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Effects of aggregating electric load in the United States

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ABSTRACT

This study quantifies the effects of aggregating electric load over various combinations (Aggregation Groupings) of the 10 Federal Energy Regulatory Commission (FERC) regions in the contiguous U.S. Generator capacity capital cost savings, load energy shift operating cost savings, reserve requirement cost savings, and transmission costs due to aggregation were calculated for each Aggregation Grouping. Eight scenarios of Aggregation Groupings over the U.S. were formed to estimate overall system cost. Transmission costs outweighed cost savings due to aggregation for all scenarios and nearly all Aggregation Groupings. East–west transmission layouts had the highest overall cost, and interconnecting ERCOT to adjacent FERC Regions resulted in increased costs, both due to limited existing transmission capacity. This study found little economic benefit of aggregating electric load alone (e.g., without aggregating renewable generators simultaneously), except in the West and Northwest U.S. If aggregation of load alone is desired, small, regional consolidations yield the lowest overall cost. This study neither examines nor precludes benefits of interconnecting geographically-dispersed renewable generators with load. It also does not consider effects from sub-hourly load variability, fuel diversity and price uncertainty, energy price differences due to congestion, or uncertainty due to forecasting errors; thus, results are valid only for the assumptions made.

1. Introduction

This study examines the effects of interconnecting electric load from various geographic areas of the contiguous U.S. through an enhanced transmission grid. These effects were translated into system costs, which include generator capacity capital cost savings, load energy shift operating cost savings, reserve requirement cost savings, and additional transmission line capital costs. In order to isolate the effects of aggregating load alone, this study does not consider the effects of aggregating geographically-dispersed renewable generators.

Previous studies on geographic aggregation have focused primarily on the effects of interconnecting renewable energy generation of either a single variable resource – such as wind and solar power – over a large geographic area, or of a portfolio of complementary renewable energy technologies. In both cases, the individual components are often negatively or weakly correlated, allowing for an overall smoothing of the aggregated supply. One of the earliest studies documenting the benefits of geographic aggregation was by Kahn (1979), who calculated the correlation, or linear dependence, of wind speed among six California sites to show that correlation decreases as distance between sites increases. Recent studies have demonstrated various benefits of interconnecting wind farms across a large geographic area, including reduction in the occurrence of zero and maximum wind power output, resulting in a smaller range of overall wind power fluctuations (Archer and Jacobson, 2007; Holttinen, 2005; Kempton et al., 2010; Sinden, 2007; Wan et al., 2003); reduction in the standard deviation of wind power variations, yielding a smoother power output (Beyer et al., 1993; Estanqueiro, 2008; Holttinen, 2005; Wan et al., 2003); and a reduction in ramp rate magnitudes and an increase in the aggregate wind capacity factor (King et al., 2011). Solar photovoltaic studies have shown similar aggregation benefits due to the same spatial correlation relationship (Wiemken et al., 2001). Changes in cloud cover can result in steep variations in power output, but aggregating geographically diverse solar resources has been shown to reduce variability on both short and longer time scales (combined range of 1–180 min) (Mills et al., 2009; Mills and Wiser, 2010). For solar PV plants, the benefits of geographic aggregation are due primarily to the stochastic fluctuations of cloud cover, but additional fluctuations occur due to the deterministic position of the sun. In general, the extent of the benefits of geographic aggregation of wind or solar resources depends on the scale of the temporal and spatial differences between the individual generators.

A number of renewable energy integration studies have stated that geographic aggregation of load is likewise desirable. These

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studies conclude that combining balancing areas reduces load variability through geographic and temporal diversity (EnerNex Corporation, 2010; European Climate Foundation, 2010; GE Energy, 2010; Gramlich and Goggin, 2008; Holttinen et al., 2007; Kirby and Milligan, 2008; Miller and Jordan, 2006); allows for a larger pool of flexible generating resources (EnerNex Corporation, 2010; European Climate Foundation, 2010; GE Energy, 2010; Gramlich and Goggin, 2008; Holttinen et al., 2007; Kirby and Milligan, 2008); reduces peak generator capacity, raises the minimum load, and increases the load factor (King et al., 2011); reduces ramping requirements for load (King et al., 2011; Milligan and Kirby, 2008); reduces requirements for certain ancillary services for load alone (EnerNex Corporation, 2006); and reduces the cost of serving load (Milligan and Kirby, 2010). However, quantitative results supporting these statements are either given for limited geographic areas or lack transparent methodologies. For example, a wind integration case study of New York state showed that combining the operation of the eleven zones in the New York power system reduced hourly variability of load by 5% and 5-min variability by 55% (Miller and Jordan, 2006), and a wind integration study of Minnesota (EnerNex Corporation, 2006) demonstrated that consolidating all balancing areas within the state reduced the regulation reserve capacity required for load alone by almost 50% and had additional load following reserve benefits for load alone. Studies of larger geographic areas, such as the Western Wind and Solar Integration Study (WWSIS) (GE Energy, 2010) and the Eastern Wind Integration and Transmission Study (EWITS) (EnerNex Corporation, 2010), provided evidence of variability reduction due to geographic aggregation, but focused primarily on the benefits of combining renewable energy generation with load within one region. A large-scale European study of the integration of renewable energy stated that a transmission grid connecting Europe would reduce the variability and ratio of peak to minimum electric load, but the report provided limited quantitative results and methodologies to demonstrate these specific load aggregation benefits (European Climate Foundation, 2010).

To date, there has been no large-scale analysis published that quantifies the effects of aggregating electric load throughout the U.S. by enhancing the transmission system. The objective of this research was to calculate the effects of interconnecting temporally and geographically varying electric loads in the contiguous U.S. Various combinations of regional groupings and the resulting impacts on generator capacity requirements, generation operation, reserve requirements, and transmission capacity requirements were evaluated. This study did not consider the impact of integrating renewable resources into the grid, nor did it evaluate additional load aggregation effects from sub-hourly load variability, fuel diversity and price uncertainty, energy price differences due to congestion, or uncertainty due to forecasting errors.

2. Study structure and data

This section discusses the contiguous U.S. electric system, the geographic structure for this study, and the corresponding data used in this study.

2.1. FERC Regions

This analysis covers the 10 Federal Energy Regulatory Commission (FERC) Regions. The FERC Regions encompass the contiguous U.S. and consist of seven independent system operators (ISOs)/regional transmission organizations (RTOs) and three non-ISO/RTO FERC Regions. The ISO/RTO FERC Regions are ISO New England (ISONE), New York ISO (NYISO), PJM Interconnection (PJM), Midwest Independent Transmission System Operator (MISO), Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT), and California ISO (CAISO). The non-ISO/RTO FERC Regions are Northwest (NW), Southwest (SW), and Southeast (SE). For this analysis, a modified “All CA” FERC Region, consisting of CAISO plus all non-ISO entities within California, was used. Fig. 1 shows a map of the FERC Regions. Boundaries were approximated using publicly-available FERC maps and purchased GIS transmission data (Rextag Strategies, 2008).

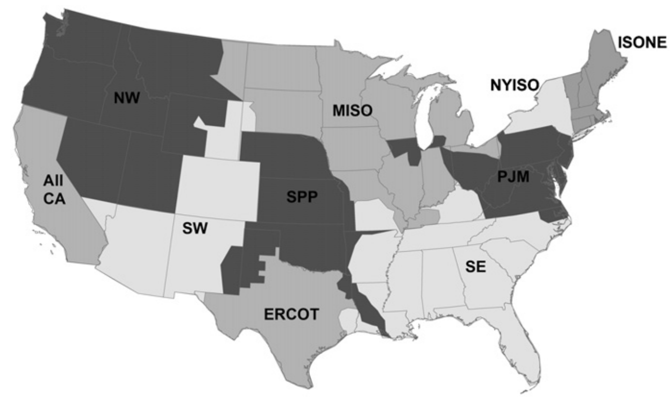

Fig. 1. Federal Energy Regulatory Commission (FERC) Regions.

The nameplate generator capacity that existed in 2006 within each FERC Region is shown in Fig. 2. Data were collected by state (U.S. Energy Information Administration, 2008) and aggregated into the FERC Regions based on the approximate percentage of land area that each state has within each FERC Region. The SE FERC Region has notably the largest total installed capacity, followed by the PJM and MISO FERC Regions. Fossil fuel generators – mainly coal and natural gas – dominate all FERC Regions, except for the NW FERC Region, which consists primarily of hydroelectric generators and is the only FERC Region to have a significant portfolio contribution from renewable energy. Most of the nuclear and coal generator capacity is in the East and Midwest areas of the U.S.

2.2. Electric load data for FERC Regions

Hourly electric load data were collected for each FERC Region for 2006 and 2007. Load data were gathered from the ISO/RTO websites for ERCOT (Electric Reliability Council of Texas, 2005–2007), SPP (Southwest Power Pool, 2000–2007), MISO (Midwest ISO, 2005–2006, 2006–2007), PJM (PJM Interconnection, 2005–2007), NYISO (New York ISO, 2005–2007), and ISONE (ISO New England, 2005–2007). Load data for All CA, NW, SW, and SE were obtained from FERC's Form 714 Submission and Viewer softwares, (Federal Energy Regulatory Commission, 2006–2007). Hourly data were converted to Greenwich Mean Time (GMT). For reference, GMT is 5 h ahead of Eastern Standard Time.

Fig. 3 shows the resulting hourly load time series for all FERC Regions for 2006–2007. Daily averages of these hourly load values are displayed in Fig. 4. Fig. 5 shows one summer week of hourly load values for all FERC Regions from July 16–22, 2006, while Fig. 6 shows one winter week from January 22–28, 2006. In Figs. 3–6, all hours are in GMT, and the loads are the average value for an hour ending at the given time (e.g., data for hour 1 in Figs. 3 and 4, and 1 am in Figs. 5 and 6, are the average load values during the hour ending at 01:00).

Figs. 3 and 4 illustrate the varying magnitudes and seasonal trends of electricity demand in the FERC Regions. The SE, PJM, and MISO FERC Regions, all in the Eastern U.S., are large and contain

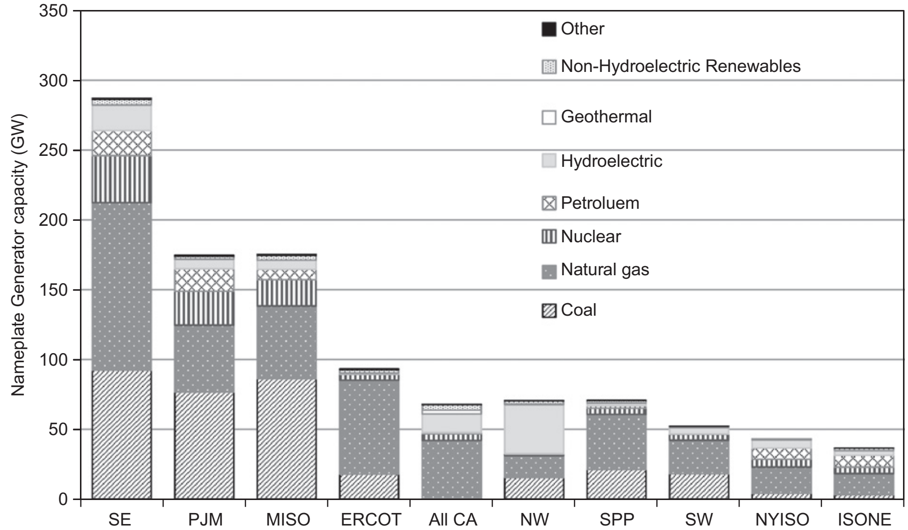

Fig. 2. 2006 Generator Capacity by FERC Region. *"Non-Hydroelectric Renewables" include biomass, solar thermal, PV, wind, wood and wood fuels. "Hydroelectric" includes hydroelectric and pumped storage.*

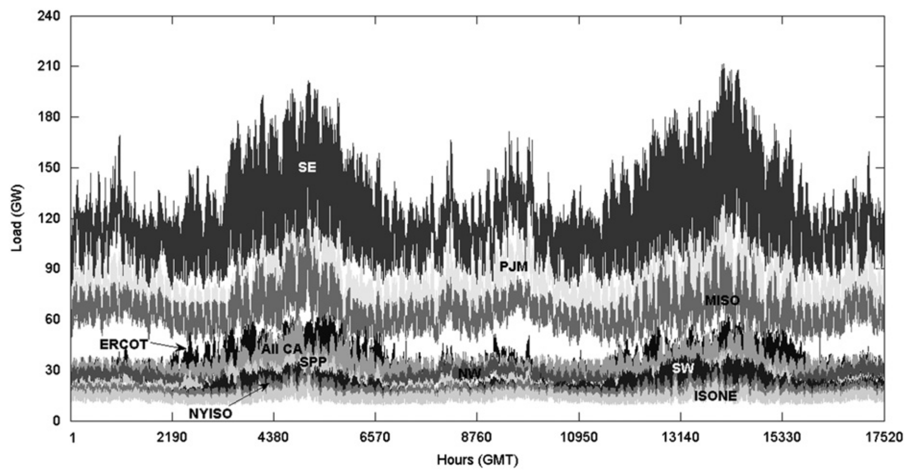

Fig. 3. Hourly Electric Load in Each FERC Region for 2006–2007. *Hour 1 is 01:00 on January 1, 2006.*

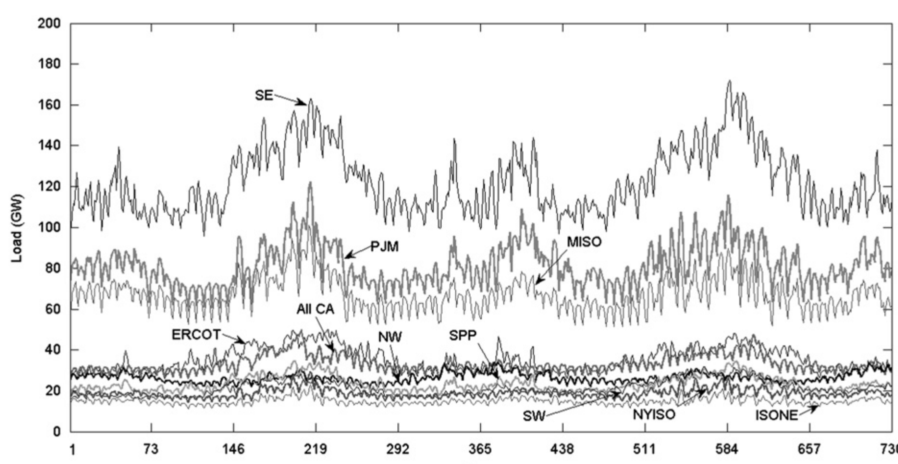

Fig. 4. Daily average electric load in each FERC Region for 2006–200**7**. *Day 1 is January 1, 2006.*

heavily populated urban load centers. All FERC Regions peak during the heavy air conditioning summer months, except for the winter-peaking NW FERC Region. The summer peak values are generally larger in 2006 than in 2007, except for the SE FERC Region, which has larger summer peak values in 2007. The West, Midwest, and Northeast areas of the U.S. experienced severe heat during 2006, while the Southeast area faced intense heat waves in 2007. During the winter months, there are unexpected short

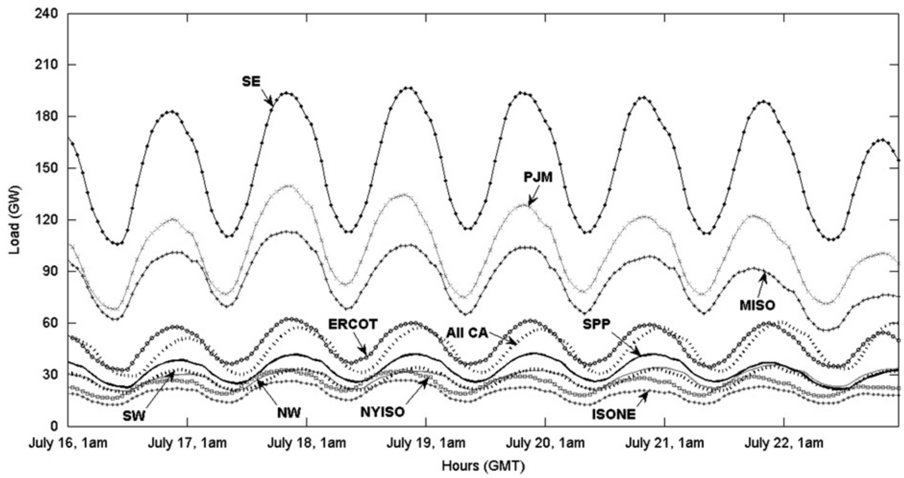

Fig. 5. Summer hourly electric load in Each FERC Region for July 16, 2006 (Sunday) to July 22, 2006 (Saturday).

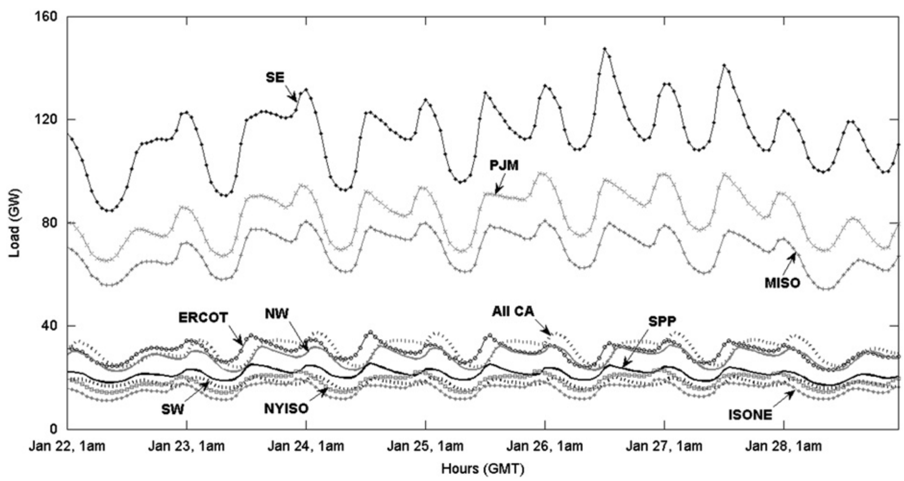

Fig. 6. Winter hourly electric load in Each FERC Region for January 22, 2006 (Sunday) to January 28, 2006 (Saturday).

Table 1
Aggregation Groupings and constituent FERC Regions.

Aggregation Grouping	Constituent FERC Regions
East	MISO, SPP, SE, PJM, NYISO, ISONE
West	All CA, NW, SW
All East	ERCOT, MISO, SPP, SE, PJM, NYISO, ISONE
East Coast	SE, PJM, NYISO, ISONE
Mid-East	MISO, SE
North	NW, MISO, PJM, NYISO, ISONE
Mid-North	NW, MISO
South	All CA, SW, SPP, ERCOT, SE
Mid-South	SW, ERCOT, SPP
Central	ERCOT, SPP, MISO
Northwest	All CA, NW
Mid-Northwest	All CA, NW, MISO
Northeast	PJM, NYISO, ISONE
Mid-Northeast	MISO, PJM, NYISO, ISONE
Southeast	ERCOT, SPP, SE
Mid-Southeast	ERCOT, SPP, MISO, SE
Southwest	All CA, SW
Mid-Southwest	SW, SPP, ERCOT, MISO
Mid-West-South	MISO, SE, SPP
Mid-All-South	SW, SPP, ERCOT, SE
Central-Southwest	All CA, SW, SPP, ERCOT

spikes in load for Southern areas of the country (mainly SE and ERCOT), which are likely due to the use of electric heaters during cold winter days.

Fig. 5 zooms in on one summer week in 2006, while Fig. 6 zooms in on one winter week in 2006. There is a double peak in the winter daily load profiles during (local time) late-morning and evening (Fig. 5), while the summer load is characterized by a single (local time) mid- or late-afternoon peak (Fig. 6). The summer loads are generally larger than the winter loads, and the electric load decreases slightly during the weekend (Saturday and Sunday).

2.3. Aggregation Groupings

In order to analyze the electric load data for aggregation benefits, various groupings of FERC Regions were created. The twenty-one Aggregation Groupings each consist of clusters of two or more adjacent FERC Regions and represent possible combinations of interconnected geographic areas of the contiguous U.S. Table 1 summarizes these Aggregation Groupings and their constituent FERC Regions.

2.4. Transmission distances for interconnection

A simple transmission topology was formulated to estimate the relative transmission distance required for the interconnection of each Aggregation Grouping. This network consists of one node at the geographic center of each FERC Region and a segment connecting nodes between each adjacent FERC Region. Alternative

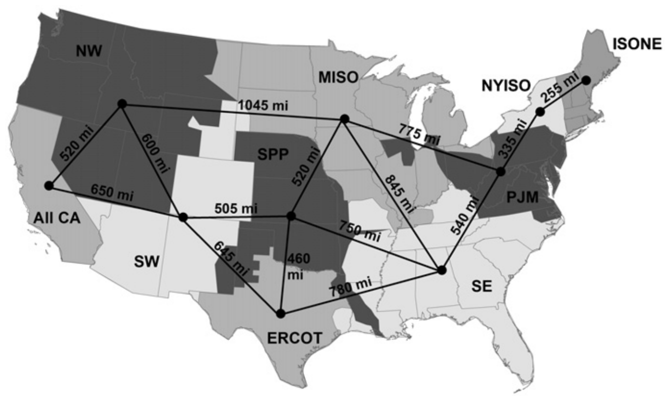

Fig. 7. FERC Regions with transmission topology. *Proxy values for transmission line distances (miles) are shown for each segment.*

Table 2
Transmission distance required to interconnect Aggregation Groupings.

Aggregation Grouping	Transmission distance for interconnection (miles)
East	4020
West	1770
All East	5260
East Coast	1130
Mid-East	845
North	2410
Mid-North	1045
South	3790
Mid-South	1610
Central	980
Northwest	520
Mid-Northwest	1565
Northeast	590
Mid-Northeast	1365
Southeast	1990
Mid-Southeast	3355
Southwest	650
Mid-Southwest	2130
Mid-West-South	2115
Mid-All-South	3140
Central-Southwest	2260

configurations for node placement and connecting segments were considered but were less desirable based on a sensitivity analysis. Fig. 7 shows the network topology with estimated segment distances connecting the FERC Regions. This topology assumes full interconnection within each FERC Region, so that, for example, linking two adjacent FERC Regions by the connecting segment effectively links all points within those two FERC Regions. When using this transmission topology, the existing inter-region transmission line capacities were removed to determine only the additional required capacity for each segment.

The segment distances serve as approximate proxies for the relative transmission distances required to interconnect adjacent FERC Regions. A proxy for transmission distance required for interconnection of each Aggregation Grouping was calculated by summing all segments connecting nodes between adjacent, constituent FERC Regions. Table 2 summarizes the transmission distance to interconnect the constituent FERC Regions within each Aggregation Grouping.

3. The effects of aggregating load

Electric load time series were created for each Aggregation Grouping for 2006 and 2007 by summing the hourly load time series data of all of its constituent FERC Regions. Three metrics were then calculated to evaluate the effect of aggregating electric load on

1) peak electric load,
2) shift of load energy from higher-load to lower-load hours, and
3) standard deviation of hour-by-hour load variations.

The percent change due to aggregation was evaluated for each Aggregation Grouping for each metric. Calculations were performed for 2006 and 2007 separately and then averaged. The average percent changes were plotted against the required transmission distance to show the relative transmission burden for obtaining the aggregation benefits.

3.1. Peak electric load

Two methods were used to determine the peak electric load for each FERC Region and Aggregation Grouping:

1) Method 1 provided the 99th percentile of electric load using MATLAB's built-in percentile function.
2) Method 2 used the load value at 2.4 h on the load duration curve (LDC) as the peak value. This 2.4 h criterion was taken from the common loss of load expectation (LOLE) standard of 2.4 h/year (approximately 1 day per 10 years). This study did not use the LOLE standard as a measure of reliability, but rather as a benchmark for quantifying the peak electric load.

LDCs were created for each FERC Region and Aggregation Grouping by sorting the load values for each year from highest to lowest and then plotting the resulting curve so that hour 1 contained the largest load value and hour 8760 contained the smallest. The peak load value was interpolated at 2.4 h on each FERC Region LDC and Aggregation Grouping LDC.

The percent decrease in peak electric load was then calculated for each Aggregation Grouping using Eq. (1) with the peak load values obtained from Methods 1 and 2.

$$\left(\frac{\sum(\text{Constituent FERC Region Peak Load})-\text{Aggregation Grouping Peak Load}}{\sum(\text{Constituent FERC Region Peak Load})}\right)*100\% \quad (1)$$

Fig. 8 shows the percent decreases in peak load values for each Aggregation Grouping for Methods 1 and 2. Aggregation Groupings

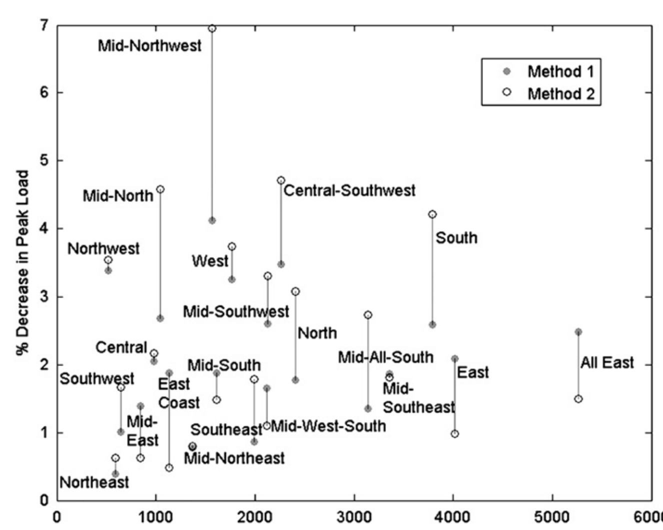

Fig. 8. 2006 and 2007 average percent decrease in peak load.

in the upper left section of this plot are the most desirable, as they have the largest relative aggregation benefit for the smallest transmission distance.

Peak load is an indicator of the required generator capacity, as the generation system is sized to accommodate the maximum expected load with a certain probability of failing to do so. The peak loads calculated with Methods 1 and 2 are, therefore, indications of the generator capacity required. Aggregating electric load results in generator capacity savings, which can be realized as fewer and/or smaller generators, with a direct savings in capital costs.

The 15 highest-load hours of the LDCs for 2006 and 2007 are shown in Fig. 9 for the Mid-Northwest Aggregation Grouping (Fig. 9(a) and (b)) and the Northeast Aggregation Grouping (Fig. 9(c) and (d)). The Aggregation Grouping LDC is the solid line, and the sum of constituent FERC Regions LDC is the dashed line.

The generator capacity savings due to aggregation that was calculated with Method 2 was the difference in load between the solid and dashed LDC lines at 2.4 h. Some Aggregation Groupings, such as the Mid-Northwest (Fig. 9(a) and (b)), have very smooth and steady LDCs with large generator capacity savings, while other Aggregation Groupings, such as the Northeast (Fig. 9(c) and (d)), have very jagged and unsteady LDCs with small generator capacity savings.

In general, the LDCs are smooth for all Aggregation Groupings, except those in the Eastern U.S. (such as the Northeast Aggregation Grouping). This part of the country has large, coincident peak loads due to heavily populated urban load centers within the same time zone and weather systems. This lack of load diversity results in very little difference between the Aggregation Grouping LDC and the sum of individual constituent FERC Regions LDC during higher-load hours, as reflected in the lower percent savings values in Fig. 8 for the Aggregation Groupings in the Eastern U.S.

3.2. Shift of load energy from higher-load hours to lower-load hours

The load energy that was shifted from higher-load hours to lower-load hours in the LDCs was calculated by comparing the Aggregation Grouping LDCs against the sum of constituent FERC Regions LDCs.

Fig. 10 shows an example of this comparison for the Mid-Northwest Aggregation Grouping for 2006. The Aggregation Grouping LDC is the solid line, and the sum of constituent FERC Regions LDC is the dashed line. The load energy that was shifted

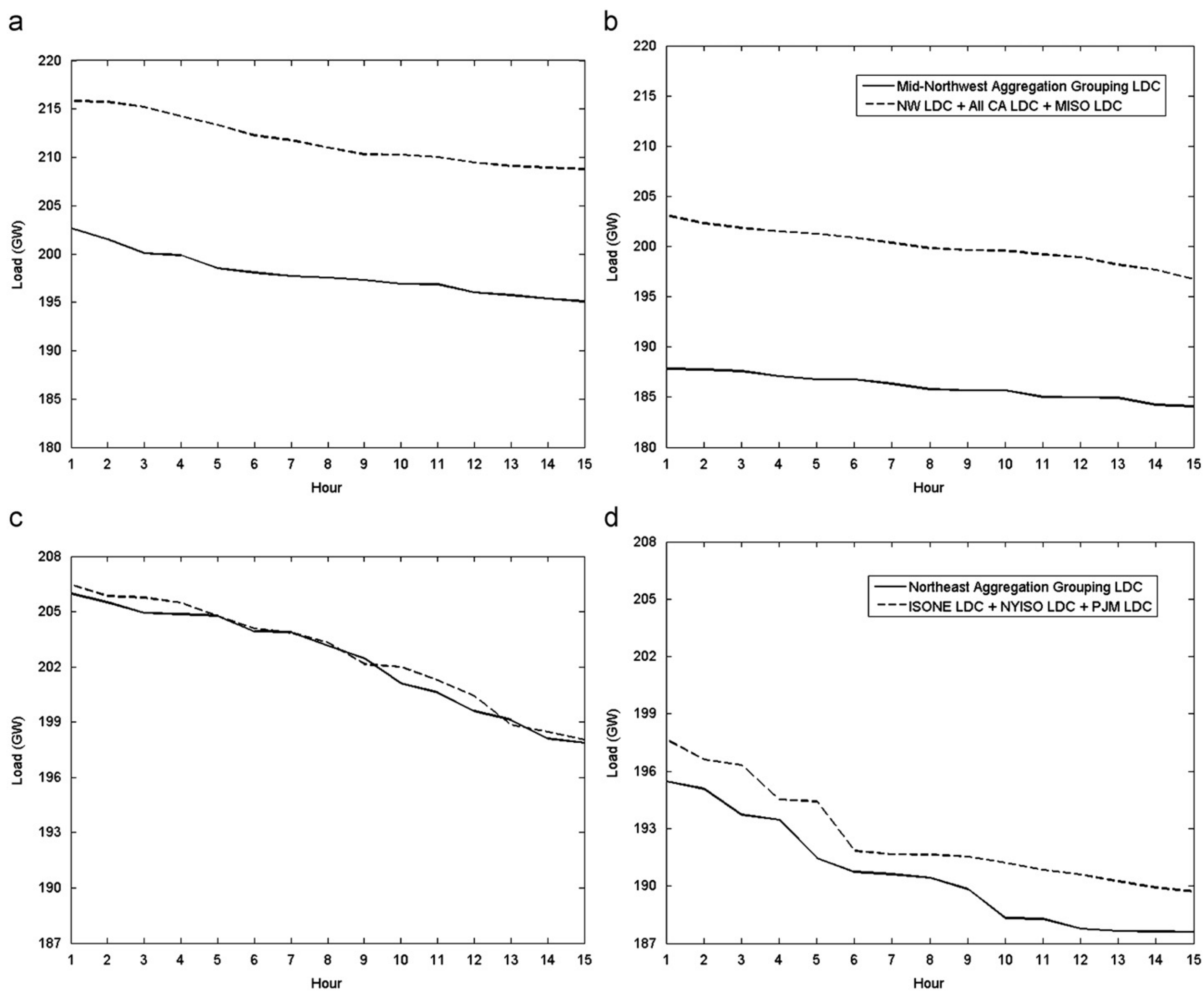

Fig. 9. Mid-Northwest 2006 (a) and 2007 (b) and Northeast 2006 (c) and 2007 (d) load duration curves.

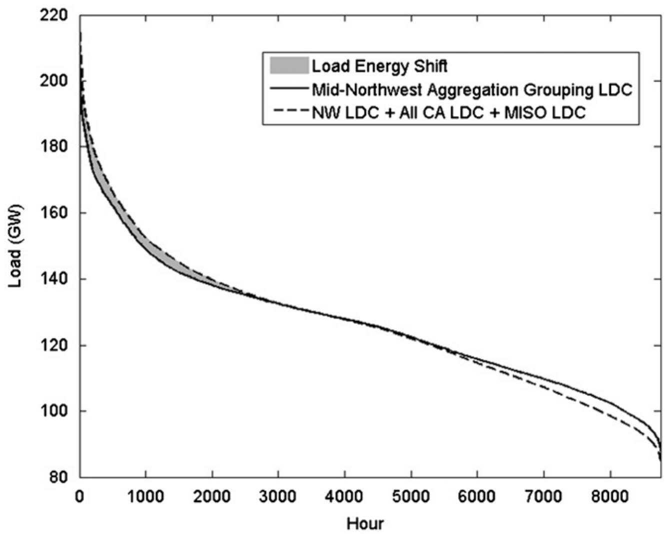

Fig. 10. 2006 load energy shift for Mid-Northwest Aggregation Grouping.

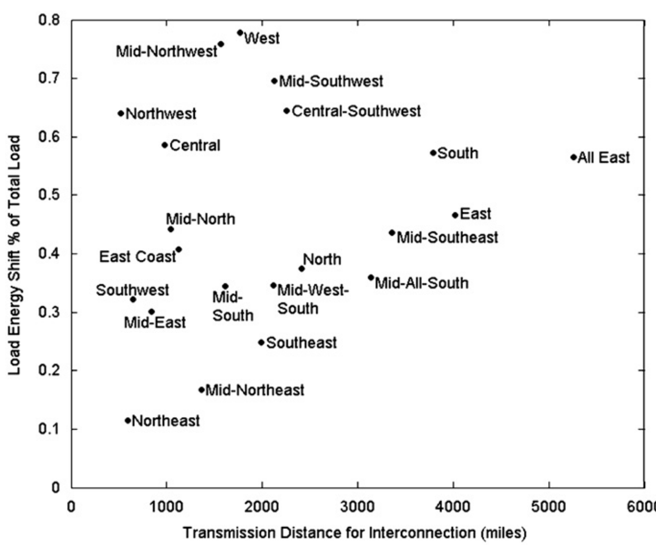

Fig. 11. 2006 and 2007 average load energy shift percent of total load.

from higher-load hours to lower-load hours is the sum of the hourly differences between the two lines when the dashed line is larger. This is shown as the gray area in Fig. 10.

Aggregation shifts energy used from higher-load hours (gray area) to lower-load hours (white area). There is no change in energy used, but rather only a shift, as the areas under both LDCs contain the same amount of energy.

The load energy that was shifted from higher-load hours to lower-load hours was calculated for each Aggregation Grouping. To determine the relative size of the shift, the load energy shift was calculated as a percent of the total load for each year using Eq. (2).

$$\left(\frac{\text{Energy Shifted due to Aggregation}}{\sum(\text{Aggregation Grouping Hourly Load Values})}\right)*100\% \qquad (2)$$

Fig. 11 shows the average of the percentage values for 2006 and 2007 for each Aggregation Grouping.

This shifting of energy from higher-load hours to lower-load hours most likely causes a shift from more-expensive generators, such as peaking plants, to less-expensive generators, such as baseload plants, resulting in operating cost savings.

3.3. Standard deviation of load variability

The changes in load from one hour to the next were tabulated for each FERC Region and Aggregation Grouping, and the standard deviations of these load variability time series were calculated.

The percent reduction due to aggregation was then calculated using Eq. (3)

$$\left(\frac{\sum(\text{Constituent FERC Region }\sigma)-\text{Aggregation Grouping }\sigma}{\sum(\text{Constituent FERC Region }\sigma)}\right)*100\% \qquad (3)$$

where σ is the standard deviation of hour-to-hour load variability. Fig. 12 shows the percent reductions for each Aggregation Grouping. Aggregation Groupings in the upper, left section of this plot have the largest relative reduction in load fluctuations with the smallest transmission distance.

The difference between 3σ of the Aggregation Grouping and the sum of the constituent FERC Regions was then calculated for each Aggregation Grouping using Eq. (4)

$$\sum(\text{Constituent FERC Region }3\sigma)-\text{Aggregation Grouping }3\sigma \qquad (4)$$

where 3σ is three times the standard deviation of load variability. Holttinen et al. (2008) showed that load following reserve requirements of a power system can be estimated using the standard deviation of the variability of the load; for the U.S., 2.3–2.5σ covers 99% of load variations, and 3.4σ covers 99.7%. For this study, 3σ was used. Eq. (4) therefore approximates the savings in load following reserve requirements due to aggregation. Load following reserve is provided by generating units that provide response on the time scale of 10–60 min and are either committed in advance or able to quick start and synchronize with the grid. These reductions in the standard deviation of load variability represent a savings in load following reserve capacity and cost.

These calculations for load following reserves neglect additional effects from uncertainty due to load forecasting errors. Holttinen et al. (2008) compared hourly load variability to load forecast variability for a case study in Finland and found that about half of the load variability can be predicted. This suggests that the load following reserves calculated for the individual FERC Regions and Aggregation Groupings in the study here are an upper bound; fewer load following reserves would be needed since some of the hour-to-hour fluctuations could be predicted.

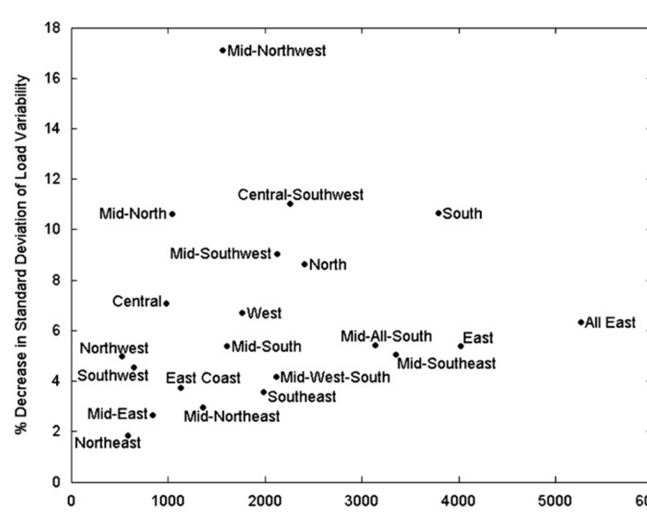

Fig. 12. 2006 and 2007 average percent decrease in standard deviation of load variability.

The amount by which the load following reserves would be further reduced for each Aggregation Grouping due to this predictability depends on the impact of aggregation on load forecasting errors. GE Energy (2010), Milligan et al. (2011), Holttinen et al. (2007), and Milligan and Kirby (2010) either demonstrated or stated that the relative forecast errors decrease as the geographic area increases, representing an aggregation benefit. Therefore, while it is difficult to predict the exact impact without actual forecast data, it is likely that the Aggregation Groupings would have additional load following reserve savings due to the load forecasting benefits from aggregation.

Since only hourly load data was available, this study also ignores additional effects from sub-hourly variability. Milligan and Kirby (2008) asserted that, since correlation between individual loads generally decreases at faster time frames, aggregating multiple loads would yield greater benefits in the sub-hourly and minute-to-minute time scale than in the hourly time scale. Such results were found in Miller and Jordan (2006), which demonstrated a greater reduction in variability with 5-min load data than with hourly data. As a result, additional generator capacity, reserve requirements, and transmission capacity benefits would likely be realized in this study on a sub-hourly time scale.

To approximate at least part of the effects of sub-hourly variability, regulation reserve requirements were estimated for each Aggregation Grouping and constituent FERC Region. Regulation reserves operate on the time scale of 1–10 min. Following the method from the WWSIS (GE Energy, 2010) and EWITS studies (EnerNex Corporation, 2010), regulation reserves were calculated as 1% of the peak load values (more specifically, these studies assumed regulation reserves were 3 standard deviations of minute-to-minute load variability, which they approximated as 1% of load). The percent decrease in regulation reserve requirements due to aggregation was calculated for each Aggregation Grouping using Eq. (5).

$$\left(\frac{\sum(\text{Constituent FERC Region Peak}*1\%)-\text{Aggregation Grouping Peak}*1\%}{\sum(\text{Constituent FERC Region Peak}*1\%)}\right)*100\% \tag{5}$$

Method 1 (99th percentile) peak load values were used. Since this calculation depends only on peak load, the percent savings for each Aggregation Grouping are the same as the percent reduction in peak load for Method 1 in Fig. 8.

In addition to load following and regulation reserves, savings in contingency reserves would also be realized with aggregation. Contingency reserves guard against unforeseen equipment failures. They consist of separate generating capacity whose size is based on the single largest potential source of failure in the system — usually a generator or transmission line. Contingency reserve requirement savings were approximated using values for each FERC Region gathered either from other studies (EWITS study (EnerNex Corporation, 2010) for the eastern U.S. and (Kirby, 2007) for ERCOT) or estimated as 6% of the peak load for the Western U.S. (following the WWSIS (GE Energy, 2010) method). Table 3 summarizes these FERC Region values, which were assumed to be unaffected by additional inter-regional transmission capacities calculated in this study.

The percent decrease in contingency reserve requirements was then calculated for each Aggregation Grouping using Eq. (6)

$$\left(\frac{\sum(\text{Constituent FERC Region Contingency})-\max(\text{Constituent FERC Region Contingency})}{\sum(\text{Constituent FERC Region Contingency})}\right)*100\% \tag{6}$$

where max(Constituent FERC Regions Contingency) is the largest contingency reserve capacity among all constituent FERC Regions in each Aggregation Grouping, since the contingency reserve capacity depends only on the single largest potential source of failure in the aggregated system. Fig. 13 shows the percent savings for each Aggregation Grouping. Among load following (Fig. 12), regulation (same as Method 1 results in Fig. 8), and contingency reserves (Fig. 13), the relative savings is largest with contingency reserves.

The methods to approximate load following, regulation, and contingency reserves were necessarily simple, and without the use of detailed production simulations (such as the production-cost model used in EWITS (EnerNex Corporation, 2010) or the minute-to-minute simulations in WWSIS (GE Energy, 2010)), it is not possible to accurately quantify the amount of reserves needed by the system. For example, the WWSIS found that the calculated additional load-following reserves were not required by the system because enough thermal units had extra online capacity to provide the load following needs (GE Energy, 2010). The potential for double-counting is therefore significant (Milligan

Table 3
Contingency reserve values assumed for each FERC Region.

FERC Region	Contingency reserve (MW)	Source
All CA	3182	WWSIS[a]
ERCOT	1875	(Kirby, 2007)[b]
ISONE	1158	EWITS[c]
NW	2053	WWSIS[a]
NYISO	1200	EWITS[c]
MISO	2271	EWITS[c]
PJM	3350	EWITS[c]
SE	2890	EWITS[c]
SPP	1539	EWITS[c]
SW	2070	WWSIS[a]

[a] WWSIS values calculated as 6% of peak load (GE Energy, 2010), assuming Method 1 (99th percentile) for peak load.
[b] To be consistent with the EWITS values, the single largest source of failure in ERCOT (1250 MW generator) was multiplied by 1.5 to obtain the final value.
[c] EWITS values taken directly from (EnerNex Corporation, 2010), which used 1.5*(single largest hazard). The only exception was SE, which was assumed to be the sum of TVA and SERC contingency values due to the large magnitude of the SE load.

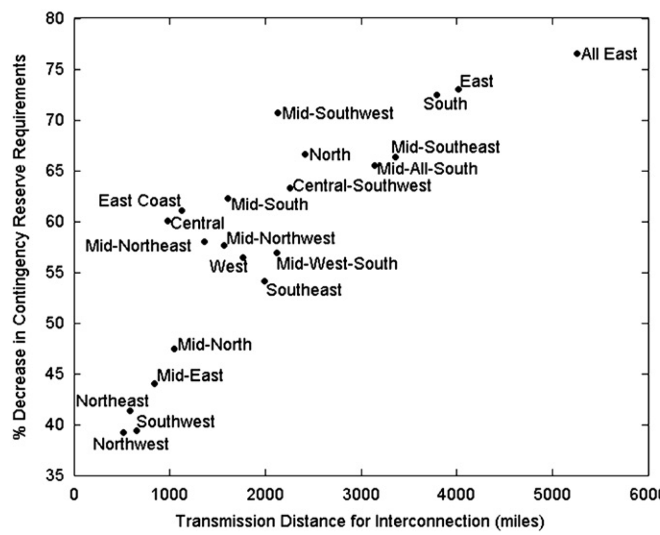

Fig. 13. 2006 and 2007 average percent decrease in contingency reserve requirements.

et al., 2011) and can result in over-estimating the amount of reserves needed. The reserve values presented here likely do overestimate the required capacity; however, the *relative* savings give a reasonable *approximation* of the system reserve benefits due to aggregation.

4. Costs of Aggregation Groupings

The results of the metrics evaluated in Section 3 were translated into their respective cost savings:

1) generator capacity capital cost savings,
2) generation operating cost savings, and
3) reserve requirement cost savings.

Yearly cost savings were calculated from each metric for each Aggregation Grouping. These costs savings were then compared against the capital costs for additional transmission capacity required to achieve interconnection. All cost savings and costs are reported in 2004 USD.

4.1. Generator capacity capital cost savings

Generator capacity capital cost savings were calculated from the generator capacity savings in Section 3.1. These capacity savings were the result of reduced peak values due to aggregation. Overall cost savings were annualized assuming natural gas combined cycle generators with a 30 year lifetime and 7.4% discount rate.

The generator capacity requirements, generator capacity savings due to aggregation, and the corresponding yearly capital cost savings are shown in Table 4 for each Aggregation Grouping for peak value Methods 1 (99th percentile) and 2 (2.4 h on LDC). The percent decrease in peak load values in Table 4 are the same values that are in Fig. 8. The percentage values also correspond to the percent savings in generator capacity (and the associated capital costs) due to aggregation, since the peak load values are proxies for generator capacity values.

4.2. Generation operating cost savings

Generation operating cost savings were calculated from the load energy that was shifted from higher-load hours to lower-load hours in Section 3.2. This shift was assumed to be from generation with conventional natural gas combustion turbines to conventional natural gas combined cycle generators, where the former has a larger levelized operating cost than the latter.

Table 5 shows the yearly total load, yearly energy shift due to aggregation, and associated yearly operating cost savings for each

Table 4
Generator capacity capital cost savings due to aggregation.

Aggregation Grouping	Method 1					Method 2				
	Aggregation generator capacity (GW)	Sum of FERC Regions generator capacity (GW)	Generator capacity savings (GW)[a]	Amortized yearly capital cost savings (Millions 2004$)[b]	% decrease in peak load (%)[c]	Aggregation generator capacity (GW)	Sum of FERC Regions generator capacity (GW)	Generator capacity savings (GW)[a]	Amortized yearly capital cost savings (Millions 2004$)[b]	% decrease in peak load (%)[c]
East	495	506	10.6	$659	*2.1*	554	559	5.49	$342	*1.0*
West	119	123	4.00	$249	*3.3*	131	136	5.13	$319	*3.8*
All East	549	563	14.0	$868	*2.5*	612	621	9.28	$577	*1.5*
East Coast	360	367	6.90	$429	*1.9*	405	407	1.96	$122	*0.5*
Mid-East	288	292	4.08	$254	*1.4*	314	316	1.96	$122	*0.6*
North	305	310	5.49	$341	*1.8*	338	349	10.7	$668	*3.1*
Mid-North	131	135	3.59	$223	*2.7*	141	148	6.82	$424	*4.6*
South	366	375	9.71	$604	*2.6*	391	409	17.2	$1,071	*4.2*
Mid-South	128	130	2.45	$152	*1.9*	140	142	2.09	$130	*1.5*
Central	192	196	4.01	$249	*2.0*	210	214	4.63	$288	*2.2*
Northwest	85.0	88.0	2.98	$185	*3.4*	95.4	98.9	3.49	$217	*3.5*
Mid-Northwest	180	188	7.71	$480	*4.1*	194	209	14.5	$903	*7.0*
Northeast	175	175	0.67	$41.5	*0.4*	200	201	1.24	$77	*0.6*
Mid-Northeast	273	275	2.11	$131	*0.8*	309	311	2.47	$154	*0.8*
Southeast	285	288	2.49	$155	*0.9*	305	310	5.54	$345	*1.8*
Mid-Southeast	380	387	7.25	$451	*1.9*	413	420	7.59	$472	*1.8*
Southwest	86.6	87.5	0.89	$55.3	*1.0*	96.7	98.3	1.66	$103	*1.7*
Mid-Southwest	224	230	5.99	$373	*2.6*	243	252	8.27	$515	*3.3*
Mid-West-South	325	330	5.47	$340	*1.7*	354	358	3.92	$244	*1.1*
Mid-All-South	318	322	4.35	$271	*1.4*	338	348	9.46	$589	*2.7*
Central-Southwest	177	183	6.37	$396	*3.5*	193	203	9.56	$595	*4.7*

[a] Generator capacity savings is the difference between the generator capacity for the Aggregation Grouping and the sum of the generator capacities for the constituent FERC Regions. All generator capacity values shown are the average of the 2006 and 2007 values.

[b] Natural gas combined cycle generator capital cost for 2005 ($742 /kW 2004 USD) was used (Short et al., 2009). Total cost savings were amortized assuming 30 year lifetime and 7.4% discount rate, to be consistent with levelized costs used in Table 5 (U.S. Energy Information Administration, 2010).

[c] Generator capacity savings divided by the sum of generator capacities for the consistent FERC Regions. These values are the % reduction in peak load (as shown in Fig. 8) due to aggregation; they also represent the % savings in generator capacity (and the associated capital cost), since peak load values are proxies for generator capacity values.

Table 5
Generation operating cost savings due to Aggregation.

Aggregation Grouping	Average yearly total load generation (TW h)[a]	Average yearly energy shift (TW h)[b]	Average yearly operating cost savings from shift (Millions 2004$)[c]	Load energy shift % of total toad (%)[d]
East	**2.88E+03**	13.4	$327	*0.47*
West	**7.09E+02**	5.52	$135	*0.78*
All East	**3.19E+03**	18.0	$439	*0.57*
East Coast	**2.08E+03**	8.47	$207	*0.41*
Mid-East	**1.66E+03**	4.99	$122	*0.30*
North	**1.83E+03**	6.85	$167	*0.37*
Mid-North	**8.21E+02**	3.62	$88.5	*0.44*
South	**2.07E+03**	11.8	$289	*0.57*
Mid-South	**7.02E+02**	2.42	$59.2	*0.34*
Central	**1.10E+03**	6.48	$158	*0.59*
Northwest	**5.23E+02**	3.35	$81.8	*0.64*
Mid-Northwest	**1.11E+03**	8.44	$206	*0.76*
Northeast	**1.01E+03**	1.16	$28.4	*0.12*
Mid-Northeast	**1.60E+03**	2.68	$65.6	*0.17*
Southeast	**1.59E+03**	3.95	$96.6	*0.25*
Mid-Southeast	**2.18E+03**	9.48	$232	*0.44*
Southwest	**4.78E+02**	1.54	$37.5	*0.32*
Mid-Southwest	**1.29E+03**	8.97	$219	*0.70*
Mid-West-South	**1.87E+03**	6.47	$158	*0.35*
Mid-All-South	**1.78E+03**	6.38	$156	*0.36*
Central-Southwest	**9.93E+02**	6.39	$156	*0.64*

[a] Average of the 2006 and 2007 sum of hourly electric load values.

[b] Yearly average of 2006 and 2007 energy due to aggregation that is shifted from higher-load hours to lower-load hours in the LDC.

[c] Operating costs for higher-load hours were assumed to be from a conventional natural gas combustion turbine, while costs for lower-load hours were assumed to be from a conventional natural gas combined cycle generator. Levelized operating cost data that were used (Fixed O&M and Variable O&M) assumed a financing term of 30 years and a weighted average cost of capital of 7.4% (conventional natural gas combustion turbine fixed O&M cost of $3.7/MWh and variable O&M cost of $71.5/MWh, and conventional natural gas combined cycle fixed O&M cost of $1.9/MWh and variable O&M cost of $45.6/MWh, all in 2009 USD) (U.S. Energy Information Administration, 2010). All costs were converted to 2004 USD using implicit price deflators for gross domestic product from the Bureau of Economic Analysis, National Income and Product Accounts Table (Table 1.1.9).

[d] Average yearly energy shift divided by the average yearly total load generation. These values are the load energy shift % of total load (as shown in Fig. 11) due to aggregation.

Aggregation Grouping. The load energy shift percent of total load values in Table 5 correspond to the percentage values in Fig. 11.

4.3. Reserve requirement cost savings

Load following reserve requirement annual cost savings were calculated from the load following reserve requirement capacity savings in Section 3.3, assuming that these values were the *average hourly* load following reserve capacity savings and using hourly spinning (1/3) and non-spinning (2/3) reserve costs from (King et al., in press). These reserve requirement savings were the result of reduced standard deviation of hourly load variability due to aggregation.

The load following reserve capacity requirements, load following reserve requirement capacity savings due to aggregation, and the corresponding yearly cost savings are shown in Table 6 for each Aggregation Grouping. The percent decrease in load following reserve values in Table 6 correspond to the percentage decrease in standard deviation of load variability values in Fig. 12.

Regulation reserve requirement annual cost savings were calculated from the regulation reserve requirement capacity savings in Section 3.3, assuming that these values were the *average hourly* regulation reserve capacity savings and using hourly regulation reserve costs from (King et al., in press). These reserve requirement savings correspond to 1% of peak load savings due to aggregation.

The regulation reserve capacity savings due to aggregation and the corresponding yearly cost savings are shown in Table 7 for each Aggregation Grouping. Since the regulation reserve requirements were estimated from Method 1 peak load values, the percent decrease in regulation reserve values in Table 7 correspond to the Method 1 percent decrease in peak load values in Table 4.

The regulation reserve requirement capacity estimates and percent savings values (Table 7) are markedly smaller than those for the load following reserves (Table 6). Other studies have stated that aggregation reduces regulation requirements more than load following requirements due to the lower correlation among individual loads in the regulation time frame (Milligan et al., 2011). This suggests that the regulation reserve requirements in this study are either underestimated, or more likely, that most of the regulation reserve requirements are embedded within the load following reserve requirements since only hourly data was used, as was assumed for a case with Finland, Denmark, and Nordic countries in (Holttinen et al., 2008).

Contingency reserve requirement capital cost savings were calculated from the contingency reserve requirement capacity savings in Section 3.3. These reserve requirement savings correspond to the avoidance of all but one contingency reserve capacity from constituent FERC Regions; generating capacity need only be set aside for the single largest potential source of failure in the aggregated system. Overall cost savings were annualized assuming natural gas combustion turbines with a 30 year lifetime and 7.4% discount rate.

The contingency reserve capacity requirements, contingency reserve requirement capacity savings due to aggregation, and the corresponding yearly capital cost savings are shown in Table 8 for each Aggregation Grouping. The percent decrease in contingency reserve requirement values in Table 8 correspond to the percentage values in Fig. 13.

Table 6
Load following reserve requirement cost savings due to aggregation. LF=Load following.

Aggregation Grouping	Aggregation LF reserve requirement (GW)	Sum of FERC Regions LF reserve requirement (GW)	LF Reserve savings (GW)[a]	Average yearly cost savings (Millions 2004$)[b]	% decrease in LF reserve requirement (%)[c]
East	40.4	42.7	2.31	$47.0	*5.4*
West	10.2	10.9	0.73	$14.9	*6.7*
All East	44.8	47.8	3.02	$61.5	*6.3*
East Coast	30.8	32.0	1.20	$24.4	*3.7*
Mid-East	23.8	24.4	0.65	$13.3	*2.7*
North	24.1	26.4	2.28	$46.5	*8.6*
Mid-North	9.90	11.1	1.18	$24.0	*10.6*
South	28.9	32.4	3.45	$70.2	*10.7*
Mid-South	10.3	10.9	0.59	$12.0	*5.4*
Central	14.7	15.9	1.12	$22.8	*7.1*
Northwest	7.69	8.09	0.41	$8.25	*5.0*
Mid-Northwest	13.2	15.9	2.71	$55.3	*17.1*
Northeast	15.0	15.3	0.28	$5.79	*1.9*
Mid-Northeast	22.4	23.1	0.68	$13.9	*2.9*
Southeast	23.9	24.7	0.88	$17.9	*3.6*
Mid-Southeast	30.9	32.5	1.64	$33.5	*5.1*
Southwest	7.27	7.62	0.35	$7.03	*4.5*
Mid-Southwest	17.0	18.7	1.69	$34.4	*9.0*
Mid-West-South	26.3	27.4	1.14	$23.2	*4.2*
Mid-All-South	26.1	27.6	1.50	$30.5	*5.4*
Central-Southwest	14.0	15.7	1.73	$35.3	*11.0*

[a] Load following reserve savings is the difference between the load following reserve requirement for the Aggregation Grouping and the sum of the load following reserve requirements of the constituent FERC Regions. Values shown are the average of the 2006 and 2007 values.

[b] Estimated assuming that the load following reserve savings were the average capacity savings held constant over all hours and using hourly spinning (assume 1/3 of cost) and non-spinning (assume 2/3 of cost) reserve costs from King et al. (in press). All costs were converted to 2004 USD using implicit price deflators for gross domestic product from the Bureau of Economic Analysis, National Income and Product Accounts Table (Table 1.1.9).

[c] Load following reserve requirement savings divided by the sum of the load following reserve requirements of the constituent FERC Regions. These values are the % decrease in standard deviation of load variability (as shown in Fig. 12) due to aggregation.

Table 7
Regulation reserve requirement cost savings due to aggregation.

Aggregation Grouping	Regulation reserve savings (MW)[a]	Average yearly cost savings (Millions 2004$)[b]	% decrease in regulation reserve requirement (%) [c]
East	106	$9.70	*2.1*
West	40	$3.66	*3.3*
All East	140	$12.8	*2.5*
East Coast	69	$6.32	*1.9*
Mid-East	41	$3.74	*1.4*
North	55	$5.03	*1.8*
Mid-North	36	$3.29	*2.7*
South	97	$8.90	*2.6*
Mid-South	24	$2.24	*1.9*
Central	40	$3.67	*2.0*
Northwest	30	$2.73	*3.4*
Mid-Northwest	77	$7.07	*4.1*
Northeast	7	$0.61	*0.4*
Mid-Northeast	21	$1.93	*0.8*
Southeast	25	$2.29	*0.9*
Mid-Southeast	72	$6.64	*1.9*
Southwest	9	$0.82	*1.0*
Mid-Southwest	60	$5.49	*2.6*
Mid-West-South	55	$5.02	*1.7*
Mid-All-South	44	$3.99	*1.4*
Central-Southwest	64	$5.84	*3.5*

[a] Regulation reserve capacity savings is the difference between the regulation reserve capacity for the Aggregation Grouping and the sum of the regulation reserve capacities for the constituent FERC Regions. All regulation reserve capacity values shown are the average of the 2006 and 2007 values and were calculated using peak values from Method 1 (99th percentile of peak load).

[b] Estimated assuming that the regulation reserve savings were the average capacity savings held constant over all hours and using hourly regulation reserve costs from King et al. (in press). All costs were converted to 2004 USD using implicit price deflators for gross domestic product from the Bureau of Economic Analysis, National Income and Product Accounts Table (Table 1.1.9).

[c] Since the proxy for regulation reserves is based on peak load, these savings correspond to the % decrease in peak load values in Table 4.

4.4. Transmission costs

The costs for additional transmission required to achieve the aggregation cost savings were estimated.

For each Aggregation Grouping, generator capacity values were approximated for each constituent FERC Region as a fraction of the Aggregation Grouping total generator capacity using Eq. (7) with generator capacity values from Method 1

Table 8
Contingency reserve requirement capital cost savings due to aggregation.

Aggregation Grouping	Aggregation contingency reserve requirement (GW)	Sum of FERC Regions contingency reserve requirement (GW)	Contingency reserve savings (GW)[a]	Amortized yearly capital cost savings (Millions 2004$)[b]	% Decrease in contingency reserve requirement (%)[c]
East	3.35	12.4	9.06	$452	*73*
West	3.18	7.30	4.12	$206	*56*
All East	3.35	14.3	10.93	$545	*77*
East Coast	3.35	8.60	5.25	$262	*61*
Mid-East	2.89	5.16	2.27	$113	*44*
North	3.35	10.0	6.68	$333	*67*
Mid-North	2.27	4.32	2.05	$102	*47*
South	3.18	11.6	8.37	$418	*72*
Mid-South	2.07	5.48	3.41	$170	*62*
Central	2.27	5.69	3.41	$170	*60*
Northwest	3.18	5.23	2.05	$102	*39*
Mid-Northwest	3.18	7.51	4.32	$216	*58*
Northeast	3.35	5.71	2.36	$118	*41*
Mid-Northeast	3.35	7.98	4.63	$231	*58*
Southeast	2.89	6.30	3.41	$170	*54*
Mid-Southeast	2.89	8.58	5.69	$284	*66*
Southwest	3.18	5.25	2.07	$103	*39*
Mid-Southwest	2.27	7.75	5.48	$274	*71*
Mid-West-South	2.89	6.70	3.81	$190	*57*
Mid-All-South	2.89	8.37	5.48	$274	*65*
Central-Southwest	3.18	8.67	5.48	$274	*63*

[a] Contingency reserve savings is the difference between the contingency reserve requirement for the Aggregation Grouping and the sum of the contingency reserve requirements of the constituent FERC Regions.
[b] Natural gas combustion turbine capital cost for 2005 ($595/ kW 2004 USD) was used (Short et al., 2009). Total cost savings were amortized assuming 30 year lifetime and 7.4% discount rate, to be consistent with levelized costs used in Table 5 (U.S. Energy Information Administration, 2010).
[c] Contingency reserve requirement savings divided by the sum of the contingency reserve requirements of the constituent FERC Regions. These values correspond to the percentage values in Fig. 13.

(99th percentile).

$$\left(\frac{\text{Constituent FERC Region Generator Capacity}}{\sum(\text{Constituent FERC Region Generator Capacity})}\right) \\ *\text{AggregationGrouping Generator Capacity} \quad (7)$$

These generator capacity values were then assumed to be the instantaneous power generation for each hour for their respective constituent FERC Region within each Aggregation Grouping.

The required transmission line capacity for each segment in each Aggregation Grouping was estimated. For each Aggregation Grouping, the hourly generation values (as calculated from Eq. (7)) were compared with the hourly electric load data in each constituent FERC Region to determine the hourly power deficit or excess at that node, which could be transmitted from or to adjacent constituent FERC Regions through the transmission network segments. The maximum absolute value of all hourly power deficit or excess energy quantities transmitted through each segment was assumed to be the approximate required line capacity. This methodology assumes direct current (DC) electricity flow between FERC Regions and no transmission line losses.

To avoid double-counting, existing inter-region transmission line capacities were subtracted from the calculated required line capacities. GIS data of existing transmission lines (Rextag Strategies, 2008) and FERC Region boundaries were used to estimate transmission lines with significant cross-over between adjacent FERC Regions. These line capacities, given in kV, were converted to MW assuming 100 mile lines (Shankle, 1971; Weiss and Spiewak, 1999). The resulting transmission line existing capacities are shown in Fig. 14 and were subtracted from the required line capacities to determine the additional transmission line capacities needed for aggregation.

Transmission capital costs were calculated from the additional required transmission line capacities and the proxy of transmission distances for interconnection (see Fig. 7) using an average new transmission line cost for any generation technology of $1600/MW-mile (2004 USD) (Short et al., 2009). The cost for asynchronous

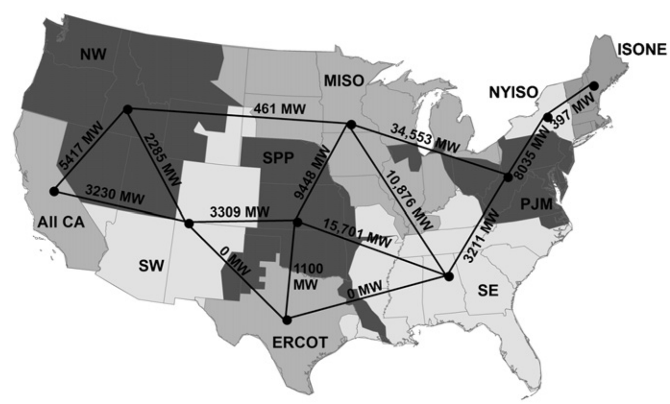

Fig. 14. Transmission topology with significant existing inter-region transmission line capacities (MW).

interconnection was included as $100,000/MW (2007 USD) (Delucchi and Jacobson, 2011) for transmission segments crossing the eastern, western, or ERCOT interconnect boundaries (i.e., NW-MISO, SW-SPP, SW-ERCOT, SPP-ERCOT, and SE-ERCOT segments). Total transmission costs were then annualized assuming a 70 year lifetime (Delucchi and Jacobson, 2011) and 7.4% discount rate. Table 9 shows the average of the 2006 and 2007 total and yearly transmission capital costs for each Aggregation Grouping.

Since the transmission model neglects any intra-regional transmission requirements, the total transmission costs in Table 9 are likely underestimated, especially for FERC Regions with spatially disperse load centers or areas of congestion. Comparing transmission power flows and total costs to those from studies with a finer spatial resolution suggests that this assertion is valid, with larger total costs but smaller per MW-mile costs for a finer spatial resolution transmission layout. The EWITS study, which generated numerous intra-regional transmission flows across its mostly Eastern U.S. footprint, and the WWSIS study, which

Table 9
Cost for additional transmission required for aggregation.

Aggregation Grouping	Average total capital cost (Billions 2004$)[a]	Amortized yearly capital cost (Billions 2004$)[b]
East	$84.7	$6.31
West	$6.66	$0.50
All East	$108	$7.87
East Coast	$103	$7.66
Mid-East	$28.9	$2.15
North	$68.0	$4.91
Mid-North	$36.3	$2.56
South	$128	$9.05
Mid-South	$10.8	$0.73
Central	$24.1	$1.68
Northwest	$4.99	$0.37
Mid-Northwest	$48.2	$3.43
Northeast	$26.0	$1.94
Mid-Northeast	$33.7	$2.51
Southeast	$61.3	$4.34
Mid-Southeast	$58.4	$4.12
Southwest	$4.49	$0.33
Mid-Southwest	$36.0	$2.51
Mid-West-South	$32.6	$2.43
Mid-All-South	$94.9	$6.66
Central-Southwest	$24.6	$1.72

[a] Average of 2006 and 2007 values. Transmission cost data of $1600/MW-mi (2004 USD) from Short et al. (2009). Asynchronous interconnect cost data of $100,000/MW (2007 USD) from Delucchi and Jacobson (2011) ("station equipment" in Table A. 2a), and converted to 2004 USD using implicit price deflators for gross domestic product from the Bureau of Economic Analysis, National Income and Product Accounts Table (Table 1.1.9).

[b] Total capital costs were amortized assuming 70 year lifetime and 7.4% discount rate.

determined inter-state transmission flows across part of the Western U.S., both yielded larger power flows but similar total capital costs for roughly equivalent geographic areas as the study here. The West Aggregation Grouping in this study is the closest match to – but notably larger than – the WWSIS study area (transmission additions to/from CA and most of the Pacific Northwest were not included in the WWSIS scenarios). Both had similar total transmission costs (approximately 7 billion dollars (2008 USD)), but the inter-state scenarios in the WWSIS study resolved slightly larger power flows than between equivalent areas in this study (on the order of 2 million additional MW-mi in this study, and on the order of 2–7 million MW-mi in the WWSIS study). The East Aggregation Grouping in the study here is the closest match to – but also slightly larger than – the EWITS study area (Florida was not included in the EWITS area). Both had similar total transmission costs (on the order of 90 billion dollars (2009 USD)), but the EWITS study resolved double the power flow as this study (on the order of 50 million additional MW-mi in this study, and on the order of 100 million MW-mi in the EWITS study[1]) (EnerNex Corporation, 2010). These results suggest that the WWSIS and EWITS studies, which included transmission interconnections on a finer spatial resolution, would have had larger total costs but smaller per MW-mi costs than those in the study here *if* the footprints were more closely matched.

However, this study also ignores additional aggregation benefits that could be gained by interconnecting smaller balancing areas within each FERC Region. More research is needed at a finer spatial resolution to examine the tradeoffs between additional costs and savings at the intra-regional level.

In addition to the spatial resolution differences, some of the transmission power flow differences between the study here and the EWITS and WWSIS studies are likely due to the inclusion of renewable generators. The EWITS and WWSIS studies focused on connecting renewable energy production to load centers, while this study isolates the transmission requirements for load alone. As a result, new transmission lines in the EWITS and WWSIS studies were sited to most economically and reliably transfer power from wind farms to load centers, whereas the transmission enhancements in the study here were mostly dependent on the relative magnitude of load and amount of existing inter-region transmission capacity. For example, in the East Aggregation Grouping, the largest relative additional transmission capacity requirements were along the congested East Coast, where insufficient transmission capacity currently exists for interconnecting these heavy load areas (this is corroborated by a U.S. Department of Energy study (2009) that identified multiple areas of congestion along the East Coast). Only the MISO-PJM connection had sufficient existing capacity in this Aggregation Grouping (Fig. 14 reveals that this connection has by far the largest existing capacity of any inter-region segment). By contrast, the largest new transmission lines in the EWITS study were east–west oriented, connecting the best wind resources in the Midwest and Plains to the large load centers along the East Coast.

4.5. Overall costs

The generator capacity capital cost savings, generation operating cost savings, reserve requirement cost savings, and transmission capital costs were summed to determine the overall costs for interconnecting each Aggregation Grouping. Fig. 15 shows the overall costs broken down into each cost category for each Aggregation Grouping. The generation capacity cost savings are from peak value Method 1 (99th percentile).

Fig. 15 reveals that, for nearly all Aggregation Groupings, the transmission costs required for interconnection (positive striped segment) significantly exceed the cost savings (negative solid segments) due to aggregating electric load. The overall cost (data point with corresponding dollar value) is positive for all Aggregation Groupings except the West and Northwest Aggregation Groupings. Even if transmission costs were reduced by 50%, the overall cost remains positive for all Aggregation Groupings except the West, Northwest, Southwest, Mid-South, and Central-Southwest.

In general, the largest cost savings were from the generator capacity capital cost savings, while the smallest were from the regulation reserve requirement cost savings, which were usually two orders of magnitude smaller than any other cost savings and are not visible in Fig. 15. Many of the Aggregation Groupings with the largest cost savings also have the largest transmission costs (due to larger load magnitudes) and consist of large geographic areas (e.g., East, All East, and South).

The only cost effective Aggregation Groupings are the West and Northwest, whose overall cost values (net savings) are significantly lower than all other Aggregation Groupings. The West and Northwest Aggregation Groupings both contain the NW FERC Region, which has a winter-peaking load with relatively close proximity to adjacent FERC Regions and large amounts of existing transmission capacity, making it a good complement for the summer-peaking All CA and SW FERC Regions in these Aggregation Groupings. Additionally, these Aggregation Groupings along with the remainder from the 50% transmission cost case (Southwest, Mid-South, and Central-Southwest), consist of FERC Regions with the same order of magnitude load (see Fig. 3). Aggregating FERC Regions with significantly different magnitudes of coincident load – which is the case in many of the Eastern U.S. Aggregation Groupings – diminishes the relative smoothing benefits.

Many of the overall cost results from this study of load data are reflected by the current contiguous U.S. electric system. The

[1] The reported transmission kV values were converted to MW assuming kV ratings for 100 mile length lines (Weiss and Spiewak, 1999), 1000 MW capacity for 400 kV lines, and 6400 MW capacity for 800 kV lines.

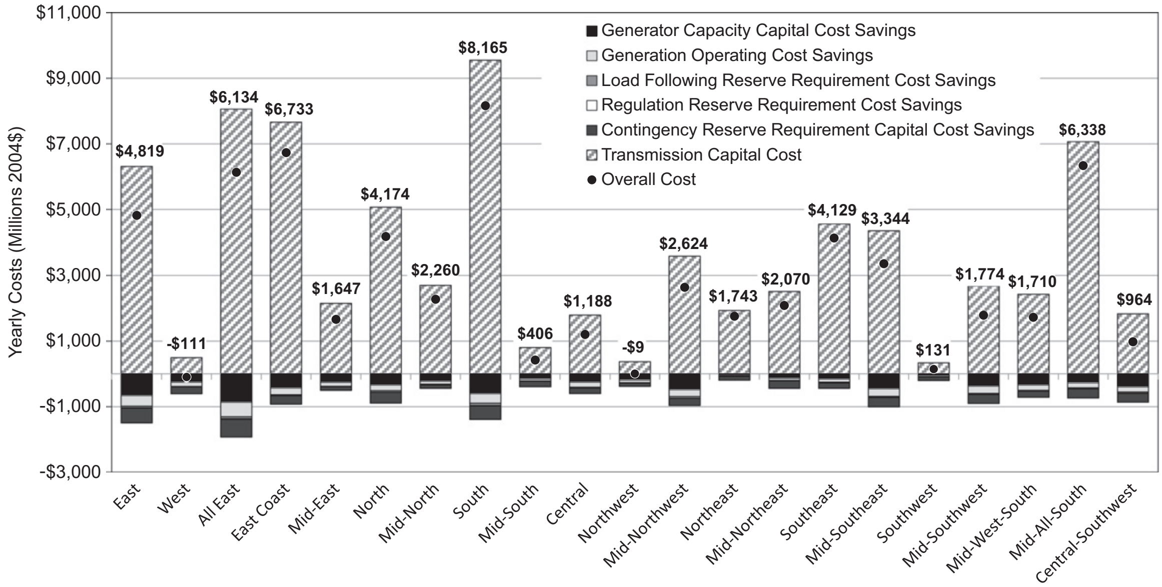

Fig. 15. Average yearly costs for Aggregation Groupings. *Dollar values correspond to overall cost data points.*

beneficial connections in the West and Northwest Aggregation Groupings are corroborated by the large amounts of electricity currently transmitted from the NW and SW FERC Regions to the All CA FERC Region. Additionally, the results reveal significant cost barriers with aggregating electric load across very large geographic areas. Costs are particularly high in the Eastern and Southern areas of the U.S. (e.g., East, All East, East Coast, South, and Mid-All-South Aggregation Groupings), where the transmission distance and additional capacity needed for interconnection – due primarily to insufficient existing inter-region transmission capacities for transferring the comparatively large load magnitudes – are too substantial. The current power system reflects these implications, with little inter-region coordination in these locations over large geographic areas.

5. Overall costs of Scenarios

5.1. Scenarios for U.S. electric system structure

To evaluate the effect of aggregating load on the U.S. electric system as a whole, multiple Scenarios, each with various combinations of Aggregation Groupings that together comprise the entire contiguous U.S., were created. These Scenarios present possible ways that the contiguous U.S. could be organized for transmission planning. The eight most interesting Scenarios are presented. Fig. 16 displays the layout of these selected Scenarios.

The transmission distance values for all Aggregation Groupings (Table 2) within each Scenario were summed to obtain the total transmission distance requirement proxy for each Scenario. Table 10 summarizes the composition and transmission distances for the eight selected Scenarios.

5.2. Overall costs

The generator capacity capital cost savings, generation operating cost savings, reserve requirement cost savings, and transmission capital costs from all Aggregation Groupings (as shown in Fig. 15) within each Scenario were summed to obtain the overall U.S. system cost for each Scenario. Fig. 17 shows the overall costs broken down into each cost component for each Scenario.

As with the Aggregation Groupings, Fig. 17 reveals that the transmission costs required for interconnection (positive striped segment) far exceed the cost savings (negative solid segments) due to aggregating electric load. The overall cost (data point with corresponding dollar value) is positive for all Scenarios.

In general, Scenarios with larger overall costs consist of fewer, larger Aggregation Groupings (e.g., Scenarios 1 and 3), while Scenarios with smaller overall costs consist of more, smaller Aggregation Groupings (e.g., Scenarios 7 and 8). This suggests that, if aggregation of electric load is desired, consolidation should be limited to relatively smaller geographic areas.

Scenarios with a predominantly east-to-west transmission orientation (e.g., Scenarios 1 and 2) have a larger overall cost (see Figs. 16 and 17). These Scenarios have a disproportionately high cost for transmission, as there is very little existing transmission capacity running east-to-west (particularly in the NW-MISO, SPP-SW, SW-ERCOT, and ERCOT-SE connections, as shown in Fig. 14). This result implies that, based on electric load alone, if interconnecting the middle of the U.S. to the coastal areas is desired (such as to gain greater load diversity from multiple times zones and different weather systems), it may actually be more cost-effective to interconnect the *entire* contiguous U.S. (Scenario 3) than to aggregate multiple east-to-west corridors.

Among Scenarios with similar Aggregation Grouping layouts (e.g., Scenario 4 versus 5, and Scenario 6 versus 8), the Scenarios that interconnect ERCOT with other FERC Regions (Scenarios 4 and 6) had greater overall costs. Interconnecting ERCOT results in smaller transmission capacity requirements in the Eastern portions of the Aggregation Groupings that contain ERCOT, but this also yields larger transmission capacity requirements in the segments connecting directly to/from ERCOT. There is very little existing transmission capacity in these segments, resulting in greater total transmission costs.

This study evaluated the effects of geographic aggregation through physical consolidation of various regions of the contiguous U.S. However, some benefits of aggregation could be realized instead through *virtual* consolidation, whereby constituent regions electronically pool their variability without the need for additional transmission. Virtual consolation can be achieved through various mechanisms, including ACE (area control error) Diversity Interchange (ADI), which allows for sharing of regulation services to balance variability; fast energy markets (such as 5 min economic dispatch), which ensure that economic dispatch

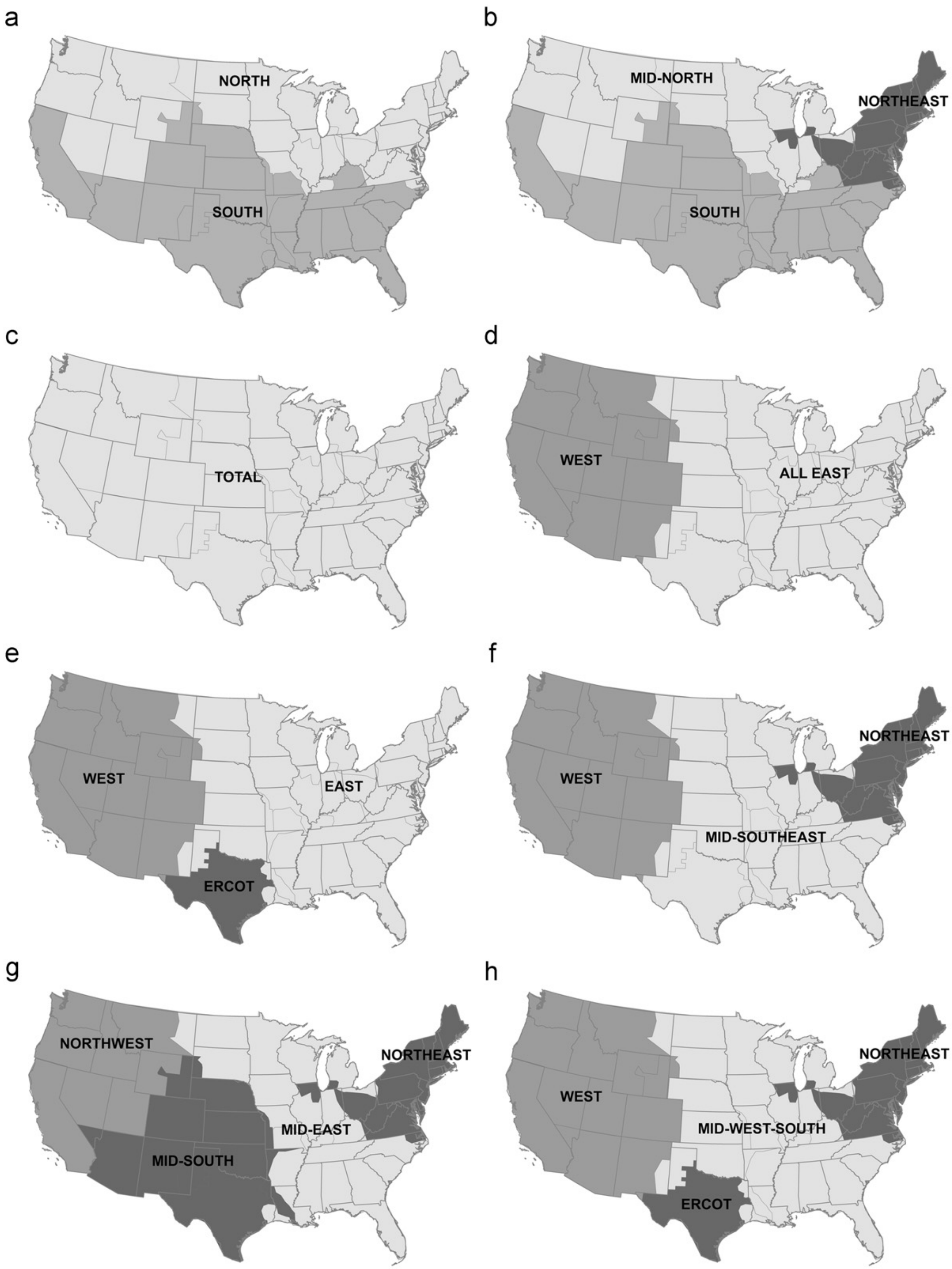

Fig. 16. Select Scenarios with constituent Aggregation Groupings. (a) Scenario 1, (b) Scenario 2, (c) Scenario 3, (d) Scenario 4, (e) Scenario 5, (f) Scenario 6, (g) Scenario 7 and (h) Scenario 8.

generators are not restricted from responding to changing demands and reduce the burden on regulating units; energy imbalance market (EIM), which is a regional economic dispatch tool that supplies imbalance energy; or dynamic scheduling, which can be used to electrically move a generator, load, or combination to a different region (Milligan and Kirby, 2010; Milligan et al., 2010).

6. Ratio of mean to peak electric load

An additional metric was evaluated to quantify the effect of aggregating electric load on the generating plant operator. The ratio of mean to peak electric load was calculated for each FERC Region and Aggregation Grouping. Peak values from Methods 1 and 2 (as defined in Section 3.1) were both used.

The weighted average of the ratio of mean to peak electric load of the constituent FERC Regions was calculated for each Aggregation Grouping using Eq. (8), where mean load values were used as the weights for each FERC Region.

$$\frac{\sum((\text{Constituent FERC Region Mean : Peak})*(\text{Constituent FERC Region Mean}))}{\sum(\text{Constituent FERC Region Mean})} \tag{8}$$

The percent increase in the ratio of mean to peak load due to aggregation was then calculated as a simple difference between the Aggregation Grouping and the weighted average of the constituent FERC Regions (the result of Eq. (8)) using Eq. (9).

$$((\text{Aggregation Grouping Mean : Peak}) - (\text{Weighted Average of Constituent FERC Region Mean : Peak}))*100\% \tag{9}$$

Fig. 18 shows the percent increase in the ratio of mean to peak load values for each Aggregation Grouping. The ratio of mean to peak electric load is a reflection of the load factor of the generators. Therefore, Aggregation Groupings in the upper left section of Fig. 18 are the most desirable, as they have the largest relative increase in load factor for the smallest transmission distance.

Aggregation smoothes out the overall load profile so that the mean load value is closer to the peak load value. The plant operator can then run the plant closer to the rated power for more hours of the year. This results in better plant utilization and higher revenue for the plant operator.

7. Conclusions

This study examined the effects of aggregating electric load alone from various geographic areas of the contiguous U.S. Twenty-one Aggregation Groupings were formed from different combinations of the 10 Federal Energy Regulatory Commission (FERC) Regions. Eight Scenarios of various combinations of

Table 10
Scenarios and total transmission distance required for interconnection.

Scenario	Aggregation Groupings	Total transmission distance for interconnection (miles)
1	North, South	6200
2	Mid-North, South, Northeast	5425
3	All 10 FERC Regions	9225
4	West, All East	7030
5	West, East, ERCOT	5790
6	West, Mid-Southeast, Northeast	5715
7	Northwest, Mid-South, Mid-East, Northeast	3565
8	West, ERCOT, Mid-West-South, Northeast	4475

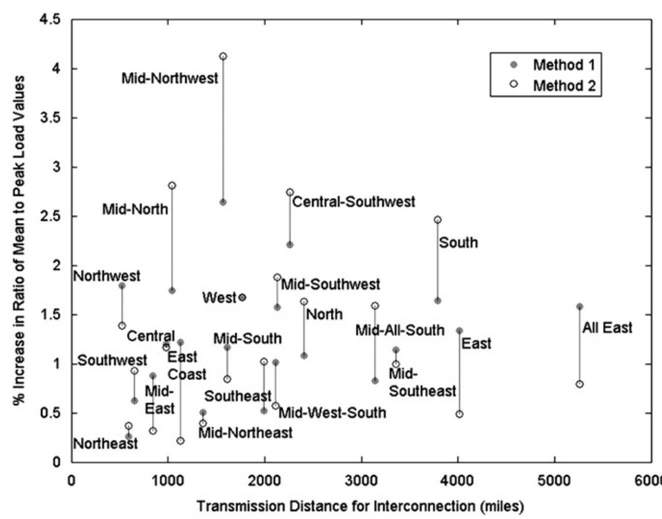

Fig. 18. 2006 and 2007 average percent decrease in ratio of mean to peak load values.

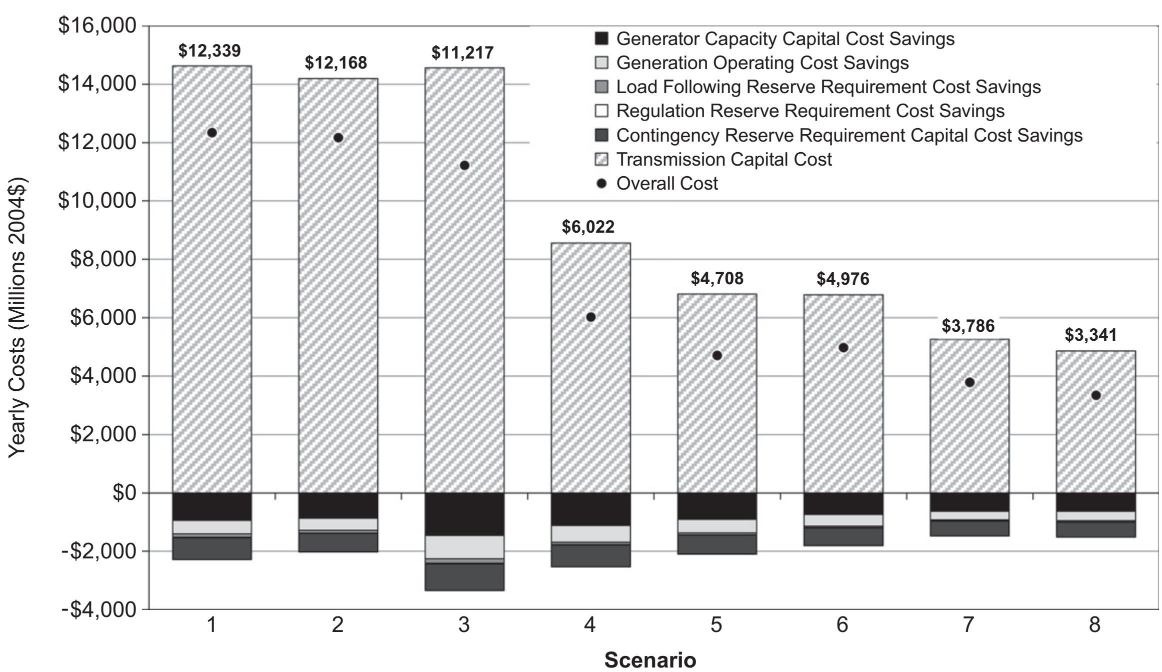

Fig. 17. Average yearly costs for select Scenarios. *Dollar values correspond to overall cost data points.*

Aggregation Groupings that comprise the U.S. were then created to estimate the overall U.S. system cost.

Interconnecting electric load was found to provide benefits for each Aggregation Grouping for each metric considered. Benefits for the power system include reduction in peak load, resulting in generator capacity savings; load energy shifted from higher-load hours to lower-load hours in the LDCs, resulting in a shift from more-expensive to less-expensive generation; and reduction in the standard deviation of load variability, resulting in load following reserve requirement savings. Additional savings were found for regulation reserve and contingency reserve requirements. Benefits to the plant operator include an increase in the ratio of mean to peak electric load, resulting in an increased load factor and better generating plant utilization.

The power system aggregation benefits were translated into cost savings, including generator capacity capital cost savings, generation operating cost savings, and reserve requirement cost savings. In general, the generator capacity capital cost savings provided the greatest cost savings, while the regulation reserve requirement cost savings provided the smallest.

A simple transmission network topology was created to estimate the relative inter-region transmission distances and the additional transmission capacities needed for aggregation. The corresponding transmission capital costs were found to significantly outweigh the cost savings due to aggregation for all Aggregation Groupings except the West and Northwest. The overall costs were generally positive and varied widely among all Aggregation Groupings and Scenarios.

Among the Aggregation Groupings, the only cost-effective interconnections were the Northwest and West, which are corroborated by the large amount of electricity that is already transmitted from the NW and SW FERC Regions into the All CA FERC Region. Many of the large Aggregation Groupings in the Eastern and Southern areas of the U.S. cover too large of a distance with too little relative existing transmission capacity for interconnection to be cost-effective, which is validated by the limited existing inter-region coordination across these large geographic areas.

Overall costs for the Scenarios indicate that east–west transmission layouts have the highest overall cost due to the large distances and lack of existing transmission capacity connecting the middle of the U.S. to the coasts. In the Scenarios considered, interconnecting ERCOT to adjacent FERC Regions (versus ERCOT operating independently) resulted in higher costs, also due to limited existing inter-region transmission capacity. Scenarios with the lowest overall cost have more, smaller Aggregation Groupings, while Scenarios with the highest overall cost have fewer, larger Aggregation Groupings.

This study suggests that there are no economic benefits for aggregating electric load within the U.S., except for the West and Northwest Aggregation Groupings. If aggregation of electric load alone is desired, the way in which the power system is interconnected can significantly impact the overall system cost. This study indicates that small, regional consolidation yields the lowest overall system cost.

This study was based on electric data alone and a simplified electric system. Results could change if additional inputs, such as a high penetration of renewable energy resources, and additional factors, such as sub-hourly load variability, fuel diversity and price uncertainty, energy price differences due to congestion, and uncertainty due to forecasting errors, are considered. More research is needed to determine the impact of these components.

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