Local Technological and Demographic Effects on Electricity Transmission: A Spatially Lagged Local Estimation of New England Marginal Losses

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Abstract
Electricity transmission is subject to distribution losses and congestion costs. Economists have prior theorized that these transmission imperfections could create divided markets with electricity generating spatial oligopolists. This concern has been largely dismissed because of recent technological advances in electricity transmission. The effects of local technological and demographic indicators on electricity transmission costs remains both commonly accepted as negligible and spatially untested. This analysis employs a spatially lagged local estimation of New England's marginal electricity losses with respect to both technological and demographic indicators. The results of this analysis are consistent with the widely accepted notion that technological advances have mitigated the effect of local distribution losses and local congestion costs on electricity prices.

Keywords
electricity, electricity transmission

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Electricity transmission is subject to distribution losses and congestion costs. Economists have prior theorized that these transmission imperfections could create divided markets with electricity generating spatial oligopolists. This concern has been largely dismissed because of recent technological advances in electricity transmission. The effects of local technological and demographic indicators on electricity transmission costs remains both commonly accepted as negligible and spatially untested. This analysis employs a spatially lagged local estimation of New England’s marginal electricity losses with respect to both technological and demographic indicators. The results of this analysis are consistent with the widely accepted notion that technological advances have mitigated the effect of local distribution losses and local congestion costs on electricity prices.

Keywords: Transmission grid losses, locational marginal prices, New England ISO, technological indicators.

Introduction

Electricity markets and other networked goods like water, oil, cable television and railways have become an enjoyable research pastime for economists concerned with market structure issues. Electricity markets are embedded with unique commodity specific and trade specific considerations that complicate the analysis of this market. The two most important electricity specific considerations are (1) the physical laws that electricity must abide by and (2) the limitations of electricity transmission via infrastructural constraints.

Electricity, in the form of electrons transmitted along a transmission cable, is subject to a certain degree of “resistance”. This resistance is defined in the form
of two foundational laws of electricity (1) Ohm’s Law and (2) Kirchoff’s Law. Ohm’s law connects the three concepts of current, voltage and resistance. Current can be defined simply as electrons moving through a transmission cable between two points. Voltage is the force that allows these electrons to move between two points and resistance is the measurable inhibiting force between those two points caused by electron transit friction (Kostiner, 1994). Kirchoff’s Law states that the “sum of all currents entering and exiting a node must be equal to zero”. In essence, this law states that electrons will travel the path of least resistance. These two laws have direct applications to electricity trade markets that must be taken into consideration (Kostiner, 1994).

Under Kirchoff’s law, unlike most traditional commodities, electricity cannot be stored for future consumption. The transmission grid is therefore always in a state of perfect production-consumption equilibrium. Ohm’s law also states that with “resistance” as a function of voltage capacity (the size of the transmission cable) and current strength there will be inherent distribution losses of electricity. These distribution losses are also a function of the distance that electrons travel from the point of production to the point of consumption and the local weather (Robertazzi, 2007). The existence of “resistance” on the transmission grid also makes possible transmission grid “congestion” to occur. This congestion occurs when the current from point A to point B on the transmission grid reaches the voltage capacity of that respective transmission line. Under Kirchoff’s law, however, we know that electrons will take the path of least resistance and congestion into and out of any particular node will be equal.

The physical properties of electricity also have unique benefits. In theory, a transmission grid without congestion (a high enough voltage and low enough current) can transfer electricity across long distances, instantly. It has been argued, for example, that electricity produced from solar resources in Northern
Africa could be traded competitively in the European electricity markets with proper transmission voltage capacity expansions (Bauer et. al., 2008). The demand schedule of electricity is predictable but inconstant. For example, peak-demand typically occurs during a warm day in the early evening when electricity consumption is high. The transmission grid’s unique range may allow distant competitive suppliers of electricity to exploit far-reaching peak-demand markets during their off-peak hours (Shakourig et. al., 2009).

Conventional theory recognizes price increases as a result of distribution losses and congestion but the impossibility of predicting where produced electricity will be consumed has overshadowed the potential influence of citing generation sources in close proximity to electricity demand centers. Furthermore, the spatial analysis of these grid losses, on a local scale, may have lost its appeal because advances in transmission capacity are occurring rapidly and better integrating larger regions. In theory, this would make local indicators less important and spatial demographic and technological indicators less predictable. The purpose of this analysis is to estimate locational marginal price losses, resulting from electricity distribution losses and congestions, using local and demographic indicators.

**Literature Review**

Two and a half decades ago Benjamin Hobbs (1985) predicted that the deregulation of electricity generation would create spatial oligopolists resulting from network barriers. Hobbs conducted a theoretic Nash-Bertrand spatial equilibrium to predict the price variation of electricity in New York’s regional markets. His results showed that transport costs and significant scale economies would yield generator spatial oligopolists. The spatial oligopolists would cause regional price increases and the ability for generators – with natural
barriers caused by transport costs - to exercise market power. Over the past 25 years, however, the scale of these economies has increased drastically. The grid is interconnected extremely well and technological advances have allowed for less costly electricity transmission across further distances. These changes may have removed the natural barriers that Hobbs envisioned in the mid-1980s. Additionally, Hobbs’ analysis is conducted using a theoretic price equilibrium calculated using mathematically linear programs to obtain local spatial price equilibria. This theoretic concept deserves attention using spatial analysis.

The Independent Electricity Market Operator (IEMO) in charge of operating the electricity grid in Ontario released a PowerPoint in January, 2004 outlining historical nodal pricing analysis on their grid. This operator references spatial analysis and its relevance to the impact of congestion and relative losses on the electricity market. The presentation uses locational marginal prices (LMPs) that include a congestion and loss component. This analysis found that losses, not congestion, contributed the most to pricing variation on the local grid. These system operators have perfect information and were able to determine which transfers incurred the highest losses. In this case, the highest rate of congestion occurred along the East-West Transfer interfaces, whereas the highest losses from distribution occurred between the Northwest and Northeast regions of the grid. No spatial analysis was considered to determine if generators’ proximity to demand centers influenced grid losses.

Ostergaard (2004) examines critically the geographic distribution of electricity generation in relation to grid losses in Denmark. The Danish example is particularly interesting because over 40% of consumed electricity is covered by scattered sources as a result of large scale wind turbine investments. Ostergaard

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1 In theory, an electricity system (in this case IEMO) will have one theoretic price across the entire system – any pricing deviations occur as a result of incurred congestion and distance of travel losses.
adopts basic assumptions to map the distribution of generated electricity in order to conduct a consumption-production spatial analysis. In order to model transmission grid flows, Ostergaard uses EnergyPro GRID a complex model founded on an algorithm designed to predict transmission flows throughout a grid. His analysis concludes that it is essential for Denmark to control generation not only at an aggregate level but also at a local level to prevent congestion from occurring. A suggestion is given to coordinate local and regional electricity production to ensure a fair balance without the inefficient alternative of electricity traveling far distances, incurring distribution costs.

Baban and Perry (2000) used spatial analysis to determine the optimized locations of new wind farm investments in England. These clean electricity generators were determined based upon geographic constraints (including topography, land use, wind direction, wind speed, population, road access, hydrology and historical and cultural land marks). The only factor that was considered with regard to transmission compatibility was a constraint that the wind farm is within 10 KM of the transmission grid. On the demand side, the only consideration with regard to population was actually a 2 KM buffer on large settlements. This type of consideration speaks volumes of traditional electricity generator citing ideologies. The cost in distribution losses, transmission losses and congestion losses are not considered carefully when citing an electricity generator in distant proximity from its intended consumers of electricity.

**Methodology**

I retrieved the source data for LMP nodes across New England for the year of 2008. This data was created by the Independent System Operator of New England (ISO-NE). I used Google Earth to locate the coordinates of each of these nodes and converted this coordinate data to a point data shapefile. This
pricing data is in terms of $/Kilowatt Hour (KWH) and is valid for June 11th, 2008 for electricity trade from 6:00PM – 7:00PM. I retrieved source data for electricity generators, with their respective generating capacities, present in New England valid for the year of 2008. I used the Environmental Protection Agency’s (EPA) facility registration database to locate each of these generator’s respective addresses. I then used Google Earth to locate the coordinates of these addresses and created a point data shapefile with these coordinates (Figure 1). United States (U.S.) spatial demographic data valid for the year of 2000 was retrieved from the U.S. census, to create demographic indicators (population and population density). Finally, transmission grid spatial data, including individual line voltage capacities, was obtained from the Federal Emergency Management Agency (FEMA) valid for 1993.

I created 587 Thiessen polygons around my 813 LMP nodes (Figure 2). In some cases, there was more than one node located at an identical location. These prices were averaged because under Ohm’s and Kirchoff’s laws and the framework of the transmission network, electricity prices at identical locations are by identity, equal. I estimated the population and population density of each Thiessen polygon by converting my census block-level population data to a raster file and then using zonal statistics to sum population. I then calculated the geometry of these polygons and conducted a simple field summation to determine estimated population density. I also use field calculations to estimate electricity generation capacity, transmission capacity/per capita, and total transmission length within each polygon.

I employed a spatially-lagged ordinary least squares (OLS) model to estimate the effect of these spatial and technological indicators on the nodal marginal

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2 This date and time was chosen because it was one of the warmest days recorded during the summer of 2008. This year was also the most recent year that LMP data was available.
electricity losses. In addition to the focal indicators, I included a dummy variable that was present (1) if my dependant variable spatial accuracy was to the street level and not-present (0) if the dependant variable was only accurate to the town level.

\[ Y_i = b_0 + b_1X_1 + b_2X_2 + b_3X_3 + b_4X_4 + b_5X_5 + b_6Y_{Ni} + u_i \]

- \( Y \) = Marginal Loss Component ($/KWH)
- \( X_1 \) = Length of grid (Miles)
- \( X_2 \) = Generator Capacity (Kilowatts)
- \( X_3 \) = Voltage Capacity / Per Capita (Kilovolts)
- \( X_4 \) = Population Density (PP/KM²)
- \( X_5 \) = Precision Dummy Variable (1,0)
- \( Y_{Ni} \) = Spatially Lagged Neighborhood Weights of Marginal Loss Component

Lastly, a breusch-pagan test was employed to test our estimates for the presence of heteroskedasticic errors.

**Results**

None of the focal explanatory variables had an estimated coefficient that was statistically significant in difference from zero (Table 2). The coefficient estimate on the dummy variable for dependant variable precision (at the street level) was negative and statistically significant. This dummy variable suggests that my flawed data reporting accuracy does affect my overall estimates. This dummy variable coefficient is relatively intuitive as it would appear that estimated effects on a marginal loss price component would be less in an area that the node may not actually exist. These nodal centers are likely to have higher population densities and transmission grid presence. Flawed accuracy may discount this estimation.

The spatially lagged estimated coefficient is positive and statistically significant. This is expected as most of our chosen variables are inherently spatially-autocorrelated (Table 1). The worst spatial autocorrelation exists within our dependant variable with a positive Moran’s I coefficient of 0.79 (Table 1). The coefficient estimates do not appear to have heteroskedastic error terms but despite the spatially lagged variable the coefficient estimates still suffer from spatial autocorrelation.
Conclusions

These results do not support my null hypothesis that local technological and demographic indicators affect electricity’s marginal loss component at LMP nodes. These results support multiple conclusions. In a perfectly operating transmission network there would be no variation across our spatially lagged variable. That is, the distribution losses would be constant and minimal across spatial units. The estimated model only explains about three-quarters of the variation in our loss component. We can conclude, therefore that there are technological and demographic negative influences on the New England transmission network causing distribution losses.

Since we have variation in our distribution loss prices but that variation cannot be explained with local indicators, we can conclude that the distribution losses are being incurred at locations beyond the reaching of our spatial “Thiessen polygon” units. This may support that electricity is being produced in distant locations from where it is being consumed. This conclusion is a success story for the New England transmission grid. A distant spatial relationship between supply and demand of electricity supports that there is little congestion mitigating distant trade. This conclusion is also supported by the Federal Energy Regulatory Commission (FERC) stating recently that New England is a transmission system with close to no transmission congestion.

This study does suffer from many limitations. This study does not account for a potential “edge effect”. I was not able to obtain import and export data for New England or spatial data for the neighboring New York Independent System Operator (NYISO). New York City is a major demand center in close proximity to Connecticut. This may be one reason why the left-hand side observations in this area have such a high Moran’s I coefficient (Figure 3). Also, limited resources and funding have forced me to use imperfect data. My transmission grid data was created by FEMA for national security impact assessment not transmission grid analysis. This particular dataset is also two decades invalid. Finally, despite using a spatially-lagged model, my regression estimates still suffer from the presence of autocorrelated errors. I chose not to pursue this problem any further because the
spatially autocorrelated errors preserve unbiased but inefficiency estimates. The relatively low z-scores of my estimates indicate that even with corrected errors the coefficients would likely remain statistically insignificant.

Appendix

**Figure 1** – Electricity structure in Suffolk County, Boston, MA including 2008 electricity generators, 2008 locational marginal prices, 1993 transmission grid, and the local county boundaries.
Figure 2 – New England electricity marginal losses ($/KWH) for June 11th, 2008 from 6:00PM-7:00PM. This map includes generators and locational marginal price (LMP) nodes.

Figure 3 – Thiessen polygon-level Moran’s I values for New England Electricity Marginal Losses on June 11\textsuperscript{th}, 2008 from 6:00 PM-7:00 PM.

Figure 3: New England Electricity Marginal Losses Moran’s I Values (June 11th 6:00 PM-7:00 PM, 2008)

Table 1 – Estimations from spatially-lagged ordinary least squares (OLS) regression as well as summary statistics and tests for heteroskedastic and spatially autocorrelated error terms.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Coef.</th>
<th>Std. Error</th>
<th>Z-score</th>
<th>Prob &gt; Izl</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lagged marginal loss component ($/KWH)</td>
<td>0.8545</td>
<td>0.0226</td>
<td>37.85</td>
<td>0.0000</td>
</tr>
<tr>
<td>Precision Dummy</td>
<td>-0.8103</td>
<td>0.2433</td>
<td>-3.33</td>
<td>0.0009</td>
</tr>
<tr>
<td>Length (Miles)</td>
<td>-0.0522</td>
<td>0.1096</td>
<td>-0.48</td>
<td>0.6337</td>
</tr>
<tr>
<td>Generating Capacity (KWH)</td>
<td>-0.0304</td>
<td>0.0318</td>
<td>-0.96</td>
<td>0.3384</td>
</tr>
<tr>
<td>Grid Capacity/PP (KV/PP)</td>
<td>0.1182</td>
<td>0.3604</td>
<td>0.33</td>
<td>0.7430</td>
</tr>
<tr>
<td>Pop Density (PP/KM²)</td>
<td>0.0003</td>
<td>0.0003</td>
<td>1.02</td>
<td>0.3073</td>
</tr>
<tr>
<td>Constant</td>
<td>-0.2295</td>
<td>0.4526</td>
<td>-0.51</td>
<td>0.6122</td>
</tr>
</tbody>
</table>

Summary Statistics

<table>
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<tr>
<th>R-Squared</th>
<th>Likelihood Ratio Test</th>
<th>Breusch-Pagan Test</th>
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<tbody>
<tr>
<td>0.7679</td>
<td>p=0.0000</td>
<td>p=0.49</td>
</tr>
</tbody>
</table>

Table 2 – Univariate Moran’s I coefficients for each variable.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Moran’s I Coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>Locational Marginal Prices ($/KWH)</td>
<td>0.7940</td>
</tr>
<tr>
<td>Length of transmission grid (Miles)</td>
<td>0.3188</td>
</tr>
<tr>
<td>Generation capacity (KWH)</td>
<td>-0.0029</td>
</tr>
<tr>
<td>Capacity/Per Capita (KV/PP)</td>
<td>0.3729</td>
</tr>
<tr>
<td>Population Density (PP/KM²)</td>
<td>0.5140</td>
</tr>
</tbody>
</table>
Works Cited


