

**Interfuel substitution, hydroelectricity consumption and CO₂ emissions
mitigation in Malaysia: Evidence from a transcendental logarithm (trans-log)
cost function framework**

Mufutau Opeyemi Bello

Department of Economics, Faculty of Social Sciences, University of Ilorin, P.M.B

1515, Ilorin, Nigeria.

Email: bello.oo@unilorin.edu.ng; muphtty_2004@yahoo.com

Sakiru Adebola Solarin

Faculty of Business, Multimedia University, 75450 Melaka, Malaysia.

Email: sasolarin@mmu.edu.my

Yuen Yee Yen

Faculty of Business, Multimedia University, 75450 Melaka, Malaysia.

Email: yyyuen@mmu.edu.my

Abstract

The main objective of this paper is to estimate the interfuel substitution elasticities between hydropower and the fossil fuels of coal and natural gas used in the generation of electricity for Malaysia. Due to the violation of the OLS method on account of the correlated error terms in the system of equations, the econometrics techniques of seemingly unrelated regression (SUR) was adopted to obtain the parameter estimates using dataset that covers the period 1988 to 2016. The main finding is that there exists substantial substitution possibility between hydropower and fossil fuels in the generation of electricity for Malaysia. CO₂ emissions mitigation scenarios were also conducted to explore the possible effects of substituting fossil fuels for hydropower to generate electricity. The results show that switching from high carbon emitting fuels to renewable energy such as hydropower will substantially reduce CO₂ emission and assist the country towards achieving the carbon emissions reduction targets. Policy recommendations are offered in the body of the manuscript.

Keywords: Interfuel substitution, Hydropower, CO₂ emission mitigation, Malaysia, Trans-log Cost Function, Seemingly unrelated regression (SUR)

1. Introduction

As the worrying wave of global warming continues to spread across the globe, concerns about the sustainability of the planet are, more than ever before, increasingly taking the front burner of important policy issues for government and policy makers alike. The common consensus is that global warming should be tackled head on to prevent an imminent undesirable environmental consequence (Intergovernmental Panel on Climate Change (IPCC) 2015, Lu and Stern, 2016).

One of the major factors responsible for this worrying scenario is the dominance of fossil fuels in the generation of electricity with severe and damaging consequences that border on environmental safety and resource sustainability (Bello et al. 2018). Environmental safety is threatened as fossil fuels for electricity generation are the cause of over a third of human-induced greenhouse gas emission (World Nuclear Association (WNA), 2014). Resource sustainability is threatened due to the non-renewable characteristic of fossil fuels. The United States Energy Information Administration (EIA) warned that the present trajectories in the supply of energy are environmentally, socially, and economically unsustainable and by the year 2050, CO₂ emissions from energy consumption will be more than double and increase in the demand for oil will aggravate security concerns over supplies unless drastic actions are taken (EIA, 2016).

To address this situation the quickest and most efficient way is to decarbonize the electricity generation process towards attaining a low carbon economy (Rogelj et al., 2013, 2014). Decarbonization of the electricity generation process involves the switching from high carbon emitting fossil fuels to carbon reducing renewable energy sources. Among the several renewable sources of electricity generation to decarbonize the electric power sector, hydropower is the most dominant and frontline candidate as

it is the world's largest renewable electricity source. Hydropower has numerous advantages which include dependability, established technology, capacity to store energy in large container, and relatively inexpensive costs of running and up-keep (International Energy Agency (IEA), 2012). This paper therefore investigates the possibility of increasing the proportion of hydropower in the process of generating electricity through interfuel substitution and the effect of such substitution on the mitigation of CO₂ emission for Malaysia.

We have chosen Malaysia because the situation with Malaysia mirrors that of the global phenomenon. Despite playing important role in the economic growth process of the country, high carbon emitting non-renewable coal and natural gas dominate the electricity generation system in the country with untoward repercussions. In 2009 during framework on climate change organized by the United Nations in Copenhagen, Malaysian government voluntarily undertook a 40% reduction of the GDP emission intensity of year 2005 by 2020- a parameter defined by the total CO₂ emissions related to the GDP. However, by the end of the year 2017, three years away from the target year, available statistics indicate that Malaysia is unlikely to achieve this self-imposed target. World Development Indicator (WDI) of the World Bank shows that Malaysia's total CO₂ emission intensity of GDP in year 2005 was 0.88 metric tons per capita. This figure is put at 0.70 metric tons per capita in 2017 which is only a 20% decrease instead of the proposed reduction of 40%. This means that the country is about 50% off the mark. Realizing the possibility of not meeting this target, the government has further refined the target to reducing its emissions intensity of GDP in relation to 2005 levels by 45% by 2030. In any case, unless some drastic measures are taken, the current trend does not suggest that the new target will be achieved by 2030.

Between 1988 and 2016, Malaysia's CO₂ emissions increased from 45.4 million tonnes to 252.1 million tonnes representing an increase in excess of 455% within the period while the proportion of total CO₂ emissions from electricity and heat production increased from 36.2% in 1988 to 54% in 2014 (World Bank, 2018; BP 2018). Similarly, in 1988, the country's bio-capacity per person was 3.7 global hectares (gha) against 2.4gha for ecological footprint per person resulting to a positive bio-capacity per person of 1.3gha. However, this scenario has reversed as the latest data released by the Global Footprint Network (GFN), (2018) show that Malaysia's ecological footprint per person in 2014 has increased to 4.4gha leapfrogging the country's bio-capacity per person which was put at 2.0gha per person making the country with a deficit bio-capacity of 2.4gha. Consequently, Malaysia is currently ranked 29 among 188 countries in terms of ecological footprint.

The question of resource sustainability is also of critical relevance to Malaysia. Both coal and natural gas accounted for almost 90% of the electricity generation fuel mix of Malaysia in 2015 (38.6% and 49% respectively). Malaysia's proven reserve of natural gas was 2.7 trillion cubic metres at the end of year 2017 and its estimated to last for another 34.9 years assuming there are no more additional recoveries and the current consumption rate is maintained the country can exhaust its natural gas reserves by the end of the year 2052 (British Petroleum (BP), 2018).

Our contribution to the extant literature are as follows. We examined the possibility of substituting fossil fuels for hydropower in the process of electricity generation. This is important as, apart from Bello et al., (2018), most of the previous published works on interfuel substitution such as Azlina et al., (2013); Wesseh and Lin (2018); and Solarin and Bello (2019), have ignored the possibility of fuel substitution within the electricity sector as they have focused on the aggregate economy. It is important to examine

interfuel substitution at sub-aggregate level as this will provide a more specific policy framework as aggregate analyses can sometimes conceal the distinctive natures of individual fuels and can, therefore, lead to incorrect deductions of policies for individual energy component (Bello et al., 2018).

Furthermore, in addition to estimating the own and cross price elasticities of and between individual fuels, this study also analysis the possible effects of fuel substitution on CO₂ emission mitigation in the country. The only published paper on interfuel substitution in Malaysia, known to the authors (Bello et al., 2018), to have included hydropower in the analysis of interfuel substitution neither estimated own and cross price elasticities of and between individuals nor examined the possible effects of fuel substitution on CO₂ emission mitigation in Malaysia.

Moreover, Malaysia as a country has received very limited attention in the analysis of interfuel substitution. This creates a gap in the literature that needs to be bridged because without an empirically proven estimates of inter-fuel substitution, government and policy makers alike may not be properly guided on the appropriate policies to effectively trade-off pollutant fuels for cleaner and efficient ones in the electricity generation for the country. In the end, the study is expected to serve as a form of guideline to the government and relevant stakeholders in matters of the environment looking for appropriate policy directions needed to meet the carbon reduction agenda.

What follows in this paper are the review of related literature in section 2, methodology in section 3, discussion of empirical results in sections 4 and conclusion with policy implications and recommendations in section 5.

2. Review of related literature

Empirical research on inter-fuel substitution studies is quite robust. Majority of the published works have focused on investigating the substitution possibilities among the dominant energy types namely oil, natural gas, coal and electricity while some other authors have also introduced fuels such as biomass, and petroleum products like diesels and gasoline into the analysis. These studies have adopted models such as the generalised Cobb-Douglas production function, nested constant elasticity of substitution, differential fuel allocation model, the translog production and cost function and the logit model with estimation techniques such as the iterative 3-stage and 2-stage least squares, the full information maximum likelihood techniques, the ridge regression procedure and the seemingly unrelated regression technique and the outcomes have been largely mixed between substitutability and complementarity relationship among the energy types. Andrikopoulos et al., (1989); Jones (1996); Tsita and Pilavachi (2013); Azlina et al., (2013); Moore et al. (2013); Jones (2014); Lin et al., (2016); Suh (2016), Lin and Atsagli (2017); Lin and Tian (2017); Wesseh and Lin (2018); Considine (2018); Zhang et al., (2018); Bello et al., (2018), Sadaf et al., (2018); Arshad et al., (2018); and Solarin and Bello (2019) have all provided evidence that the energy inputs are substitutes.

While substitutability relationship is the dominant outcomes from most of the empirical research, some authors have also provided evidence of contrary outcomes which support complementary relationships between the input fuels. For instance, Prywes (1986) show evidence of a complimentary relationship between the energy fuels in the manufacturing sector for the US. Similar outcome was also reported for India by Uri (1979) in the case of electricity and oil and between petroleum and electricity in a joint study of four countries namely the US, Canada, Italy and Japan by Hall (1986). Vlachou

and Samouilidis (1986) also found evidence in support of complimentary relationship between liquid fuel and solid fuel in Greek's Agriculture, Industrial and transport sectors while Taheri (1994) found same between oil and gas in US manufacturing sector and Lin and Ankrah (2019) found evidence of that energy from renewable source can serve as substitutes for energy from non-renewable source for Nigeria. Suh (2016) found evidence of complementary relationship between biomass and electricity for the US industrial sector.

A couple of points can be deduced from the forgoing survey of literature. Firstly, majority of the studies have ignored hydropower from the analyses of interfuel substitution. The only exception has been Bello et al., (2018) who included hydropower in the case of electricity sector for Malaysia. However, this study is different from Bello et al., (2018) as it does not only estimate the own and cross price elasticities of and between individual fuels it also investigates the possible effects of fuel substitution on CO₂ emission mitigation in Malaysia.

Secondly, there is a lack of unified results on the pattern of relationships (substitutes or compliments) between factors and between fuels. Griffin and Gregory (1976) and Stern (2012) have explained that differences in the nature of data, adopted techniques of estimation, size of the sample are some of the factors responsible for different outcomes. It is therefore difficult to make generalisation on the nature of relationships between fuels across different nation. Within the context of Malaysia, the underlying hypotheses are that substituting the fossil fuels for non-fossil fuels can reduce carbon dioxide emissions in the process of generating electricity that substitution is feasible between hydropower and the fossil fuels of natural gas and coal which are the mostly used fuels for electricity generation in Malaysia. For Malaysia, natural gas and coal

play prominent role so it is hypothesized that there should be a high elasticity of substitution between these fuels and hydropower.

3. Methodology

3.1. Model

The model specification begins with a production function for a produced electricity as output of the form:

$$E = e[K, L, F, M] \quad (1)$$

Where E is the output which is total electricity generation in this case, K is capital, L is labor, F is a combination of the fuel inputs and M represents other materials used in the generation of electricity. In the studies on inter-fuel substitution, the production function is assumed to be weakly separable in the inputs such that F input(s) as a group are weakly separable from K , L and M inputs. Thus, the mix of F inputs (in this case coal, gas, and hydro) is independent of non-energy inputs (K , L , and M). This assumption of weak separability not only allows for the analysis of a separate production function for energy input(s) alone, but also helps reduce the number of parameters to be estimated. This means that the aggregate F is homothetic of the three fuels coal, natural gas, and hydropower denoted respectively as (c), (g), and (h). With these assumptions, the production function for electricity production of the general form is specified as such:

$$E = e[K, L, F(c, g, h), M] \quad (2)$$

F is homothetic of the three fuels- (c , g , h).

The production function is a technical representation of the relationship between the output and the several input combinations. Correspondingly, the relationship is also represented by a cost function that describes what it costs to produce a particular level of output given prices and quantities of different input factors. Applying the duality theory of production and cost functions, the assumption of weak separability of the production function is also applicable to the cost function (Chambers, 1988). Accordingly, the cost function is written as:

$$C_E = c[P_K, P_L, P_F(P_c, P_g, P_h)P_M; E] \quad (3)$$

Where C_E is the aggregate cost electricity produced, P_K is the price of capital input, P_L is the price of labor input, P_F is an index of aggregate price of fuel that aggregate the prices of individual fuel inputs- coal, gas, and hydro. P_M represents price of other materials. As the main aim here is to examine the possibility of substitution among the fuel inputs and the fact that the cost function is weakly separable into K, L, M and the competing fuels inputs, the cost function is thus reduced to this flexible functional form:

$$C_E = c(E, P_F(P_c, P_g, P_h)) \quad (4)$$

Based on microeconomics theory of cost, the cost function is required to satisfy the homogeneity, monotonicity, curvature, and positivity theoretical regularity conditions. Homogeneity implies that the cost function is linearly homogenous in input prices. The monotonicity condition of the cost function is satisfied when the input demand which is the first order derivative is non-negative. Curvature requires the cost function to be a concave function of prices and the condition of positivity is met when the estimated cost values for all data points is positive.

With these theoretical regularity conditions, the electricity generation cost function can be written as:

$$C_E = E.P_F(P_c, P_g, P_h) \quad (5)$$

Employing a functional form that is flexible, the homothetic trans-log cost function for the generation of electricity takes the form:

$$\ln C_E = \beta_0 + \sum_{i=1}^n \beta_i \ln P_i + 0.5 \sum_{i=1}^n \sum_{j=1}^n \beta_{ij} \ln P_i P_j \quad (6)$$

Where $i, j = c, g, h$ and P_i, P_j are the prices of individual fuels. When the cost function is differentiated with respect to the input prices, the respective cost of each input relative to the total cost is derived as:

$$\frac{\partial \ln C_E}{\partial \ln P_i} = \frac{\partial C_E}{\partial P_i} \cdot \frac{P_i}{C_E} = \beta_i + \sum_j \beta_{ij} \ln P_j \quad i, j = c, g, h \quad (7)$$

Going by the envelope theorem of the cost function and from Shephard's Lemma result:

$$\frac{\partial C_E}{\partial P_i} = Q_i \quad (8)$$

Equation (8) is the conditional input demand function for the i th input. (in this case, c, g, h). Substituting equation (8) into equation (7), equation (9) is obtained as follows:

$$Q_i \cdot \frac{P_i}{C_E} = \beta_i + \sum_j \beta_{ij} \ln P_j \quad (9)$$

Equation (9) is the cost share of the individual fuels in the total electricity cost denoted as S_i where $i = c, g, h$

$$Q_i \cdot \frac{P_i}{C_E} = \beta_i + \sum_j \beta_{ij} \ln P_j = S_i \quad (10)$$

Thus, when the cost function is differentiated with respect to the input prices and applying Shepard's lemma, the following cost shares equations are obtained:

$$\begin{aligned} S_c &= \beta_c + \beta_{cc} \ln P_c + \beta_{cg} \ln P_g + \beta_{ch} \ln P_h \\ S_g &= \beta_g + \beta_{gc} \ln P_c + \beta_{gg} \ln P_g + \beta_{gh} \ln P_h \\ S_h &= \beta_h + \beta_{hc} \ln P_c + \beta_{hg} \ln P_g + \beta_{hh} \ln P_h \end{aligned} \quad (11)$$

Where:

$$S_c = \left(\frac{P_c Q_c}{P_c Q_c + P_g Q_g + P_h Q_h} \right); S_g = \left(\frac{P_g Q_g}{P_c Q_c + P_g Q_g + P_h Q_h} \right); S_h = \left(\frac{P_h Q_h}{P_c Q_c + P_g Q_g + P_h Q_h} \right) \quad (12)$$

Where S_c , S_g , and S_h are the cost shares for coal, natural gas, and hydro respectively.

The system of equations in (11) is used to empirically estimate the parameters. The parameter estimates provide the elasticities of substitution between the three fuels.

The condition of linear homogeneity, represented by the following parameter restriction, must be fulfilled by equation (11).

$$A = \sum_{i=1}^n \beta_i = 1, B = \sum_{i=1}^n \beta_{ij} = 0, C = \sum_{i=1}^n \beta_{ji} = 0, \text{ and } D = \beta_{ij} = \beta_{ji}$$

Where A , B , and C are the restrictions for the adding up criteria while D is the symmetry restriction.

To empirically estimate the systems of share equations in (11), a disturbance error term is appended to each of the equations. Thus, for each share equations, the vector of errors $\mathcal{E}_i = (\mathcal{E}_c, \mathcal{E}_g, \mathcal{E}_h)$ which are assumed to be multivariate normally distributed with zero

mean and the 3 by 3 error covariance matrix Ω . Hence, the share equation systems (11) can be written as:

$$\begin{aligned} S_c &= \beta_c + \beta_{cc} \ln P_c + \beta_{cg} \ln P_g + \beta_{ch} \ln P_h + \varepsilon_c \\ S_g &= \beta_g + \beta_{gc} \ln P_c + \beta_{gg} \ln P_g + \beta_{gh} \ln P_h + \varepsilon_g \\ S_h &= \beta_h + \beta_{hc} \ln P_c + \beta_{hg} \ln P_g + \beta_{hh} \ln P_h + \varepsilon_h \end{aligned} \quad (13)$$

The sum of the share cost is one i.e. $\sum_{i=1}^n S_i = 1$, and the sum of the random error terms in of the share cost is zero $\sum_{i=1}^n \varepsilon_i = 0$. This gives rise to the possibility of correlation between the errors in the system of share equation thereby leading to a singular covariance matrix in which case OLS estimates becomes inconsistent. A suitable approach in this case is the maximum likelihood procedure such as the seemingly unrelated regressions-SUR. In this instance, the third hydro equation is deleted such that the three equations in a framework of symmetry-constrained, with the imposition of homogeneity restrictions is expressed as:

$$\begin{aligned} S_c &= \beta_c + \beta_{cc} \ln(P_c / P_h) + \beta_{cg} \ln(P_g / P_h) + \varepsilon_c \\ S_g &= \beta_g + \beta_{gc} \ln(P_c / P_h) + \beta_{gg} \ln(P_g / P_h) + \varepsilon_g \end{aligned} \quad (14)$$

In this case, the resulting variance-covariance matrix of the disturbance error terms are no longer singular and the parameter of the third deleted (hydro) equation are derivable using the restrictions of linear homogeneity as:

$$\beta_h + \beta_c + \beta_g = 1; \rightarrow \rightarrow \therefore \beta_h = 1 - \beta_c - \beta_g \quad (15)$$

$$\beta_{hc} + \beta_{cc} + \beta_{cg} = 0; \rightarrow \rightarrow \therefore \beta_{hc} = -(\beta_{cc} + \beta_{cg}) \quad (16)$$

$$\beta_{hg} + \beta_{gc} + \beta_{gg} = 0; \rightarrow \rightarrow \therefore \beta_{hg} = -(\beta_{gc} - \beta_{gg}) \quad (17)$$

$$\beta_{hh} + \beta_{hc} + \beta_{hg} = 0; \rightarrow \rightarrow \therefore \beta_{hh} = -(\beta_{hc} - \beta_{hg}) \quad (18)$$

3.2 Dynamic version of the trans-log cost function.

It should be noted that the estimate of elasticities derived so far are static and holds only in equilibrium because static models are premise on the assumptions that inputs react instantaneously to changes in the economic environment whether or not there are short run restrictions on some inputs. Static models do not describe differences between short-run and long-run elasticities, or how the adjustment to the long-run takes place. However, failure to account for imperfect adjustment to disequilibrium ignores the realities of the production process. For example, it is reasonable to expect that in the long-run the aggregate production function exhibits constant returns to scale, but that it exhibits non-constant returns to scale in the short-run. Models of empirical analysis that neglect the adjustment process of price changes can affect the consistency of the test of hypothesis. As argued by Berndt and Christensen (1974), serial correlation and inconsistent standard errors are part of the challenges in estimating static models which can result to type II errors in hypothesis testing.

Consequently, a dynamic trans-log cost function that permits adjustment to constant returns over time is specified. To do this, the approach adopted by Pindyck (1977) is adopted through the introduction of a dynamic adjustment factor directly into the share equations. This is done with the assumption that the shares adjust to a set of desired shares as follows:

$$\begin{aligned} \Delta S_{it} &= (1 - \delta)(S_{it}^* - S_{it-1}) \\ S_{it} - S_{it-1} &= (1 - \delta)(S_{it}^* - S_{it-1}) \quad i = c, g, h \end{aligned} \quad (19)$$

Where S_{it}^* is the desired fuel of factor cost share and S_{it} is the actual share at time t . $(1-\delta)$ (which is to be estimated) is the rate of adjustment of S_{it} to S_{it}^* . In this case S_{it}^* represents the shares cost as in equation (10). Solving for S_{it}^* in shares equation (19) and substituting into equation (10), we obtain the dynamic lagged share system of fuel as:

$$S_{it}^* = \beta_i^* + \sum_j^n \beta_{ij}^* \ln P_j + \delta_t S_{i,t-1}; i, j = c, g, h \quad (20)$$

Equation (20) is somewhat identical to the static version in equation (10) with the addition of the lagged dependent variable term, whose coefficient δ measures the rate of the dynamic adjustment. The estimation procedure follows the same pattern as in the static model.

3.3 Elasticities

Once the estimates of the parameters of the equations of the cost share obtained, the estimates of the substitution elasticities between the inputs can be computed. Three of the most common used measures of price responsiveness are: 1. Own and Cross Price Elasticities 2. The Allen-Uzawa Elasticity of Substitution (AES) named after Allen (1938) and Uzawa (1962); and 3. The Morishima Elasticity of Substitution (MES) (1967).

For a two-factor production function, the cross-price elasticity given by $\eta_{ij} = \partial \ln x_i / \partial \ln P_j$ was related to Hick's elasticity of substitution as:

$$\eta_{ij} = \frac{x_j P_j}{Y P} \cdot \sigma = s_j \sigma \quad (21)$$

Where Y is output, output price is denoted as p and the share of factor j relative to total revenue is given as $s_j = x_j p_j / Yp$. Assuming that the production function is linearly homogenous, s_j is equivalent to $x_j p_j / C$. In a multi-input scenario, the cross-price elasticity is given as:

$$\eta_{ij} = \frac{\partial \ln x_i}{\partial \ln p_j} = \frac{p_j}{x_i} \frac{\partial x_i}{\partial p_j} = \frac{p_j}{x_i} \frac{\partial C_i}{\partial p_j} = \frac{p_j}{x_i} C_{ij} \quad (22)$$

Where C_{ij} is an abbreviation of the second partial derivative $\partial^2 C / \partial p_i \partial p_j$.

Completing equation (20) by x_j and C and utilizing the Shepard's lemma again leads to:

$$\eta_{ij} = \frac{p_j x_j}{C} \frac{CC_{ji}}{x_i x_j} = \frac{p_j x_j}{C} \frac{CC_{ij}}{C_i C_j} = s_j \frac{CC_{ij}}{C_i C_j}. \quad (23)$$

Intuitively, when equation (23) is compared to equation (21) it is seen that the

$AES_{ij} = \eta_{ij} / s_{ij}$. Hence given that AES denoted as σ_{ii}^a and σ_{ij}^a is computed as:

$$\sigma_{ii}^a = \frac{\beta_{ii} + S_i^2}{S_i^2}, i = c, g, h; \quad (24)$$

$$\sigma_{ij}^a = \frac{\beta_{ij}}{S_i S_j} + 1, i = c, g, h; i \neq j. \quad (25)$$

It follows that:

$$\eta_{ii} = \sigma_{ii}^a S_i; i = c, g, h. \quad (26)$$

$$\eta_{ij} = \sigma_{ij}^a S_j; i, j = c, g, h; i \neq j. \quad (27)$$

It follows that the relevant elasticity of substitution is the own and cross price elasticity as the AES merely divides the own (η_{ii}) and cross price (η_{ij}) elasticities by the cost shares without providing extra information. It is also noted that the AES is symmetry i.e. $\sigma_{ij}^\alpha = \sigma_{ji}^\alpha$, and thus irrelevant since the impacts of interests usually depends upon which price is changing (p_i or p_j). Thus, cross and own price elasticities are the relevant estimates of focus in this study as they are asymmetric i.e. $\eta_{ii} \neq \eta_{ij}$. Morishima elasticity of substitution (MES) considers the effect of the ratio of the two inputs q_i/q_j i.e. examining the effect of variation in the price of input j on the ratio quantity q_i/q_j while keeping the price of input i constant and it's given as:

$$\sigma_{ij}^m = S_i(\sigma_{ij}^a - \sigma_{jj}^a), i, j = c, g, h. \quad (28)$$

Thus, it is not adopted here because the relevant effect here is the own price and not relative prices. This is also in line with the submissions of authors such as Sorrell (2014), and Li and Lin (2016) that own and cross price elasticities are the preferred elasticity estimates than the AES and MES. Positive estimates indicate substitutability and complementarity is inferred when the estimates are negative.

Under the dynamic specification of share equations, the short-run partial own and cross price elasticities of input factors are calculated as:

$$\xi_{ii} = \frac{\eta_{ii} + S_i^2 - S_i}{S_i}; i = c, g, h. \quad (29)$$

$$\xi_{ij} = \frac{\eta_{ii} + S_i S_j}{S_i}; i \neq j; i, j = c, g, h. \quad (30)$$

The long run partial own and cross elasticities are calculated as:

$$\xi_{ii}^* = \frac{\xi_{ii}}{(1-\delta)}; i = c, g, h. \quad (31)$$

$$\xi_{ij}^* = \frac{\xi_{ij}}{(1-\delta)}; i \neq j; i, j = c, g, h. \quad (32)$$

3.4 Data

The dataset for coal price is the average prices of the Australian, Colombian, and South African coal expressed in US\$ per metric tons (US\$/mt). Gas prices are obtained by the average of the US and European prices expressed US\$ per million British thermal unit (US\$/mmbtu). Hydro, being an indigenous factor, its prices are proxy by the Producer Price Index (PPI). This approach of using the PPI is consistent with Yang, Fan, Fang, and Hu (2014) and Li and Lin (2016). All the remaining variables are as been defined in the previous sections and covers the period 1988 – 2016. The chosen time frame is based on the period when the fuel has a non-zero positive input value and that begins with 1988 when coal, gas and hydro all has non-zero positive input in the process of generating electricity for Malaysia.

4 Empirical results and discussion

4.1 The substitution elasticities

Investigating the potential for substituting hydro for the non-renewable fuels of natural gas and coal in the generation of electricity in Malaysia requires the estimation of the trans-log cost function. For robustness sake, the static and dynamic models of the trans-log cost function have been estimated. Due to the adding-up, homogeneity, and symmetry constraints and the possibility that the errors in the system of equations may be correlated, the seemingly unrelated regression techniques have been employed to generate the parameter estimates of the variables in the systems of equations.

Table 1: Parameter estimates of cost share equations.

	Static Model		Dynamic Model	
	Parameter	t-stat	parameter	t-stat
cost share equation for coal: Dependent variable (S_{coal})				
Constant (β_{coal})	0.316*	1.758	0.105	1.334
$\beta_{coal-coal}$	0.416**	2.540	0.175***	3.294
$\beta_{coal-gas}$	-0.105	-1.643	-0.027	-0.953
$\beta_{coal-hydro}$	-0.311	-	-0.1481	-
δ	-	-	0.802***	16.97
R^2	0.073		0.9143	
cost share equation for gas: Dependent variable (S_{gas})				
Constant (β_{gas})	0.568***	3.822	0.164**	2.095
$\beta_{gas-coal}$	-0.105	-1.643	-0.027	-0.953
$\beta_{gas-gas}$	0.168***	3.097	0.052*	1.850
$\beta_{gas-hydro}$	-0.062	-	-0.0255	-
δ	-	-	0.802***	16.97
R^2	0.533		0.732	-
Diagnostic tests				
Breuch-Pagan test	2.658* (0.10)		5.925** (0.02)	
F-test	18.955*** (0.0001)		9.099*** (0.0004)	

* Denotes statistical significance at 10% level, ** Denotes statistical significance at 5% level, *** Denotes statistical significance at 1% level,

Figures in parentheses are the probability values. Source: Authors' computation

Table 1 presents the parameter estimates for both the static and dynamic models. A couple of points can be made from the estimated results. First, most of the parameter estimates in both equations are significant. The parameter estimates for the dropped equation for hydro are obtained from the adding-up criteria and are given in Table 2.

Table 2: Parameter estimates of the omitted (hydro) share equation

Static Model

$$\beta_{hydro} = 1 + \beta_{coal} - \beta_{gas} = 1 - 0.316 - 0.568 = 0.116$$

$$\beta_{hydro-coal} = -(\beta_{coal-coal} + \beta_{coal-gas}) = -(0.416 - 0.105) = -0.311$$

$$\beta_{hydro-gas} = -(\beta_{gas-coal} - \beta_{gas-gas}) = -(0.105 + 0.168) = -0.063$$

$$\beta_{hydro-hydro} = -(\beta_{hydro-coal} + \beta_{hydro-gas}) = -(0.311 + 0.062) = -0.373$$

Dynamic Model

$$\beta^*_{hydro} = 1 + \beta^*_{coal} - \beta^*_{gas} = 1 - 0.105 - 0.164 = 0.731$$

$$\beta^*_{hydro-coal} = -(\beta^*_{coal-coal} + \beta^*_{coal-gas}) = -(0.175 - 0.027) = -0.148$$

$$\beta^*_{hydro-gas} = -(\beta^*_{gas-coal} - \beta^*_{gas-gas}) = -(0.027 + 0.052) = -0.025$$

$$\beta^*_{hydro-hydro} = -(\beta^*_{hydro-coal} + \beta^*_{hydro-gas}) = -(-0.148 + 0.025) = 0.173$$

N.B: The parameters are obtained from the imposed linear homogeneity restrictions.

Source: Authors' computation

Second, the Breusch-Pagan test of no interdependence between the systems of equation is significant in both the static and dynamic models, thus the null hypothesis of no equation interdependence between the systems of cost share equations is rejected. This confirms the suitability of the SUR estimation techniques as the traditional OLS techniques would have been inappropriate due to heteroscedasticity. Third, comparing the static model with the dynamic model, it is observed that the R^2 in the latter is relatively larger than that of the former which suggests that the explanatory power of the parameters is larger in the dynamic model than it is in the static model. Similarly, the dynamic adjustment parameter δ is about 80% significant at 1% implying that there exists a lagged, rather than an instantaneous, response to the equilibrium position in the long run. This, in addition to the fact that the dynamic model enables the derivation of the long-run elasticity of substitution estimates, makes it preferred to the static model.

Table 3: Own and cross price elasticities (Dynamic model).

	Short run		Long run	
	Elasticities	Standard errors	Elasticities	Standard errors
Own Price				
η_{coal}	-0.674***	0.061	-3.401***	0.307
η_{gas}	-1.210	1.630	-6.109	8.229
η_{hydro}	-0.383**	0.187	-1.933**	0.942
Cross Price				
$\eta_{coal-gas}$	0.152***	0.017	0.768***	0.087
$\eta_{coal-hydro}$	0.401***	0.040	2.025***	0.204
$\eta_{gas-coal}$	0.480***	0.039	2.421***	0.197
$\eta_{gas-hydro}$	0.474***	0.056	2.394***	0.285
$\eta_{hydro-coal}$	0.470***	0.041	2.373***	0.205
$\eta_{hydro-gas}$	0.216***	0.034	1.090***	0.172

Note: Elasticities are given at mean cost shares of fuels where $S_{coal} = 0.45$, $S_{gas} = 0.13$, and $S_{hydro} = 0.42$ represent the mean cost shares for coal, gas, and hydro respectively. ** Denotes statistical significance at 5% level; *** Denotes statistical significance at 1% level. Source: Authors' computation

Using the estimated parameters of the dynamic model, the generated short-run and long-run substitution elasticities results are presented in Table 3. The elasticities, calculated at the mean cost shares of fuels, shows a negative own price elasticity for all fuels in the short-run as well as in the long-run. The own price elasticity values in the long-run are significantly higher than the short-run values suggesting that the fuels are more elastic in the long-run than in the short run. As a matter of fact, apart from natural gas the fuels have own price elasticities that are lesser than one in absolute values which confirm the fuels as price inelastic in the short run. The negative values of the estimates of the own price elasticities in both the short-run and the long-run is consistent with a-priori expectation of price-commodity inverse relationship in microeconomics theory and other empirical works including that of Yang et al., (2014) for China and Serletis et al., (2010) for the United States. In terms of the cross-price elasticities, all estimates

are positive and significant suggesting that the fuels are substitutes both in the short run and long run.

Focusing on the cross-price response of hydro to coal and natural gas, the usage of hydro in electricity generation increases by 0.401% and 0.474% in the short run and 2.025% and 2.394% in the long run in response to a 1% increase in the prices of coal and natural gas respectively. The short run response in the usage of coal and natural gas in electricity generation to a 1% change in the price hydro is respectively 0.470% and 0.216% while the corresponding long run responses are respectively 2.373% and 1.090%. This implies that hydro demand has higher propensity to respond to changes in the coal and natural gas prices than the response of coal and natural gas to change in the price of hydro. It is noted that the response of coal to change in hydro price is higher than that of natural gas. This is probably a reflection of the fact that natural gas is a cleaner fuel compared to coal and more of it has to be substituted for hydro in the quest for decarbonizing the electricity generation process for Malaysia.

The results also show a wide margin between the short-run and the long estimates of the own and cross price elasticities as the long-run parameters are about six times larger than the short-run estimates. This is a reflection of the limited scope of substitution in the short-run and the lengthy adjustment process to long-run equilibrium. This is unsurprising as the long-run dynamic adjustment parameter δ is about 80% significant at 1%. The lengthy adjustment process to the long-run equilibrium may be as a result of two reasons. First, equipment and machineries in coal and gas fired plants are usually fixed and expensive to replace thereby making it difficult to achieve more substitution in the short-run. Second, different fuels use different technologies which makes it difficult to switch from one fuel to the other. So naturally, it takes quite a longer time for the adjustment process to allow optimum inter-fuel substitution.

4.2 Hydropower consumption and CO₂ emissions mitigation scenario

The extent to which hydroelectricity consumption can reduce the level of CO₂ emissions can be evaluated using the estimates of the cross-price elasticities which capture the response of hydro to changes in the prices of competing fuels of coal and natural gas. The overriding objective of electricity generating firms to minimize cost shapes the reaction to changes in fuel prices in choosing the optimum fuel quantity which in turn influences the level of CO₂ emissions based on the different CO₂ emission factor of the different fuels input. Following Suh (2016), the variations in the level of CO₂ emissions can be estimated with the following equation:

$$\Delta e_{ij} = \frac{\sigma_{ij}}{100} k_i \bar{F}_i$$

where Δe_{ij} is the variation in the level of emitted CO₂ from fuel i due to changes in the price of j th fuel; k_i represents the emission factor of fuel i expressed in metric tons of CO₂ per million tons of oil equivalent (mtoe) of fuel i ; and \bar{F}_i is the mean consumption of fuel i during the sample period. The emission factor measures the volume of CO₂ emitted from fuel combustion, which differs with respect to each fuel. According to the Energy Information Administration (EIA) of the US, the emission coefficient for coal is 0.095 tons of CO₂ per million British thermal unit (Btu) and 0.053 tons of CO₂ per million (btu) for natural gas. There are two scenarios for hydro in terms of emissions factors. On one hand, hydro itself is assumed not to emit greenhouse gases in which case its emission factor is zero (0) and on the other hand there are some scholarly works that show that, though the rate of emissions per unit of electric generation from hydropower is much lower than for fossil fuel technologies, there are emissions from electric generation from hydroelectric facilities. Therefore, the CO₂ emission factor for

hydro is not zero. According to Scherer and Pfister (2016), the global average emission factor of hydro is estimated to be 173 kg CO₂ per MWh which is equivalent to 0.051 tons of CO₂ per million (btu).

Table 4: Scenario 1*: Changes in CO₂ emissions in response to fuel price changes (metric tons per MTOE).

CO ₂ emissions from	Short run			Long run		
	1% price change for					
	Coal	Gas	Hydro	Coal	Gas	Hydro
Coal usage	-903.3	204.1	537.9	-4,559.9	1,030.3	2,715.0
Gas Usage	760.5	-1,919.0	752.0	3,839.2	-9,686.3	3,796.2
Hydro Usage	-	-	-	-	-	-
Net CO₂ Emissions	-142.8	-1,714.8	1,289.9	-720.92	-8,656.00	6,511.17

Scenario 1*: Assuming CO₂ emissions from hydro = 0. Source: Authors' computation

Table 5: Scenario 2*: Changes in CO₂ emissions in response to fuel price changes (metric tons per MTOE).

CO ₂ emissions from	Short run			Long run		
	1% price change for					
	Coal	Gas	Hydro	Coal	Gas	Hydro
Coal usage	-903.3	204.1	537.9	-4,559.9	1,030.3	2,715.0
Gas Usage	760.5	-1,919.0	752.0	3,839.2	-9,686.3	3,796.2
Hydro Usage	113.18	51.92	-92.1	570.8	262.1	-464.9
Net CO₂ Emissions	-29.74	-1,552.8	1,197.8	-150.1	-8,393.9	6,046.3

Scenario 2*: Assuming CO₂ emissions from hydro ≠ 0. Source: Authors' computation

The estimates of the changes in the level of CO₂ due to changes in the usage of the fuel inputs in electricity generation in response to changes in the prices of the fuel inputs under the assumption that emission from hydro is zero are presented in Table 4 while Table 5 presents the estimates under the assumption that emission from hydro is not zero.

In the short-run, under the assumption that hydro emits zero emission, a 1% increase in coal prices reduces the amount of coal usage in electricity generation which in turn reduces CO₂ emissions by 903.3 metric tons per MTOE and increases the amount of natural gas usage which in turn increases CO₂ emissions by 760.5 metric tons per MTOE. With hydro emission being zero, the net CO₂ emission changes in response to a 1% increase in the price of coal is a reduction by 142.8 metric tons per MTOE. Similarly, a 1% increase in the price of Gas reduces natural gas usage in electricity generation which reduces CO₂ emission from natural gas by 1,919 metric tons per MTOE and, through interfuel substitution, increases coal usage and CO₂ emission by 204.1 metric tons per MTOE. Again, with hydro emission being zero, the net emission reduction in response to a 1% increase of natural gas is 1,714.8 metric tons per MTOE. However, with a hydro, a 1% price increase results into increased usage of both coal and natural gas in electricity generation with also increase the amount of CO₂ emissions from electricity generation by 537.9 and 752.0 metric tons per MTOE respectively. This results into an increase in net emission of 1,289.9 metric tons per MTOE.

However, under the assumption that the emission from hydroelectric facility is not zero, a 1% increase in the price of coal would have generated additional CO₂ emission of 113.18 metric tons per MTOE from increased hydro and decreased the net emission reduction to only 29.74 metric tons per MTOE. Similarly, a 1% increase in the price of natural gas would have also increased emissions from hydro by 51.92 metric tons per

MTOE which would have also reduced the total net emission decrease to 1,662.8 while a 1% increase in hydro prices would have reduced hydro usage and emission from hydro by 92.1 metric tons per MTOE and increase total net emission by 1,197.8 metric tons per MTOE.

The long-run scenario mirrors what is obtainable in the short run. In the long run, under the assumption that hydro emits zero emission, a 1% increase in coal prices reduces the amount of coal usage in electricity generation which in turn reduces CO₂ emissions by 4,559.9 metric tons per MTOE and increases the amount of natural gas usage which in turn increases CO₂ emissions by 3,839.2 metric tons per MTOE. With hydro emission being zero, the net CO₂ emission changes in response to a 1% increase in the price of coal is a reduction by 720.92 metric tons per MTOE. Similarly, a 1% increase in the price of gas reduces natural gas usage in electricity generation which reduces CO₂ emission from natural gas by 9,686.3 metric tons per MTOE and, through interfuel substitution, increases coal usage and CO₂ emission by 1,030.3 metric tons per MTOE. Again, with hydro emission being zero, the net emission reduction in response to a 1% increase of natural gas is 8,656.0 metric tons per MTOE. However, with hydro, a 1% price increase results into increased usage of both coal and natural gas in electricity generation with also increases the amount of CO₂ emissions from electricity generation by 2,715.0 and 3,796.2 metric tons per MTOE for coal and natural gas respectively. This results into an increase in net emission of 6,511.17 metric tons per MTOE.

However, under the assumption that the emission from hydroelectric facility is not zero, in the long run, a 1% increase in the price of coal would have generated additional CO₂ emission of 570.8 metric tons per MTOE from increased hydro and decreased the net emission reduction to only 150.1 metric tons per MTOE. Similarly, a 1% increase in the price of natural gas would also increase emissions from hydro by 262.1 metric tons

per MTOE which would have also reduced the total net emission decrease to 8,393.9 while a 1% increase in hydro prices would have reduced hydro usage and emission from hydro by 464.9 metric tons per MTOE and increase total net emission by 6,046.3 metric tons per MTOE.

5. Conclusion, policy implications and recommendations

In this study, we have estimated the elasticities of substitution between hydropower and the main non-renewable fuels of natural gas and coal used in the process of generating electricity in Malaysia employing the econometrics techniques of the seemingly unrelated regression (SUR) with time series data that span from 1988 to 2016. We also conducted a CO₂ emissions mitigation scenario of substituting high carbon emitting fuels of coal and natural gas to hydropower in the process of electricity generation in Malaysia.

The analysis of the trans-log cost function suggests that there are strong inter-fuel substitution possibilities between hydropower and the fossil fuels of coal and natural in electricity generation for Malaysia. More substitution is possible in the long-run than the short-run due to the lag in the adjustment process. The CO₂ emission mitigation scenario analyses also show that switching from fossil fuels to hydro can significantly reduce the level of CO₂ emission in the country. Regardless of whether hydro is assumed to have zero emission or not increasing the price of hydro will lead more CO₂ emission than increasing the prices of both coal and natural gas. More mitigation is possible in the long-run than in the short-run.

There are a couple of important policy implications to be deduced from these outcomes. The evidence of positive elasticity of substitution between hydropower and the non-renewable fuels suggest that it is possible for Malaysia to transit from the environmental

endangering natural gas and coal to the cleaner and more environmentally friendly hydropower in the process generating electricity. This is significant as Malaysia is poised to reduce its emission intensity of GDP relative to the 2005 levels by 45% by 2030. This possibility is underscored by the fact that the current installed capacity of 4,738 megawatt (mw) of hydropower in the country is only about 24% of the 20,000 mw of the technically feasible and exploitable hydropower potential. Thus, there is an opportunity for the country to increase the share of renewable in electricity generation by optimizing the use of hydropower with most of the developments such as the ongoing construction of the Baleh hydropower project which has installed capacity of 1,285mw expected to materialize on Borneo island in Sarawak due to its high rainfall endowment and favorable geography (Sarawak Energy, 2019). It is projected that Sarawak's electricity generation from hydropower will increase from 35% in 2012 to 60% in 2020 (International Hydropower Association, 2017).

The CO₂ mitigation scenarios show that trading off fossil fuels such as natural gas and coal for hydropower in the process of electricity generation can help the country in meeting up with the carbon emission reduction goals. Furthermore, the transition from fossil fuels to hydropower in electricity generation implies that adequate electricity need of the country can be supplied without negative repercussions on the environment. Invariably, the sustainability agenda of the country can be maintained as environmental sustainability is key to the attainment of the sustainable development agenda. Also, important within the context of sustainable development is resource sustainability. Hydropower is a renewable energy while the fossil fuels of natural gas and coal are non-renewable. Switching from the non-renewable fuels to renewable hydropower will ensure that the country's use of energy resource to generate electricity is sustainable over time.

In order to fully maximize the potential of hydropower in the country and meet the country's carbon emission reduction target in the country, government and relevant policy makers should make efforts to increase the share of hydro energy in the electricity generation fuel mix. To achieve this government should provide incentives in the form of subsidy to the producers of hydroelectricity to make pricing and operations competitive. Apart from the provision of subsidy, carbon tax should also be imposed to discourage the use of carbon emitting fuels to generate electricity as this will complement the effect of the subsidy on hydropower to ensure maximum positive impacts on not only on the environment but also on the economy.

On carbon tax, the country's endowment in fossil fuels has served as a platform for a viable tax source to pay for investments; affordable energy that has benefitted consumers; and an important manufacturing and service sector led by PETRONAS and other Oil & Gas extracting companies (De Oliveira, 2018). Significant efforts have also been made on energy subsidies. For instance, between 1997 and 2010, a total sum of RM86.6 billion in subsidies payment was made by Petronas to the power sector which is equivalent of an excess of RM12,000 per household of an average of four persons assuming a population size of 28 million during that period thereby resulting to the country having one of the lowest electricity rates within the Asian region (Sustainable Energy Development (SEDA), 2019). However, significant proportion of the subsidies should be directed to renewable energies like hydropower to maximize the benefit not only on the economy but also on the environment.

As already noted, large scale hydropower facilities are sometimes capital intensive in nature that needs time to build which explain the lag in the adjustment process to the long run equilibrium. In this situation, Malaysia should make attempts to accelerate the development of mini hydro projects to complement the large scale and compensate for

the time lag that characterizes the large-scale hydro facilities. This can take the form of organizing training programs for the installation, operation, and maintenance of mini hydro facilities that will involve the combined efforts of both the government and non-governmental organizations.

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