The University of Texas at Austin
Energy Institute

Discussion Paper No. 1 for the Energy Infrastructure of the Future study, January, 2019

U.S. Transmission Miles in relation to Electricity Generation, Peak Power, and Number of Customers

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Abstract

The transmission network connects electricity providers to end use customers, and thus, it plays a very important role in the United States' electricity network. It's important to understand how this network operates in order to make responsible decisions with future energy infrastructure investments. For the Energy Infrastructure of the Future study, we used data from the Federal Energy Regulatory Commission (FERC) to analyze the size of the transmission system in relation to the amount of electricity it carries, the number of customers it reaches, and the peak load it has to handle in a normal year. Missing and erroneous data from FERC made it difficult to perform an in-depth analysis for certain regions, but the general trends are still representative of the US-48 overall. Of the three study variables, transmission miles most highly correlated with annual consumption in terawatt hours. There were similar trends when comparing transmission miles to customers and peak load, however, with lower correlation levels between the data. In order to establish an even better understanding of the transmission network, more research should be done into the regional factors that might cause variation in miles of transmission, such as population distribution.

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Introduction

The Energy Infrastructure of the Future (EIoF) study seeks to provide a comprehensive understanding of the state of energy infrastructure in the United States throughout all stages, from fuel extraction to end use consumption. This white paper summarizes data collected from the Federal Energy Regulatory Commission Form 1 – Electric Utility Annual Report. FERC Form 1 “is a comprehensive financial and operating report submitted annually for electric rate regulation, market oversight analysis, and financial audits by major electric utilities, licensees and others” (FERC, 2018). The goal of this paper is to achieve a better understanding of current and future needs of electrical transmission systems in the United States by providing analysis of the relation between miles of transmission lines and their peak load, electrical generation, and number of customers serviced. For the purposes of this study, the country is divided into geographic regions established by the EIoF project (see Figure 1). The regional definitions enable us to investigate broad geographical differences in energy infrastructure quantities, costs, regulations, and customers that can be compared to trends for the continental United States. In total, there are 13 regions comprised of one or more states.

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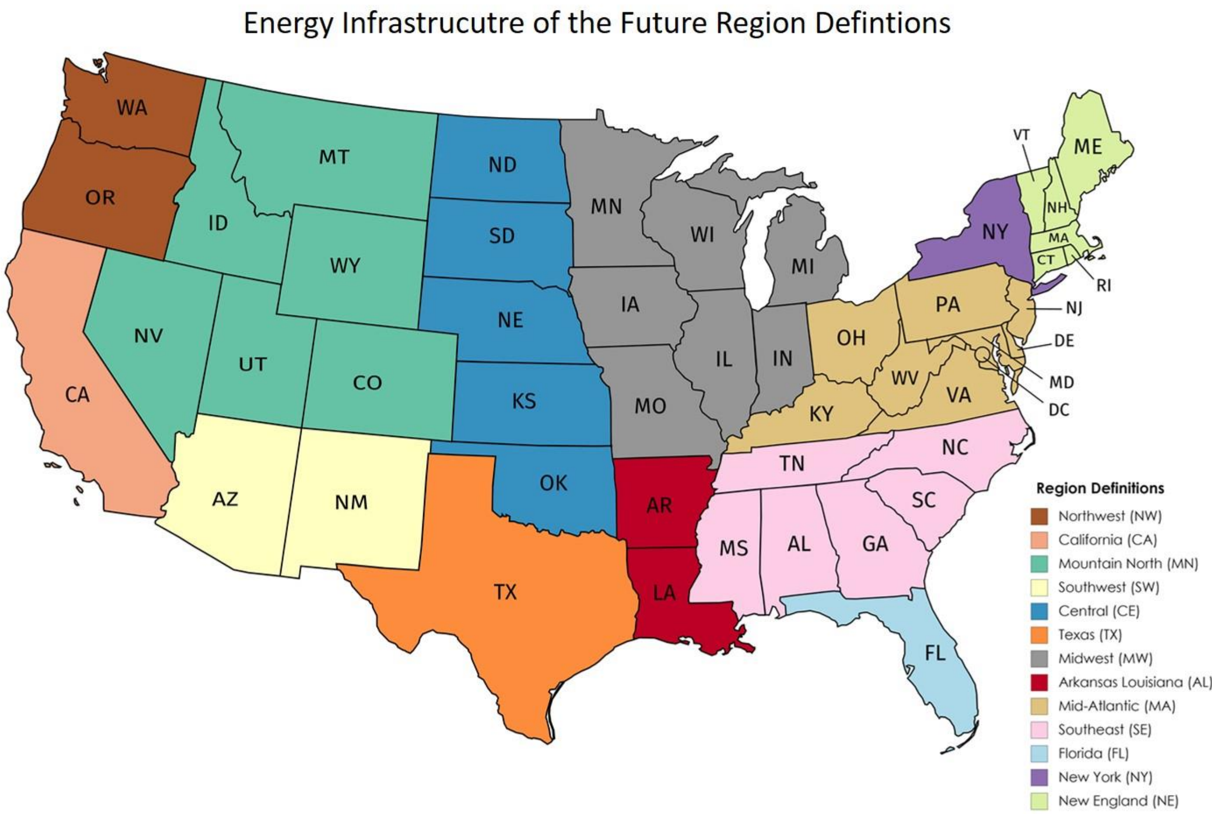

Figure 1. Regional definitions used for analysis in the Energy Infrastructure of the Future study

The electric grid serves customers who demand both energy (kWh over some time period) and power (kW at each instant). Fares and King (2017) previously used data from FERC Form 1 to relate transmission and distribution (T&D) utility expenditures to the number of customers, peak demand, and annual electricity consumption. We now perform an analysis similar to Fares and King (2017) but by relating how annual electricity consumption, peak power demand, and the number of customers relate to the total mileage of transmission lines instead of utility spending. For this analysis, we assume all power line data represent transmission lines, rather than lower voltage distribution lines, per reporting instructions outlined on Form 1. The reasoning for this is summarized below in the *Explanation of Methods* section.

Analysis and Discussion

Figure 2 shows a time series of the miles of transmission per region from 2004 to 2016. Overall, there was a 13% increase in miles of transmission line from 2004 to 2016 in the U.S. The Mid-Atlantic (MA) region has the most transmission miles; in addition, this region also had the highest percent increase in miles of transmission, adding 13,000 miles over the thirteen-year time period. Table 1 shows the percent change in miles of transmission from 2004 to 2016 by region. Only three regions showed a percentage increase that was significantly higher than the U.S.-48 overall. These are the MA region, the New England (NE) region, and Texas (TX).

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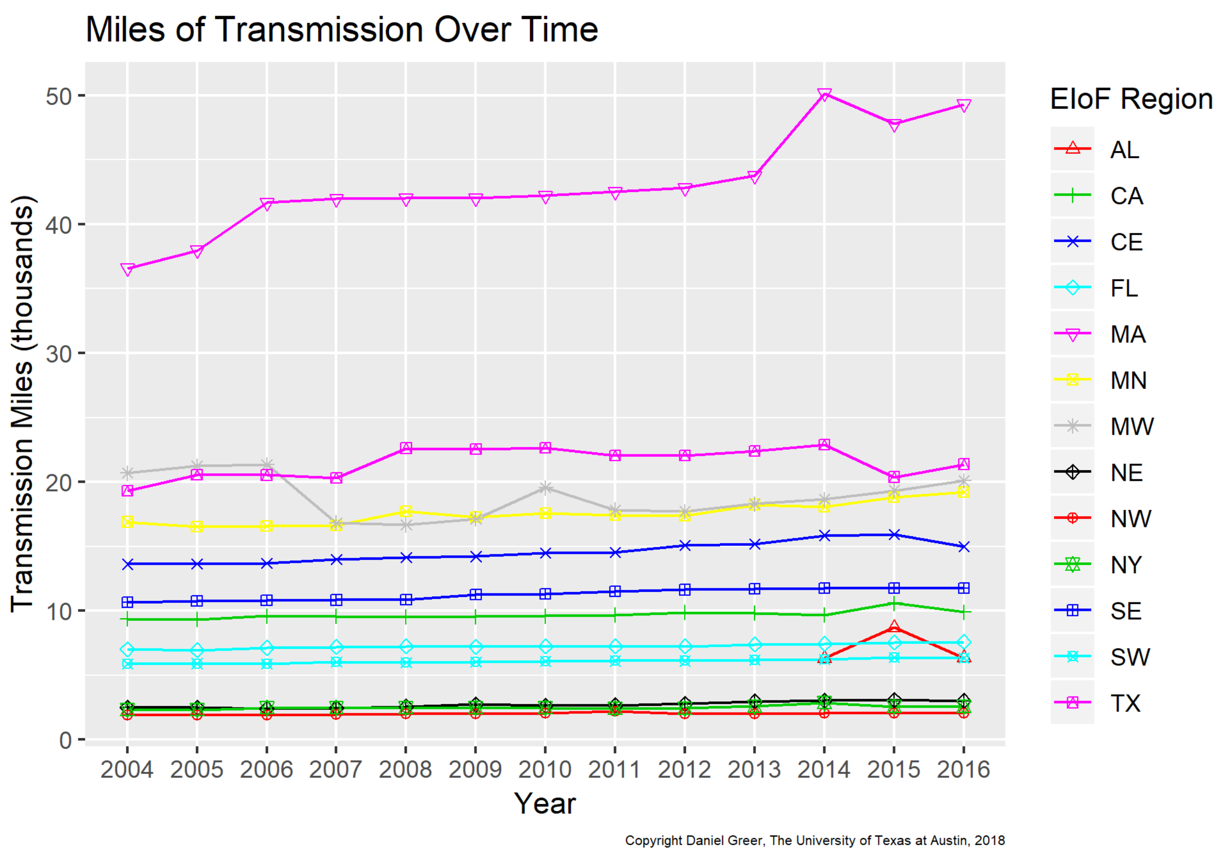

Figure 2. Miles of transmission (all voltage ratings) per region 2004-2016

Table 1. The percentage change in transmission miles, per region 2004-2016.

REGION	PERCENT CHANGE IN MILES OF TRANSMISSION (2004-2016)
AL	-17.2%
CA	5.6%
CE	10%
FL	8%
MA	34.8%
MN	13.7%
MW	-2.9%
NE	21%
NW	7.6%
NY	10.9%
SE	10.7%
SW	7.9%
TX	19.4%
U.S.	13%

The following Figures 3-5 represent miles of transmission compared to each of our study variables and show a positive correlation in each instance. Figure 3 shows the relationship between miles of transmission and annual energy (terawatt hours) reported as transmitted across that transmission system.

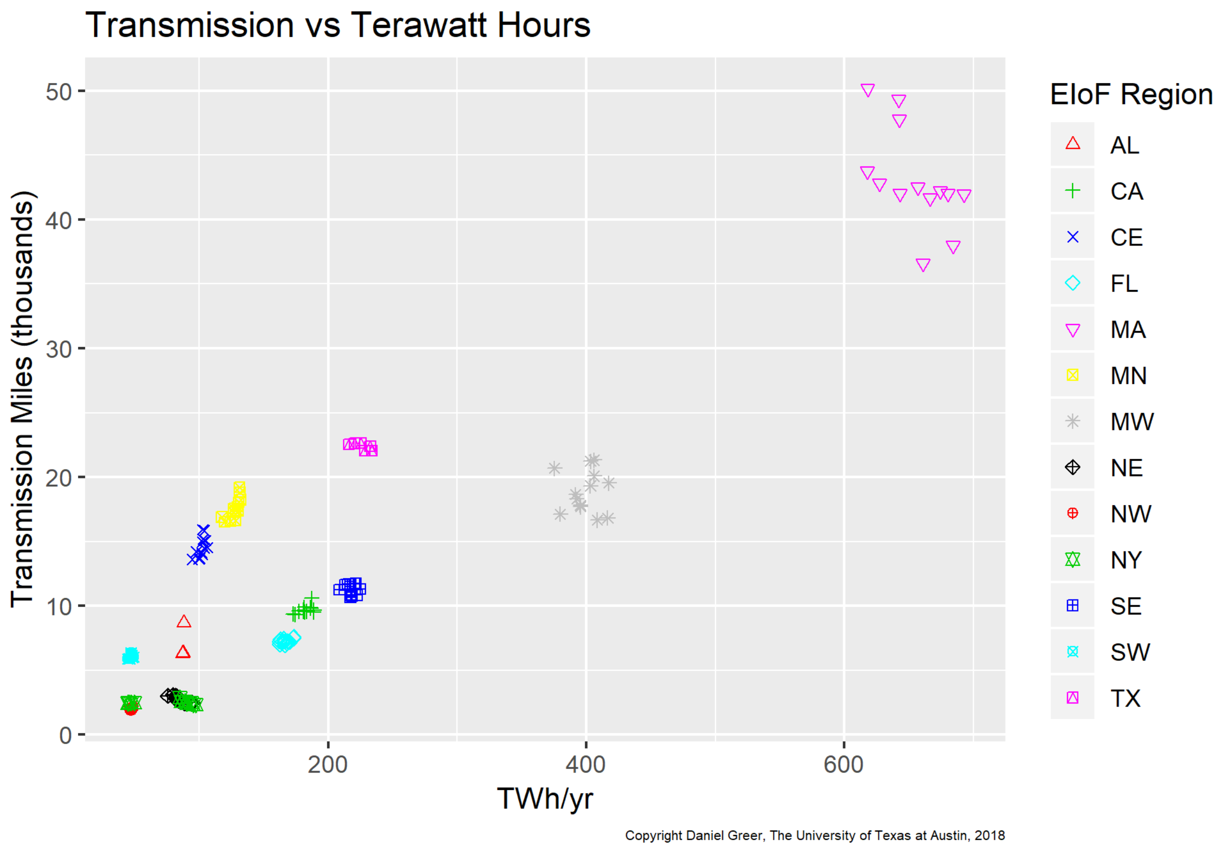

Figure 3. Miles of 132 kV or greater transmission power lines versus annual electricity consumption (TWh/yr). Transmission miles (thousands) = 1.71 + 0.06*TWh/yr (r^2 = 0.79)

A linear regression of transmission miles as a function of terawatt hours provides an R^2 value of 0.79, higher than regressing miles to peak GW or the number of customers. Though there is not a single, clear trend for all regions, further analysis might suggest that these regions fall into two groups following different trends based on annual output from the region. Some regions show a sharper rise in transmission miles, but lower overall output, while others have higher output with fewer additions to transmission. This demonstrates the geographic variations regarding infrastructure needs in different regions.

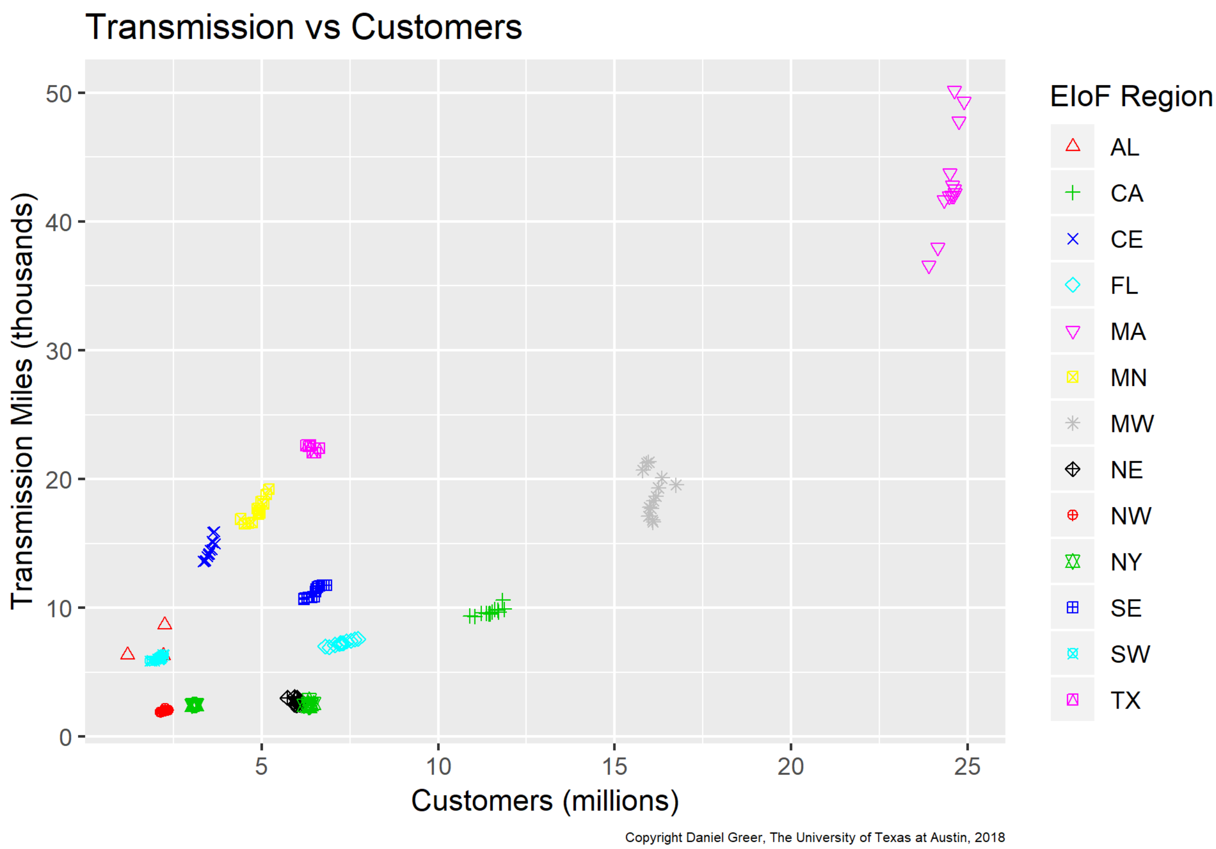

Figure 4. Total Miles of transmission power lines versus average number of utility customers. Transmission miles (thousands) = 1.93 + 1.4*Customers (r^2 = 0.71)

Figure 4 compares the number of customers in a region to the miles of transmission in that region. As expected, we see similar trends as in Figure 3. As the number of customers increase, power and energy demand increase, necessitating additional transmission connecting generation to load centers. Fares and King (2017) also indicated that all of power demand, energy consumption, and the number of customers were highly correlated to T&D utility spending, with customers having the highest correlation to spending. However, the miles of transmission are less correlated to the number of customers (r^2 = .63) than they are to the TWh transmitted.

Figure 5 shows the relationship between miles of transmission and the annual peak load on the transmission system. Again, higher peak power demand correlates to more miles of transmission. From 2004 to 2013, there was a 2.5% increase in reported peak load for all 13 regions, or the US-48 states. Following 2013 period, the reported peak load decreased 22% in just one year, and as we discuss below, these are likely related to erroneous data from two primary regions (AL: Arkansas-Louisiana and SE: Southeast). Eleven of the regions fall along a consistent linear trend running from the Northwest (NW) to the Mid-Atlantic (MA) region. The Southeast (SE) and Florida (FL) regions fall along a different pattern with much fewer high-voltage (> 132 kV) transmission miles per peak power demand. These two regions might rely much more heavily on lower voltage transmission and have geographic and climatic differences (hot and humid southern regions) that account for the different pattern.

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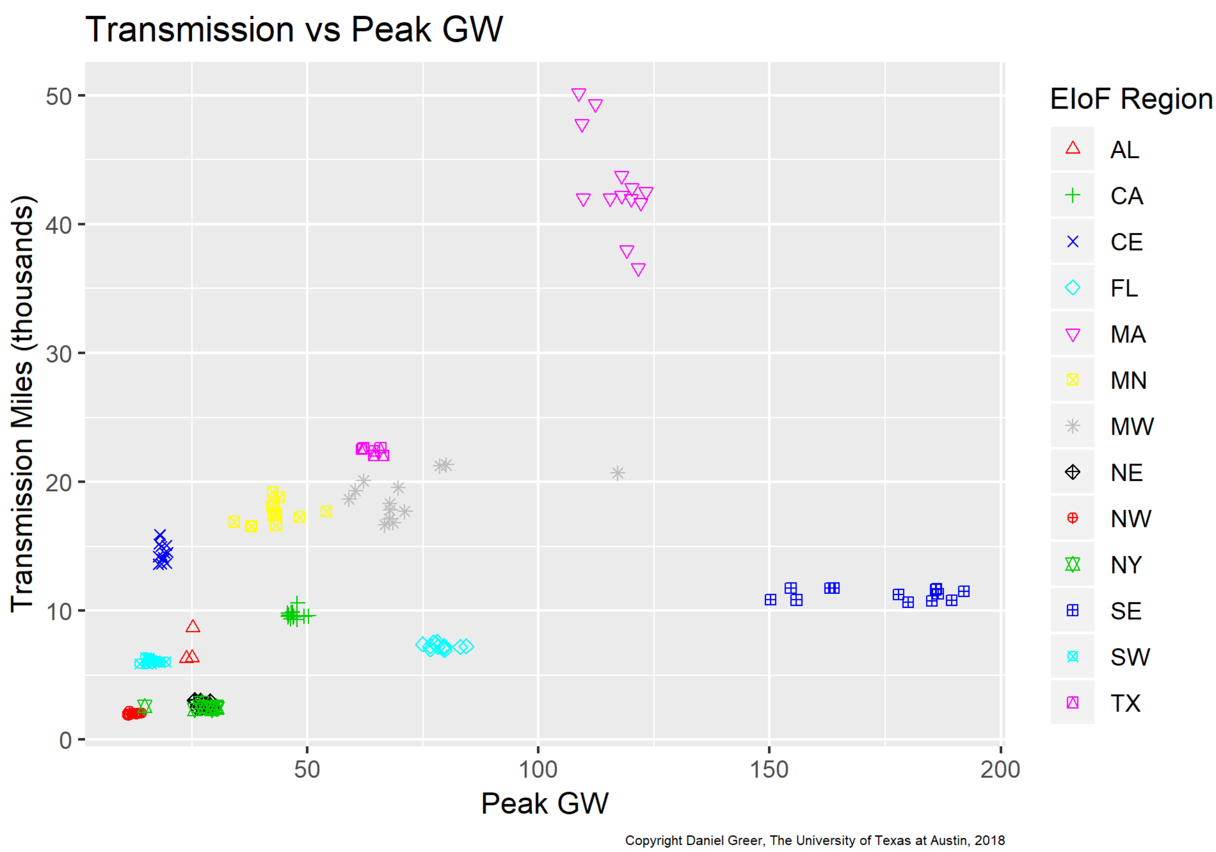

Figure 5. Total Miles of transmission power lines versus the coincident peak regional monthly power demand (GW).

The SE shows a large range, 150 to 200 GW, for peak load, even though there is very little variation in transmission miles. Figure 6 shows a time series plot of the annual peak GW load in the SE region. Here we can see fluctuating loads for the region with significant drops from 2006 to 2008 and 2013 to 2016. However, the data do not reveal anything obvious that may have caused these drops More research should be done to analyze any possible reasons for drops in peak load. Regardless, the SE region likely has high voltage transmission that is not being used to its full capacity.

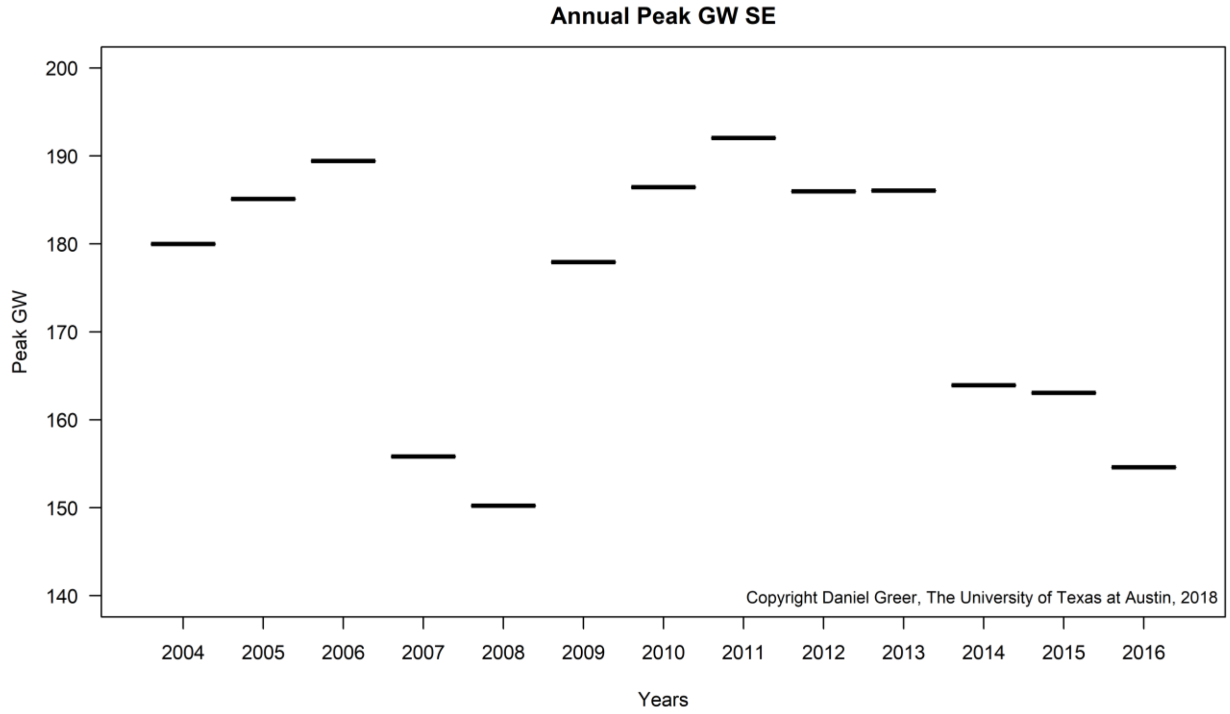

Figure 6. Peak GW over the transmission over time in the SE Region

The Florida (FL) region data also exist somewhat outlying the general pattern between transmission miles and peak load of Figure 5. Similar to the SE region, each of the peak demands occurred during the summer months of either July or August. This is reasonable due to the geographic similarities of these two regions. Florida also saw a large increase in total customers (14%) despite miles of transmission remaining constant. This reinforces our theory of existing transmission not being used to its full capacity and possible reliance on lower voltage transmission.

The data for the Arkansas/Louisiana region (AL) are inconsistently reported. For reasons as follows, we only report three data points in Figure 5 as estimates for 2014-2016. From 2004 to 2016, the four subsidiaries of the company Entergy Corp. report the same values for peak load, and we think this largely overstates the total regional peak by counting the same load four times (through 2013). While this pattern continued, in 2014, all four of these companies started reporting peaks that were more than 40% lower compared to previous years. Together, these companies accounted for a reduction of approximately 85 GW to the annual peak load near 50 GW reported for 2014-2016. We believe this to be an error in how the data were reported. In Figure 5, we report values only for 2014-2016, and we do not count the reported peak MW for Entergy subsidiaries more than one time. Other data, such as the state summary data reported by the Energy Information Administration, imply that Arkansas and Louisiana have peak generation well below 50 GW and closer to 20-30 GW.

Conclusion

Energy (terawatt hours) and number of customers serviced proved to be effective metrics for estimating miles of high voltage transmission. Both relationships show high correlation in the data. However, there is a lower and less clear correlation of transmission miles to peak power flow across transmission even though one major driver for transmission is to meet peak power flow. It is possible that there is a higher correlation of transmission miles to a combination of our study variables, however, due to discrepancies in the data, additional research is required to determine which of energy, customers, or peak demand might be responsible for a need for more transmission. Further investigation should take into account regional variation in customer distribution as well as lower voltage transmission for which reporting is not required in FERC Form 1.

References

Fares, Robert L. and King, Carey W. (2017) Trends in transmission, distribution, and administration costs for U.S. investor-owned electric utilities, *Energy Policy*, 105 (June 2017), 354-362, doi: 10.1016/j.enpol.2017.02.036.

Federal Energy Regulatory Commission. (2018). *FERC Form No. 1 - Annual Report of Major Electric Utility* [Multiple data files]. Retrieved from https://www.ferc.gov/docs-filing/forms/form-1/data.asp?csrt=9631626665246131585

Explanation of Methods

Data Collection

Using the information provided in FERC Form 1, we compiled several data sets describing expenditures, revenues, asset values, and outputs of major electric utilities by year from 2004 to 2016. Only entities classified as "major electric utilities" report using Form 1[1].

From these data sets, we extracted data, organized by utility, for the annual mileage of transmission lines owned, monthly peak power (gigawatt), annual average number of customers serviced, and annual energy transmitted (terawatt hours, TWh). Each of these data subsets was aggregated by region and year to find the total for each region in each year. To calculate an annual peak megawatt for a transmission utility, we used the highest monthly peak for that year. We compare the total number of miles of power lines to three different independent variables.

[1] Major utilities are described as maintaining one of the following statuses for three calendar years: 1) 1 million MW hours of annual sales 2) 100 MW hours of sales for resale 3) 500 MW hours of annual power exchanges delivered 4) 500 MW hours of annual wheeling for others

These variables are the annual peak gigawatt load on the transmission system, the average number of customers serviced by the utilities, and the annual TWh of electricity output. Here we describe the metrics derived from the data in FERC Form 1. The data are listed for single utilities, and we aggregate the data into our study regions based on those geographical definitions established by the EIoF project.

Summary of Data Used

1. Miles of transmission: This data came from page 422 of FERC Form 1
    a. Transmission is defined in FERC's Uniform System of Accounts[2]
    b. Each line of 132 kV or higher is required to be reported
    c. Lines lower than 132 kV are reported in group totals
    d. In this study, we sum the miles of transmission lines owned by all utilities
2. Peak power flow (GW): This data came from page 400 of FERC Form 1
    a. Data represents the monthly peak load on a utilities transmission system
    b. The monthly peak load was summed for all utilities in a region
    c. The highest monthly peak for a region for each year is used for comparison
3. Number of Customers: This data came from page 300 of FERC Form 1
    a. Utilities report average number of customers per month per year
    b. Customers include residential, commercial and industrial customers
    c. Average number of customers was summed per region per year
4. Annual electricity generation (TWh/year): This data came from page 300 of FERC Form 1

[2] "All lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply" (FERC Uniform System of Accounts, 2018)

a. Utilities report the total number of MWh sold in a year
b. Generation was summed per region per year

It is important to note that only lines rated for 132 kV or higher are required to be reported. Because of this, we cannot be certain what proportion of total low voltage distribution lines are reported in FERC Form 1[3]. Thus, in order to provide the most accurate analysis possible, we removed any data representing lines rated for less than 132 kV. The resulting dataset consisted of 4,771 observations aggregated into the 13 regions shown in Figure 1 for each year of 2004 through 2016.

[3] Distribution lines are rated for a lower voltage than transmission lines