Supplementary Material: Econometric Formulation and Results for California Energy Demand

This material describes the formulation of the energy demand models for the residential, commercial, industrial, and transportation sectors of the California economy, and the results of the econometric analysis.

1. End-Use Stationary Energy Demand

This study uses a nested two–stage structure for the demand for natural gas, petroleum products and electricity in the residential, commercial, and industrial sectors. The first stage determines the level of total energy consumption. The second stage model disaggregates aggregate energy consumption by fuel type. The demand models involve a non-homothetic, two-stage optimization framework. The first tier assumes an aggregate energy demand relationship:

$$\ln Q_{st}^{d} = \eta_s + \kappa_s \ln\left(P_{st}^{d} / PGDP_t\right) + \mu_s \ln X_{st} + \tau_s T_t + \lambda_s \ln Q_{st-1} + \varepsilon_{st} \tag{1}$$

where Q_{st}^{d} is a divisia quantity index of total energy demand for sector s in period t; P_{st}^{d} is a divisia index of aggregate fuel prices; $PGDP_t$ is a price deflator; X_{st} is an exogenous demand shifter that differs by sector; T_t is a time trend for technological change; $\eta_s, \kappa_s, \mu_s, \lambda_s, \tau_s$ are unknown parameters; and ε_{st} is a random error term. For the residential sector, this study accounts for the effect of a change in population on total energy demand by scaling Q_{st}^{d} by the population of California.

The divisia price index is a share weighted moving average of logarithmic first differences in fuel prices defined by the following identity:

$$P_{st}^{d} = P_{t-1}\left[1 + 0.5\sum_{j=1}^{n}\left(S_{jt} + S_{jt-1}\right)\left(\ln P_{jt} - \ln P_{jt-1}\right)\right] \tag{2}$$

where *n* indexes the fuels used in the particular sector. For instance, prices for electricity, liquid propane gas, and natural gas comprise the divisia price index for the residential sector. The corresponding divisia quantity index is defined as energy expenditures divided by the divisia price index.

This specification assumes that the fuels in the energy price index are weakly separable from other goods and services. In other words, the marginal rate of substitution between two fuels is independent of the rate at which aggregate energy substitutes with other goods. Substitution possibilities between energy and other goods and services are likely to be very limited within the time span considered in this study.

In the second stage, a system of linear logit share equations determines the mix of fuels within each sector's energy aggregate. The unrestricted linear logit model of cost shares is as follows:

$$S_{it} = \frac{P_{it}Q_{it}}{C_t} = \frac{e^{f_{it}}}{\sum_{j=1}^{n} e^{f_{jt}}} \ \forall\ i \tag{3}$$

where:

$$f_{it} = \alpha_i + \sum_{j=1}^{n}\beta_{ij}\ln\left(P_{jt}\right) + \gamma_i Y_t + \tau_i T_t + \eta_i HDD_t + \sigma_i CDD_t + \phi \ln\left(Q_{it-1}\right) + \varepsilon_{it} \tag{4}$$

and where Q_{it} is the quantity of fuel *i* in period *t*; P_{it} is the price of fuel *i*; C_t is expenditure on fuels in the aggregate; T_t is a time trend; Y_t is real income or sector output; HDD_t and CDD_t are heating and cooling degree days respectively; $\alpha_i, \beta_{ij}, \gamma_i, \tau_i, \eta_i, \sigma_i, \phi$ are unknown parameters to be estimated; and ε_{it} is a random disturbance term. The inclusion of Y_t in Equation (4) allows for non-homothetic demand functions within a two-stage demand model.

Substituting Equation (4) into Equation (3), taking logarithms, normalizing on the *n*th cost share, and imposing symmetry and homogeneity following the procedures developed by Considine and Mount [1], yields the following share system:

$$\begin{aligned}\ln\left(\frac{S_{it}}{S_{nt}}\right) &= \left(\alpha_i - \alpha_n\right) - \left[\sum_{k=1}^{i-1} S_k^* \beta_{ik}^* + \sum_{k=i+1}^{n} S_k^* \beta_{ki}^* + S_i^* \beta_{in}^*\right] \ln\left(\frac{P_{it}}{P_{nt}}\right) + \sum_{k=1}^{i-1}\left(\beta_{ki}^* - \beta_{kn}^*\right) S_k^* \ln\left(\frac{P_{kt}}{P_{nt}}\right) \\ &+ \sum_{k=i+1}^{n}\left(\beta_{ik}^* - \beta_{kn}^*\right) S_k^* \ln\left(\frac{P_{kt}}{P_{nt}}\right) + \left(\gamma_i - \gamma_n\right)\ln Y_t + \left(\tau_i - \tau_n\right) T_t + \varphi \ln\left(\frac{Q_{it-1}}{Q_{nt-1}}\right) \\ &+ \left(\eta_i - \eta_n\right)\ln\left(HDD_t\right) + \left(\sigma_i - \sigma_n\right)\ln\left(CDD_t\right) + \left(\varepsilon_{it} - \varepsilon_{nt}\right)\end{aligned} \quad (5)$$

for all fuels, i, in the cost share model, where S_k^*'*s* are the mean cost shares. The energy cost share systems for the residential, commercial and industrial sectors all include equations of this basic form. Equations (1) and (5) contain lagged quantities, which allow dynamic adjustments in demand and the computation of short and long–run elasticities. The price and income (output) elasticities are cost share-weighted functions of the parameters. The adjustment parameter, ϕ, determines the difference between short and long-run elasticities.

2. Demand for Gasoline and Diesel

A baseline projection of gasoline and diesel fuel is required in order to track carbon emissions from the transportation sector. Unlike the residential, commercial and industrial sectors, very little or no interfuel substitution yet occurs in the transportation sector. The models in this sector take the same form as Equation (1), where the demand shifter includes real personal disposable income and price is the real price including taxes.

3. Electricity Generation & Fuel Use

The model computes electricity generation by fuel type on the basis of available capacity and average operating rates. For instance, generation from capacity *i* in year *t* in megawatt hours is defined as follows:

$$G_{it} = H_i \times C_{it} \quad (6)$$

where H_{it} is the number of hours capacity is operated and C_{it} is rated capacity in megawatts. Fuel demand is simply generation multiplied by the average heat rate:

$$F_{it} = HR_i \times G_{it} \quad (7)$$

where HR_i is the heat rate in tons of oil equivalent per megawatt hour. The forecasts produced below assume fixed operating hours and heat rates, computed using historical values.

The computation of forecasted power generation and fuel use by electric utilities can be seen as a sequence of steps. First, total electricity production is determined by adding predicted electricity demand and power line losses. Electricity imports are determined by the difference between power demand and the sum of generation from all sources. Marginal generation costs for electricity are computed by taking an output-weighted average of generation costs by capacity, which is simply the product of fuel prices and heat rates. Margins for transmission and distribution costs are estimated over the historical period by subtracting marginal generation costs from end-use electricity prices. Adding these margins to average generation costs projects end-use electricity prices. This formulation allows end-use electricity prices to vary with oil, coal and natural gas prices, which then feedback on electricity demand and production.

4. Econometric Results

The parameters of the four energy demand models—residential, commercial, industrial, and transportation—are estimated with econometric techniques for the period 1972–2008 using data from the EIA State Energy Data System [2]. The presence of total energy quantity on the right-hand side of the cost share equations requires instrumental variable estimation to avoid simultaneous equation bias in the estimated coefficients. The Generalized Method of Moments (GMM) estimator is employed, which corrects for hetereoscedasticity and autoregressive moving average error components in the stochastic error terms.

The strategy for selecting the instrumental variables is the same for each sector; using prices lagged one-period, quantities lagged two periods, a time trend, and lagged values of the exogenous variables in the total energy quantity models, such as the number of customers or real production.

The GMM estimates for the residential energy model, which contains three estimating equations, appear below in Table 1. The parameters reported in the top half of Table 1 correspond with those that appear in Equation (5) above. Six of the fourteen parameters of the residential cost share system are significantly different from zero at the 5% level.

Reported in the center of Table 1 are the parameter estimates from Equation (1) above. The double log partial adjustment formulation of the total energy demand equation implies that the coefficients on price and the other exogenous variables in the equation are short-run elasticities. For example, the short-run own price elasticity of total residential energy demand, which is the sum of electricity, natural gas, and petroleum products, is −0.15. The adjustment parameter −0.488 implies that the long-run own price elasticity for residential energy is −0.29. Also included in this equation are real per capita personal disposable income and heating degree and cooling degree days as exogenous demand shifters. Our estimates imply that for a 1% increase in per capita disposable income there is a 0.26% increase in total energy demand in the short-run and a 0.5% increase in the long-run. In addition, for a 1% increase in heating and cooling degree days, total energy demand increases 0.26% and 0.06% and in the short-run, respectively.

The summary fit statistics reported in Table 1 result from computing the predicted cost shares and using the cost share identity to compute predicted quantities. Although a dynamic simulation, which involves using lagged endogenous quantities, is used below in the forecasts, a static method of fit assessment is preferred so that errors are not propagated. Using a static-fit method reveals that the residential model provides an excellent fit of the quantities as measured by the correlation between fitted and actual values. In particular, theses correlation coefficients are above 0.9 for natural gas, electricity, and total energy consumption per capita. Moreover, the Durbin-Watson statistics suggest the absence of auto-correlation in the residuals.

Table 1. Parameter estimates for residential energy model.

Cost Share System			
Parameters*	Coefficient	*t*-statistic	*P*-value
β_{12}	0.131	0.1	[0.898]
β_{23}	−1.211	−4.7	[0.000]
β_{13}	−0.884	−13.3	[0.000]
φ	0.589	3.4	[0.001]
γ_1	−0.414	−1.0	[0.323]
τ_1	−0.009	−3.1	[0.002]
η_1	0.700	5.7	[0.000]
α_1	−0.120	−2.4	[0.018]
σ_1	−7.761	−1.9	[0.056]
γ_2	1.364	1.1	[0.251]
τ_2	0.005	0.7	[0.461]
η_2	0.283	0.6	[0.534]
α_2	−0.002	−0.0	[0.988]
σ_2	6.840	0.6	[0.577]
Dependent variable: ln(Q_e/POP)			
Constant	−8.848	−5.7	[0.000]
ln(P_e/PGDP)	−0.154	−4.7	[0.000]
ln($Q_{e,t-1}$/POP)	0.488	4.8	[0.000]
Trend	−0.004	−2.2	[0.027]
ln(Real DPI/POP)	0.257	2.5	[0.013]
ln(HDD)	0.264	6.6	[0.000]
ln(CDD)	0.056	2.0	[0.042]
Dependent Variable	Correlation Coefficient	Durbin Watson	
Natural Gas	0.940	1.815	
Liquid Propane Gas	0.784	1.831	
Electricity	0.997	1.874	
Total Energy Consumption per capita	0.931	1.504	

NOTE: 1 = Natural Gas; 2 = Liquid Propane Gas; 3 = Electricity; * See Equations (1) and (5).

Three sets of elasticities calculated from these parameter estimates appear in Table 2 below. The gross elasticities are short-run elasticities holding the level of total energy use constant. The net elasticities allow for the induced effect of prices and other explanatory variables to affect the aggregate level of energy use. Finally, the net long-run elasticities allow dynamic adjustments.

Table 2. Estimated elasticities of demand for California residential energy.

Quantities	Natural Gas Price	LPG Price	Electricity Price	Real Income	Heating Days	Cooling Days	Time Trend
			Gross Elasticities				
Natural gas	−0.104	0.029	0.075	−0.312	0.46	−0.08	−0.006
t-statistic	−2.3	1.1	1.8	−1.1	5.4	−2.4	−3.2
P-value	[0.022]	[0.272]	[0.079]	[0.289]	[0.000]	[0.017]	[0.001]
Liquid Propane Gas	0.376	−0.241	−0.136	1.466	0.043	0.038	0.007
t-statistic	1.1	−0.6	−0.8	1.2	0.1	0.3	1.25
P-value	[0.272]	[0.533]	[0.415]	[0.231]	[0.924]	[0.790]	[0.211]
Electricity	0.039	−0.005	−0.033	0.102	−0.24	0.04	0.003
t-statistic	1.8	−0.8	−1.9	0.8	−6.1	2.2	2.64
P-value	[0.079]	[0.415]	[0.062]	[0.430]	[0.000]	[0.026]	[0.008]
			Net Elasticities				
Natural gas	−0.155	−0.022	0.024	0.177	0.724	−0.024	−0.01
t-statistic	−3.3	−0.8	0.5	1.7	7.0	−0.5	−4.29
P-value	[0.001]	[0.424]	[0.598]	[0.094]	[0.000]	[0.642]	[0.000]
Liquid Propane Gas	0.372	−0.245	−0.14	0.633	0.307	0.094	0.003
t-statistic	1.1	−0.6	−0.8	2.0	0.7	0.6	0.45
P-value	[0.276]	[0.526]	[0.401]	[0.043]	[0.497]	[0.557]	[0.647]
Electricity	−0.06	−0.104	−0.132	0.283	0.024	0.096	−0.002
t-statistic	−1.9	−4.7	−5.0	2.3	0.5	4.2	−0.73
P-value	[0.058]	[0.000]	[0.000]	[0.021]	[0.615]	[0.000]	[0.461]
			Net Long-Run Elasticities				
Natural gas	−0.354	−0.028	0.082	0.121	1.637	−0.085	−0.02
t-statistic	−2.5	−0.3	0.9	0.2	2.7	−0.6	−6.4
P-value	[0.014]	[0.743]	[0.345]	[0.815]	[0.007]	[0.556]	[0.000]
Liquid Propane Gas	0.908	−0.594	−0.338	2.292	0.621	0.201	0.01
t-statistic	0.8	−0.5	−0.9	1.2	0.6	0.5	0.47
P-value	[0.423]	[0.599]	[0.388]	[0.213]	[0.561]	[0.586]	[0.638]
Electricity	−0.099	−0.206	−0.274	0.626	−0.069	0.207	−0.002
t-statistic	−1.9	−6.6	−6.3	2.4	−0.2	4.6	−0.75
P-value	[0.059]	[0.000]	[0.000]	[0.018]	[0.859]	[0.000]	[0.452]

The gross own price elasticity of demand for electricity reported in Table 2 is −0.03 with a probability value of 0.06, suggesting a very price inelastic demand for electricity, which is consistent with findings in many other parts of the world. The own price elasticity for natural gas is somewhat larger in absolute terms at −0.10 with a probability value of 0.02. Similarly, the own price elasticity for liquid propane gas is considerably larger in absolute terms at −0.24 but the probability value indicates statistical insignificance.

Changing relative fuel prices affect the price of aggregate fuels to households that in turn changes the desired level of household energy budgets. The second group of elasticities in Table 2, labeled net elasticities, account for these effects on total energy consumption. The net own price elasticities of demand are larger in absolute terms. This is logical, given the negative own price elasticity of demand for aggregate household energy demand. The net elasticities are −0.16, −0.25, and −0.13 for natural gas, liquid propane gas, and electricity respectively, where the net elasticities for natural gas and electricity are statistically significant. The net long run elasticities, provided in the third panel of Table 2, are as expected even larger. They are a function of the net elasticities divided by one minus the respective adjustment parameters. For example, the long-run own price elasticity of demand for electricity is −0.27.

Also provided in Table 2 are elasticities for the exogenous demand shifters. These include real per capita disposable income elasticities, which measure how the demand for fuels by households varies with the level of income. The short-run net income elasticities for natural gas, liquid propane gas, and electricity are 0.18, 0.63, and 0.28, respectively. All are significant at the 10% level. However, of the long-run net income elasticities, only electricity is significant at the 10% level (equal to 0.63).

In addition, there are elasticities for heating and cooling degree-days. The short-run net elasticities indicate that a 1% increase in heating degree-days leads to a 0.72% increase in natural gas demand, which is highly significant. This increases to 1.6% in the long-run. In addition, a 1% increase in cooling degree-days leads to a 0.1% increase in electricity demand, which is also highly significant. This increases to 0.21% in the long-run. Otherwise, the heating and cooling degree-day net elasticities are insignificant.

Also reported in Table 2 are elasticities of fuel demand with respect to the time trend variable, which is a proxy for technological change. More energy efficient energy consuming durables induced by technological change or efficiency standards imposed by state or federal regulations are just one example. The time trend variable commonly used in many studies of energy demand serves as a proxy for these gradual adjustments in energy consumption patterns. Of the three fuels included in the residential energy demand model, only natural gas has a significant technological change effect. The coefficient on this time trend is negative, indicating that holding prices, income, and weather constant, the trend is for lower per capita natural gas use, consistent with the gradual replacement of old furnaces with more fuel-efficient models.

The objective function value of the GMM estimator is distributed as a Chi-Squared statistic, providing a test of the over-identifying restrictions for the model. For the residential model the probability value for the over-identifying restrictions is 0.737, suggesting that the restrictions cannot be rejected. Hence, the overall model is supported by the data sample. The curvature conditions, which follow from consumer utility maximization, are checked at the mean of the data by computing the Eigen values of the first derivatives of the estimated demand functions. The residential estimates imply that these conditions are satisfied.

The same model specification for the residential sector provided the basis for initial estimation for the commercial sector. In this case, however, the weather variables and trend terms were consistently insignificant. As a result, these variables are dropped from consideration in the commercial model. Nonetheless, the overall findings from the econometric estimation of the commercial energy demand model are quite similar to the residential result (see Table 3).

The exogenous demand shifter in this model is value added in the service sectors of the California economy. As Table 3 indicates, five out of the eight parameters in the commercial cost share system have probability levels less than 10%. While the own price elasticity for aggregate commercial energy has a probability value of 0.87, the output elasticity is 0.323 in the short-run with a probability value of

0.02. The overall fit of the commercial sector is quite good and the Durbin-Watson statistics do not suggest autocorrelation.

Table 3. Parameter estimates for California commercial energy model.

Cost Share System			
Parameters*	Coefficient	*t*-statistic	*P*-value
β_{12}	−0.629	−0.4	[0.672]
β_{23}	−0.861	−1.7	[0.085]
β_{13}	−0.839	−8.5	[0.000]
φ	0.491	3.4	[0.001]
γ_1	−0.497	−1.9	[0.062]
α_1	4.001	1.7	[0.098]
γ_2	−1.294	−1.5	[0.147]
α_2	10.857	1.3	[0.199]
Dependent variable: ln(Q_e)			
Constant	4.387	2.5	[0.012]
ln(P_e/PGDP)	0.008	0.2	[0.873]
ln(Commercial Output)	0.323	2.3	[0.019]
ln($Q_{e,t-1}$)	0.666	5.1	[0.000]
Dependent Variable	Correlation Coefficient	Durbin Watson	
Natural Gas	0.735	1.558	
Petroleum Products	0.828	2.514	
Electricity	0.994	2.462	
Total Energy Consumption	0.976	2.264	

Notes: 1 = Natural Gas, 2 = Petroleum Products, 3 = Electricity; * See Equations (1) and (5).

The elasticities for the commercial sector are reported in Table 4. As with the residential sector, all the own-price elasticities are negative but are not estimated with sufficient precision to be statistically significant. The test of the over-identifying restrictions for the commercial model cannot be rejected, while the curvature conditions are all satisfied.

Table 4. Elasticities of demand for California commercial energy model.

Quantities	**Natural Gas Price**	**LPG Price**	**Electricity Price**	**Commercial Sector Production**
		Gross Elasticities		
Natural gas	−0.144	0.014	0.130	−0.373
t-statistic	−1.4	0.2	1.6	−1.9
P-value	[0.162]	[0.803]	[0.104]	[0.061]
Liquid Propane Gas	0.057	−0.170	0.113	−1.170
t-statistic	0.2	−0.7	0.3	−1.4
P-value	[0.803]	[0.504]	[0.781]	[0.156]
Electricity	0.025	0.005	−0.030	0.124
t-statistic	1.6	0.3	−1.3	1.8
P-value	[0.104]	[0.781]	[0.190]	[0.080]

Table 4. *Cont.*

Quantities	Natural Gas Price	LPG Price	Electricity Price	Commercial Sector Production
		Net Elasticities		
Natural gas	−0.142	0.015	0.131	0.294
t-statistic	−1.4	0.3	1.7	1.1
P-value	[0.168]	[0.793]	[0.096]	[0.266]
Liquid Propane Gas	0.058	−0.170	0.113	−0.504
t-statistic	0.3	−0.7	0.3	−0.6
P-value	[0.802]	[0.504]	[0.780]	[0.555]
Electricity	0.031	0.012	−0.023	0.790
t-statistic	0.8	0.3	−0.5	5.8
P-value	[0.440]	[0.791]	[0.639]	[0.000]
		Net Long−Run Elasticities		
Natural gas	−0.281	0.028	0.257	−0.066
t-statistic	−1.4	0.3	1.4	−0.2
P-value	[0.177]	[0.787]	[0.174]	[0.810]
Liquid Propane Gas	0.113	−0.334	0.221	−1.634
t-statistic	0.3	−0.6	0.3	−1.5
P-value	[0.793]	[0.535]	[0.791]	[0.139]
Electricity	0.055	0.016	−0.052	0.910
t-statistic	1.2	0.3	−0.7	6.5
P-value	[0.216]	[0.756]	[0.507]	[0.000]

The econometric estimates for the industrial sector are displayed below in Table 5. Like the commercial model, heating and cooling-degree days are not significant and so were dropped. Unlike the commercial model, industrial production was not found to be significant in the share equations but the time trend terms was found to be highly significant. Hence, industrial production was dropped from the share equations, which implies that the energy demand equations are homothetic. The estimation results in Table 5 show that the short-run output elasticity of aggregate energy demand is 0.096 for the industrial sector, which is significant at the 1% level, and together with the adjustment coefficient implies a long-run elasticity of 0.18. The short-run own price elasticity of industrial energy demand is −0.078 with a long-run own price elasticity of −0.15.

Table 5. Parameter estimates for California industrial energy model.

Cost Share System			
Parameters*	Coefficient	*t*-statistic	*P*-value
β_{12}	−0.397	−1.7	[0.081]
β_{23}	−1.154	−13.7	[0.000]
β_{13}	−0.779	−6.4	[0.000]
Φ	0.823	11.3	[0.000]
T_1	0.006	3.1	[0.002]
α_1	−0.088	−1.5	[0.146]
T_2	−0.004	−3.5	[0.000]
α_2	0.217	2.4	[0.017]

Table 5. *Cont.*

Dependent variable: ln(Q_e)			
Constant	4.022	5.1	[0.000]
ln(P_e / PGDP)	−0.078	−3.5	[0.000]
ln(Industrial Output)	0.096	3.9	[0.000]
ln($Q_{e,t-1}$)	0.481	5.2	[0.000]
Dependent Variable	Correlation Coefficient	Durbin Watson	
Natural Gas	0.931	1.963	
Petroleum Products	0.825	2.084	
Electricity	0.844	1.638	
Total Energy Consumption	0.701	1.766	

Notes: 1 = Natural Gas, 2 = Petroleum Products, 3 = Electricity; * See Equations (1) and (5).

For the industrial sector model, the tests of the over-identifying restrictions are not rejected. The estimates also satisfy the curvature conditions, implying that the demand equations are consistent with producer cost minimization. Like the residential and commercial sectors, the short-run demand for electricity is extremely price inelastic with a gross own price elasticity of −0.01. This increases to −0.12 for the net long-run elasticity, although it remains insignificant. On the other-hand, the net long-run own price elasticities for natural gas and petroleum, equal to −1.65 and −0.67 respectively, are significant at the 1% level. Finally, the time trend coefficients imply that technological change is insignificant in the industrial demand for electricity, but technological change is significant for natural gas and petroleum product use in the industrial sector (see Table 6).

Table 6. Elasticities of demand for California industrial energy model.

Quantities	**Natural Gas Price**	**Petroleum Price**	**Electricity Price**	**Time Trend**
		Gross Elasticities		
Natural Gas	−0.285	0.199	0.086	0.006
t-statistic	−2.7	2.7	1.8	3.4
P-value	[0.007]	[0.008]	[0.069]	[0.001]
Petroleum	0.17	−0.11	−0.06	−0.005
t-statistic	2.7	−2.4	−1.8	−3.7
P-value	[0.008]	[0.015]	[0.067]	[0.000]
Electricity	0.062	−0.051	−0.011	0.000
t-statistic	1.8	−1.8	−0.5	−0.9
P-value	[0.069]	[0.067]	[0.647]	[0.382]
		Net Elasticities		
Natural Gas	−0.307	0.177	0.064	0.006
t-statistic	−2.9	2.3	1.4	3.4
P-value	[0.004]	[0.020]	[0.166]	[0.001]
Petroleum	0.144	−0.136	−0.086	−0.005
t-statistic	2.2	−3	−2.6	−3.7
P-value	[0.028]	[0.003]	[0.009]	[0.000]
Electricity	0.032	−0.081	−0.042	0.001
t-statistic	1	−2.9	−1.4	−0.9
P-value	[0.340]	[0.004]	[0.159]	[0.382]

Table 6. *Cont.*

Quantities	Natural Gas Price	Petroleum Price	Electricity Price	Time
		Net Long−Run Elasticities		
Natural Gas	−1.652	1.082	0.443	0.034
t-statistic	−4.2	5.0	1.9	3.6
P-value	[0.000]	[0.000]	[0.063]	[0.000]
Petroleum	0.908	−0.67	−0.388	−0.027
t-statistic	5.0	−3.3	−3.0	−4.1
P-value	[0.000]	[0.001]	[0.003]	[0.000]
Electricity	0.292	−0.345	−0.123	−0.002
t-statistic	1.8	−3.1	−0.8	−0.9
P-value	[0.078]	[0.002]	[0.445]	[0.389]

The final block of estimated econometric equations includes the demands for gasoline and diesel fuel used in transportation. These equations are estimated to track the carbon emissions from the transportation sector. The results of this estimation appear in Table 7. The short and long-run price and income elasticities of demand have the expected signs. Like electricity, the short-run price elasticity of demand for both fuels is very inelastic, indicating that consumer expenditures do not fall sharply as prices increase. In the long run, the elasticities increase but remain inelastic. The price elasticity for gasoline is statistically significant in the short run at the 1% level, and in the long run at the 10% level, while the price elasticities for diesel in the short and long run are insignificant.

Table 7. Elasticities of demand for California gasoline and diesel.

	Coefficient	***t*-statistic**	***P*-value**
Dependent variable: $\ln(Q_{gasoline})$			
Constant	0.970	2.8	[0.004]
$\ln(P_{gasoline} / PGDP)$	−0.048	−3.1	[0.002]
ln(Real Personal Income)	0.103	2.4	[0.018]
$\ln(Q_{gasoline,t-1})$	0.727	6.7	[0.000]
Dependent variable: $\ln(Q_{diesel})$			
Constant	−11.828	−5.3	[0.000]
$\ln(P_{diesel} / PGDP)$	−0.057	−1.0	[0.334]
ln(Real GDP)	0.775	6.0	[0.000]
$\ln(Q_{diesel,t-1})$	0.017	0.1	[0.915]
Dependent Variable	Correlation Coefficient	Durbin Watson	
Gasoline	0.979	1.430	
Diesel	0.932	1.845	

Table 7. *Cont.*

	Coefficient	***t*-statistic**	***P*-value**
	Short-Run		
		Price Changes	
	Gasoline	*Diesel*	*Income*
	−0.048		0.103
Gasoline	−3.1		2.4
	[0.002]		[0.018]
		−0.057	0.775
Diesel		−1.0	6.0
		[0.334]	[0.000]
	Long−Run		
	−0.176		0.377
Gasoline	−1.8		10.6
	[0.079]		[0.000]
		−0.058	0.789
Diesel		−0.9	17.1
		[0.351]	[0.000]

References

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