cinergy, 1 June 2007 – 31 December 2008



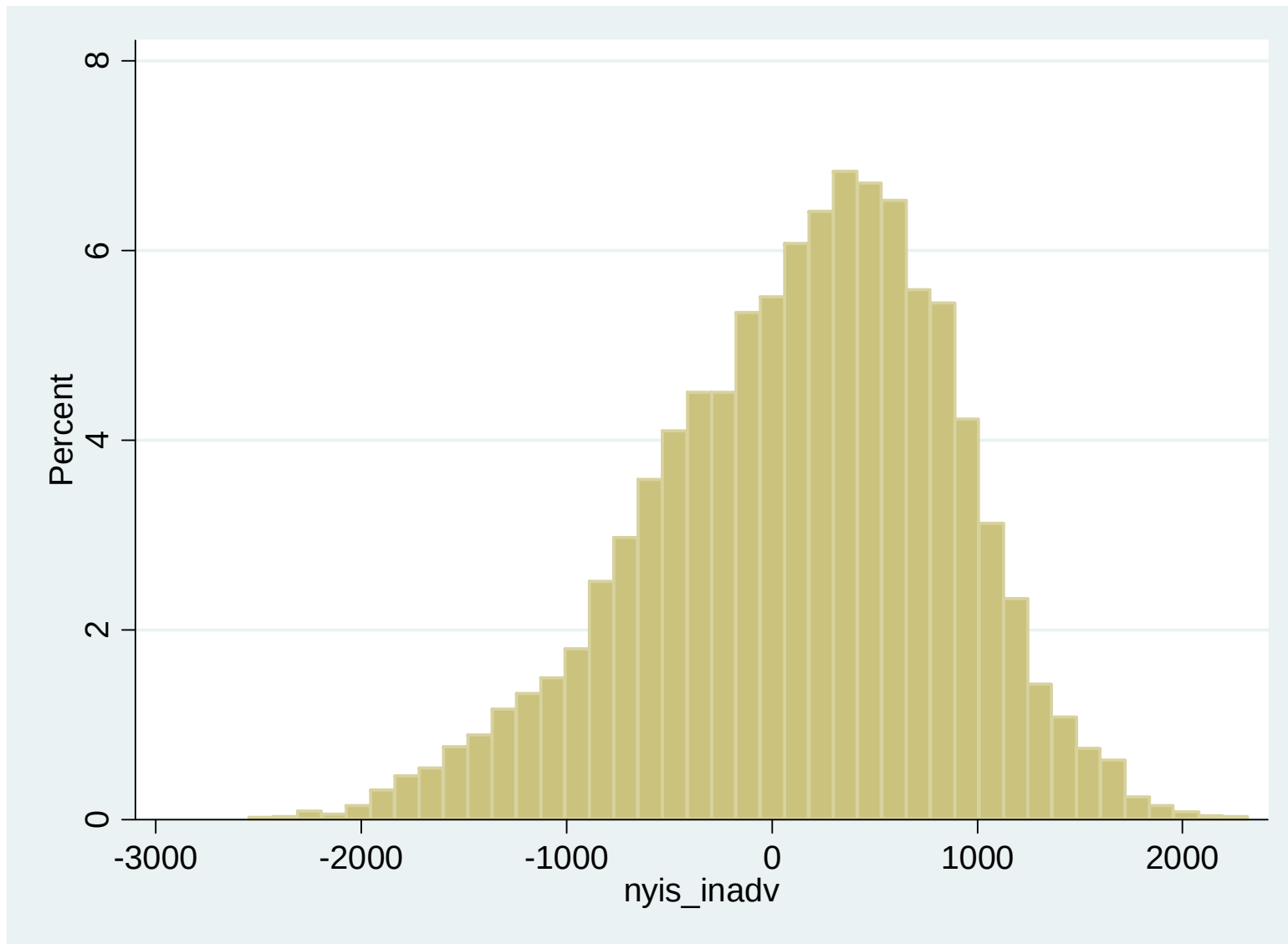
A Histogram of the Inadvertent Electricity Flow Between PJM and MidAmerican(MEC), 1 June 2007 – 31 December 2008



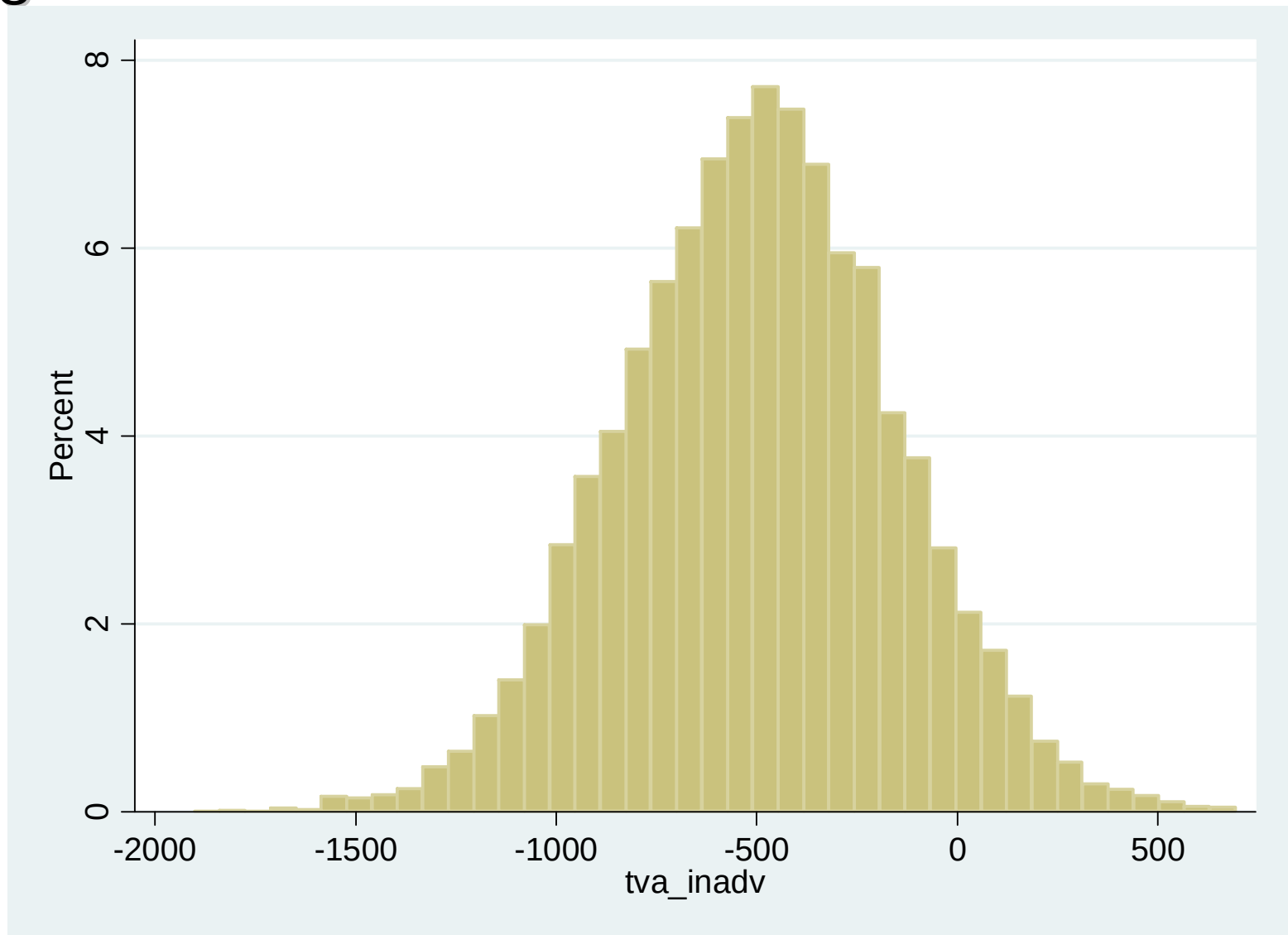
A Histogram of the Inadvertent Electricity Flow Between PJM and Michigan Electric Coordinated System, 1 June 2007 – 31 December 2008



A Histogram of the Inadvertent Electricity Flow Between PJM and the New York ISO, 1 June 2007 – 31 December 2008



A Histogram of the Inadvertent Electricity Flow Between PJM and TVA, 1 June 2007 – 31 December 2008



Results

- The multivariate analysis indicated that electricity flows are statistically related with a proxy for geomagnetically induced currents.
- There is strong evidence of “network effects” in the sense that actual flows are related with its scheduled flows to other interfaces
- A number of the proxies for the day-ahead expected conductivity of the grid are highly statistically significant.
- Not surprisingly, temperature also affects the flows

PJM's Actual Flows with Cinergy
are highly statistically related
with

- PJM scheduled flows with Carolina Power and Light (both East and West), City Water Light and Power, East Kentucky Power Cooperative, and Alliant Energy East
- Day-ahead congestion costs with MISO
- Day-Ahead losses for the PJM system as a whole, losses at the FE interchange, the Chicago Hub and the AFP Dayton Hub

PJM's Actual Flows with MidAmerican Energy are highly sensitive to

- PJM's scheduled flows with Carolina Power and Light West, Ameren (Illinois), East Kentucky Power Cooperative, First Energy, and TVA
- Day-Ahead Congestion Costs with Ohio Valley Electric Corporation.
- PJM's System wide Day-Ahead Losses losses at the Chicago Hub, and Losses at the MISO Interface.

PJM's Actual Flows with Michigan Electric Coordinated System are highly sensitive to

- PJM's scheduled flows with East Kentucky Power Cooperative, First Energy, MidAmerican Energy, Carolina Power and Light West, City Water Light and Power,
- Congestion Costs at AEP Dayton
- Day-Ahead Losses at the Chicago and Ohio Hubs, and the MISO, First Energy and Northern Indiana

PJM's Actual Flows with New York are highly sensitive to

- PJM's scheduled flows with Carolina Power and Light West, First Energy, Indianapolis Power and Light, East Kentucky Power Cooperative, Cinergy, Ameren, Michigan Electric Coordinated System , Northern Indiana Public Service
- Day-Ahead congestion costs at the AEP Hub and First Energy and Ontario Interfaces
- Day-Ahead Losses at the New York and MISO interfaces and the Chicago Hub

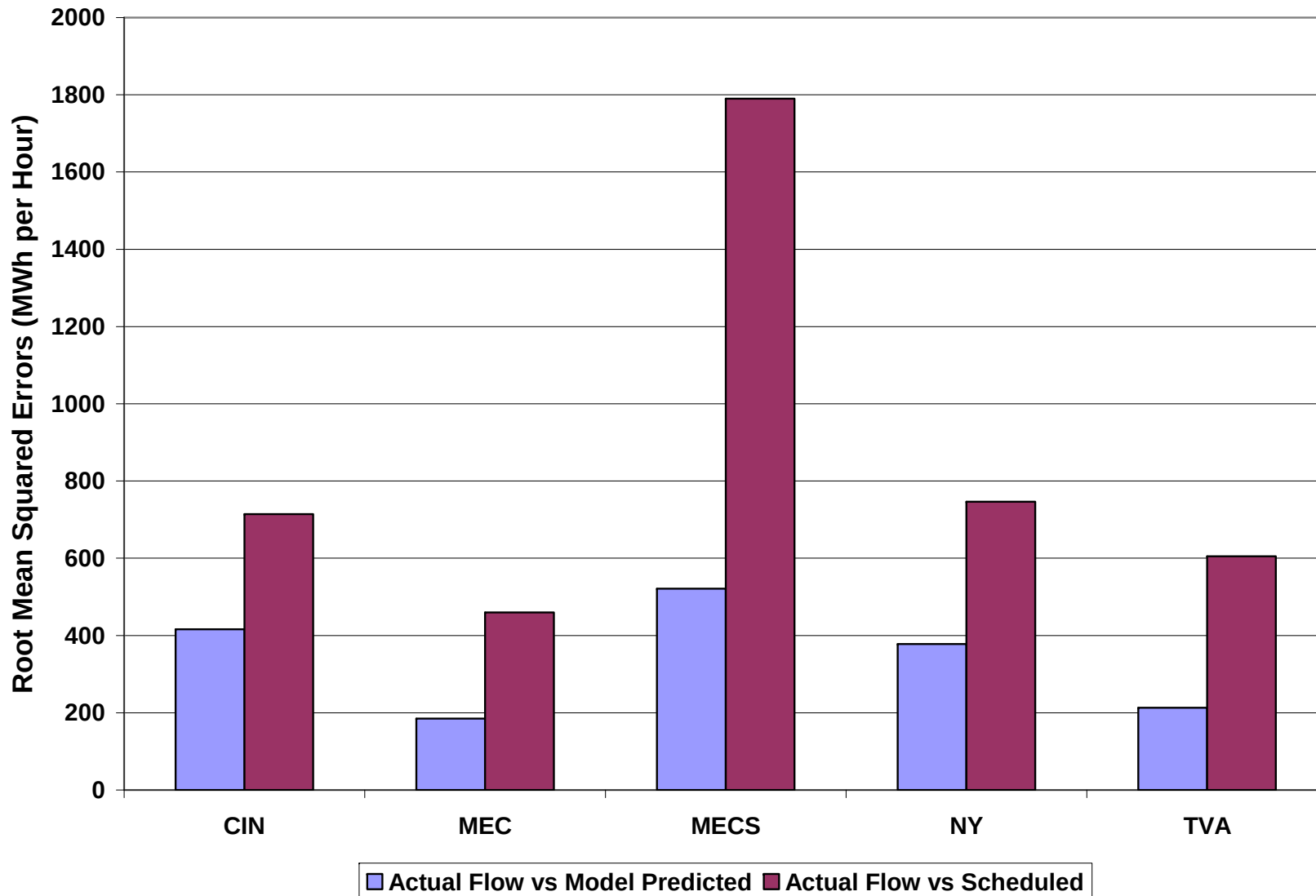
PJM's Actual Flows with TVA are highly sensitive to

- PJM's scheduled flows with Carolina Power and Light West, City Water Light and Power, East Kentucky Power Cooperative , MidAmerican Energy
- Day-Ahead congestion costs at the Chicago and AEP Hubs
- Day-Ahead system wide losses, Losses at the Chicago Hub, losses at the interface with Northern Indiana Public Service

Unexpected Flows

- For each modeled interface, the predicted electricity flow was calculated for each hour of the sample
- The predicted value was compared to the actual flow and the root-mean-squared-error was calculated.
- This error was compared to the error one obtains when comparing the actual vs. scheduled flow

The Root-Mean-Squares of the Unexpected Flows



Next Steps

- Refine the model to account for nonlinearities
- Incorporate additional measures of conductivity into the model(e.g. MISO's day-ahead measures of losses and congestion)
- Incorporate PJM's measures of ground currents into the model
- Perform “out of sample” testing of the model's forecasting performance
- Assess the feasibility of forecasting the GIC proxy and/or PJM's ground currents based on Space Weather Forecasts.