Environ. Sci. Technol. **2005**, *39,* 8584−8590

Environmental Effects of Interstate Power Trading on Electricity Consumption Mixes

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Although many studies of electricity generation use national or state average generation mix assumptions, in reality a great deal of electricity is transferred between states with very different mixes of fossil and renewable fuels, and using the average numbers could result in incorrect conclusions in these studies. We create electricity consumption profiles for each state and for key industry sectors in the U. S. based on existing state generation profiles, net state power imports, industry presence by state, and an optimization model to estimate interstate electricity trading. Using these "consumption mixes" can provide a more accurate assessment of electricity use in life-cycle analyses. We conclude that the published generation mixes for states that import power are misleading, since the power consumed in-state has a different makeup than the power that was generated. And, while most industry sectors have consumption mixes similar to the U. S. average, some of the most critical sectors of the economy—such as resource extraction and material processing sectors—are very different. This result does validate the average mix assumption made in many environmental assessments, but it is important to accurately quantify the generation methods for electricity used when doing life-cycle analyses.

Introduction

The emissions and other environmental stressors from energy use or, more specifically, from electricity generation are significant contributors to the total inventory in the life-cycle assessments of many products, processes, or industry sectors. In the manufacture of cars and airplanes, for instance, over 25% of the energy use is in the form of electricity (*1*, *2*, *3*). In primary production sectors, such as the extraction and production of such raw materials as aluminum and steel, these values can be even higher. The environmental burden from this use occurs in the form of air and water pollution, fuel and land consumption, and global warming emissions. It is important to have good measures of these stressors to quantify the possible implications for health, environment, and economy.

However, many current product and process analyses that include the impacts of electricity generation use aggregate or average data for the electricity generation mix; all sectors consuming electricity are assumed to use the U. S. average generation mix, which is largely fossil-fuel-based—over 50% coal and 70% fossil fuels including natural gas and petroleum. These analyses might not do this explicitly, but as in the case of thousands of users of the Economic Input−Output Life-Cycle Analysis tool developed at Carnegie Mellon (*1*), they might just treat electricity generation and consumption casually, without considering where the facility being analyzed is located. A great deal of detail is lost at the state or facility level since certain sectors—based on geographic location or purchasing choices—buy and consume electricity with a very different generation profile than the more aggregate and fossil-fuel-dominated average mix. It is easy to imagine cases where the total impact of a sector is unfairly burdened with environmental impacts of a generation type it does not actually use. Aircraft manufacturing or aluminum production facilities located in the Pacific Northwest, for instance, may use more than 80% hydroelectric power (*4*). Using hydroelectric generation has significant effects on the impacts associated with these industries, such as lowering CO_2 emission estimates.

Disaggregating data on electricity generation or splitting it up by primary energy source would allow the assignment of a specific mix of generation types—and therefore a specific mix of environmental effects—to each product or process. We call this a consumption mix. In this paper, we look at the results of one method of disaggregation and create an optimization model for interstate electricity trading to improve its accuracy. The analysis highlights some unexpected results and the implications that these results have for environmental impact assessment of electricity consumption.

We do not attempt to address the issue of which generation type is better than another or even try to state definitively what all of the differences are. Global warming, ecosystem disruption, hazardous waste, and security—both energy and homeland—are elements that must be considered. The cost to the environment and to human health from electricity generation is large, but is a separate body of research.

In summary, there are six primary energy sources reported by the Environmental Protection Agency's eGRID database and used in this research: coal, petroleum, natural gas, nuclear, hydro, and "other", which encompasses all other types of generation including solar, wind, geothermal, biomass, and other fossil fuel types. None is completely benign from an environmental standpoint. The fossil fuel generation types—coal, petroleum, and natural gas—all emit large amounts of carbon to the atmosphere as they are burned, but there are significant variations in the amounts and makeup of their other emissions. Nuclear fuel has virtually no local emissions, but creates large amounts of hazardous radioactive waste that must be managed. Hydroelectric power is renewable and has little waste but dramatically alters the ecosystem wherever dams are built as well as incurring a large impact during the construction and from biomass decay in the reservoir (*5*). About 1.5% of the U. S. generation mix or half of the Other category is biomass burning, which is generally considered carbon neutral (*6*). The small but growing amount of wind and solar power in the United States is included here, as are geothermal, waste-to-energy plants, and "other fossil fuels" such as used tires (*4*). The impacts of these types are diverse, and certainly none is perfect (*7*).

Materials and Methods

Ideally, to disaggregate and move away from using the U. S. average mix for environmental analysis, we would have, broken down by type, the amount of electricity that every facility in the United States used. An automobile manufacturing plant near Detroit, for instance, might have a published "consumption mix" that would show that the electricity that

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10.1021/es0506859 CCC: $30.25
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Published on Web 10/07/2005

they consumed was generated with 75% coal and 25% nuclear. Comprehensive consumption mix data like this at the plant level would require the synthesis of millions of power transactions from thousands of firms. It would be necessary to collect the amount of electricity each facility purchased from each supplier and the type of generation methods that those suppliers were using or purchasing themselves. Models would match supply and demand and allocate electrons via the various grid-connected entities of different generation types based on values changing daily, if not more often. But these numbers are not readily available; in general, contracts between utility companies and their customers are confidential, even if the grid were metered at that level. It is apparent that some level of geographic aggregation is necessary, since the data needed to achieve complete disaggregation is not available.

We can make educated guesses about facility-level consumption mixes, based on the idea that electrons flow from the closest available source. Carnegie Mellon University in Pittsburgh, for instance, consumes power produced just down the Ohio River at one of several large coal plants and some from a nuclear plant 30 miles away in Beaver Valley. We can make this statement because we know two important things: (1) where Carnegie Mellon is located geographically and (2) the generation assets in that region. Similarly, if we can identify the location of manufacturing facilities and combine that information with accurate regional generation profiles, then we can systematically produce consumption mixes for all manufacturing sectors across the country.

Both pieces of information are readily available from public sources. Both the U. S. Department of Energy and the U. S. Environmental Protection Agency provide yearly state generation mixes (that is, the percent of each generation type—coal, gas, nuclear, etc.—generated in the state in a given year). The Bureau of Economic Analysis collects census data for every industry sector in the U. S. We use the median number of employees for each sector in a state as an indicator of presence in the state, then divide by the total number of employees in that sector countrywide to produce a percentage in that state (*8*).

Each industry sector then has a specific set of six percentage values assigned to it (for coal, petroleum, gas, nuclear, hydro, and other), which is a combination of fractions of the generation mixes for each state that the sector has facilities in. In some cases, sectors will have locations in all 50 states; in other cases, there will only be a few states with facilities from a specific sector. For example, as in eq 1, if we know that 60% of all widgets are manufactured in Idaho and 40% are produced in Kentucky, then the generation mix of Idaho—expressed as a six-element array where each element is a percentage of a particular generation type—shown in eq 1 is multiplied by 0.6 and the generation mix of Kentucky is multiplied by 0.4. This produces two new arrays, which are added to produce a single array: [39.1 0.1 5.3 0 52.9 2.7]. This is the new sector consumption mix for widgets. Equation 1 shows sample calculations for a consumption mix for the widget manufacturing sector using real state generation mixes from Idaho and Kentucky. The type order in the array is coal, petroleum, natural gas, nuclear, hydro, and other.

$$\begin{array}{lcccccc} & C & P & G & N & H & O \\ \text{Idaho} & [0.6\% & 0.1\% & 8.5\% & 0.0\% & 86.5\% & 4.5\%] \\ & & & & & \times & 60\% \\ \hline & [0.3\% & 0.0\% & 5.1\% & 0.0\% & 51.9\% & 2.7\%] \\ \text{Kentucky} & [96.8\% & 0.2\% & 0.5\% & 0.0\% & 2.5\% & 0.0\%] \\ & & & & & \times & 40\% \\ \hline & [38.7\% & 0.1\% & 0.2\% & 0.0\% & 1.0\% & 0.0\%] \end{array} \quad (1)$$

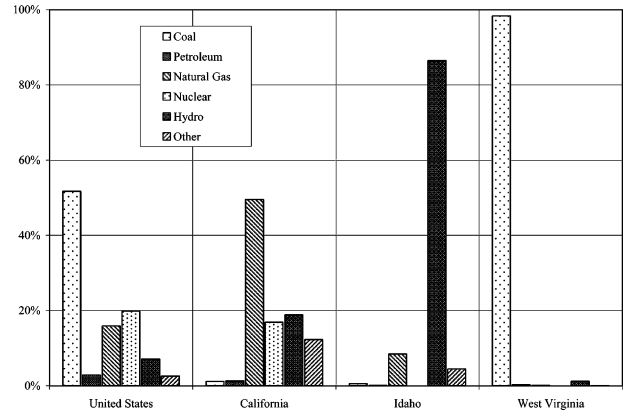

FIGURE 1. Selected state electricity generation mixes vs the U. S. average mix for 2000 (*4*).

One of the major assumptions that this method uses is the choice of states as the basic unit to capture regional differences in generation type. Although it is not difficult to think of cases where states have different generation profiles within the different regions of the state, many regional variations and state policies are captured by the state profile. County, ZIP code, or power control area data might capture much more of this variation but are unavailable for the whole United States.

In Figure 1, the differences between the U. S. average generation mix and the generation mixes of states in different regions of the country, such as California, Idaho, and West Virginia, are apparent. Environmentally progressive policies in California have created a generation mix that uses extremely small amounts of coal-fired electricity and large amounts of cleaner-burning natural gas and low-emission hydroelectric power. Or, as we will see later, these policies simply push coal generation across the state's eastern borders. California also has significant amounts of geothermal, biomass, and wind power, which is reflected in the other category. West Virginia, like several other states in the region, has large amounts of coal available for mining, and this is apparent in its mix. Idaho, however, has been able to generate nearly all of its power with hydroelectric dams.

Another assumption made in the method described above is that it does not take into account interstate power sales. Not including interstate trading might have been a valid assumption prior to large-scale deregulation of the electricity industry in 1996, but deregulation brings the additional complication of states being able to purchase electricity not only from a different state but in fact from a particular company with a particular generation type. For example, Carnegie Mellon University purchases 6% of its total electricity as wind power from 75 miles away in Somerset County. While not from a different state, purchases such as this illustrate the ability of consumers to choose their generation type, regardless of state or regulatory borders (*9*). In 2000, interstate net exports totaled nearly 10% of the total electricity consumed in the United States (*4*).

Interstate Trading

So, although regional variation in generation types are accounted for by the state mixes, large power surpluses or deficits of electricity are not. Large amounts of power moves across state borders from states with excess capacity to those with a lack of electricity. California, the country's largest consumer and importer, brought in 26% of its power in 2000—67 terawatt-hours (TWh) worth. West Virginia exported nearly 70% of the power generated in-state (*4*). It appears that the inclusion of import and export data has significant effects on the electricity consumed within the state. California, for

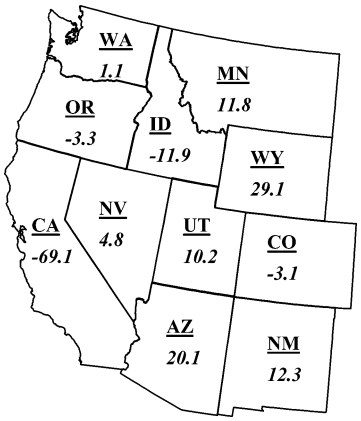

FIGURE 2. California and western U. S. net electricity exports (TWh) (*4*).

example, generates a little over 1% of its electricity with coal, but it imports nearly 30% of the electricity it consumes, much of which is probably generated in nearby coal-heavy states such as Arizona and Wyoming.

Surprisingly, data on which states shipped power and to whom is not readily available. The National Energy Board in Canada publishes information about gross interprovincial electricity transfers (*10*), but in the United States the only data consistently available are the net generation numbers published by the EPA. Basically, the net generation is the state's gross consumption for a particular year subtracted from its gross generation. A negative number means the state is a net importer for the year; a positive number indicates a net exporter. This does not mean that a net importer exported no power. It is in fact quite likely that power was shipped out one border and in another, but this is not indicated by the net values available. We do not attempt to "fix" this, since assumptions about gross imports and exports would likely lead to a large amount of uncertainty and unverifiable results given the data gaps described above.

Modeling all electricity flow across the grid in North America is not an easy task. It is an incredibly complicated system with millions of components, constantly fluctuating supplies and demands, and hundreds of players attempting to maximize their own benefits. Again, as with disaggregation itself, assumptions and simplifications need to be made to make the problem tractable given the data available.

In lieu of the creation of a perfect representation of the entire North American grid, a model was made that approximated the grid's high-level physical behavior rather than a model based on the economic transactions that drive it. Consider again the example of Carnegie Mellon University purchasing wind power; while the university's purchase drives demand for the wind generation plants, due to the distance involved and the proximity of other local generation it is quite unlikely that any of the power generated there is actually used by the university without a direct link (a transmission line) between them. Power will flow over the grid to the closest demand or, more accurately, along the path of least resistance, which all other things being equal will be the shortest path. And the closest demand for Somerset's wind power is not 75 miles away in Pittsburgh but likely in Somerset County itself.

Given this reasonable physical assumption that electricity will flow to the closest demand, the first model that we considered was one that used adjacent states as the sources of imports. However, the data available do not make this a feasible model to use; as shown in Figure 2, a state such as California with a 67 TWh electricity deficit must import electricity from more than the three states immediately adjacent to it since, even when summed together, they do not produce enough to cover California's deficit. As a result, it is likely that California imports electricity from as far away as Montana, Wyoming, and Canada.

Given the limitation of the data, a simple transportation linear programming model provides an estimate that makes intuitive sense. Traditional transportation optimization models are used to minimize the distance traveled (and the associated cost of that travel) given a set of supply and demand constraints (*11*, *12*). In this case, the model output will be a matrix, called an import−export matrix, which will show where each state with a deficit imported from and how much was imported from that state.

The data needed to develop this model were available primarily from the Environmental Protection Agency's eGRID program and from the Department of Energy's Energy Information Administration. From these two sources we gathered the state generation mixes for the year 2000 (the latest year for which complete data are available), along with gross generation and gross consumption amounts. A net import−export value was calculated by subtracting consumption from adjusted gross generation. Adjusted gross generation is the state's gross generation value multiplied by an average grid loss factor, which according to EPA data averages 9.5% (*4*). This is to account for power that is lost as it travels across transmission lines (before it can be consumed). A positive net import−export means that the state had an electricity surplus, and a negative net import−export means that the state had a deficit in 2000. In 2000, there were 27 importers and 27 exporters. The 54 total entities included the 48 contiguous states as well as the District of Columbia, Canada, and Mexico; California, Mexico, and Canada were counted as both importers and exporters since gross data were available (*4*).

These data provided the first parts of the model, which were the suppliers (exporters), customers (importers), and constraints (supplies and demands for each state). The second portion of the data for the model was the distance between each importer and exporter—a straightforward great circle distance between the geographic centroids of the entities (*13*). The full distance matrix is included in the Supporting Information.

In addition to this basic data, there were some additional elements of the power grid that we modeled, one of which was the presence of three (Western, Eastern, and Texas) managed interconnect regions in the United States and Canada. The borders for these regions are complicated but can be approximated with state boundaries. The Texas interconnect region is basically the state of Texas, and the border between the Western and Eastern interconnect falls along the eastern border of the states shown in Figure 2. There are few connections between interconnects, and in fact the regions are asynchronous—the alternating current (AC) power is phased differently, making direct transfer impossible. A direct current (DC) tie line is needed to move power from one interconnect to another. It would be unrealistic if the model moved large amounts of power between the interconnect regions.

To reduce the amount of cross-interconnect transfer happening, but not prevent it entirely, we reduce the distances between states within the same interconnect by multiplying the distance by a certain factor, making it unlikely that the model would move power between states not in the same interconnect. The factor that we used was 0.1, or a 90% reduction. A series of factors between 0 and 1 were tested, and a lower factor proved more effective at preventing transfer.

In general, high voltage direct current (HVDC) lines are put in place to facilitate the movement of excess power from the generator to a place without enough generation and provide known electricity transfer "routes" that can be

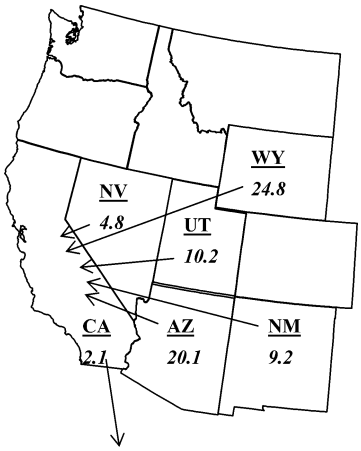

FIGURE 3. California transfers from optimization model (TWh).

modeled. But the linear optimization performs this task already, without the need to artificially modify the distances to make it more likely that power will travel along certain routes. And with the creation of ever larger AC transmission lines, it would be necessary to create these lines in the model as well as DC lines. A decision was made to keep the model simple rather than attempt to recreate the entire grid.

Finally, to modify the optimization to adhere to some limitations of the data, certain adjustments were made. Canada is not allowed to ship power to Mexico or vice versa, since the export data for Canada explicitly goes to the United States. Further, all of Mexico's imported power in 2000 came from California, so this transfer is made a constraint in the optimization. California then has its total electricity import increased by 2.1 TWh—the amount it transfers to Mexico.

When run, the optimization minimizes the sum product of the weighted distance matrix and the import−export matrix, both described above, by modifying the values in the import−export matrix. This minimized value is the total "cost" of moving electricity from the exporters to the importers. It is subject to two main sets of constraints. Each row sum in the import−export matrix must be exactly equal to the amount of excess power available in that state, and the column sums must be exactly equal to the power deficit of that state.

The final results of the optimization for all states are included in the Supporting Information, although the results for California are shown in Figure 3. This is a linear programming problem, so the result is the minimum cost that can be achieved with the given constraints. But the results seem to make intuitive sense as well. California imports from Arizona (29%), New Mexico (13%), Nevada (7%), Utah (15%), and Wyoming (36%). All had large electricity surpluses and are within the Western Interconnect.

With the values from the optimized import−export matrix and knowing the amount of electricity generated in the importing states, we can calculate a new electricity mix, which we refer to as a consumption mix, for each state. It is found by multiplying the percentage of imports received from each state by the generation mix from that state (assuming that the electricity that they export will follow the generation mix for electricity used in-state) and multiplying that by the importing state's current generation mix.

In the example shown in Figure 4, the consumption mix for California is calculated based on the results shown in Figure 3. We know the percentage of power imported to the state, and this is broken out as percentages of the states that exported power to California. We therefore know the percentage of total consumption that each import makes up. And since we know the original EPA generation mixes for all the states in question, we can multiply each mix array by the respective state's percentage of consumption. By adding each generation type, we can get a final consumption mix for California that includes all of the imports provided by the optimization.

The new generation mix for California is shown in Figure 5. The impact of the large amount of coal imports from Wyoming, Utah, and Arizona is obvious. Despite the published generation mix for California, which seems to promote clean air, the results here suggest that California consumes almost 20% of its electricity overall from coal-fired power plants. This would lead to an increase of over 30% in tons of CO_2 emitted from the burning of fossil fuels to generate electricity for California, from 850,000 tons to almost 1.3 million tons (*4*). And due to the general flow of air and pollutants from west to east in the western United States, California does not see all of the emissions resulting from this consumption.

Verification of the model results are difficult. The model was built because little data about interstate trading were available. However, there is some high-level aggregate information about where states get their power. Each year the California Energy Commission (CEC) estimates its electricity imports and which region they were imported from. It separates the importers into three regions: Pacific Southwest, Pacific Northwest, and Other (*14*, *15*) and creates a net system power calculation, which is similar to our consumption mix (*15*, *16*). A summary of these values is shown in Table 1; both are estimates, and the total difference is less than 20%.

The final import−export matrix and the new consumption mixes for each net importer are included in the Supporting Information. A summary of the top 10 importers and their

California In-state Production		73.9%
California Imported Power		26.1%
California Imports	AZ	29.0%
As percent of imports,	NM	13.3%
results from optimization	NV	7.0%
	UT	14.8%
	WY	35.9%
		100.0%
As percent of CA consumption	AZ	7.6%
(.290 x .261 = .076, etc.)	NM	3.5%
	NV	1.8%
	UT	3.9%
	WY	9.4%
		26.1%
	CA	73.9%
		100.0%

In-State Generation Mixes *From EPA eGrid data*		*Coal*	*Oil*	*Gas*	*Nuc*	*Hyd*	*Oth*
	CA	1.1%	1.4%	49.5%	16.9%	18.8%	12.3%
	AZ	46.1%	0.2%	9.8%	34.1%	9.7%	0.0%
	NM	85.4%	0.3%	13.6%	0.0%	0.6%	0.0%
	NV	53.5%	0.1%	35.9%	0.0%	6.8%	3.7%
	UT	94.8%	0.2%	2.4%	0.0%	2.0%	0.6%
	WY	95.9%	0.1%	1.0%	0.0%	2.2%	0.7%
CA Consumption *As percent of consumption, by state and by gen. type*	CA	0.8%	1.0%	36.6%	12.5%	13.9%	9.1%
	AZ	3.5%	0.0%	0.7%	2.6%	0.7%	0.0%
	NM	3.0%	0.0%	0.5%	0.0%	0.0%	0.0%
	NV	1.0%	0.0%	0.7%	0.0%	0.1%	0.1%
	UT	3.7%	0.0%	0.1%	0.0%	0.1%	0.0%
	WY	9.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CA Consumption Mix		20.9%	1.0%	38.6%	15.1%	14.9%	9.2%

FIGURE 4. Creating a state mix example.

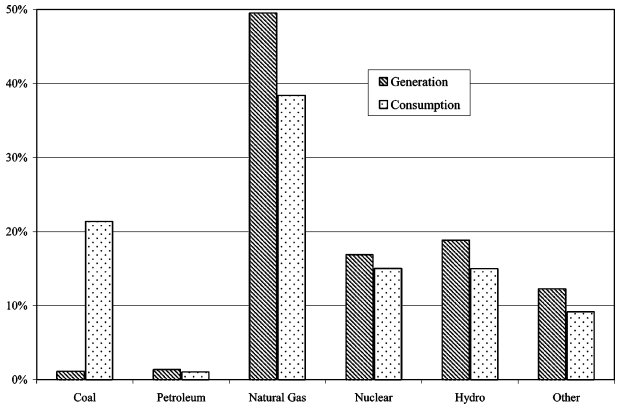

FIGURE 5. 2000 electricity generation mix for California vs consumption mix, which includes interstate electricity trading.

TABLE 1. Comparison of California Energy Commission Net System Power vs Model Calculated Consumption Mix (*16*)

	CEC net system power	model results
coal	15.7%	21.4%
natural gas	35.1%	38.4%
petroleum	1.3%	1.0%
nuclear	17.2%	15.0%
hydroelectric	21.8%	15.0%
other	8.9%	9.2%

new consumption mixes is included in Table 2. These new consumption mixes for each importing state are combined with the original generation mixes for each exporting state and are used in the same industrial sector disaggregation process explained earlier, which assigns a consumption mix to each industrial sector.

Analysis

With the optimization and two sets of disaggregations complete, there are two sets of data to compare. The first is the initial disaggregation, which does not include interstate electricity trading, and the second includes the results of the import−export model. Each set has 519 arrays of six percentages—one array for each U. S. industry sector. To assess the impact of disaggregation, we compare each of these arrays to the 2000 average U. S. generation mix, since prior to disaggregation these are the values that were being used to calculate environmental impact. To do a comparison, we developed an index value that takes the absolute value of the pairwise differences between the values in the sector array and U. S. average array and then sums these absolute values. The theoretical maximum value for this index value was calculated to be 19.48 using the method shown below, which is the index value when the U. S. average mix is compared to the array that is the most different; this theoretical most different mix would have 100% of the power allocated to the other category, and 0% allocated to each of the other five generation types. The index values for all 519 sectors were then sorted and plotted.

The calculation for the differential index for this consumption mix is as follows

$$(|0.52 - 0| + |0.03 - 0| + |0.16 - 0| + |0.20 - 0| + |0.07 - 0| + |0.03 - 1.0|)(10) = 19.48 \quad (2)$$

The results of these calculations for all sector consumption mixes are plotted and discussed below in the Discussion section.

Before the analysis was begun, we expected to see that disaggregation had a significant impact on the consumption mixes for all industrial sectors. "Impact" in this case was defined as a measure of how different the process-generated consumption mix was from the originally assigned U. S. average mix. We had further expected that adding imports and exports would exacerbate this result; the consumption mixes would look less like the U. S. averages. But analysis done on the results of the disaggregations lead us to reject our initial hypotheses—while some sectors have disaggregated consumption mixes quite different from the U. S. average, most are very similar to it. Additionally, the inclusion of imports and exports has an averaging effect, which makes consumption mixes more like the U. S. average rather than more different.

The plots of the two sets of disaggregated sector mix difference index values are shown in Figure 6. This figure shows a cumulative percentage of sectors at a particular index value or above. For instance, approximately 20% of sectors are at index values of 3 or more for both the import−export set and the original sector set, without import−export. The

TABLE 2. Comparison of Electricity Generation and Consumption for the Top 10 Electricity Importers

				published 2000 electricity generation mix					
				2000 electricity consumption mix					
		imported amount (TWh)	% consumption imported	coal	petroleum	natural gas	nuclear	hydroelectric	other
1	Washington, DC	10.5	99%	0%	100%	0%	0%	0%	0%
				97%	*1%*	*0%*	*0%*	*1%*	*0%*
2	Delaware	6.0	53%	69%	14%	14%	0%	0%	3%
				63%	*8%*	*7%*	*20%*	*0%*	*2%*
3	Idaho	11.9	52%	1%	0%	8%	0%	86%	4%
				26%	*1%*	*5%*	*0%*	*66%*	*3%*
4	Massachusetts	16.5	32%	29%	20%	27%	14%	6%	5%
				36%	*14%*	*19%*	*22%*	*5%*	*5%*
5	Virginia	30.1	30%	51%	4%	6%	36%	0%	3%
				65%	*3%*	*4%*	*25%*	*0%*	*2%*
6	Rhode Island	2.0	27%	0%	1%	97%	0%	0%	2%
				15%	*1%*	*71%*	*10%*	*0%*	*2%*
7	California	67.0	26%	1%	1%	50%	17%	19%	12%
				21%	*1%*	*38%*	*15%*	*15%*	*9%*
8	Mississippi	11.5	25%	37%	8%	22%	28%	0%	4%
				41%	*6%*	*18%*	*31%*	*0%*	*3%*
9	Maryland	15.4	25%	58%	5%	6%	27%	3%	2%
				66%	*4%*	*4%*	*22%*	*3%*	*1%*
10	New Jersey	17.5	25%	16%	2%	28%	50%	0%	3%
				27%	*2%*	*22%*	*47%*	*0%*	*3%*

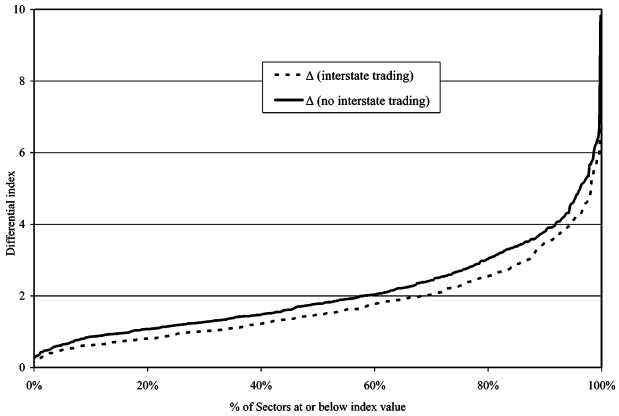

FIGURE 6. Measure of sector mix difference from the U. S. average mix. Note, maximum sector differenetial is 19.48.

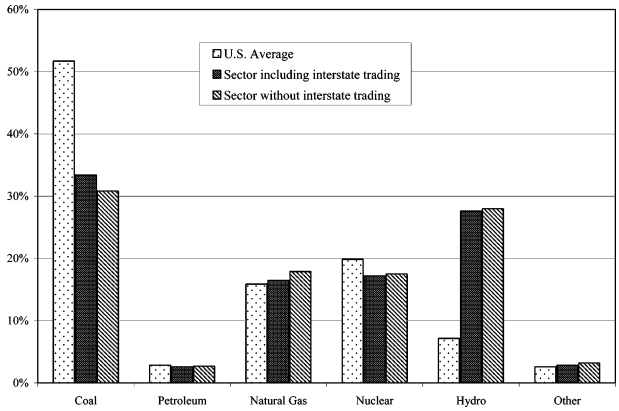

FIGURE 7. Sector consumption for aircraft manufacturing (NAICS 336441).

maximum index value for the no import–export sector mix was 9.8, and for the import–export set, the maximum differential value was 7.25, both out of a theoretical maximum of 19.48 (shown at the top of the scale). The minimum values were 0.15 and 0.26 for import–export and no import–export, respectively.

Discussion

The most likely explanation for the trend toward the average, both for the standard disaggregation consumption mix and the disaggregation with trading consumption mix, is spatial diffusion. Sectors spread out across the country will have profiles much like the country itself. This is obvious for sectors such as restaurants, hospitals, and oil change shops. What is interesting is how many other sectors, which we were not expecting to be diffused across the country, actually are or at least appear to be, based on their consumption mixes with low differential index values.

That interstate trading would have an averaging effect on consumption mixes should have, in retrospect, been obvious. As states get power from a wider variety of sources, the chance that those sources together will look like the U. S. average increases. When we look at some simple comparisons, we can see this effect quite clearly. Prior to including imports and exports, the top three states in terms of difference from the U. S. average were Idaho (due to large amounts of hydroelectric power), Rhode Island (generates internally with mostly natural gas), and Hawaii (generates electricity with petroleum). When the optimization was run and the new generation mixes were compared to the old, the two states that had changed the most were Idaho and Rhode Island. Looking again at a comparison to the U. S. average mix, but this time using the new generation mixes, Rhode Island and Idaho are no longer even in the top 10 for difference from the average. The inclusion of imports made them more like the average and dropped them out of the top spots. Overall, however, the effect of adding imports and exports is small, with the total difference between the normal disaggregate results and those including interstate trading being about 3%.

Although the difference in results for this particular use is small, it is still interesting to be able to quantify the difference. This comparison would have been made much easier with better data availability. Gross import and export data, such as that available from the Canadian National Energy Board and certain states, such as California, should be regularly collected and made available either through the EPA or Department of Energy. This information could be used to answer many other questions where the source of electricity—and its associated pollutants—is important. Simply providing the gross import and export data would allow researchers to create their own methods for deciding where the imports and exports end up. It could be a simple optimization such as ours or a more complex physical model where specific transmission lines are included.

Despite many of the sectors being close to the average, it is nonetheless interesting to look at the top 5%. More so than the hundreds of sectors that trend toward the average, these top sectors are good verification of the disaggregation process. Oil and gas equipment (NAICS 333132) are manufactured in states that use lots of natural gas. Sightseeing transportation (NAICS 487000) is the top sector for petroleum; not coincidentally, Hawaii with its large interisland tourism industry is the top petroleum state. Aircraft manufacturing (NAICS 336441), the consumption mix of which is shown in Figure 7, has long made its home in hydro-heavy Washington and California, and the disaggregated results show about 30% hydroelectric generation. There are also more wineries in California than anywhere else in the country, and California has a large amount of other power; wineries are a top sector for the use of other generation types such as geothermal and wind.

Also among the list of top sectors for the use of each generation type are some of the most critical sectors of the economy—fundamental resource and material production sectors such as aluminum, steel production, and coal mining—on which many products are based. While it seems a rather unexciting conclusion to draw that most sectors have the same generation mix that they would have had before disaggregation or modeling of interstate trading, this is nonetheless an important result. It validates the assumption made in many environmental assessments that the impacts are average impacts based on average generation mixes.

A more general conclusion is to be sure that the particular product or process being assessed is looked at carefully. The results of a life-cycle analysis looking at the production of a washing machine are very different when the production uses an electricity consumption mix consisting of 80% coal rather than 50%, so too with aircraft or wine. It is important to accurately quantify the environmental impacts associated with electricity use in life-cycle analyses, especially those that involve large manufacturing sectors such as primary raw materials extraction and U.S. EPA, Grant R829597 for support.

Acknowledgments

We thank Paul Fischbeck, David Keith and Mitch Small for feedback on very early versions of this work, Thomas Grahame at the Department of Energy for valuable views from the real world and U.S. EPA, Grant R829597 for support.

Supporting Information Available

Original distance matrix used in the interstate trading optimization, the modified distance matrix, the final results of the optimization, the consumption mixes for the top 10 industrial sectors for each generation type, and the full list of consumption mixes for the 50 U. S. states. This material is available free of charge via the Internet at http://pubs.acs.org.

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Received for review April 10, 2005. Revised manuscript received August 7, 2005. Accepted August 28, 2005.

ES0506859