SPACE WEATHER, VOL. 6, S10003, doi:10.1029/2007SW000350, 2008

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Solar activity and economic fundamentals: Evidence from 12 geographically disparate power grids

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Received 24 July 2007; revised 28 May 2008; accepted 9 July 2008; published 25 October 2008.

[1] This study uses local (ground-based) magnetometer data as a proxy for geomagnetically induced currents (GICs) to address whether there is a space weather/electricity market relationship in 12 geographically disparate power grids: Eirgrid, the power grid that serves the Republic of Ireland; Scottish and Southern Electricity, the power grid that served northern Scotland until April 2005; Scottish Power, the power grid that served southern Scotland until April 2005; the power grid that serves the Czech Republic; E.ON Netz, the transmission system operator in central Germany; the power grid in England and Wales; the power grid in New Zealand; the power grid that serves the vast proportion of the population in Australia; ISO New England, the power grid that serves New England; PJM, a power grid that over the sample period served all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia; NYISO, the power grid that serves New York State; and the power grid in the Netherlands. This study tests the hypothesis that GIC levels (proxied by the time variation of local magnetic field measurements (dH/dt)) and electricity grid conditions are related using Pearson's chi-squared statistic. The metrics of power grid conditions include measures of electricity market imbalances, energy losses, congestion costs, and actions by system operators to restore grid stability. The results of the analysis indicate that real-time market conditions in these power grids are statistically related with the GIC proxy.

Citation: Forbes, K. F., and O. C. St. Cyr (2008), Solar activity and economic fundamentals: Evidence from 12 geographically disparate power grids, *Space Weather*, *6*, S10003, doi:10.1029/2007SW000350.

1. Introduction

[2] At one time some economists actually believed that the sunspot cycle and the business cycle were related. This theory was first advanced by William Stanley Jevons, one of the most prominent economists of the 19th century. Jevons was the codeveloper of the neoclassical theory of consumer behavior theory which literally transformed microeconomic theory by giving rise to such fundamental economics concepts such as marginal utility, marginal cost, and consumer surplus. *Jevons*'s [1866] book analyzed the possible consequences of energy resource depletion, arguably making him the first energy economist.

[3] Economic theory in the 19th century was unable to explain macroeconomic fluctuations. Jevons attempted to remedy this deficiency by attributing them to the sunspot cycle. He reasoned that changes in sunspot activity affected crop output and prices that in turn affected overall economic activity. The theory was considered plausible as late as the 1930s when *Garcia-Mata and Shaffner* [1934] reported a coefficient of correlation of −0.886 between monthly measures of solar radiation and stock prices in New York. This result, which almost all economists today would view as spurious, can largely be attributed to the fact that their sample consisted of 12 observations for the year 1929 and that the October 1929 stock market crash coincided with an increase in solar radiation during that particular month.

[4] Unfortunately for Jevons' reputation, the evidence to support his theory was ultimately shown to be weak at best and the theory was eventually discredited, so much so that in a spoof on Jevons', the term "sunspot variable" in economics refers to a variable that has no effect on economic fundamentals [*Shell and Smith*, 1992].

[5] The sunspot cycle had been discovered in 1843 by the German amateur astronomer Schwabe; hence it was rather new and in vogue when Jevons presented his business cycle theory in 1875. During this same period,

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researchers realized that disturbances in Earth's magnetic field (called "geomagnetic storms") could be statistically linked to this new sunspot cycle.

[6] Similar to economists' dismissal of "sunspots" as a driver of economic activity, physical scientists now understand that the sunspot cycle is neither a reliable quantitative measure, nor is it the physical driver of solar activity that impacts earth. While sunspots remain the best known public manifestation of our magnetically variable star, it is now recognized that they are little more than an indicator of solar conditions.

[7] Technologists now recognize a multitude of societal impacts caused by solar variability. In contrast to Jevons who sought to explain the variability of the economy over the time span of years, the timescale of many space weather affects ranges from minutes to hours. Foremost among the affected systems is the power grid, where electricity transmission and the operation of transformers can be severely impeded by geomagnetic storms. The starting point of this paper is the documented evidence that geomagnetic storms can impair the performance of electricity grids [*Boteler*, 1994, 2003; *Girgis and Ko*, 1992; *Lanzerotti*, 1979, 1983; *Kappenman*, 2003; *Molinski*, 2002; *Pirjola*, 1983, 2007]. Of course, the Sun is the source of all major geomagnetic storms, by transmitting energy through its extended atmosphere (the corona and the solar wind) into Earth's magnetosphere. The primary solar source of recurrent geomagnetic disturbances are unipolar magnetic regions at the Sun called "coronal holes," which can blast Earth with high speed solar wind every 27 d as the Sun rotates. Most major geomagnetic storms are caused by sporadic "coronal mass ejections" at the Sun, where large eruptions of plasma and magnetic fields are propelled into the inner heliosphere.

[8] Very large geomagnetically induced currents (GICs) can disrupt grid performance to the point of system collapse. For example, during the very large geomagnetic storm of 13 March 1989, GICs contributed to a transformer failure on one of the main power transmission lines in the Hydro Quebec system which in turn led to the collapse of the entire power grid. Six million people lost power for 9 or more hours [*Kappenman and Albertson*, 1990; *Czech et al.*, 1992]. *Erinmez et al.* [2002] have indicated that the March 1989 geomagnetic storm was one of several storms that have disturbed the power grid in England and Wales. More recently, *Pulkkinen et al.* [2005] have observed that the "Halloween" storms in late October 2003 led to significant operational problems for the Swedish power grid.

[9] *Forbes and St. Cyr* [2004] have reported evidence that the market price on the PJM power grid located in the mid-Atlantic region of the United States was affected by space weather events over the period June 2000 through December 2001. Econometric evidence was presented that space weather, as measured by Dst, a global measure of geomagnetic activity, resulted in a real time price that was approximately one dollar per MWh higher than what would be expected in the absence of space weather. Econometric evidence was also presented that space weather increases the geographical dispersion in PJM's zonal prices. But the analysis was largely silent on the etiology of the relationship between space weather and the electricity market. This has led some to wonder whether their results are analogous to Jevons' sunspots. For example, John Kappenman, a noted expert in the engineering aspects of space weather as it relates to power grids, who has also long emphasized the vulnerability of power grids to space weather, has sharply questioned the notion that electricity markets are affected by space weather events [*Kappenman*, 2006]. *Forbes and St. Cyr* [2006] provided a response to each point raised by *Kappenman* [2006], but the exchange has resulted in skepticism by some parties as to whether the impact of space weather on wholesale electricity prices has been econometrically demonstrated.

[10] In the study reported in this manuscript we address that skepticism by presenting multiple instances of space weather affects on electricity market outcomes in geographically disparate grids, over varying lengths of time. We have used local (ground-based) magnetometer data as a GIC proxy to address whether there is space weather/electricity market relationship in 12 power grids: Eirgrid, the power grid that serves the Republic of Ireland; Scottish and Southern Electricity, the power grid that served northern Scotland until April 2005; Scottish Power, the power grid that served southern Scotland until April 2005; the power grid that serves the Czech Republic; E.ON Netz, the transmission system operator in central Germany; the power grid in England and Wales; the power grid in New Zealand; the power grid that serves the vast proportion of the population in Australia; ISO New England, the power pool that serves New England; PJM, a power grid that over the sample period served all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia; NYISO, the power grid that serves New York State; and the power grid in the Netherlands. These power grids were chosen for analysis on the basis of data availability and geography.

[11] This study tests the hypothesis that GIC levels (proxied by the time variation of local magnetic field measurements (dH/dt)) and various measures of electricity grid conditions are related using Pearson's chi-squared statistic. The power grid metrics include measures of electricity market imbalances, energy losses, congestion costs, and responses of system operators to network instability. Where available, we have included real-time price information in the analysis. However, even for those cases where pricing data were either not available or of limited value because of market intervention by regulators it seems self-evident that the disruptions to the various power grids would have a market impact in a well functioning market where prices reflect actual operating conditions.

2. Solar Activity and Power Grids

[12] Solar activity such as coronal mass ejections (huge clouds of plasma gas ejected by the Sun) can lead to severe

geomagnetic storms that can cripple power grids [e.g., *Kappenman and Albertson*, 1990; *Kappenman*, 1996, 2001, 2003, 2004; *Lanzerotti*, 1979; *Pirjola*, 1983, 2007; *Boteler*, 1994, *Boteler et al.*, 1998]. These space weather storms can adversely effect the performance of power grids because transformers are vulnerable to GICs. One cause of this vulnerability stems from the fact that power grids are almost exclusively alternating current systems while GICs are quasi direct currents. In the words of *Kappenman* [2001],

> GICs are produced when shocks resulting from sudden and severe magnetic storms subject portions of the Earth's surface to fluctuations in the planet's normally quiescent magnetic field. These fluctuations induce electric fields across the Earth's surface – which causes GICs to flow through transformers, power system lines, and grounding points. Only a few amperes (amps) are needed to disrupt transformer operation . . . (p. 336)

[13] There is also evidence of an increase in reactive power consumption when GICs pass through a transformer [*Kappenman*, 2003, p. 4]. This form of power is critical to the delivery of real power. Specifically, excessive reactive power consumption has the potential to lead to voltage collapse [*Sauer*, 2003, p 3]. Citing *Kappenman* [2003],

> Though these quasi-DC currents are small compared to the normal AC current flows in the network, they have very large impacts upon the operation of transformers in the network. . ..The principal concern to network reliability is due to increased reactive power demands from transformers that can cause voltage regulation problems, a situation that can rapidly escalate into a grid-wide voltage collapse. (p. 4)

Other researchers have also noted the impact of GICs on reactive power demands. For example, *Molinski* [2002, p. 1770] has noted that there is evidence of a linear relationship between GICs levels and the reactive power consumption by high-voltage transformers.

[14] On the basis of findings of the above research, we expect to find evidence that energy losses and transmission congestion are higher during periods of moderate to high geomagnetic activity. Specifically, following from *Forbes and St. Cyr* [2004], we expect to observe a positive relationship between GICs and the geographic dispersion in real-time prices for those power grids that use real-time locational marginal pricing to reflect transmission constraints and energy losses. For those power grids that do not employ real-time locational pricing but instead balance electricity supply and demand using a balancing market, we expect to generally observe that negative market imbalances are more prevalent during periods of high geomagnetic activity. For these same markets, we also expect to generally observe a positive relationship between GICs and both the quantity and price of power that is dispatched to relieve market shortages. One possible exception might be when a grid is a net exporter and GIC induced transmission constraints lead to a curtailment in exports to other grids, thereby leaving the grid with an excess supply of power. Because GICs can degrade the performance of a transmission system, we expect to find evidence of a relationship between GICs and inadvertent interchange between grids, inadvertent interchange being electricity flows that are neither desired nor planned by system operators. Finally, following from above noted findings concerning GICs and network reliability, we expect to observe that actions undertaken by system operators to stabilize the grid are more frequent during periods of high geomagnetic activity.

3. Measuring Geomagnetic Induced Currents

[15] Ideally, a study that examines the market impact of geomagnetic storms would measure geomagnetic activity using data on GICs gathered within the power grid in question. Unfortunately, we do not have access to such direct data for all the power grids in this study. Instead, this study proxies GIC levels using data that represent fluctuations in the geomagnetic field. The field is actually a vector that can be represented in terms of a vertical component (Z), and a horizontal component (H), or as a north component (X), an east component (Y), and a total intensity component F. From the Pythagorean Theorem, the X, Y, and H components are interrelated in the following way [*Backus et al.*, 2005, p. 23]:

$$X^2 + Y^2 = H^2. \tag{1}$$

[16] Previous literature has indicated that GIC levels in power grids are closely related to dH/dt, the time derivative of the horizontal component of the magnetic field [*Bolduc et al.*, 1998; *Coles et al.*, 1992; *Mäkinen*, 1993; *Viljanen*, 1998, *Viljanen et al.*, 2001]. Accordingly, GICs in this study are proxied by dH/dt, the rate of change in the horizontal component of the geomagnetic field.

[17] The data were obtained from Intermagnet, the global network of geomagnetic observatories (http://www.intermagnet.org). In most cases, the definitive geomagnetic data were obtained from a geomagnetic observatory which is located within or relatively near to each power grid's control area. The two exceptions are New England and New York power grids where the analysis made use of geomagnetic data from an observatory that is several hundred kilometers from the boundaries of each of the two control areas.

[18] The observatories whose data are employed are reported in Table 1. In most cases, data on H was not directly reported. In these cases, the one minute values of the horizontal component were first calculated on the basis of the geomagnetic data that were reported using equation (1). The rate of change in the horizontal component was then calculated for each electricity market period as the largest change (in absolute value) in the one minute values of H.

[19] Before proceeding, it should be noted that geomagnetic storms are global in scope. Indicative of this, an analysis of data supplied by the ten stations whose data are employed in this study reveals that the hourly dH/dt measurements in 2003, a year of well documented geo-

Table 1. Geomagnetic Observatories Whose Data are Used in this Study

Name of Observatory	Location	Power Grid(s)
Budkov (BDV)	Czech Republic	Czech Republic
Canberra (CNB)	Australia	Australian National Electricity Market
Eskdalemuir (ESK)	Scotland	Scottish Power, Scottish and Southern Electricity
Eyrewell (EYR)	New Zealand	New Zealand
Fredericksburg (FRD)	Virginia, United States	PJM
Doubes (DOU)	Belgium	Netherlands
Hartland (HAD)	United Kingdom	England and Wales
Niemegk (NGK)	Germany	E.ON Netz
Ottawa (OTT)	Ottawa, Canada	New York, New England
Valential (VAL)	Ireland	Ireland

magnetic activity, have a correlation of 0.578 or higher (Table 2). Indicative of the global nature of geomagnetic storms, all of the peak values were over the Halloween period 29–31 October 2003. Consistent with the view that there are significant differences in the intensity of storms within the midlatitudes, the 2003 peak values range from 90 nT/min to 758 nT/min.

4. Research Method

[20] Our method has been to test the null hypothesis that power grid operating conditions are statistically independent from GIC levels. The study makes use of Pearson's chi-square test. One advantage of this test is that it makes no assumption about the underlying distributions of the two variables. Moreover, in contrast to simple correlation analysis, it does not presume that the relationship between the two variables, if it exists, is linear. This may be an important consideration given our suspicion that the impact of GICs might be subject to a threshold, i.e., the minimum GIC value for which there is an impact may be greater than zero. There are two obvious disadvantages to this approach. First, because the method is nonparametric, it does not yield an estimated parameter that quantifies the relationship. Second, the method does not control for terrestrial factors that also may affect the power grid metric under consideration. One approach to eliminate this latter effect is to examine data from geographically disparate grids, which will not all be affected at the same time by terrestrial factors.

[21] One can use the chi-square methodology to test for statistical independence by first establishing mutually exclusive categories that represent all possible values of the two variables. One then constructs a cross tabulation between the two variables and reports on the observed frequency in each cell. This observed frequency is then compared to the frequency that would be expected if the two variables were statistically independent. The chi–square statistic is then calculated on the basis of the differences in the observed and expected frequencies. The test statistic is calculated as follows:

$$\chi = \sum_{i=1}^{R} \sum_{j=1}^{C} \frac{\left(f_{i,j}^{o} - f_{i,j}^{e}\right)^2}{f_{i,j}^{e}}, \tag{2}$$

where $f_{i,j}^{o}$ represents the observed frequency, $f_{i,j}^{e}$ represents the expected frequency under the assumption that the null hypothesis is true, R is the number of row categories, and C is the number of column categories.

[22] High values of the statistic cast doubt on the null hypothesis of statistical independence. If the calculated statistic exceeds a critical value, the null hypothesis of statistical independence is rejected. The critical value is based in part on the researcher's willingness to risk incorrectly rejecting the null hypothesis. The more or less accepted standard is that the critical value should be based on a probability of 5%, i.e., that the probability of rejecting the null hypothesis should be 5% or less under the assumption that the null hypothesis is true. In this analysis, the critical values of the chi-square statistic are based on a 1% probability, which is a more stringent criterion. The logic and details of this methodology is presented in

Table 2. The 2003 Peak Values and Correlations of Hourly dH/dt Measurements for 10 Geomagnetic Observatories[a]

	Peak Values of dH/dt	BDV	CNB	DOU	ESK	EYR	FRD	HAD	OTT	NGK	VAL
BDV	90	1.000	–	–	–	–	–	–	–	–	–
CNB	151.1	0.738	1.000	–	–	–	–	–	–	–	–
DOU	199.5	0.858	0.651	1.000	–	–	–	–	–	–	–
ESK	627.7	0.774	0.666	0.832	1.000	–	–	–	–	–	–
EYR	170.6	0.674	0.908	0.583	0.657	1.000	–	–	–	–	–
FRD	178.4	0.738	0.697	0.741	0.753	0.711	1.000	–	–	–	–
HAD	289	0.818	0.632	0.911	0.893	0.578	0.730	1.000	–	–	–
OTT	758	0.667	0.657	0.699	0.697	0.645	0.791	0.661	1.000	–	–
NGK	265.2	0.858	0.680	0.882	0.892	0.641	0.708	0.937	0.665	1.000	–
VAL	251	0.723	0.576	0.825	0.864	0.559	0.694	0.929	0.637	0.864	1.000

[a]The estimated correlation coefficients are based on a common sample of 8250 hourly observations.

Table 3. Descriptive Statistics for Spill Volumes, Top Up Volumes, and *dH*/*dt*

	Spill Volume (MWh)	Top Up Volume (MWh)	GIC Proxy (nT/min)
25th percentile	2.7	2.7	0.6
Median	23.9	16.7	1.0
75th percentile	62.4	111.0	1.8

more detail by *Sheskin* [2007, pp. 619–627]. Readers may also wish to consult *Press et al.* [2007].

5. Application of the Chi-Square Methodology to GICs and Real Time Metrics of Power Grid Conditions

[23] To avoid the results subsequently being judged spurious, an examination of the GIC/power grid relationship would ideally analyze an identical set of metrics across disparate power grids over the entire solar cycle if not longer. Unfortunately, these ideals cannot be realized because of the variety of operational methods and market designs employed across grids as well as the fact that some power grids/electricity markets have only recently begun to report the required data. In some markets, the price of electricity is determined on the basis of location and real-time operating conditions. An obvious metric in these cases are the differences in the locational real-time prices. In other markets, the spot price of electricity is established in a day ahead market or the price is proprietary because the trading arrangements are strictly bilateral between electricity providers and distributors. In these cases, other metrics have been identified and used in our study.

5.1. Power Grid in the Republic of Ireland

[24] Ireland's electricity market provides for bilateral transactions and thus we will consider a nonprice metric of power grid performance. Electricity flows are scheduled with the system operator, Eirgrid (http://www.eirgrid.com), one day prior to operations. Given that these schedules are based on demand forecasts, imbalances are a normal occurrence although the magnitudes of the imbalances can vary substantially. Two types of imbalances are reported. The first is the "top up" volume which represents the underdelivery of power, i.e., a negative market imbalance. The second is the "spill" volume which represents the overdelivery of power, i.e., a positive market imbalance. These imbalances are not mutually exclusive, both imbalances are reported for each market period. Table 3 reports the descriptive statistics for these imbalances. The prices of these imbalances are established by the regulator [*IPA Energy Consulting*, 2006, p. 21] and thus are less than ideal metrics of power grid operations.

[25] To test whether the market imbalances and GICs are statistically independent, data were collected for each 30 min market period over the period 1 January 2002 through 31 December 2005. The electricity market data were obtained from the system operator. There were 70,080 valid observations. To facilitate the presentation of the results, four categories were constructed for each imbalance variable. Specifically, we denote a category for each quartile of the absolute value of the total top off volume (the reported values are negative and thus we take the absolute value of the variable to simplify the subsequent discussion) for each market period: Topup1, Topup2, Topup3, and Topup4 where Topup1 represents the first quartile (all values less than or equal to the 25th percentile), Topup2 represents the second quartile (all values greater than the 25th percentile and less than or equal to the 50th percentile), Topup3 represents the third quartile (all values greater than the 50th percentile and less than or equal to the 75th percentile), and Topup4 represents the fourth quartile (all values greater than the 75th percentile). With minor exceptions, this naming convention applies to all the variables considered in this paper (the exceptions are when more than 25% of the observations representing conditions on the grid have a value of zero). We also constructed a category for each quartile of the reported spill volume: Spill1, Spill2, Spill3, and Spill4. Finally, we created a category for quartile of the GIC proxy: GIC1, GIC2, GIC3, and GIC4.

[26] The observed frequencies for each GIC/top up category are reported in Table 4a. The expected frequencies for each cell were then calculated under the null hypothesis that grid conditions and GIC levels are statistically independent. This is easily done for each cell by multiplying the row total by the corresponding column total and then dividing it by the size of the sample [*Sheskin*, 2007, p. 625]. In this case, the expected frequencies in each cell equal 4380 given that the data are categorized by quartile (70,080/16 = 4380). The ratio of the observed to expected frequencies are reported in Table 4b. Inspection of the Table 4b reveals that a significant number of the reported ratios are different from unity by over 5%. This is not expected under the null hypothesis of no relationship; under the null hypothesis, the reported ratios should be very close to one given the size of the sample. Consistent with the hypothesis that there is a causal relationship between GIC levels and the top up volumes, the reader should observe that the ratio corresponding to both Topup3 and Topup4, the categories corresponding to the largest negative imbalances, generally increase as the GIC category increases. For example, the observed ratio associated with GIC1 $\cap$ Topup4 is about 9% lower than expected while the observed ratio associated with GIC4 $\cap$ Topup4 is about 13% higher than what would be expected under the null hypothesis of statistical independence. It is also worth noting that the ratio corresponding to Topup1, the category representing the smallest negative imbalances, declines as the GIC category increases. In this case, the reported ratio corresponding to GIC1 $\cap$ Topup1 is about 25% higher than expected

Table 4a. Observed Frequencies for the Categories Representing GICs and Top Up Volumes in Eirgrid, 1 January 2002 Through 31 December 2005

	Topup1	Topup2	Topup3	Topup4	Totals
GIC1	5478	4276	3766	4000	17,520
GIC2	4481	4438	4285	4316	17,520
GIC3	4082	4564	4599	4275	17,520
GIC4	3480	4241	4870	4929	17,520
Totals	17,521	17,519	17,520	17,520	70,080

while the ratio associated with GIC4 $\cap$ Topup1 is about 21% lower than what would be expected under the null hypothesis of statistical independence.

[27] The ratio of the observed to expected frequencies for each GIC/spill category are reported in Table 5. Similar to the top up results, there are a number of cases where the reported ratio is different from its expected value of unity by over 5%. Consistent with the hypothesis that there is a causal relationship between GIC levels and the spill volumes, observe that there are more and more observations as compared to expected in the lowest spill category as the GIC category increases. Observe also that there are fewer and fewer observations as compared to expected in the highest spill category as the GIC category increases.

[28] There is also a discernable pattern as one looks across some of the rows of Tables 4b and 5. Specifically, observe that the ratios corresponding to GIC4 increase as the top up category increases (Table 4b). Notice also in Table 5 that the ratios corresponding to GIC4 decline as the spill category increases.

[29] On the basis of the observed and expected top up/GIC frequencies, the calculated chi-square statistic is 757. For the spill volume/GIC frequencies, the calculated statistic is 635. Both of these calculated statistics are many times larger than the critical value of the statistic corresponding to the 1% level of statistical significance when there are nine degrees of freedom. More specifically, the corresponding p values, i.e., the probabilities of obtaining these chi-square values under the assumption that the null hypothesis is true, are 3.331×10^{-157} and 5.719×10^{-131}, respectively. These values are obviously lower than 0.01 and thus one can reject the null hypothesis of statistical independence at the 1% level. Thus, consistent with the GIC/market imbalance hypothesis presented in section 2, one can reject the null hypothesis that GIC levels and market imbalances in Eirgrid are unrelated.

Table 4b. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Top Up Volumes in Eirgrid, 1 January 2002 Through 31 December 2005

	Topup1	Topup2	Topup3	Topup4
GIC1	1.251	0.976	0.860	0.913
GIC2	1.023	1.013	0.978	0.985
GIC3	0.932	1.042	1.050	0.976
GIC4	0.794	0.968	1.112	1.125

Table 5. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Spill Volumes in Eirgrid, 1 January 2002 Through 31 December 2005

	Spill1	Spill2	Spill3	Spill4
GIC1	0.785	1.067	1.095	1.053
GIC2	0.971	0.972	1.012	1.045
GIC3	1.017	0.969	0.983	1.031
GIC4	1.227	0.992	0.910	0.871

[30] An anonymous reviewer has queried whether the finding of a relationship between the GIC proxy and the market imbalances is sensitive to the number of categories we have considered. To address this question, we increased the number of categories for each variable to 10. In this case, the calculated chi-square statistic for the top up/GIC frequencies equals 1260 while the calculated statistic for the spill/GIC frequencies is 1226. The corresponding p values are 5.647×10^{-211} and 7.317×10^{-204}, respectively. Both of these values are many times lower than when the analysis was based on four categories. Accordingly, adding categories strengthens the finding that top up and spill are not independent of the GIC proxy. This is not entirely surprising given that increasing the number of categories reveals differences between the observed and expected frequencies that are suppressed from the calculation of the chi-square statistic when the number of categories is small.

[31] Another anonymous reviewer has asked whether the finding of a relationship between the GIC proxy and the market imbalances is dependent on a single period of intense geomagnetic activity such as October 2003. To address this question, we calculated the chi-square statistics for each year of the sample. The results are reported in Table 6. While the statistics vary widely from year to year (e.g., the chi-square statistic for the top up volumes equals 425 and 34 in 2003 and 2005, respectively), in every case the p values are well below 0.01 and thus the null hypothesis of statistical independence is rejected in each of the 4 years. Accordingly, our finding is not dependent on a single unique time period.

[32] The finding of a statistically significant relationship between the GIC proxy and the electricity market imbalances may have gone undiscovered if the relationship had been presumed to have been linear. Indicative of this, the Pearson correlation coefficient, which measures the linear association between two variables, equals 0.0056 with respect to the GIC proxy and the Eirgrid top up volumes. The associated t statistic is 1.47 which is less than the critical value of the t statistic needed to reject the null hypothesis of no linear correlation between the two variables.

[33] The remainder of this section presents a detailed analysis for the remaining 11 power grids. Readers who

Table 6. Calculated Chi-Square Statistics Between the GIC Proxy and Ireland's Electricity Market Imbalances by Year

		Top Up Volumes		Spill Volumes	
Year	Number of Observations	Chi-Square Statistic	*p* Value	Chi-Square Statistic	*p* Value
2002	17,250	257	3.008E−50	303	6.251E−60
2003	17,250	425	5.909E−86	583	7.947E−120
2004	17,250	149	1.265E−27	198	9.878E−38
2005	17,250	34	1.012E−4	65	1.349E−10
2002−2005	70,080	757	3.331E−157	635	5.719E−131

are uninterested in the specific details may wish to proceed to section 6 of the paper where Table 33 of the findings is presented.

5.2. Power Grids in Scotland

[34] There were two power grids in Scotland prior to their April 2005 integration with the network that serves England and Wales. In the north of Scotland, Scottish and Southern Electricity (SSE) operated the grid. The network in the south of Scotland was operated by Scottish Power (SP). As in Ireland, both system operators reported top up and spill volumes.

[35] To test whether the market imbalances and GICs are statistically independent or not, data were collected for each 30 min market period over the period 1 January 2004 through 31 December 2004. The electricity market data were obtained from British Government's Office of Gas and Electric Markets (http://ofgem2.ulcc.ac.uk/ofgem/index.jsp). There were 17,520 valid observations. For each system operator, four categories were constructed for each imbalance variable. Specifically, we denote a category for each quartile of the top up volume for each market period: Topup1, Topup2, Topup3, and Topup4. We also constructed a category for each quartile of the reported spill volume: Spill1, Spill2, Spill3, and Spill4. Finally, we created a category for each GIC proxy quartile: GIC1, GIC2, GIC3, and GIC4. Table 7 reports the descriptive statistics for the top up volumes, the spill volumes, and the GIC proxy.

[36] The ratio of the observed to expected frequencies for each GIC/top up category are reported in Tables 8 and 9. Inspection of Tables 8 and 9 reveals that a significant number of the reported ratios are different from unity by over 5%. Consistent with the results for Ireland, observe that the ratios for both SP and SSE corresponding to Topup4 increase as the GIC category increases. For example, the observed ratio for SP corresponding with GIC1 $\cap$ Topup4 is about 16% lower than expected while the observed ratio associated with GIC4 $\cap$ Topup4 is about 11% higher than what would be expected under the null hypothesis of statistical independence. Observe also that the ratios for both grids corresponding to Topup1 decline as the GIC category increases. The reported ratio for SP corresponding to GIC1 $\cap$ Topup1 is about 18% higher than expected while the ratio associated with GIC4 $\cap$ Topup1 is about 21% lower than what would be expected under the null hypothesis of statistical independence.

[37] On the basis of the observed and expected top up/GIC frequencies, the calculated chi-square statistics for Scottish Power and Scottish and Southern Energy are 147 and 125, respectively. The corresponding p values are 3.720×10^{-27} and 1.348×10^{-22}. For the spill volume/GIC frequencies (not reported but available upon request), the calculated chi-square statistics are 48 and 77, respectively. The corresponding p values are 2.249×10^{-7} and 7.358×10^{-13}. Accordingly, one can reject the null hypothesis that GIC levels and market imbalances in Scotland were unrelated over the sample period.

[38] We close this section by noting that *Trichtchenko et al.* [2007] have observed a clear relationship between the rate of change in the north component of the geomagnetic field in Scotland (also using data from the Eskdalemuir geomagnetic observatory) and GICs in the Scottish Power grid over a portion of this same sample period. For the sake of brevity we do not present the tabular data, but we have also investigated using both dY/dt and dX/dt as the proxy for GICs. For either component we also reject the null hypothesis at the 1% level that GICs and market imbalances in the Scottish Power grid were unrelated over the sample period.

5.3. Czech Republic

[39] The Electricity Market Operator OTE (http://www.ote-cr.cz/) is charged with maintaining the system balance in the Czech Republic. As with both Ireland and the former grid operators in Scotland, it reports both negative (top up) and positive (spill) imbalances for each market period.

[40] To test whether the market imbalances and GICs are statistically independent or not, data were collected for

Table 7. Descriptive Statistics for Spill Volumes, Top Up Volumes, and dH/dt

	Scottish Power		Scottish and Southern Electricity		
	Spill Volume (MWh)	Top Up Volume (MWh)	Spill Volume (MWh)	Top Up Volume (MWh)	GIC Proxy (nT/min)
25th percentile	5.4	2.5	1.2	0.7	1.0
Median	10.9	6.8	13.5	1.3	1.7
75th percentile	17.7	14.2	25.4	3.8	2.9

Table 8. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Top Up Volumes in the Scottish Power Control Area, 1 January 2004 Through 31 December 2004

	Topup1	Topup2	Topup3	Topup4
GIC1	1.176	1.001	0.980	0.843
GIC2	1.066	0.949	0.995	0.989
GIC3	0.972	0.966	1.005	1.057
GIC4	0.785	1.083	1.020	1.111

each 60 min market period over the period 1 February 2003 through 31 December 2005. The electricity market data were obtained directly from OTE. There were 25,536 valid observations. Four categories were constructed for each imbalance variable. Specifically, we denote a category for each quartile of the absolute value of the top off volume for each market period: Topup1, Topup2, Topup3, and Topup4. We also constructed a category for each quartile of the reported spill volume: Spill1, Spill2, Spill3, and Spill4. OTE also reports the incremental unit cost of balancing that it uses in billing. To assess whether there is a relationship between GICs and these costs we constructed a category for each quartile of the reported balancing costs: BC1, BC2, BC3, and BC4. Finally, we created a category for each GIC proxy quartile: GIC1, GIC2, GIC3, and GIC4. Table 10 reports the descriptive statistics for the top up volumes, the spill volumes, the balancing costs, and the GIC proxy.

[41] The ratio of the observed to expected frequencies for each GIC/top up category are reported in Table 11. Consistent with the results for both Ireland and Scotland, observe that the ratios corresponding to Topup4 increase as the GIC category increases. For example, the observed ratio with GIC1 $\cap$ Topup4 is 15% lower than expected while the observed ratio associated with GIC4 $\cap$ Topup4 is 16% higher than what would be expected under the null hypothesis of statistical independence. Observe also that the ratios corresponding to Topup1 decline as the GIC category increases.

[42] The ratio of the observed to expected frequencies for each GIC/spill category are reported in Table 12. Observe that the ratio corresponding to Spill1 increases as the GIC category increases. For example, the reported ratio corresponding to GIC1 $\cap$ Spill1 is about 11% lower than the expected while the reported ratio associated with GIC4 $\cap$ Spill1 is 11% higher than what would be expected under the null hypothesis of statistical independence. Observe also that the ratio corresponding to Spill4 declines modestly as the GIC category increases.

Table 9. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Top Up Volumes in the Control Area Operated by Scottish and Southern Energy, 1 January 2004 Through 31 December 2004

	Topup1	Topup2	Topup3	Topup4
GIC1	1.144	1.053	0.870	0.933
GIC2	1.031	1.043	0.976	0.950
GIC3	0.958	1.003	1.067	0.973
GIC4	0.867	0.901	1.088	1.144

Table 10. Descriptive Statistics for Spill Volumes, Top Up Volumes, and dH/dt in the Czech Republic, 1 February 2003 Through 31 December 2005[a]

	Spill Volume (MWh)	Top Up Volume (MWh)	Balancing Cost (CZK/MWh)	GIC Proxy (nT/min)
25th percentile	44.4	48.7	0	0.7
Median	82.0	90.9	18.9	1.2
75th percentile	137.4	153.7	77.9	2.0

[a]One Czech koruna (CZK) equals 0.04689 USD as of 11 June 2007.

[43] The ratio of the observed to expected frequencies for each GIC/Balancing Cost category are reported in Table 13. Observe that the ratios corresponding to BC4 increase as the GIC category increases. For example, the observed ratio with GIC1 $\cap$ BC4 is 17% lower than expected while the observed ratio associated with GIC4 $\cap$ BC4 is about 19% higher than what would be expected under the null hypothesis of statistical independence. Observe also that the ratios corresponding to BC1 decline as the GIC category increases.

[44] On the basis of the observed and expected top up/GIC frequencies, the calculated chi-square statistic is 121. For the spill volume/GIC frequencies, the calculated chi-square statistic is 63. For the Balancing Cost/GIC frequencies, the calculated chi-square statistic is 197. The corresponding p values are 7.070×10^{-22}, 4.061×10^{-10}, and 1.130×10^{-37} which are obviously smaller than 0.01. Accordingly, one can reject the null hypotheses that the volumes and costs of electricity market imbalances in the Czech Republic were not related with GICs over the sample period.

5.4. E.ON Transmission System in Germany

[45] E.ON Netz is the transmission system operator for central Germany. Its control area stretches from Scandinavia to the Austrian Alps. With approximately 32,600 km of 380/220/110 kV lines, the company operates one of Germany's longest high-voltage grids. As system operator, E.ON is charged with maintaining a balance between power generation and demand within its control area.

Table 11. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Top Up Volumes in the Czech Republic, 1 February 2003 Through 31 December 2005

	Topup1	Topup2	Topup3	Topup4
GIC1	1.068	1.091	0.993	0.848
GIC2	1.016	1.003	1.012	0.970
GIC3	0.988	0.966	1.025	1.020
GIC4	0.928	0.940	0.970	1.163

Table 12. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Spill Volumes in the Czech Republic, 1 February 2003 Through 31 December 2005

	Spill1	Spill2	Spill3	Spill4
GIC1	0.889	1.058	1.026	1.027
GIC2	0.968	1.030	0.986	1.016
GIC3	1.033	0.979	0.996	0.992
GIC4	1.110	0.932	0.993	0.965

E.ON meets this goal through the deployment of balancing energy using a market that clears every 15 min.

[46] The electricity market data used in this analysis were obtained from http://www.eon-netz.com/EONNET-Z_eng.jsp. The sample period is 1 December 2001 through 31 December 2005. There are 143,063 valid observations.

[47] The descriptive statistics for the balancing deployments, the price of balancing energy, and the GIC proxy are reported in Table 14. Following the approach presented above, we created a category for each quartile of the balancing deployments: Balancing1, Balancing2, Balancing3, and Balancing4. With respect to the price of balancing power, approximately 40% of the observations had a value of zero (this occurs when the dispatch of balancing power is negative but small in absolute value). To reflect these observations, the categorical variable Price0 was created. Categorical variables representing each quartile when the price was positive were also constructed: Price1, Price2, Price3, and Price4. Finally, we created a category for each GIC proxy quartile: GIC1, GIC2, GIC3, and GIC4.

[48] The ratio of the observed to expected frequencies for each GIC/Balance category are reported in Table 15. There are a significant number of cases where the reported ratio is different from its expected value of unity by over 5%. Consistent with the hypothesis that there is a causal relationship between GIC levels and the deployments, observe that the lowest quartile of the deployments (Balancing1) decreases with increasing GIC, whereas the highest quartiles (Balancing3 and Balancing4) increase with increasing GIC values. For example, the reported ratio corresponding to GIC1 $\cap$ Balancing4 is about 12% lower than the expected while the reported ratio associated with GIC4 $\cap$ Balancing4 is about 7% higher than what would be expected under the null hypothesis of statistical independence.

[49] On the basis of the observed and expected frequencies corresponding to Table 15, the calculated chi-square statistic is 632. The corresponding p value is 3.133×10^{-130} which is well below 0.01. Accordingly, one can reject the null hypothesis that GIC levels and conditions on the E.ON transmission system are unrelated.

Table 13. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Balancing Costs in the Czech Republic, 1 February 2003 Through 31 December 2005

	BC1	BC2	BC3	BC4
GIC1	1.110	1.011	1.013	0.830
GIC2	1.058	0.994	1.001	0.924
GIC3	0.975	0.994	0.981	1.057
GIC4	0.857	1.001	1.006	1.189

Table 14. Descriptive Statistics for E.ON Transmission System and the GIC Proxy[a]

	Balancing Energy Deployed (MW)	Price of Balancing Energy (€t/kWh)	GIC Proxy (nT/minute)
25th percentile	−197	0.3	0.7
Median	−72	6.8	1.1
75th percentile	76	8.2	1.9

[a]The percentiles for the price of balancing energy are conditional on the price of balancing power being greater than zero. ∈ct represents Euro cents.

[50] The ratio of the observed to expected frequencies for each GIC/Balancing Price category are reported in Table 16. Consistent with the hypothesis that there is a causal relationship between GIC levels and the price of balancing energy, observe also that there are fewer observations than expected in Price0, the category representing when the price is zero, as geomagnetic conditions become more adverse. Observe also that the ratios corresponding to Price1, Price2, and Price3 increase as the GIC proxy category increases. For example, the reported ratio corresponding to GIC1 $\cap$ Price3 is about 23% lower than expected while the reported ratio associated with GIC4 $\cap$ Price3 is about 23% higher than what would be expected under the null hypothesis of statistical independence. The ratios corresponding to Price4 only partly exhibit this same pattern. One possible reason for this is that the analysis has not controlled for the trend in energy prices over the sample period.

[51] On the basis of the observed and expected frequencies, the calculated chi-square statistic corresponding to Table 16 is 1827. The corresponding p value is less than 2.522×10^{-308} and thus one can reject the null hypothesis that GIC levels and the price of balancing power in the E.ON transmission system are unrelated.

5.5. Power Grid in England and Wales

[52] In 2001 the electricity market institutions in England and Wales were reformed and the New Electricity Trading Arrangements (NETA) were introduced. Under NETA all market participants trade on a bilateral basis.

[53] Under the normal course of events, the system operator, National Grid, balances the system in each

Table 15. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Balancing Deployments in the E.ON Transmission System

	Balancing1	Balancing2	Balancing3	Balancing4
GIC1	1.136	1.050	0.939	0.875
GIC2	1.024	0.997	0.972	1.007
GIC3	0.957	0.978	1.019	1.046
GIC4	0.884	0.975	1.070	1.072

Table 16. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and the Price of Balancing Energy in the E.ON Transmission System

	Price0	Price1	Price2	Price3	Price4
GIC1	1.183	0.863	0.964	0.769	0.931
GIC2	1.006	0.987	0.994	0.973	1.033
GIC3	0.948	1.029	1.011	1.046	1.052
GIC4	0.845	1.133	1.035	1.234	0.994

30 min market period by accepting previously submitted offers by market participants to increase production/decrease consumption and/or bids to decrease production/increase consumption. In general, these balancing actions are nonlocational, and are undertaken to ensure the overall matching of generation with demand. The system operator can supplement these acceptances by initiating the direct dispatch of balancing power outside the "normal" balancing mechanism. The economic metric that will be considered here is one of these actions. Specifically, the metric is the upward deployment of balancing power to ensure stable system operation. The official name of this variable is the "System Buy Volume Adjustment"or (SBVA). *National Grid* [2007] formally defines SBVA as the maximum of zero or the difference between purchases and sales of all services for system balancing.

[54] The sample period for this study is 11 March 2003 through 31 March 2005. The starting date of the sample period represents the first day following a revision in the balancing mechanism. The ending date of the sample period is one day prior to Scotland's inclusion into the trading arrangements. The electricity market data used in this analysis were obtained from http://www.bmreports.com. There were 36,046 valid observations. The descriptive statistics for the GIC proxy and the deployment of the balancing energy to ensure grid stability are reported in Table 17.

[55] Five categorical variables representing the upward deployment of balancing power to ensure grid stability were created. The first variable, SBVA0, represents those instances when the upward deployment of energy to ensure stability was not deployed, i.e., when SBVA was equal to zero. The other four variables, SBVA1, SBVA2, SBVA3, and SBVA4, represent the respective quartiles in which there was an upward deployment of balancing power to ensure stability of the grid. A category for each GIC proxy quartile was also constructed: GIC1, GIC2, GIC3, and GIC4.

Table 17. Descriptive Statistics for the Power Grid that Serves England and Wales and the GIC Proxy, 11 March 2003 Through 31 March 2005[a]

	SBVA (MWh)	GIC Proxy (nT/min)
25th percentile	98	0.8
Median	150	1.4
75th percentile	250	2.5

[a]The reported percentiles for SVBA only reflect the 4159 market periods in which SVBA power was dispatched.

Table 18. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and the Upward Deployment of Balancing Power to Ensure Grid Stability in England and Wales

	SBVA0	SBVA1	SBVA2	SBVA3	SBVA4
GIC1	1.050	0.787	0.664	0.529	0.486
GIC2	1.019	1.035	0.811	0.797	0.782
GIC3	0.992	1.207	0.988	1.163	0.881
GIC4	0.940	0.970	1.537	1.511	1.852

[56] The ratio of the observed to expected frequencies for each GIC/SBVA category are reported in Table 18. There are a nontrivial number of cases where the ratio of observed to expected frequencies are quite different from unity. Consistent with the hypothesis that there is a causal relationship between GIC levels and SBVA, observe that the ratio corresponding to SBVA2, SBVA3, and SBVA4 increases as the GIC category increases. For example, the reported ratio corresponding to GIC1 $\cap$ SBVA4 is about 51% lower than the expected while the reported ratio associated with GIC4 $\cap$ SBVA4 is about 85% higher than what would be expected under the null hypothesis of statistical independence. Table 18 also indicates that the ratio associated with SBVA0, the category representing no deployment, declines as the GIC category increases.

[57] On the basis of the observed and expected frequencies corresponding to Table 18, the calculated chi-square statistic equals 687. The corresponding p value is 1.934×10^{-139}. Given this result, one can reject the null hypothesis at the 1% level of statistical significance that GIC levels and the upward deployment of balancing power to ensure grid stability in England and Wales are unrelated.

5.6. New Zealand Power Grid

[58] Wholesale electricity prices in New Zealand are determined in a real-time market with results being reported every 30 min. Prices in the market are permitted to vary across approximately 250 locations or "nodes" depending on energy losses and transmission constraints. The prices at 11 geographically dispersed nodes serve as reference prices. The price data were collected for the period 1 November 2001 (the first date for which data for all 11 nodes were available) through 31 December 2005. The nodes are as follows: Benmore (BEN), Halfway Bush (HWB), Haywards (HAY) Huntly (HLY) Invercargill (INV), Islington (ISL), Otahuhu (OTA), Stoke (STK), Stratford (SFD), Tuba (TUI), and Whakamaru (WKM). The locations of these nodes are depicted in Figure 1.

[59] The metric of power grid performance that we will consider is the standard deviation in the nodal prices. This metric will be equal to zero in the absence of energy losses and transmission constraints but will be positive and possibly quite large otherwise.

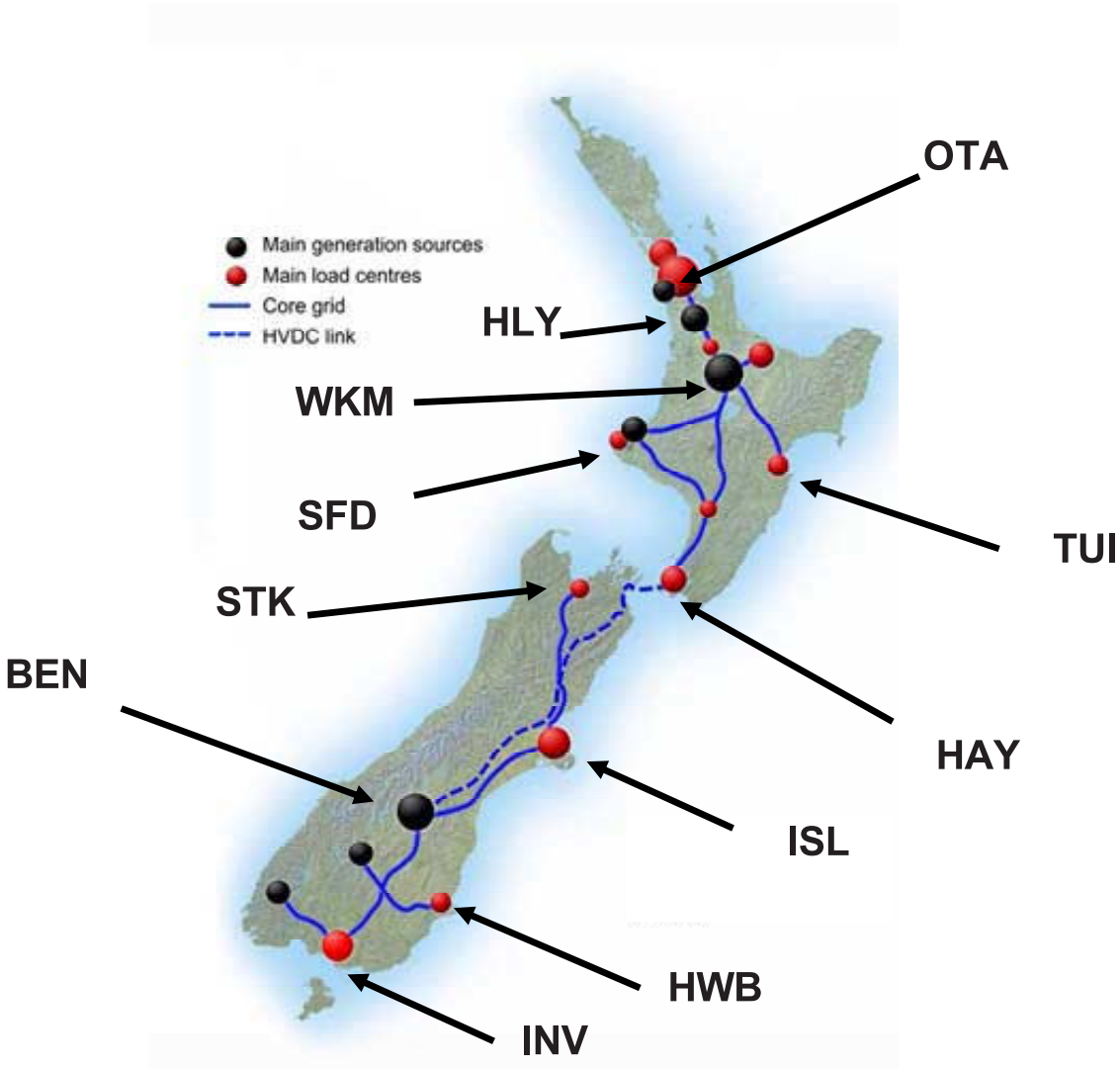

Figure 1. The location of the nodes employed in the GIC/market impact analysis for New Zealand. The nodes are as follows: Benmore (BEN), Halfway Bush (HWB), Haywards (HAY), Huntly (HLY), Invercargill (INV), Islington (ISL), Otahuhu (OTA), Stoke (STK), Stratford (SFD), Tuba (TUI), and Whakamaru (WKM). The HVDC link is the High Voltage Direct Current link. (Map courtesy of Transpower.)

[60] The electricity market data used in this analysis were obtained from http://www.stat.auckland.ac.nz/~geoff/elecprices/index.html. There were 72,926 valid observations. Table 19 reports the descriptive statistics on the standard deviation in the nodal prices, and the GIC proxy. Four categories were constructed for each variable. Specifically, we constructed a category for each quartile of the standard deviation of the nodal prices: $\sigma 1$, $\sigma 2$, $\sigma 3$, and $\sigma 4$. We also constructed a category for each quartile of the GIC proxy: GIC1, GIC2, GIC3, and GIC4.

[61] The ratio of the observed to expected frequencies for each GIC/σ category are reported in Table 20. In contrast to the other power grids that have been presented, there is no monotonic pattern to the ratio as one looks down a particular column. However, consistent with the hypothesis that GIC levels and nodal prices may be related, observe that the ratio of the observed to expected frequencies corresponding to GIC4 increases as the σ category increases. Specifically, the ratio of observed to expected frequencies associated with GIC4 $\cap$ $\sigma 1$ is approximately 20% lower than expected under the null hypothesis. This ratio rises to 15% higher than expected as the σ category increases to $\sigma 4$. The obvious implication of this is that conditional probability of $\sigma 4$ given GIC4 is

Table 19. Descriptive Statistics for the New Zealand Power Grid and the GIC Proxy, 1 November 2001 Through 31 December 2005[a]

	Standard Deviation in Nodal Prices (NZD/MWh)	GIC Proxy (nT/min)
25th percentile	1.79	1.0
Median	2.97	1.4
75 percentile	5.04	2.1

[a]One New Zealand dollar (NZD) equals 0.759 USD as of 23 November 2007.

not equal to the conditional probability of $\sigma 1$ given GIC4. This of course is inconsistent with the two variables being statistically independent.

[62] On the basis of the observed and expected frequencies, the calculated chi-square statistic for the GIC/σ relationship is 764. This is many times larger than critical value of the statistic corresponding to the 1% level of statistical significance when there are nine degrees of freedom. More specifically, the calculated chi-square statistic has a p value equal to 1.402×10^{-158} which is obviously much much lower than 0.01. Thus, consistent with the GIC/geographic dispersion in real-time prices hypothesis presented in section 2, one can reject the null hypothesis that GIC levels and real-time prices in the New Zealand power grid are unrelated.

5.7. Australia

[63] The National Electricity Market in Australia is a wholesale market for electricity that commenced operations in December 1998. It coordinates the dispatch of power on the world's longest interconnected power system with transmission lines running more than 4,000 km from Port Douglas in Queensland to Port Lincoln in South Australia [*National Electricity Market Management Company Limited*, 2005, p. 4]. The market is operated by National Electricity Market Management Company Limited (NEMMCO) who is also the system operator.

[64] Prior to the inclusion of Tasmania in 2005, the market was composed of the states of Queensland, New South Wales, Victoria, and South Australia. The Snowy Hydro Project located in the Australian Alps in eastern Victoria and southern New South Wales is also recognized as an electricity market zone. A zonal price for each region is determined in a real-time market that clears every 30 min. As in New Zealand, prices can vary across locations depending on energy losses and transmission constraints.

Table 20. Ratio of the Observed to Expected Frequencies Between Categories Representing GICs and the Standard Deviation in the Nodal Prices in New Zealand, 1 November 2002 Through 31 December 2005

	$\sigma 1$	$\sigma 2$	$\sigma 3$	$\sigma 4$
GIC1	0.987	0.938	1.079	0.996
GIC2	1.220	1.048	0.884	0.848
GIC3	1.006	1.042	0.953	0.998
GIC4	0.795	0.978	1.075	1.153

Table 21. Descriptive Statistics for Australia's National Electricity Market and the GIC Proxy, 12 December 1998 Through 15 May 2005

	Weighted Standard Deviation in the Zonal Prices	GIC Proxy (nT/min)
25th percentile	0.057	0.5
Median	0.113	0.8
75th percentile	0.297	1.5

[65] The electricity market data used in this analysis were obtained from NEMMCO (http://www.nemmco.com.au). Data were collected for the period 12 December 1998 through 15 May 2005. The first day of the sample is the market's first day of operation. The last day of the sample is one day prior to the integration of Tasmania into the market. There are 112,153 usable observations. Because the period of analysis is over 6 years in length, the terrestrial determinants of electricity market outcomes were far from being constant over the sample period. Indicative of this, the median load weighted price over all zones in 2000 was 64% higher than in 2004. For this reason, the metric that we will consider, the standard deviation in the zonal prices, will be weighted by the lowest zonal price for the market period. For almost 50% of the market periods, Queensland was the lowest price region.

[66] Table 21 reports the descriptive statistics on the standard deviation in the zonal prices and the GIC proxy. On the basis of the reported percentiles we constructed a category for each quartile of the weighted standard deviation of the zonal prices: $\sigma 1$, $\sigma 2$, $\sigma 3$, and $\sigma 4$. We also constructed a category for each quartile of the GIC proxy: GIC1, GIC2, GIC3, and GIC4.

[67] The ratio of the observed to expected frequencies for each GIC/σ category are reported in Table 22. Inspection of Table 22 reveals that while most of the reported ratios are within 5% of unity there is nevertheless a now familiar pattern to the reported values. Specifically, observe that the reported ratio for $\sigma 4$ increases as the GIC proxy category increases. Specifically, the reported ratio corresponding to GIC1 $\cap$ $\sigma 4$ is about 8% lower than expected but monotonically increases to about 9% more than expected as the GIC category increases to GIC4. Table 22 also indicates that the ratio associated with $\sigma 1$ declines as the GIC proxy category increases.

[68] On the basis of the observed and expected frequencies, the calculated chi-square statistic for the GIC/σ relationship is 152. The chi-square statistic for the GIC/unweighted standard deviation in the zonal prices is 232. While both of these reported values are lower than the statistic for New Zealand they are nevertheless much larger than the critical value of the statistic corresponding to the 1% level of statistical significance when there are nine degrees of freedom. Specifically, the respective p

Table 22. Ratio of the Observed to Expected Frequencies Between Categories Representing GICs and the Weighted Standard Deviation in the Zonal Prices in Australia's National Energy Market, 1 December 1998 Through 15 May 2005

	$\sigma 1$	$\sigma 2$	$\sigma 3$	$\sigma 4$
GIC1	1.037	1.012	1.028	0.924
GIC2	1.006	1.019	1.006	0.970
GIC3	0.986	0.992	1.009	1.013
GIC4	0.972	0.977	0.958	1.093

values are 4.159×10^{-28} and 6.637×10^{-45}. On the basis of these values, one can reject the null hypothesis that GIC levels and conditions in Australia's National Electricity Market are unrelated.

5.8. New England

[69] ISO New England coordinates 32,000 megawatts of total supply within New England. The grid has over 8,000 miles of high-voltage transmission lines with 12 interconnections to electricity systems in New York and Canada. As of 1 March 2003, ISO New England has operated both real-time and day ahead markets for energy. Prices in these markets are reported hourly. As with New Zealand and Australia, the prices are location based. There are eight load zones: Connecticut, Maine, Western Massachusetts, Northeastern Massachusetts, Southeastern Massachusetts, New Hampshire, Rhode Island and Vermont.

[70] The electricity market data used in this analysis were obtained from ISO New England (http://www.iso-ne.com). Data were collected for the period 1 March 2003 through 31 December 2005. There are 24,833 usable observations. The terrestrial determinants of electricity market outcomes were far from being constant over the sample period. Indicative of this, the median reference price over period 1 March through 31 December 2005 was 58% higher than over the same period in 2003. For this reason, the metric that we will consider, the standard deviation in the zonal prices, will be weighted by the lowest zonal price for each 1 h market period. For almost 70% of the market periods, Maine was the lowest price region.

[71] Table 23 reports the descriptive statistics on the standard deviation in the zonal prices and the GIC proxy. On the basis of the reported percentiles we constructed a category for each quartile of the weighted standard deviation in the zonal prices: $\sigma 1$, $\sigma 2$, $\sigma 3$, and $\sigma 4$. We also constructed a category for each quartile of the GIC proxy: GIC1, GIC2, GIC3, and GIC4.

Table 23. Descriptive Statistics for ISO New England and the GIC Proxy, 1 March 2003 Through 31 December 2005

	Weighted Standard Deviation in the Zonal Prices	GIC Proxy (nT/min)
25th percentile	0.022	1.3
Median	0.028	2.3
75th percentile	0.037	4.4

Table 24. Ratio of the Observed to Expected Frequencies Between Categories Representing GICs and the Weighted Standard Deviation in the Zonal Prices in New England, 1 March 2003 Through 31 December 2005

	$\sigma 1$	$\sigma 2$	$\sigma 3$	$\sigma 4$
GIC1	1.193	1.051	0.944	0.815
GIC2	1.065	1.080	0.942	0.914
GIC3	0.927	0.985	1.010	1.077
GIC4	0.796	0.881	1.109	1.210

[72] The ratio of New England's observed to expected frequencies for each GIC/σ category are reported in Table 24. Consistent with the results for New Zealand and Australia, observe that the reported ratio for $\sigma 4$ increases as the GIC proxy category increases. Specifically, the reported ratio corresponding to GIC1 $\cap$ $\sigma 4$ is about 18% lower than expected but monotonically increases to 21% more than expected as the GIC category increases to GIC4. Table 24 also indicates that the ratio associated with $\sigma 1$ declines monotonically as the GIC proxy category increases.

[73] On the basis of the observed and expected frequencies, the calculated chi-square statistic for the relationship between the GIC proxy and the weighted standard deviation in the zonal prices in New England equals 349. The chi-square statistic for the GIC/unweighted standard deviation in the zonal prices is 310. The respective p values are 1.022×10^{-69} and 2.445×10^{-61}. On the basis of these values, one can reject the null hypothesis that GIC levels and the standard deviation in the zonal prices in New England are unrelated.

5.9. PJM Power Grid

[74] PJM Interconnection is a regional transmission organization that as of 30 April 2004 coordinated the dispatch of 76,000 megawatts of generating capacity over 20,000 miles of transmission lines in all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia (PJM, Commonwealth edison successfully integrated into PJM, press release, 1 May 2004). PJM operates both real-time and day ahead markets for energy. Prices in these markets are reported hourly. As with New Zealand, Australia, and New England, the prices are location based.

[75] The electricity market data used in this analysis were obtained from http://www.pjm.com/index.jsp. The sample period for this analysis is 1 April 2002 through 30 April 2004. During this time period, there were 12 geographic zones. The starting date of the sample period represents the first day of PJM's functional control of Allegheny Power's five state transmission system (PJM, PJM West goes into operation, press release, 1 April 2002). The ending date of the sample period is one day prior to the integration of Commonwealth Edison's control area in northern Illinois into PJM (PJM, Commonwealth edison

Table 25. Descriptive Statistics for the PJM Power Grid and the GIC Proxy, 1 April 2002 Through 30 April 2004

	Standard Deviation in the Zonal Prices (USD/MWh)	Unscheduled Flows Between New York and PJM (MWh)	GIC Proxy (nT/min)
25th percentile	0	−611	0.9
Median	0.46	−388	1.6
75th percentile	4.74	−161	2.8

successfully integrated into PJM, press release, 1 May 2004). There were 17,688 valid observations.

[76] For each hour, a given amount of power is scheduled to flow to or from PJM to other power grids. For approximately 91% of the hours in the sample period PJM was scheduled to be a net exporter of power to New York. The difference between the actual and scheduled net flow is the unscheduled flow. The unscheduled flow can be negative, zero, or positive. The unscheduled flow will be negative when PJM is scheduled to be a net exporter but actual net exports are larger than scheduled or when PJM is scheduled to be a net importer but actual net imports are less than scheduled. The unscheduled flow will be positive when PJM is scheduled to be a net exporter but actual exports are less than scheduled or when PJM is scheduled to be a net importer but actual net imports are greater than scheduled.

[77] In this study, we will consider whether the unscheduled flows between PJM and the New York power grid are statistically related to GIC levels. Unscheduled flows between New York and PJM were negative for approximately 87% of the hours in the sample. The magnitudes of the unscheduled flows are nontrivial. Average net flows from PJM to New York were 370 MWh higher than the 1390 MWh that were scheduled during those hours when PJM was scheduled to be a net exporter to New York. Average net flows from New York into PJM were 589 MWh less than the 477 MWh that were scheduled during those period when PJM was scheduled to import electricity from New York which means of course that PJM on average was a net exporter to New York even during those periods when it was scheduled to be a net importer.

[78] We denote a category for each quartile of the unscheduled flows: UNSCH1, UNSCH2, UNSCH3 and UNSCH4. We also constructed a category for each quartile of the GIC proxy: GIC1, GIC2, GIC3, and GIC4. Table 25 reports the descriptive statistics for these two variables along with the percentiles for the standard deviation in the real-time zonal prices.

[79] The ratios of the observed to expected frequencies for each GIC/unscheduled flow category are reported in Table 26. Observe that most of the reported ratios are different from unity by more than 5%. Moreover, consistent with the hypothesis that GIC levels and the unscheduled flows may be related, observe that the number of frequencies in the cells corresponding to UNSCH1, the category that represents the most extreme negative unscheduled flows, monotonically increases as the GIC proxy category increases. Indicative of this trend, the reported value for GIC1 $\cap$ UNSCH1 is 0.698 while the observed ratio for GIC4 $\cap$ UNSCH1 is 1.317.

[80] On the basis of the observed and expected frequencies, the calculated chi-square statistic corresponding to the results reported in Table 26 equals 497. The corresponding p value equals 2.101×10^{-101} which is much lower than 0.01 and thus one can reject the null hypothesis of statistical independence at the 1% level. Thus, consistent with the GIC/energy flow hypothesis presented in section 2, one can reject the null hypothesis that GIC levels and the levels of unscheduled flows between PJM and New York are unrelated. This finding of a relationship between PJM/NY unscheduled flows does not appear to be an isolated case. For example, one can reject the null hypothesis of no relationship between the unscheduled flows and GICs for each of the grids that PJM traded power with over the sample period.

[81] The analyses for New Zealand, Australia, and New England have indicated that the standard deviation in the locational prices was not statistically independent of GIC levels. To test whether this is also the case for PJM, the standard deviation in the real-time zonal prices for each hour was calculated and grouped by quartile: $\sigma 1$, $\sigma 2$, $\sigma 3$, and $\sigma 4$.

[82] Table 27 reports on the ratio of the observed to expected frequencies for the categories representing GICs and the standard deviation in PJM's zonal prices. Observe that half of the reported ratios are different from unity by more than 5%. Table 27 reveals that the ratio of the observed to expected frequencies corresponding to $\sigma 4$ monotonically increases as the GIC category increases. Specifically, the reported ratio corresponding to GIC1 $\cap$ $\sigma 4$ is about 22% lower than expected but monotonically increases to about 20% more than expected as the GIC category increases to GIC4. Table 27 also indicates that the ratio associated with $\sigma 1$ declines as the GIC category increases.

[83] On the basis of the observed and expected frequencies the calculated chi-square statistic corresponding to the results reported in Table 27 is 181. The corresponding p value is 2.980×10^{-34}. This value permits us to reject the null hypothesis at the 1% level of statistical significance

Table 26. Ratio of the Observed to Expected Frequencies for the Categories Representing GICs and Unscheduled Flows Between New York and PJM, 1 April 2002 through 30 April 2004

	UNSCH1	UNSCH2	UNSCH3	UNSCH4
GIC1	0.698	0.907	1.038	1.357
GIC2	0.956	0.966	1.025	1.054
GIC3	1.046	1.084	1.016	0.855
GIC4	1.317	1.050	0.917	0.716

Table 27. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and the Standard Deviation in PJM's Zonal Prices, 1 April 2002 Through 30 April 2004

	$\sigma 1$	$\sigma 2$	$\sigma 3$	$\sigma 4$
GIC1	1.104	1.005	1.033	0.777
GIC2	1.056	1.014	0.973	0.923
GIC3	0.947	1.011	0.977	1.117
GIC4	0.885	0.968	1.018	1.198

that GIC levels and the standard deviation in PJM's zonal prices are unrelated.

5.10. New York Power Grid

[84] Like PJM and New England, the New York Independent System Operator (NYISO) administers both real-time and day ahead hourly markets for energy. The NYISO is divided into 11 geographic zones. Prices are determined hourly and vary by zone depending on line losses and congestion costs. This analysis will focus on the zone corresponding to New York City over the period 1 January 2000 through 31 December 2004. Over this period, New York City accounted for approximately 32% of total state-wide consumption. In this analysis, we will examine the relationship between the GIC proxy and the dollar measures of both energy losses and congestion costs associated with energy flows into New York City.

[85] The NYISO reports an hourly reference price against which all zonal transmission losses and congestion costs are calculated. This reference price is determined at the NYISO reference bus which is physically located at the Marcy 345 kV substation in Marcy, New York, located approximately 300 km from New York City. The locational marginal prices for each zone has three components: an energy or reference price component, a line loss cost component (measured in United States dollars (USD)/MWh), and a congestion cost component (measured in USD/MWh). Specifically, for zone k, in period t, the locational marginal price ($\mathrm{LMP}_{k,t}$) has the following relationship to the reference price:

$$\mathrm{LMP}_{k,t} = \text{Reference Price}_t + \text{Losses}_{k,t} - \text{Congestion}_{k,t}, \quad (3)$$

where reported losses and congestion can be positive, negative, or zero.

[86] Given the level of electricity that is produced in time period t, the overall costs of generation will be minimized when the marginal cost of generation at time period t is equal across zones. In the absence of market power by energy suppliers, the marginal cost of generation in zone k in time period t will equal $\mathrm{LMP}_{k,t}$ and thus overall generation costs are minimized when the locational marginal prices in time period t are equal to the reference price for time period t. Thus, from equation (3), generation costs are higher than their minimum whenever reported congestion costs or losses are nonzero. For this reason, this analysis will measure the dollar magnitudes of both line losses and congestion costs in terms of their absolute values.

[87] The electricity market data used in this analysis were obtained from http://www.nyiso.com. There were 43,668 valid observations. The descriptive statistics for the GIC proxy and the power grid variables are reported in Table 28. The congestion cost and energy loss statistics reported in Table 28 indicate that the transmission lines between New York City and the northern and western parts of the State were severely affected by energy losses and congestion costs over the sample period.

[88] Line losses are ubiquitous and thus four categories were constructed to represent the dollar magnitudes of the losses: LOSS1, LOSS2, LOSS3 and LOSS4. Five categories were constructed to represent congestion costs. The first variable, COST0, represents those instances where congestion costs are zero. The other four variables, COST1, COST2, COST3, and COST4, represent the frequencies for each quartile in which the absolute value of reported congestion costs are nonzero. We also constructed a category for each GIC proxy quartile: GIC1, GIC2, GIC3, and GIC4.

[89] Table 29 reports on the ratio of the observed to expected frequencies for the categories representing GIC proxies and the hourly energy losses for New York City measured in dollars per MWh. Observe that most of the reported ratios in Table 29 are different from unity by

Table 28. Descriptive Statistics for the GIC Proxy, and the Dollar Magnitudes of Line Losses and Congestion Costs for New York City, 1 January 2000 Through 31 December 2004[a]

	Losses (USD/MWh)	Congestion Costs (USD/MWh)	GIC Proxy (nT/min)
25th percentile	1.8	3.69	1.2
Median	2.99	10.60	2.1
75th percentile	4.40	23.06	4.0

[a]There were 16,958 h in which congestion costs were zero. The reported percentiles for congestion costs do not reflect these hours.

Table 29. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Energy Losses for New York City, 1 January 2000 Through 31 December 2004

	LOSS1	LOSS2	LOSS3	LOSS4
GIC1	1.351	1.082	0.895	0.669
GIC2	1.036	1.047	0.996	0.921
GIC3	0.850	0.996	1.036	1.119
GIC4	0.763	0.875	1.073	1.291

Table 30. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and Transmission Congestion Costs in New York City, 1 January 2000 Through 31 December 2004

	COST0	COST1	COST2	COST3	COST4
GIC1	1.207	0.926	0.896	0.896	0.756
GIC2	1.031	0.969	0.971	1.013	0.968
GIC3	0.914	1.027	0.991	1.071	1.131
GIC4	0.848	1.078	1.142	1.019	1.145

Table 31. Descriptive Statistics on Deployment of Emergency Power and GICs Levels in the Netherlands Power Grid, 1 January 2002 Through 31 December 2004[a]

	Deployments of Emergency Power (MW)	GIC Proxy (nT/min)
25th percentile	90	0.8
Median	132	1.2
75th percentile	200	2.0

[a]The reported percentiles on the deployment of emergency power only reflect the 409 market periods in which emergency power was

more than 5%. Moreover, the reported values vary systematically with the GIC category. For example, the reported value for GIC1 ∩ LOSS4 is 0.699. Note that the reported value corresponding to LOSS4 increases to 1.291 as the GIC category increases to GIC4. This same pattern is also evident for LOSS3. With respect to LOSS1 and LOSS2, observe that the reported ratios decline as the GIC proxy category increases.

[90] Table 30 reports on the ratio of the observed to expected frequencies for the categories representing GICs and hourly transmission congestion costs for New York City measured in dollars per MWh. Table 30 indicates that the ratio associated with COST0, the category representing no congestion costs, declines as the GIC proxy category increases. Specifically, the reported ratio corresponding to GIC1 ∩ COST0 is about 21% higher than expected. The reported ratio declines to approximately 15% less than expected as the GIC category increases to GIC4. It should also be noted that the reported ratio corresponding to GIC1 ∩ COST4 is about 24% less than expected. Observe that the reported ratio corresponding to COST4 monotonically increases to approximately 15% more than expected as the GIC category increases to GIC4.

[91] On the basis of the observed and expected frequencies, the calculated chi-square statistics corresponding to Tables 29 and 30 are 1254 and 584, respectively. Both of these are many times larger than the critical value of the statistic corresponding to the 1% level of statistical significance. Specifically, the associated p values are 3.091×10^{-264} and 5.996×10^{-120}. On the basis of these values we reject the null hypothesis that GIC levels and the energy losses in the transmission lines that carry power to New York City are unrelated. The null hypothesis regarding GICs and congestion costs is also rejected.

5.11. Power Grid in the Netherlands

[92] System balance in the Netherlands is the responsibility of TenneT, the system operator. TenneT employs a balancing market that clears every 15 min. Prices in this market are established through an auction based on the system requirements and previously submitted bids by generators. TenneT resolves market imbalances and transmission constraints by dispatching regulating and reserve power. The downward dispatch of regulating and reserve power is used to resolve positive market imbalances (market surpluses) while the upward dispatch of regulating and reserve power is used to correct for negative market imbalances (market shortages). Under very rare circumstances, the upward dispatch of regulating and reserve power is supplemented by dispatching emergency power.

[93] For this analysis, we will consider the deployments of emergency power over the period 1 January 2002 through 31 December 2004 as the metric. As the term suggests, these deployments are not inconsequential events. On average over the sample period, the total upward dispatch of power during periods when emergency power was dispatched was approximately seven times the level of upward dispatch during other periods when the upward dispatch of regulating and reserve power were required (412 MW as compared to 59 MW). Moreover, the differential between the price of an upward dispatch and the day ahead spot price over the sample period was over 200 euros per MWh during those periods in which emergency power was deployed. Interestingly, the largest price differential was associated with a series of emergency deployments that occurred on 31 October 2003, a day of well documented geomagnetic activity. During this two hour emergency, the price of balancing power was over 1,000 euros per MWh higher than the day ahead spot price. To put this number in perspective, during other periods in which there was an upward dispatch of regulating and reserve power, the price differential was approximately 40 euros per MWh.

[94] Emergency deployments of power are also a useful metric of power grid performance because of the very large societal costs that would be incurred if the system operator were unable to restore the system balance. Indicative of the possible magnitude of these costs, the lowest estimate of the economic costs to the United States of the August 2003 blackout in North America is $4 billion [*Electricity Consumers Resource Council*, 2004].

Table 32. Ratio of Observed to Expected Frequencies for the Categories Representing GICs and the Deployment of Emergency Power in the Netherlands Power Grid, 1 January 2002 Through 31 December 2004

	EMERGENCY0	EMERGENCY1	EMERGENCY2	EMERGENCY3	EMERGENCY4
GIC1	1.002	0.694	0.429	0.510	0.196
GIC2	1.000	1.025	1.190	0.824	0.510
GIC3	1.000	0.992	0.762	1.216	1.176
GIC4	0.998	1.289	1.619	1.451	2.118

Table 33. A Summary of the Research Findings

Location	System Operator	Sample Period	Number of Observations	Metric	Summary of the Observed Pattern	p Value
Ireland	Eirgrid	1 Jan. 2002 through 31 Dec. 2005	70,080	Top up volumes	The incidence of cases in which the absolute value of the top up volumes are large increases as the GIC proxy increases	3.33E−157
Ireland	Eirgrid	1 Jan. 2002 through 31 Dec. 2005	70,080	Spill volumes	The incidence of cases in which the spill volumes are small increases as the GIC proxy increases	5.719E−131
Northern Scotland	Scottish and Southern Electricity	1 Jan. 2004 through 31 Dec. 2004	17,520	Top up volumes	The incidence of cases in which the absolute value of the top up volumes are large increases as the GIC proxy increases	1.348E−22
Southern Scotland	Scottish Power	1 Jan. 2004 through 31 Dec. 2004	17,520	Top up volumes	The incidence of cases in which the absolute value of the top up volumes are large increases as the GIC proxy increases	3.720E−27
Czech Republic	OTE	1 Feb. 2003 through 31 Dec. 2005	25,536	Top up volumes	The incidence of cases in which the absolute value of the top up volumes are large increases as the GIC proxy increases	7.070E−22
Czech Republic	OTE	1 Feb. 2003 through 31 Dec. 2005	25,536	Spill volumes	The incidence of cases in which the spill volumes are small increases as the GIC proxy increases	4.061E−10
Czech Republic	OTE	1 Feb. 2003 through 31 Dec. 2005	25,536	Balancing costs	The incidence of cases in which balancing costs are high increases as the GIC proxy increases	1.130E−37
Central Germany	E.ON	1 Dec. 2001 through 31 Dec. 2005	143,063	Dispatch of balancing power	The incidence of cases in which the deployment of balancing power is positive and large increases as the GIC proxy increases	3.133E−130
Central Germany	E.ON	1 Dec. 2001 through 31 Dec. 2005	143,063	Price of balancing power	The incidence of cases in which the price of balancing power is positive and large generally increases as the GIC proxy increases	<2.522E−308
England and Wales	National Grid	11 Mar. 2003 through 31 Mar. 2005	36,046	Upward deployment of balancing power to ensure grid stability	The incidence of cases in which the upward dispatch of balancing power to ensure grid stability is large increases as the GIC proxy increases	1.934E−139

Table 33. (continued)

Location	System Operator	Sample Period	Number of Observations	Metric	Summary of the Observed Pattern	*p* Value
New Zealand	Transpower	1 Nov. 2001 through 31 Dec. 2005	72,926	Standard deviation in the nodal prices	The standard deviation in the nodal price, a measure of energy losses and transmission constraints, is more likely to be large when the GIC proxy is large	1.402E−158
Australia	NEMMCO	12 Dec. 1998 through 15 May 2005	112,153	Weighted standard deviation in the zonal prices	The incidence of cases in which the weighted standard deviation in the zonal prices is large increases as the GIC proxy increases	4.159E−28
New England	ISO New England	1 Mar. 2003 through 31 Dec. 2005	24,833	Weighted standard deviation in the zonal prices	The incidence of cases in which the weighted standard deviation in the zonal prices is large increases with increases in the GIC proxy	1.022E−69
All or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia	PJM	1 Apr. 2002 through 30 Apr. 2004	17,688	Unscheduled flows between PJM and New York	The incidence of cases in which unscheduled flows of electricity between PJM and New York are negative and large in absolute value increases with increases in the GIC proxy	2.101E−101
All or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia	PJM	1 Apr. 2002 through 30 Apr. 2004	17,688	Standard deviation in the zonal prices	The incidence of cases in which the standard deviation in the zonal prices is large increases with increases in the GIC proxy	2.980E−34
New York	New York ISO	1 Jan. 2000 through 31 Dec. 2004	43,668	Transmission losses	The incidence of cases in which transmission losses are large increases with increases in the GIC proxy	3.091E−264
New York	New York ISO	1 Jan. 2000 through 31 Dec. 2004	43,668	Congestion costs	The incidence of cases where congestion costs are large increases with increases in the GIC proxy	5.996E−120
Netherlands	TenneT	1 Jan. 2002 through 31 Dec. 2004	103,658	Dispatch of emergency power	The incidence of large emergency power deployments increases with increases in the GIC proxy	3.082E−14

[95] The electricity market data used in this analysis were obtained from http://www.tennet.org. There were 103,658 valid observations. The descriptive statistics for the GIC proxy and the power grid variable are reported in Table 31.

[96] Five categories of emergency power were constructed. The first variable, EMERGENCY0, represents the vast proportion of instances when emergency power was not deployed. The other four variables, EMERGENCY1, EMERGENCY2, EMERGENCY3, and EMERGENCY4, represent the frequencies for each quartile in which emergency power was deployed. We also constructed a category for each GIC proxy quartile: GIC1, GIC2, GIC3, and GIC4.

[97] Table 32 reports on the ratios of the observed to expected frequencies for the categories representing GICs and deployment of emergency power. Observe that 14 of the 18 entries are different from unity by more than 15%. Moreover, consistent with the hypothesis that GIC levels and the deployments may be related, observe that the ratio of the observed to expected frequencies for both EMERGENCY3, and EMERGENCY4 increase as the GIC category increases. Indicative of this trend, the reported value for GIC1 $\cap$ EMERGENCY4 is 0.196 while the observed ratio for GIC4 $\cap$ EMERGENCY4 is 2.118.

[98] On the basis of the observed and expected frequencies, the calculated chi-square statistic corresponding to Table 32 is 91. The corresponding p value is 3.082×10^{-14} and thus we reject the null hypothesis that GIC levels and deployment of emergency power in the Netherlands power grid are unrelated.

6. Summary and Conclusion

[99] In this study, we used local magnetometer data as a GIC proxy to address whether there is a space weather/electricity market relationship in 12 geographically disparate control areas around the world. For each power grid, a metric of real-time market conditions was considered. The specific metrics varied from grid to grid, but they included real-time measures of market imbalances, energy losses, congestion costs, and actions undertaken by the system operator in response to disturbances.

[100] A detailed summary of the findings is presented in Table 33. Inspection of Table 33 reveals that the observed pattern between the GIC proxies and each of the power grid metrics is consistent with the hypotheses presented in section 2 of the paper. Moreover, using Pearson's chi-squared test, the null hypothesis of no relationship is rejected at the 1% level of statistical significance.

[101] While the empirical results reported in this paper are consistent with hypotheses we have formulated, they do not prove that GICs contribute to the variation in power grid metrics that we have considered. For as anyone with formal training in statistics can attest, statistical methods are incapable of establishing or rejecting causality between two variables that are contemporaneously correlated. Instead, statistical methods inform us whether the data are consistent or not with the hypotheses we are testing. Given the observed consistency in this study, there are three logical possibilities. First, GICs contribute to the variation in the power grid metrics as we have hypothesized. The second possibility is that there is reverse causation, i.e., the power grid metrics cause the GICs. The third possibility is that GICs do not contributed to the metrics but there is instead another variable that is highly correlated with GICs that is the true cause of the observed relationships. Possibility number two, i.e., reverse causation, is a common problem in the social sciences where it is sometimes unclear whether the variable X causes the variable Y or the variable Y causes the variable X. It does not appear likely in this case. With respect to the third possibility, we know of no terrestrial variable that could possibly account for the observed GIC/power grid relationships among our 12 geographically disparate power grids. For example, given that the Australian and the PJM power grids are almost diametrically opposite from one another on the globe, it is highly implausible that there is a terrestrial variable that can account for the observed GIC/σ relationship in both of these power grids. It therefore would appear that while sunspots may not affect economic fundamentals, solar induced geomagnetic storms do, at least in the electricity markets in Ireland, Scotland, central Germany, The Czech Republic, England and Wales, New Zealand, Australia, New England, PJM, New York, and the Netherlands.

[102] **Acknowledgments.** This research was made possible by a grant from the National Science Foundation (award ATM-0318582). Earlier versions of the paper were presented at the April 2007 International Industrial Organization Conference in Savannah, Georgia, and the 2007 Space Weather Workshop in Boulder, Colorado. Thanks go to the participants of these sessions for their constructive criticism and helpful suggestions. We thank the editor and three anonymous reviewers for their helpful comments and suggestions. We thank Antti Pulkkinen for his technical critique and Michael A. Forbes for writing the programs that manipulated the large quantity of geomagnetic data used in this study. We thank the system operators of the power grids for making their data available and for answering our questions. We also thank the British Geological Survey, the Geological Survey of Canada, GeoForschungsZentrum Potsdam, the Geophysical Institute of the Academy of Sciences of the Czech Republic, Geoscience Australia, the Institute of Geological and Nuclear Sciences Ltd., the Royal Meteorological Institute of Belgium, and the United States Geological Survey. The geomagnetic data provided by these organizations were critical to the analysis. We also thank Intermagnet (www.intermagnet.org) for promoting high standards of magnetic observatory practice, an efficient mechanism for the distribution of this data. Any errors are the full responsibility of the authors.

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