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Fuel Competition in Power Generation and Elasticities of Substitution

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Executive Summary

This report analyzes the competition between coal, natural gas and petroleum used for electricity generation by estimating what is referred to by economists as the elasticity of substitution among the fuels. The elasticity of substitution concept measures how the use of these fuels varies as their relative prices change. It should be noted that many factors other than fuel prices play important roles in determining which power plants are run to meet electricity demand as it varies over time. These factors include generators' nonfuel variable operating costs, startup/shut down costs, emission rates and allowance costs, electricity grid flow constraints, and reliability constraints. Electricity system operators evaluate all of these factors when determining which plants and fuels to use.

The patterns of dispatching power generation have changed noticeably over the past few years. A number of factors, especially volatile fossil fuel costs, have altered the mix of energy sources used to produce electricity. Although petroleum has historically been a relatively modest component of the overall generation fuel mix, its share of generation was reduced even further by petroleum prices that began rising rapidly in the mid-2000s. More recently, a sudden increase in spot prices for Appalachian coal during 2008 has been followed by a sustained decline in the delivered cost of natural gas, both of which have substantially shifted the dispatch pattern for baseload generation in some parts of the country, favoring natural gas-fired units over coal-fired units.

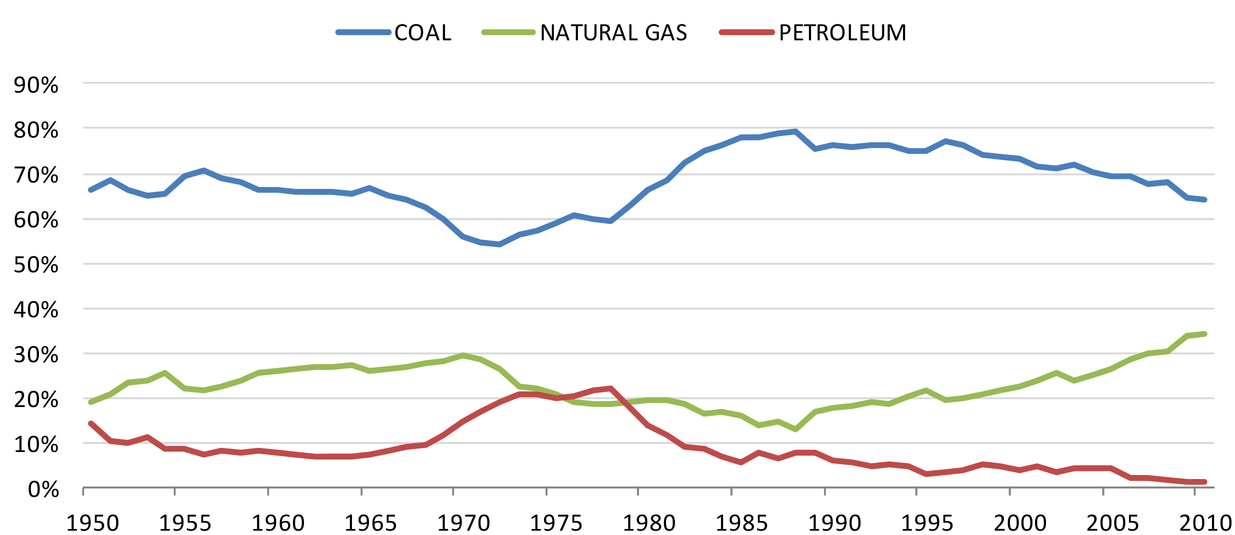
Earlier academic studies analyzed fossil fuel substitution during the period of the 1980s and 1990s. This report updates the earlier work to reflect dispatching patterns during the period of 2005-2010. The model results indicate that for the United States as a whole, a 10-percent increase in the ratio of the delivered fuel price of coal to the delivered price of natural gas leads to a 1.4-percent increase in the use of natural gas relative to coal. Generators' use of petroleum is much more responsive to relative fuel price changes. A 10-percent increase in the price ratio of natural gas to petroleum leads to a 19-percent increase in the relative use of petroleum compared with natural gas. The model results are the most robust for the southeastern United States, while fuel substitution results for the Midwest and Texas are relatively insignificant.

Background

The structure of the power industry varies from region to region. Generation dispatch decisions are made by an individual utility operating multiple plants in its service area or by an independent system operator as part of a centralized wholesale power market. In either case, generation costs are a primary driver determining the mix of fuels used to supply a region's power load. As fuel costs and technology change over time, some energy sources become more economical to utilize than others. Historically, most of the baseload power demand in the United States has been supplied by coal and nuclear generation units, owing to their low costs of operation. Generation fueled by natural gas and petroleum supplemented the baseload generators during peak and intermediate periods of demand. In some areas of the country, abundant hydropower capacity has supplied both baseload and peaking generation.

Beginning in 1970, petroleum's share of fossil fuel generation began to increase, reaching more than 20 percent by the end of the decade (Figure 1). Higher oil prices following two price shocks during the 1970s eventually stunted this growth. In 1978, the Powerplant and Industrial Fuel Use Act (PIFUA) restricted the construction of new petroleum and natural gas plants. Instead of these two fuels, PIFUA encouraged the construction of new generation capacity fueled by coal. As a result, throughout the 1980s coal's share of fossil fuel generation expanded as new power plants were constructed. By 1990, PIFUA had been repealed and the natural gas markets had been deregulated, allowing more opportunities for substitution between petroleum and natural gas as a fuel for peaking generation.

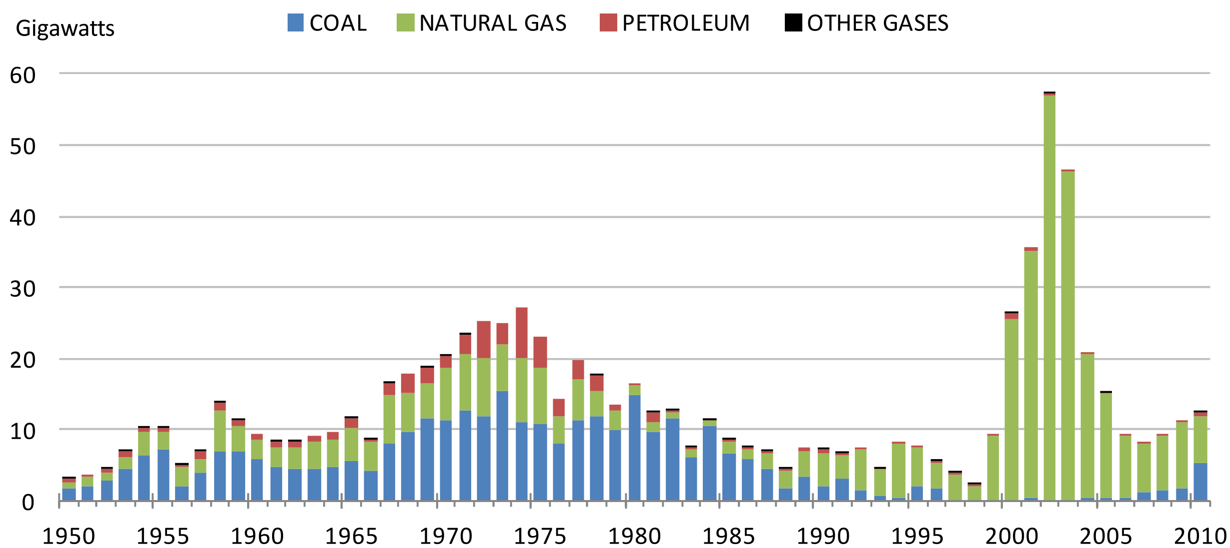
Figure 1. Share of Total Fossil Fuel Generation (All Sectors)



Note: Data through 1988 are for electric utilities only. For 1989 to the present, data include utilities, independent power producers, and the commercial and industrial sectors.
A small amount of generation from other types of fossil gases is not shown (generally <0.5%).
Source: U.S. Energy Information Administration, Annual Energy Review Table 8.2a and Electric Power Annual Table 2.1.A

A combustion turbine fueled by natural gas can be brought online quickly. Historically, combustion turbines had a lower thermal efficiency than a comparable steam-electric plant. So natural gas, as with petroleum, has traditionally been used primarily as a fuel to satisfy peak load. Combined-cycle technology takes advantage of a natural gas combustion turbine's "waste" heat to create steam, from which the unit can produce additional electricity. During the 1990s and 2000s, the heat rate and reliability of new combined-cycle units vastly improved. This improvement in generation technology, in conjunction with low natural gas prices, dramatically reduced the generation costs of plants fueled by natural gas. The low fuel prices and improved technology were two important factors behind the 96-percent growth in natural gas generating capacity between 2000 and 2010 (Figure 2). In contrast, additions to coal capacity were relatively minor during that period. Petroleum-fired capacity declined by 12 percent.

Figure 2. Fossil Fuel Electric Net Summer Capacity Additions (All Sectors)



Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report," for 2002-2010. Values for 1950-2001 were calculated using the operating (start) years listed in the Form EIA-860 report for 2002. Capacity additions for any plants that may have retired prior to 2002 are not included in this figure.

Beginning in 2005, natural gas production from domestic shale gas formations began to rapidly increase, which has led to a relatively sustained period of low natural gas prices. Natural gas spot prices at the Henry Hub averaged $7.70 per million Btu during the first quarter of 2006. After a brief spike in 2008, natural gas prices quickly tumbled to a low of about $3.20 per million Btu by the third quarter of 2009. In 2010, prices averaged a little more than $4.00 per million Btu. A continued decline in natural gas prices during 2011 and the early part of 2012 has further encouraged power plant operators to use combined-cycle units to fulfill baseload power demand, displacing some coal generation. Between 2005 and 2010, the average capacity factor for natural gas combined-cycle units running during off-peak hours (between 10 p.m. and 6 a.m.) rose from 26 percent to 32 percent (EIA, 2011).

The trend of natural gas displacing coal was especially evident in the southeastern United States between 2008 and 2009. While coal generation in the South Atlantic region declined by 77 gigawatthours (18 percent) from 2008 to 2009, generation fueled by natural gas actually increased by 29 gigawatthours (21 percent). In other words, natural gas's share of fossil fuel generation in the South Atlantic jumped from 24 to 32 percent between those two years, while coal's share fell from 73 to 65 percent. This shift in fuel use coincided with a drop of 34 percent in the average annual cost of natural gas delivered to South Atlantic electric generators and an increase of 13 percent in the annual average delivered cost of coal for the same region. Although various factors contributed to this significant year-over-year shift in the generation fuel mix, the relative change in fuel prices was likely one of the primary drivers. This shift from coal to natural gas in the southeast has continued into 2010, 2011, and 2012.

Methodology

The issues surrounding competition between coal and natural gas as a fuel for generating electricity have received quite a bit of attention in recent years. Some analyses have attempted to measure the potential displacement of fuels from a change in the fossil fuel mix. A report by the Congressional Research Service found that much of the natural gas combined cycle capacity in the United States has a relatively low utilization rate and could potentially be used in place of steam coal capacity to fulfill baseload power demand (Kaplan, 2010). After the natural gas industry and a significant part of the electricity industry were deregulated at the wholesale level in the 1980s and 1990s, a number of academic studies were published that investigated price-driven displacement among energy sources using the economic theory of production input substitution (see, for example, Bopp and Costello, 1990; Jones, 1995; Dahl and Ko, 1998; Ko and Dahl, 2001; Urga and Walters, 2003). This report updates the earlier input substitution research, specifically with regards to analyzing how power producers adjust their choice of fuel mix in response to changing fossil fuel prices.

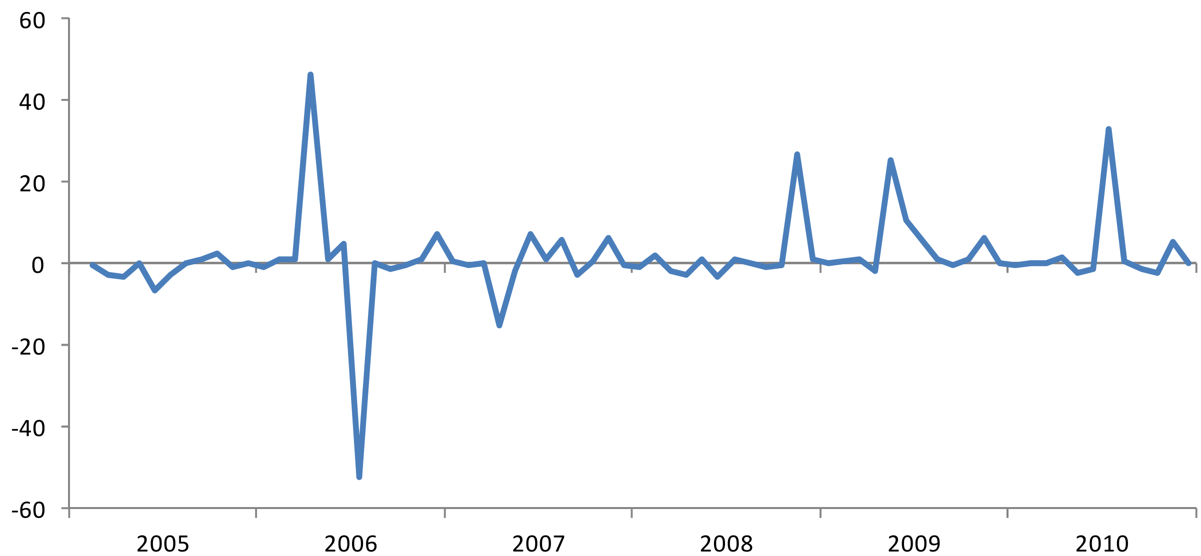
The model developed in this report estimates values for the elasticity of substitution, which is a measure of the responsiveness of producers in swapping inputs when the relative prices of those inputs change. Producers will tend to favor the input that has the lowest overall cost. However, various economic, technological and regulatory restrictions can limit this responsiveness. The concept of the elasticity of substitution (ε) between two inputs can be illustrated using the following ratio:

Eq. (1)
$$\varepsilon = \frac{\text{percent change in } (F_1/F_2)}{\text{percent change in } (P_2/P_1)}$$

where F_x is the quantity of input x used in production, and P_x is the per-unit price of the associated input of production. As the price of one input increases, basic economic theory states that producers will attempt to substitute more of other inputs. An elasticity equal to 1 indicates that for a given percentage decline (increase) in the price of input 2 relative to the price of input 1, the relative use of input 1 in production compared with input 2 will exhibit a similar percentage increase (decline). In this case, each input's share of total cost will remain constant even if the price of one input were to change. An $\varepsilon < 1$ indicates that the use of one input production would change less than proportionately to a given change in the relative prices – i.e., producers don't have much incentive or flexibility to swap one input for another in the production process. Conversely, $\varepsilon > 1$ implies that producers are more open to substituting different inputs in the production process when relative input prices change.

Simply analyzing this elasticity measure at a specific point in time can be deceptive, as Figure 3 shows for the calculated monthly U.S. elasticity of substitution between natural gas (F_1) and coal (F_2). Although the mean elasticity value is 1.5 (with a median of 0.32), there are a number of months with very large values, including some months where the elasticity takes on a negative value. There are other factors besides relative fuel prices that are impacting the relative consumption between natural gas and coal, in particular the level of generation. During particularly hot months, power producers may rely heavily on peaking generation units fueled by natural gas. Such factors can skew the elasticity value calculated from equation (1), which attributes all of the changes in fuel consumption to movements in fuel prices. A more generalized economic model can measure price-driven substitution among fuels while accounting for other factors influencing fuel consumption.

Figure 3. Monthly U.S. Elasticity of Substitution Between Natural Gas and Coal



Various models have been developed for estimating elasticities of substitution. Two of the early studies (Atkinson and Halvorsen, 1976; Christensen and Greene, 1976) applied their models to the electric power industry. Christensen and Greene investigated substitution between capital, labor, and fuel inputs. Atkinson and Halvorsen focused on the displacement of fuels between oil, natural gas, and coal. In both cases, the researchers utilized translog functional forms for the cost function in order to easily identify the elasticities of substitution. Later studies applied the translog model to the U.S. electricity industry in order to analyze regional differences in fuel substitution (Bopp and Costello, 1990) or the impact of industry restructuring (Ko and Dahl, 2001).

As computing power improved, researchers began applying more advanced models for investigating economic substitution among inputs in the production process. The linear logit model (Considine and Mount, 1984) became particularly popular for fuel substitution studies. In contrast to the translog model, the linear logit model provides more robust estimates of the elasticity of substitution even though the functional form of its cost function is more complex. In addition, this type of model can be easily adapted to analyze dynamic fuel displacement behaviors.

Most of these studies were published during the 1990s and 2000s when natural gas and petroleum were displacing each other in the power industry in response to relative fuel price fluctuations. The elasticity of substitution between these two fuels and coal was generally found to be insignificant, for the most part because the price of coal ensured its position as the primary fossil fuel used for baseload generation. This report updates some of the previous work done by Ko and Dahl (2001) and Jones (1995) using dynamic linear logit models with more recent data that reflect more pronounced displacement of coal by natural gas.

The model used in this report focuses on substitution between the three broad classes of fossil fuels: coal, natural gas, and petroleum; the model follows the structure developed by Jones (1995). The prices of other inputs, such as labor and capital, along with generation from non-fossil fuels such as nuclear, hydropower, and other renewable energy sources are assumed to have minimal impact on generators' choice of fossil fuel.

A linear logit model is based on the assumption that each input's share of total cost (S_i) can be modeled as a logistic function of the input prices and the level of output (Considine and Mount, 1984):

(Eq. 2) $$S_i = \frac{P_i Q_i}{\sum_{j=1}^{N} P_j Q_j} = \frac{e^{f_i}}{\sum_{j=1}^{N} e^{f_j}} \qquad \text{for } i = 1,2,\dots,N$$

(Eq. 3) $$\text{and } f_i = \eta_i + \sum_{j=1}^{N} \phi_{ij} \ln P_j + \alpha_i G$$

where *e* is the exponentiation operator, P_j is the price of input *j*, and *G* is the total level of output. The η_i parameters are the constant coefficients that represent the "baseline" cost shares in each input's regression estimation. The ϕ_{ij} coefficients illustrate the effect of a change in the price of input *j* on the cost share for input *i*, and the α_i coefficients indicate how the cost shares change when total output changes.

The logit model converts equations (2) into linear functions by taking the logarithm of both sides, and estimates a system of equations for all inputs simultaneously. The structure of the logit model is convenient for a cost-share analysis because it limits the estimated dependent variables to a range between zero and one. Coefficient restrictions are imposed so that the estimated cost shares will sum to one and so that the price coefficients (weighted by their average cost shares) are homogenous of degree zero (i.e., if all prices change in the same proportion, there will be no effect on relative cost shares). However, these restrictions prevent a unique solution when estimating the system of equations. To solve this problem, one equation is dropped from the system, and the remaining equations are normalized using the dropped variables. Using similar notation as in Jones (1995), the normalized system of equations can be expressed as follows:

(Eq. 4) $$\ln\left(S_{1,t}/S_{3,t}\right) = (\eta_1 - \eta_3) - \left(\phi_{12} S_{2,t} + \phi_{13}\left(S_{1,t} + S_{3,t}\right)\right) \ln\left(P_{1,t}/P_{3,t}\right)$$
$$+(\phi_{12} - \phi_{23}) \ln\left(P_{2,t}/P_{3,t}\right) + \alpha_1 \ln(G_t) + \sum_{k=1}^{11} \beta_{1i} M_{k,t} + \lambda \ln\left(Q_{1,t-1}/Q_{3,t-1}\right)$$

(Eq. 5) $$\ln\left(S_{2,t}/S_{3,t}\right) = (\eta_2 - \eta_3) - \left(\phi_{12} S_{1,t} + \phi_{23}\left(S_{2,t} + S_{3,t}\right)\right) \ln\left(P_{2,t}/P_{3,t}\right)$$

$$+(\phi_{12} - \phi_{13})\ln\left({P_{1,t}}/{P_{3,t}}\right) + \alpha_2 \ln(G_t) + \sum_{k=1}^{11} \beta_{2i} M_{k,t} + \lambda \ln\left({Q_{2,t-1}}/{Q_{3,t-1}}\right)$$

where: $S_{i,t} = \frac{P_i Q_i}{P_1 Q_1 + P_2 Q_2 + P_3 Q_3}$ = fuel i's share of total generation cost during period *t*
$P_{i,t}$ = per-unit cost of fuel i during period *t*
$Q_{i,t}$ = quantity of fuel i consumed for generation during period *t*
G_t = total level of generation during period *t*
$M_{k,t} = 1$ if period *t* corresponds to k^{th} month, = 0 otherwise.

For each dataset, the fuels are ranked by average cost share over the sample period, January 2005 – December 2010. The equation for the fuel with the largest share is dropped from the system, and the remaining two equations are normalized by the corresponding coefficients and values from the dropped equation. Since the fuel mix can vary throughout the year, depending on the need for peaking generation, a variable for the total level of generation and monthly dummy variables are included for each equation to account for this strong seasonality. A dynamic aspect is introduced to the model by including lagged consumption as a right-hand side variable (Considine and Mount, 1984). A change in relative fuel prices is assumed to impact the fuel mix over more than one period. The coefficient λ represents the generators' rate of adjustment for each period towards reaching the desired fuel consumption level.

As shown in Considine and Mount (1984), the elasticities of substitution can be derived directly from the estimated coefficients in equations (4) and (5). The cross price elasticity between fuels i and j $(i \neq j)$ can be expressed as:

Eq. (6)
$$\varepsilon_{ij} = \left(\phi_{ij} + 1\right)\bar{S}_j$$

which is measured using the mean cost share over the sample period for the second comparison fuel $\left(\bar{S}_j\right)$. Own price elasticities for each fuel can also be derived from the system coefficients:

Eq. (7)
$$\varepsilon_{ii} = (\phi_{ii} + 1)\bar{S}_i - 1$$

Although the coefficient ϕ_{ii} is not directly estimated in the system of equations, it can be derived from the other estimated coefficients using the homogeneity restriction:

Eq. (8)
$$\hat{\phi}_{ii} = {-\left[\sum_{j\neq i}\left(\hat{\phi}_{ji}\bar{S}_j\right)\right]}/{\bar{S}_i}$$

The system of equations (4) and (5) is estimated using monthly data from the Form EIA-923 database for the period 2005 to 2010.[1] Each generator within the 923 database is matched up with its plant's corresponding entry for the North American Reliability Corporation (NERC) region in which it operates, using data from the Form EIA-860 database. Monthly fuel consumption (Q_i) for each region (and for the entire United States) is calculated by summing across all observations within the group. The

[1] Prior to 2007, generation and fuel consumption data were collected using Forms EIA-906 and EIA-923. Fuel price data was collected on Forms EIA-423 and FERC-423. All of the survey questions were consolidated into Form EIA-923 beginning in 2007.

monthly average price (P_i) of coal, natural gas, and petroleum liquids for each region is determined by computing the mean cost of all observations in the group, weighted by each observation's corresponding fuel receipts.[2] The cost of generation attributed to a given fuel is the per-unit fuel price times the level of fuel consumption. A fuel's cost share is equal to its individual cost divided by the total generation cost across all fuels. Table 1 shows the mean cost share for each fuel by region.

Table 1. Average Generation Cost Shares, 2005-2010

NERC Region	Coal	Natural Gas	Petroleum
Florida Reliability Coordinating Council (FRCC)	16.9%	70.6%	12.5%
Midwest Reliability Organization (MRO)	76.9%	20.3%	2.8%
Northeast Power Coordinating Council (NPCC)	13.9%	74.0%	12.0%
ReliabilityFirst Corporation (RFC)	72.6%	24.0%	3.4%
SERC Reliability Corporation (SERC)	64.7%	33.5%	1.8%
Southwest Power Pool (SPP)	37.5%	61.7%	0.8%
Texas Reliability Entity (TRE)	22.5%	77.3%	0.2%
Western Electricity Coordinating Council (WECC)	26.0%	73.4%	0.6%
United States (US)	44.4%	51.7%	3.9%

Source: U.S. EIA Form-923 database and Form-860 database.

[2] This analysis does not include fossil fuel consumption of other gases or petroleum coke since the level of generation from these fuels is small and not very responsive to price.

Model Results

The appendix provides detailed econometric results for the regional logit models, which were estimated using the full information maximum likelihood method. The parameters that are most relevant to this report are the elasticities derived from the estimated model coefficients. Table 2 presents the short-run estimates of regional cross price elasticities of substitution between coal, natural gas, and oil (petroleum) derived from equation (6) above. The elasticities reported in the table are reported for pairwise combinations of two fuels, and they measure the flexibility that power producers have in terms of displacing the second fuel listed with the first fuel. Usage of the third fuel is assumed to be held constant. The values for one displacement pairing will differ from the value for the reverse pairing because the two fuels have different cost shares. Likewise, the magnitude of the numerator and denominator in equation (1) will vary depending on which fuel displaces the other.

Table 2. Estimated Cross Price Elasticities of Substitution and Dynamic Rate of Adjustment

NERC REGION	Coal - Gas	Coal - Oil	Gas - Coal	Gas - Oil	Oil - Coal	Oil - Gas	Adjustment Parameter
FRCC	0.43**	0.09**	0.10**	0.36**	0.13**	2.03**	0.95
MRO	0.08	0.03	0.31	0.00	0.70	0.00	0.46**
NPCC	0.14**	0.09*	0.03**	0.19**	0.10*	1.16**	0.65**
RFC	0.16**	0.02	0.49**	0.11**	0.38	0.75**	0.79**
SERC	0.20**	0.03**	0.38**	0.03**	0.89**	0.64**	0.95
SPP	-0.01	-0.01	-0.01	0.02*	-0.51	1.79*	0.73**
TRE	-0.08	0.00	-0.02	0.00	-0.30	0.85	0.86
WECC	0.14**	0.00	0.05**	0.00	0.16	0.49	0.72**
US	0.17**	-0.06**	0.14**	0.14**	-0.63**	1.89**	0.82**

Note: ** indicates coefficient is statistically significant with 95 percent level of confidence. * indicates 90 percent statistical significance. Statistical significance of elasticities determined using Chi-square statistic from Wald test. Significance of adjustment parameters is determined from standard t-test on estimated λ coefficients.

The rapid change in the prices of coal and natural gas between 2008 and 2009 provides one scenario for illustrating the interpretation of these elasticity estimates. Over the course of that two-year period, the average price of coal delivered to electric generators increased from $2.07 per million Btu (MMBtu) to $2.21/MMBtu while the average price of delivered natural gas declined from $9.01/MMBtu to $4.74/MMBtu.[3] In other words, the ratio of coal to natural gas prices increased about 103 percent between 2008 and 2009. Table 2 shows that the estimated U.S. gas-coal elasticity of substitution is 0.14. So, given the relative change of 103% in the ratio to coal to natural gas prices, the change in the ratio of generators' consumption of natural gas to consumption of coal (as measured on a Btu basis) would be expected to be about 0.14*103% ≈ 14%. In actuality, the ratio of natural gas to coal consumption increased from 0.3329 in 2008 to 0.3853 in 2009, a change of about 16%.

[3] U.S. EIA Monthly Energy Review Table 2.6.

More than half of the cross price elasticity estimates in Table 2 are statistically significant, and most of the estimates have a positive sign as economic theory predicts.[4] Negative cross-price elasticity estimates, such as the -0.63 estimate of elasticity between U.S. petroleum demand and coal price, indicate that the two inputs are complements rather than substitutes. Many generating units that are fueled primarily by coal use either residual or distillate fuel oil as a start-up fuel.

Most of the estimated values are inelastic ($\varepsilon_{ij} < 1$), meaning that the percentage change in the relative use of the fuels would be lower than the percentage change in relative fuel prices. Fuels with relatively inelastic substitutability cannot be easily swapped within the production process. The process of electricity generation is generally price inelastic because the majority of units are designed to operate with one type of fuel, especially those that serve baseload demand. Furthermore, many generating units must operate within certain ranges because of reliability or environmental restrictions. However, a number of the cross-price estimates for substitutability between petroleum and natural gas are elastic. The large values for the oil-gas elasticities reflect the relatively low share of generation cost provided by petroleum-fired units. But, another reason is that some combustion turbine and combined-cycle units are designed to run on either petroleum or natural gas, and plant operators have the flexibility to choose the most economical fuel (within the limits of any environmental or fuel supply constraints).

Comparing the cross-price elasticities across regions is difficult because the typical fuel mix as measured by the average cost share varies so much between the regions. Yet, the estimation results appear most robust for the southeast U.S. (FRCC and SERC). Displacement of fuels (both between coal-gas and between gas-oil) was most evident in this area of the country over the sample period because the region's generating capacity and transmission infrastructure allowed the industry to favor those power plants fueled by the lowest cost energy source. The estimation results for the northeast (NPCC and RFC) are also surprisingly robust even though the region's transmission infrastructure is often congested. Northeast generators appear to have slightly more flexibility to substitute fuels than generators in the southeast, even though the two regions have a fairly similar fuel mix. The impact from fuel supply constraints could be one possible reason for lower fuel displacement in the Northeast.

In contrast, the estimation results for the Texas (TRE) and Midwest (MRO) reliability regions show few statistically significant cross-price elasticities. Nearly all of Texas is contained within its own electrical interconnection and has an extremely limited ability to trade power with neighboring states. Short-run price-induced fuel displacement may have been limited in TRE because of the need for individual plants to generate at minimum levels for reliability purposes. Generation capacity in the MRO is heavily skewed towards coal. Thus, even during periods when relative prices encourage substitution between fuels, the Midwest power industry's ability to do so is limited. The western U.S. (WECC) shows a small but statistically significant ability to switch between coal and natural gas. Coal is the dominant generation fuel in the Mountain states. Much of the demand for electricity in the Pacific Northwest and California is fulfilled by either natural gas or hydropower units. The availability of hydropower in any given year can have a tremendous impact on the mix of fuels in the WECC region.

[4] Although the estimated equations included lagged fuel consumption variables, some of the model results presented in the appendix show relatively low Durbin-Watson statistics, indicating the presence of autocorrelation. In such cases, the reliability of the estimated coefficient values could be called into question. The development of more sophisticated fuel substitution models may be able to correct for any autocorrelation problems.

Table 2 also shows the estimated adjustment parameters ($= 1 - \lambda$), which identify how quickly generators in each region react to changes in fuel prices. The rates of adjustment vary from a fairly quick rate of 95 percent each period in FRCC and SERC, where many power plants operate dual-fueled units, to a slower 46 percent in the MRO region, where displacement between fuels often means having to build new capacity. Long-run elasticities of substitution can be calculated by dividing the estimated elasticities in Table 2 by the region's rate of adjustment.

The estimated coefficients from the logit model can also be used to calculate each fuel's price elasticity of demand, as shown in Table 3. These own-price elasticity results show that petroleum exhibits the most responsiveness to changes in fuel price, owing to its use primarily as a peaking fuel. In some regions coal is more responsive to price than natural gas, and in other areas it's just the opposite, depending on each fuel's relative share of the total cost.

Table 3. Own Price Elasticity Estimates

REGION	Coal	Natural Gas	Petroleum
FRCC	-0.53**	-0.46**	-2.16**
MRO	-0.11	-0.31	-0.70**
NPCC	-0.23**	-0.21**	-1.26**
RFC	-0.18**	-0.60**	-1.13**
SERC	-0.22**	-0.41**	-1.53**
SPP	0.02	-0.02	-1.28**
TRE	0.08	0.02	-0.55*
WECC	-0.14**	-0.05**	-0.64**
US	-0.11**	-0.29**	-1.26**

Note: ** indicates coefficient is statistically significant with 95 percent level of confidence, based on Chi-square statistic from a Wald test. * indicates 90 percent statistical significance.

Conclusion

The results for elasticities of substitution in the power sector indicate that industry does have some flexibility to alter the generation fuel mix in response to changing prices. However, overall, the estimated substitution elasticities are relatively low, with the exception of fuel displacement between petroleum and natural gas. There are many other factors besides price that can affect the fuels used for power generation, such as available capacity, local transmission and reliability constraints, fuel purchase or power supply contracts, and environmental regulations.

The model presented here attempted to account for changes in capacity over the long-run, but the estimated dynamic adjustment coefficients were also quite low, possibly because the capacity mix did not vary much during the sample period. One other limitation of the model is that it relies on data measured in British Thermal Units. Ideally, fuel price would be measured in dollars per MWh in order to account for relative technological efficiencies and heat rates between generators that use different types of fuel. Future adaptations of the elasticity of substitution model presented here could attempt to account for these limitations.

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Appendix – Detailed model results

The tables on the following pages show detailed model results from estimating the logit systems of equations for each of the eight NERC regions and for the United States (excluding Hawaii and Alaska). As described above, each system consists of equations for the two fuels with the smallest cost shares. The ranking of each fuel's cost share, from smallest to largest, is listed at the top of each regional table. Each variable for these two fuels is normalized by the corresponding variable for the fuel with the largest cost share. The two equations to be estimated in the system are:

(Eq. 4)
$$\ln\left(S_{1,t}/S_{3,t}\right) = (\eta_1 - \eta_3) - \left(\phi_{12}S_{2,t} + \phi_{13}\left(S_{1,t} + S_{3,t}\right)\right)\ln\left(P_{1,t}/P_{3,t}\right) + (\phi_{12} - \phi_{23})\ln\left(P_{2,t}/P_{3,t}\right) + \alpha_1\ln(G_t) + \sum_{k=1}^{11}\beta_{1i}M_{k,t} + \lambda\ln\left(Q_{1,t-1}/Q_{3,t-1}\right)$$

(Eq. 5)
$$\ln\left(S_{2,t}/S_{3,t}\right) = (\eta_2 - \eta_3) - \left(\phi_{12}S_{1,t} + \phi_{23}\left(S_{2,t} + S_{3,t}\right)\right)\ln\left(P_{2,t}/P_{3,t}\right) + (\phi_{12} - \phi_{13})\ln\left(P_{1,t}/P_{3,t}\right) + \alpha_2\ln(G_t) + \sum_{k=1}^{11}\beta_{2i}M_{k,t} + \lambda\ln\left(Q_{2,t-1}/Q_{3,t-1}\right)$$

where: $S_{i,t} = \frac{P_iQ_i}{P_1Q_1+P_2Q_2+P_3Q_3}$ = fuel i's share of total generation cost during period *t*
$P_{i,t}$ = per-unit cost of fuel i during period *t*
$Q_{i,t}$ = quantity of fuel i consumed for generation during period *t*
G_t = total level of generation during period *t*
$M_{k,t}$ = 1 if period *t* corresponds to k^{th} month, = 0 otherwise.

The coefficient statistics are shown within three groups in each table. The first group shows information about the ϕ_{ij} and λ variables that are common to both equations. The second group shows the η_{ij}, α_i, and β_{ki} coefficients for the first equation, and the third group shows the coefficients for the second equation in the system. The bottom of each table shows the R-squared and Durbin-Watson statistics describing the overall fit of each equation within the system.

Table A 1. Estimation results for Florida Reliability Coordinating Council (FRCC)

Fuel 1 = Petroleum (P)
Fuel 2 = Coal (C)
Fuel 3 = Natural gas (G)

Coefficient	Estimate	Std. Error	t-Statistic	Prob.
ϕ_{PC}	-0.2548	0.3789	-0.6724	0.5013
ϕ_{PG}	1.8766	0.3925	4.7807	0.0000
ϕ_{CG}	-0.3862	0.1206	-3.2013	0.0014
λ	0.0467	0.0901	0.5188	0.6039
$\eta_P - \eta_G$	-100.2033	29.4086	-3.4073	0.0007
α_1	4.2510	1.2639	3.3633	0.0008
β_{1Feb}	0.1547	0.3910	0.3956	0.6924
β_{1Mar}	0.1154	0.4332	0.2665	0.7899
β_{1Apr}	0.3845	0.3946	0.9745	0.3298
β_{1May}	-0.2819	0.6068	-0.4645	0.6423
β_{1Jun}	-0.5210	0.7538	-0.6911	0.4895
β_{1Jul}	-0.7294	0.6083	-1.1990	0.2305
β_{1Aug}	-0.6276	0.5581	-1.1245	0.2608
β_{1Sep}	-0.4905	0.4223	-1.1616	0.2454
β_{1Oct}	-0.1869	0.4827	-0.3871	0.6987
β_{1Nov}	-0.0865	0.4348	-0.1989	0.8423
β_{1Dec}	-0.2368	0.2344	-1.0099	0.3125
$\eta_C - \eta_G$	-5.1287	9.0808	-0.5648	0.5722
α_2	0.1959	0.3903	0.5019	0.6158
β_{2Feb}	-0.1351	0.1345	-1.0043	0.3152
β_{2Mar}	-0.3742	0.1197	-3.1259	0.0018
β_{2Apr}	-0.4754	0.1361	-3.4935	0.0005
β_{2May}	-0.4030	0.1639	-2.4594	0.0139
β_{2Jun}	-0.3769	0.2196	-1.7159	0.0862
β_{2Jul}	-0.4553	0.2184	-2.0845	0.0371
β_{2Aug}	-0.4708	0.2261	-2.0820	0.0373
β_{2Sep}	-0.4876	0.2189	-2.2275	0.0259
β_{2Oct}	-0.4504	0.1993	-2.2594	0.0239
β_{2Nov}	-0.2650	0.1617	-1.6393	0.1012
β_{2Dec}	-0.0121	0.1280	-0.0942	0.9249
	R-squared	**Durbin-Watson**		
Equation 1	0.6538	1.8290		
Equation 2	0.6937	0.8409		

Table A 2. Estimation results for Midwest Reliability Organization (MRO)

Fuel 1 = Petroleum (P)

Fuel 2 = Natural gas (G)

Fuel 3 = Coal (C)

Coefficient	Estimate	Std. Error	t-Statistic	Prob.
ϕ_{PG}	-0.9887	2.7409	-0.3607	0.7183
ϕ_{PC}	-0.0921	0.6175	-0.1491	0.8815
ϕ_{GC}	-0.5933	0.3102	-1.9125	0.0558
λ	0.5368	0.1489	3.6047	0.0003
$\eta_P - \eta_C$	-21.7175	46.9749	-0.4623	0.6439
α_1	0.9106	2.0022	0.4548	0.6492
β_{1Feb}	-0.1713	0.4222	-0.4058	0.6849
β_{1Mar}	-0.4302	0.4737	-0.9082	0.3638
β_{1Apr}	0.1508	0.5800	0.2601	0.7948
β_{1May}	0.0731	0.7332	0.0998	0.9205
β_{1Jun}	0.1107	0.4396	0.2518	0.8012
β_{1Jul}	-0.4015	0.5227	-0.7683	0.4423
β_{1Aug}	-0.3134	1.5935	-0.1967	0.8441
β_{1Sep}	-0.1749	0.5219	-0.3352	0.7375
β_{1Oct}	0.0596	0.6551	0.0910	0.9275
β_{1Nov}	-0.0126	0.4914	-0.0257	0.9795
β_{1Dec}	-0.0044	0.4835	-0.0090	0.9928
$\eta_G - \eta_C$	-40.2895	36.8370	-1.0937	0.2741
α_2	1.7034	1.5856	1.0743	0.2827
β_{2Feb}	0.1909	0.6778	0.2817	0.7782
β_{2Mar}	0.1060	0.6602	0.1605	0.8725
β_{2Apr}	0.2948	0.7555	0.3902	0.6964
β_{2May}	0.4106	0.7594	0.5407	0.5887
β_{2Jun}	0.4455	0.6456	0.6900	0.4902
β_{2Jul}	0.3241	0.6214	0.5215	0.6020
β_{2Aug}	0.2050	0.8231	0.2491	0.8033
β_{2Sep}	-0.2030	0.7299	-0.2782	0.7809
β_{2Oct}	0.3044	0.6917	0.4401	0.6599
β_{2Nov}	0.1582	0.6871	0.2302	0.8179
β_{2Dec}	0.1969	0.6981	0.2820	0.7779

	R-squared	Durbin-Watson
Equation 1	0.5102	1.3973
Equation 2	0.7258	1.6343

Table A 3. Estimation results for Northeast Power Coordinating Council (NPCC)

Fuel 1 = Petroleum (P)

Fuel 2 = Coal (C)

Fuel 3 = Natural gas (G)

Coefficient	Estimate	Std. Error	t-Statistic	Prob.
ϕ_{PC}	-0.2632	0.3786	-0.6954	0.4868
ϕ_{PG}	0.5626	0.3636	1.5474	0.1218
ϕ_{CG}	-0.8137	0.0846	-9.6187	0.0000
λ	0.3452	0.0936	3.6859	0.0002
$\eta_P - \eta_G$	-42.4401	11.9498	-3.5515	0.0004
α_1	1.8052	0.5160	3.4986	0.0005
β_{1Feb}	-0.1832	0.2307	-0.7939	0.4273
β_{1Mar}	-0.4432	0.2409	-1.8396	0.0658
β_{1Apr}	-0.4918	0.2621	-1.8762	0.0606
β_{1May}	-0.3722	0.2493	-1.4928	0.1355
β_{1Jun}	-0.2391	0.3519	-0.6793	0.4969
β_{1Jul}	-0.6216	0.2888	-2.1528	0.0313
β_{1Aug}	-0.5498	0.2996	-1.8347	0.0666
β_{1Sep}	-0.6608	0.4161	-1.5879	0.1123
β_{1Oct}	-0.5532	0.2356	-2.3482	0.0189
β_{1Nov}	-0.0973	0.3428	-0.2838	0.7765
β_{1Dec}	0.2284	0.3640	0.6273	0.5305
$\eta_C - \eta_G$	3.4313	6.6388	0.5169	0.6053
α_2	-0.1666	0.2891	-0.5761	0.5645
β_{2Feb}	0.0372	0.1933	0.1922	0.8476
β_{2Mar}	-0.0128	0.1509	-0.0850	0.9323
β_{2Apr}	-0.1281	0.1478	-0.8665	0.3862
β_{2May}	-0.0942	0.1507	-0.6250	0.5320
β_{2Jun}	-0.0847	0.1316	-0.6438	0.5197
β_{2Jul}	-0.1874	0.1547	-1.2110	0.2259
β_{2Aug}	-0.1295	0.1637	-0.7908	0.4291
β_{2Sep}	-0.0704	0.1928	-0.3653	0.7149
β_{2Oct}	-0.1434	0.1396	-1.0273	0.3043
β_{2Nov}	-0.0440	0.1343	-0.3272	0.7435
β_{2Dec}	0.0833	0.1324	0.6290	0.5293

	R-squared	Durbin-Watson
Equation 1	0.8467	1.7566
Equation 2	0.7895	1.2058

Table A 4. Estimation results for ReliabilityFirst Corporation (RFC)

Fuel 1 = Petroleum (P)

Fuel 2 = Natural gas (G)

Fuel 3 = Coal (C)

Coefficient	Estimate	Std. Error	t-Statistic	Prob.
ϕ_{PG}	2.2079	1.0982	2.0104	0.0444
ϕ_{PC}	-0.4932	0.5299	-0.9308	0.3519
ϕ_{GC}	-0.3300	0.0935	-3.5310	0.0004
λ	0.2047	0.0812	2.5206	0.0117
$\eta_P - \eta_C$	-109.4175	26.7799	-4.0858	0.0000
α_1	4.2927	1.0801	3.9743	0.0001
β_{1Feb}	0.3335	0.4425	0.7538	0.4509
β_{1Mar}	0.2970	0.4049	0.7334	0.4633
β_{1Apr}	0.4958	0.4688	1.0576	0.2902
β_{1May}	0.8587	0.4766	1.8017	0.0716
β_{1Jun}	0.5288	0.4236	1.2482	0.2120
β_{1Jul}	-0.0367	0.4886	-0.0751	0.9402
β_{1Aug}	-0.0405	0.5992	-0.0676	0.9461
β_{1Sep}	0.3858	0.4530	0.8518	0.3943
β_{1Oct}	0.3794	0.4002	0.9482	0.3430
β_{1Nov}	0.3453	0.4477	0.7714	0.4405
β_{1Dec}	0.1982	0.4096	0.4838	0.6285
$\eta_G - \eta_C$	-60.8339	11.7122	-5.1941	0.0000
α_2	2.3971	0.4738	5.0590	0.0000
β_{2Feb}	0.1889	0.2568	0.7354	0.4621
β_{2Mar}	0.3094	0.2292	1.3500	0.1770
β_{2Apr}	0.6244	0.2564	2.4355	0.0149
β_{2May}	0.5413	0.2509	2.1576	0.0310
β_{2Jun}	0.5003	0.2204	2.2702	0.0232
β_{2Jul}	0.3499	0.2255	1.5518	0.1207
β_{2Aug}	0.2893	0.2333	1.2403	0.2149
β_{2Sep}	0.4415	0.2309	1.9119	0.0559
β_{2Oct}	0.4138	0.2324	1.7809	0.0749
β_{2Nov}	0.3491	0.2584	1.3510	0.1767
β_{2Dec}	0.1408	0.2192	0.6425	0.5205

	R-squared	Durbin-Watson
Equation 1	0.6883	1.5629
Equation 2	0.8712	1.4485

Table A 5. Estimation results for SERC Reliability Corporation (SERC)

Fuel 1 = Petroleum (P)

Fuel 2 = Natural gas (G)

Fuel 3 = Coal (C)

Coefficient	Estimate	Std. Error	t-Statistic	Prob.
ϕ_{PG}	0.9048	0.7263	1.2458	0.2128
ϕ_{PC}	0.3783	0.6108	0.6193	0.5357
ϕ_{GC}	-0.4145	0.1213	-3.4156	0.0006
λ	0.0468	0.1121	0.4171	0.6766
$\eta_P - \eta_C$	-89.8509	27.0836	-3.3175	0.0009
α_1	3.5092	1.0856	3.2326	0.0012
β_{1Feb}	0.1274	0.3151	0.4044	0.6859
β_{1Mar}	-0.2429	0.3528	-0.6885	0.4912
β_{1Apr}	0.0426	0.6555	0.0650	0.9481
β_{1May}	-0.5657	0.3464	-1.6330	0.1025
β_{1Jun}	-0.6230	0.4477	-1.3915	0.1641
β_{1Jul}	-0.9661	0.4605	-2.0979	0.0359
β_{1Aug}	-0.9807	0.4644	-2.1119	0.0347
β_{1Sep}	-0.5691	0.3354	-1.6967	0.0898
β_{1Oct}	0.0267	0.3386	0.0789	0.9371
β_{1Nov}	0.0472	0.3130	0.1509	0.8800
β_{1Dec}	0.0418	0.3499	0.1194	0.9049
$\eta_G - \eta_C$	-59.5671	11.8768	-5.0154	0.0000
α_2	2.3444	0.4811	4.8731	0.0000
β_{2Feb}	0.2457	0.1507	1.6299	0.1031
β_{2Mar}	0.2932	0.1430	2.0507	0.0403
β_{2Apr}	0.5773	0.2918	1.9782	0.0479
β_{2May}	0.3317	0.1628	2.0376	0.0416
β_{2Jun}	0.3158	0.1504	2.1001	0.0357
β_{2Jul}	0.2269	0.1624	1.3973	0.1623
β_{2Aug}	0.2240	0.1741	1.2866	0.1982
β_{2Sep}	0.3566	0.1230	2.8995	0.0037
β_{2Oct}	0.4682	0.1092	4.2879	0.0000
β_{2Nov}	0.3489	0.1148	3.0382	0.0024
β_{2Dec}	0.1185	0.1252	0.9466	0.3439

	R-squared	Durbin-Watson
Equation 1	0.6746	1.4903
Equation 2	0.8307	1.0000

Table A 6. Estimation results for Southwest Power Pool (SPP)

Fuel 1 = Petroleum (P)

Fuel 2 = Coal (C)

Fuel 3 = Natural gas (G)

Coefficient	Estimate	Std. Error	t-Statistic	Prob.
ϕ_{PC}	-2.3887	2.5886	-0.9228	0.3561
ϕ_{PG}	1.9196	1.7525	1.0954	0.2734
ϕ_{CG}	-1.0131	0.0621	-16.3044	0.0000
λ	0.2712	0.1035	2.6202	0.0088
$\eta_P - \eta_G$	-77.7703	71.9850	-1.0804	0.2800
α_1	3.1257	3.0375	1.0291	0.3035
β_{1Feb}	0.7423	0.5629	1.3186	0.1873
β_{1Mar}	1.3202	0.5177	2.5504	0.0108
β_{1Apr}	1.1217	0.7462	1.5032	0.1328
β_{1May}	0.9309	0.4473	2.0811	0.0374
β_{1Jun}	-0.1443	0.7562	-0.1909	0.8486
β_{1Jul}	-0.2022	0.9265	-0.2183	0.8272
β_{1Aug}	-0.3904	0.9444	-0.4134	0.6793
β_{1Sep}	0.5053	0.5712	0.8847	0.3763
β_{1Oct}	0.9851	0.9570	1.0293	0.3033
β_{1Nov}	1.1576	0.5249	2.2055	0.0274
β_{1Dec}	0.5184	0.5109	1.0146	0.3103
$\eta_C - \eta_G$	32.6800	14.4665	2.2590	0.0239
α_2	-1.3631	0.6143	-2.2188	0.0265
β_{2Feb}	-0.1520	0.1340	-1.1347	0.2565
β_{2Mar}	-0.2898	0.1672	-1.7331	0.0831
β_{2Apr}	-0.4642	0.1806	-2.5700	0.0102
β_{2May}	-0.2582	0.1325	-1.9485	0.0514
β_{2Jun}	-0.1861	0.1167	-1.5948	0.1108
β_{2Jul}	-0.1099	0.2406	-0.4567	0.6479
β_{2Aug}	-0.1035	0.1745	-0.5933	0.5530
β_{2Sep}	-0.0703	0.0912	-0.7711	0.4407
β_{2Oct}	-0.1905	0.2276	-0.8371	0.4026
β_{2Nov}	-0.0190	0.1561	-0.1220	0.9029
β_{2Dec}	0.0677	0.0860	0.7871	0.4312

	R-squared	Durbin-Watson
Equation 1	0.5241	1.8556
Equation 2	0.9498	1.6482

Table A 7. Estimation results for Texas Reliability Entity (TRE)

Fuel 1 = Petroleum (P)
Fuel 2 = Coal (C)
Fuel 3 = Natural gas (G)

Coefficient	Estimate	Std. Error	t-Statistic	Prob.
ϕ_{PC}	-2.3196	1.8163	-1.2771	0.2016
ϕ_{PG}	0.1017	0.7931	0.1282	0.8980
ϕ_{CG}	-1.1012	0.0658	-16.7417	0.0000
λ	0.1364	0.1175	1.1611	0.2456
$\eta_P - \eta_G$	-61.0368	38.4699	-1.5866	0.1126
α_1	2.3702	1.6056	1.4762	0.1399
β_{1Feb}	-0.4468	0.3756	-1.1894	0.2343
β_{1Mar}	-0.6669	0.4435	-1.5036	0.1327
β_{1Apr}	-0.5335	0.3638	-1.4664	0.1425
β_{1May}	-1.1225	0.5009	-2.2409	0.0250
β_{1Jun}	-1.6922	0.3900	-4.3384	0.0000
β_{1Jul}	-2.2996	0.4714	-4.8782	0.0000
β_{1Aug}	-2.2844	0.4903	-4.6593	0.0000
β_{1Sep}	-1.7205	0.3518	-4.8909	0.0000
β_{1Oct}	-1.2570	0.2592	-4.8496	0.0000
β_{1Nov}	-0.5288	0.2076	-2.5471	0.0109
β_{1Dec}	-0.8634	0.3181	-2.7144	0.0066
$\eta_C - \eta_G$	32.1303	7.9563	4.0384	0.0001
α_2	-1.3444	0.3388	-3.9687	0.0001
β_{2Feb}	-0.2511	0.1142	-2.1994	0.0278
β_{2Mar}	-0.3218	0.0934	-3.4432	0.0006
β_{2Apr}	-0.3711	0.1074	-3.4555	0.0005
β_{2May}	-0.1811	0.1143	-1.5850	0.1130
β_{2Jun}	-0.1222	0.1431	-0.8537	0.3933
β_{2Jul}	-0.0260	0.1509	-0.1721	0.8633
β_{2Aug}	-0.0665	0.1688	-0.3941	0.6935
β_{2Sep}	-0.0744	0.1802	-0.4131	0.6795
β_{2Oct}	-0.1274	0.0959	-1.3287	0.1839
β_{2Nov}	-0.1052	0.0990	-1.0635	0.2876
β_{2Dec}	0.0087	0.0903	0.0960	0.9235

	R-squared	Durbin-Watson
Equation 1	0.5812	1.6054
Equation 2	0.9692	1.4870

Table A 8. Estimation results for Western Electricity Coordinating Council (WECC)

Fuel 1 = Petroleum (P)
Fuel 2 = Coal (C)
Fuel 3 = Natural gas (G)

Coefficient	Estimate	Std. Error	t-Statistic	Prob.
ϕ_{PC}	-0.5979	1.8883	-0.3166	0.7515
ϕ_{PG}	-0.2587	0.7107	-0.3640	0.7158
ϕ_{CG}	-0.8144	0.0412	-19.7728	0.0000
λ	0.2793	0.1285	2.1741	0.0297
$\eta_P - \eta_G$	23.1561	35.0007	0.6616	0.5082
α_1	-1.0985	1.4123	-0.7778	0.4367
β_{1Feb}	-0.1424	0.2273	-0.6267	0.5309
β_{1Mar}	0.0439	0.2131	0.2061	0.8367
β_{1Apr}	0.2800	0.3663	0.7643	0.4447
β_{1May}	0.2454	0.3024	0.8114	0.4171
β_{1Jun}	0.1924	0.2625	0.7330	0.4636
β_{1Jul}	-0.1024	0.1658	-0.6173	0.5371
β_{1Aug}	0.1247	0.2970	0.4198	0.6746
β_{1Sep}	0.0667	0.1694	0.3941	0.6935
β_{1Oct}	0.2519	0.1345	1.8735	0.0610
β_{1Nov}	0.2805	0.2261	1.2410	0.2146
β_{1Dec}	0.2686	0.1462	1.8374	0.0662
$\eta_C - \eta_G$	29.8934	5.9036	5.0636	0.0000
α_2	-1.2322	0.2428	-5.0762	0.0000
β_{2Feb}	-0.2013	0.0835	-2.4110	0.0159
β_{2Mar}	-0.1115	0.0787	-1.4172	0.1564
β_{2Apr}	-0.3329	0.0786	-4.2362	0.0000
β_{2May}	-0.2137	0.0860	-2.4835	0.0130
β_{2Jun}	-0.2136	0.0766	-2.7879	0.0053
β_{2Jul}	-0.1308	0.1226	-1.0664	0.2862
β_{2Aug}	-0.0307	0.1097	-0.2800	0.7794
β_{2Sep}	-0.0328	0.0896	-0.3662	0.7142
β_{2Oct}	-0.0608	0.1246	-0.4880	0.6256
β_{2Nov}	-0.0733	0.0821	-0.8926	0.3721
β_{2Dec}	-0.0391	0.0826	-0.4734	0.6359

	R-squared	Durbin-Watson
Equation 1	0.6174	1.8505
Equation 2	0.9352	1.2320

Table A 9. Estimation results for United States (excluding Hawaii and Alaska)

Fuel 1 = Petroleum (P)

Fuel 2 = Coal (C)

Fuel 3 = Natural gas (G)

Coefficient	Estimate	Std. Error	t-Statistic	Prob.
ϕ_{PC}	-2.4329	0.6736	-3.6118	0.0003
ϕ_{PG}	2.6854	0.6206	4.3271	0.0000
ϕ_{CG}	-0.6777	0.0452	-14.9949	0.0000
λ	0.1746	0.0826	2.1130	0.0346
$\eta_P - \eta_G$	-82.9373	36.1292	-2.2956	0.0217
α_1	3.0589	1.3733	2.2274	0.0259
β_{1Feb}	-0.0526	0.2506	-0.2098	0.8338
β_{1Mar}	-0.1587	0.2758	-0.5754	0.5650
β_{1Apr}	0.2202	0.4171	0.5280	0.5975
β_{1May}	0.1118	0.2873	0.3889	0.6973
β_{1Jun}	-0.0106	0.2980	-0.0355	0.9717
β_{1Jul}	-0.3638	0.3689	-0.9862	0.3241
β_{1Aug}	-0.3019	0.3658	-0.8252	0.4093
β_{1Sep}	-0.0691	0.2490	-0.2773	0.7815
β_{1Oct}	0.0165	0.3095	0.0532	0.9576
β_{1Nov}	-0.1390	0.4007	-0.3470	0.7286
β_{1Dec}	-0.1779	0.2155	-0.8257	0.4090
$\eta_C - \eta_G$	16.0547	7.6088	2.1100	0.0349
α_2	-0.5809	0.2918	-1.9905	0.0465
β_{2Feb}	-0.1019	0.0707	-1.4425	0.1492
β_{2Mar}	-0.1817	0.0676	-2.6887	0.0072
β_{2Apr}	-0.3189	0.0736	-4.3344	0.0000
β_{2May}	-0.2730	0.0644	-4.2360	0.0000
β_{2Jun}	-0.2842	0.0699	-4.0655	0.0000
β_{2Jul}	-0.3281	0.0964	-3.4056	0.0007
β_{2Aug}	-0.3031	0.0989	-3.0645	0.0022
β_{2Sep}	-0.2566	0.0683	-3.7597	0.0002
β_{2Oct}	-0.2391	0.0743	-3.2204	0.0013
β_{2Nov}	-0.1437	0.0785	-1.8288	0.0674
β_{2Dec}	-0.0510	0.0639	-0.7978	0.4250

	R-squared	Durbin-Watson
Equation 1	0.6631	1.7945
Equation 2	0.9673	1.3285