The power generation sector's demand for fossil fuels: a quantitative assessment on the viability of carbon fees for the reduction of greenhouse gas emissions

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Abstract: The demand for fossil fuels by Ontario's conventional steam power generation sector is examined in this paper. It is hypothesised that the enactment of a carbon fee policy will induce a change in the relative prices of the three fuels used in this sector (coal, natural gas and heavy fuel oil). This would lead to substantial interfuel substitution and greenhouse gas abatement. The demand share equations for the three fuels are derived from the translog functional form and set in a simulation model to estimate the value of a carbon fee necessary, to reduce carbon dioxide emissions in compliance with the Kyoto Protocol. Results suggest that a fuel specific carbon fee policy would be successful in achieving the desired emissions reduction at a negligible net cost to society.

Keywords: Greenhouse gas abatement; climate change; Kyoto; fuel-switching; interfuel substitution; translog; natural gas; fossil fuel demand; carbon tax; carbon fee; price elasticity; marginal abatement cost.

Reference to this paper should be made as follows: Seres, S. and Thomassin, P.J. (2002) 'The power generation sector's demand for fossil fuels: a quantitative assessment on the viability of carbon fees for the reduction of greenhouse gas emissions', *Int. J. Environment and Sustainable Development*, Vol. 1, No. 3, pp.283-302.

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1 Introduction

1.1 Canada and the Kyoto Protocol

The 1992 United Nations Framework Convention on Climate Change (UNFCCC), requires Annex I Parties (developed countries and countries whose economies are undergoing transition to a market economy) to take actions aimed at returning net emissions of CO_2 and other greenhouse gases to 1990 levels by the year 2000. It is now evident that none of these countries took any steps to meet that target. The Third Conference of the Parties to the FCCC in Kyoto, Japan, in December 1997 established binding emission reduction targets beyond the year 2000 for Annex I Parties. By the end of 2012 and for developed countries overall, annual greenhouse gas emissions for the previous five years must be 5.2% lower than 1990 levels.

Canada's target is a 6% reduction in aggregate emissions below 1990 levels. This is a formidable task considering that in 1995, CO2 emissions from fossil fuel use were already 9% higher than those of the base year 1990 and continue to increase at an average annual rate of 1.5%. As a result, the problem of abatement is compounded with each passing year. Although CO_2 is but one of the greenhouse gases covered by the Kyoto Protocol, it is by far the most abundant.

The problem of CO_2 emissions from the combustion of fossil fuels is, in essence, an energy problem. As is the case with any country, Canada needs energy to sustain economic activity. When this energy is derived from fossil fuels, CO_2 is released and left to accumulate in the atmosphere. The problem is intensified over time as economies grow, putting greater pressures on energy demand [1]. This link between emissions and economic growth is the main source of today's reluctance for the adoption of a CO_2 abatement policy.

However, the Kyoto Protocol does not set out to eliminate emissions, but merely to curb them. Hence, if a policy were designed to persuade fossil fuel consumers to use less carbon intense fuels, CO_2 abatement could be achieved without having to sacrifice energy or economic prosperity. This is the case for carbon taxes or tradable emission permits, so it stands to reason that the policy momentum is swinging in their favour. They would both be effective in achieving emission reduction goals, but at a fraction of the cost of traditional policy measures of command and control [2–4]. The reason for their recent popularity is that they make use of market mechanisms to efficiently reduce pollution.

The effectiveness of establishing either a carbon tax or an emissions market will be examined in this paper. For this purpose, either economic tool, whether it is a $50 per tonne tax or a permit of the same value, are assumed to reach the same goal. The focus is not on determining which is more appropriate for Canada, but on the result. For this reason both policies are lumped together and are termed a 'carbon fee'.

Carbon fees accomplish their task by effectively raising the price of fossil fuels, which would presumably lower the quantity demanded and in turn, lower CO_2 emissions. Perhaps more importantly though, a carbon fee changes the price relative to substitute fuels in accordance to each fuel's carbon content. And so, if natural gas releases less CO_2 than oil or coal for the same amount of energy generated, then the price of natural gas would rise less than that of its substitutes. It would be fair to deduce that high-energy consumers of fossil fuels would begin switching from oil and coal to the less carbon intense, relatively cheaper natural gas. This would go a long way to curtailing emissions in Canada.

In the light of Canada's interest in cutting CO_2 emissions and the expected outcome of a carbon fee policy, it becomes pertinent to ascertain just how much of a carbon fee would be needed to accomplish Kyoto's abatement goal. The solution comes from knowing the shape of the demand curves for the different fossil fuels of varying carbon intensity. Estimating demand for individual fuels would put us in a position to quantify the responsiveness to relative price changes. A lump-sum carbon fee would induce a measurable, disproportionate increase in prices for which the ensuing changes in quantity demanded for each fuel could then be ascertained. Since CO_2 emissions are directly related to the amounts and types of fuels burned, the demand model is easily extended to forecast abatement. An econometric model based on the translog cost function will thus be constructed to:

1 estimate demand for individual fuels

2 determine the degree of substitutability between them in response to relative price changes

3 quantify the carbon fee that will be needed to induce the desired abatement.

1.2 Policy context

In order to accomplish this task, there are a few issues that need to be addressed. So far, there has been no decision made in Canada on how to implement a carbon fee policy. Whether the 6% target would be applied evenly across all sectors or whether some of the higher emitting sectors would be singled out to shoulder the burden is unknown. In any case, the assumption made here is the former.

Furthermore, the industrial structure and the relative importance of energy differ significantly between sectors. It thus becomes problematic to estimate the value of a unilateral carbon fee imposed on all sectors. The scope of the present analysis will hence be limited to power generation, the single largest industrial emitter of CO_2. However, Canada's provinces and territories have vast differences in the technology employed to generate electricity. Quebec, for instance, relies almost entirely on hydro while Ontario employs nuclear, hydro and conventional steam technologies in concert. This heterogeneity is consistent throughout the provinces and so it would be unrealistic to assume that the electric power industry's demand for fuel would be the same across Canada. This necessitates a province specific focus and Ontario was chosen for its sheer CO_2 reduction potential. Seemingly, if Canada is to reduce its emissions, it might best be served by independent, provincial carbon fee policies. This will require the collaboration of both federal and provincial authorities.

1.3 Questions to be addressed

For the most part, the Annex I Parties to the UNFCCC recognise the repercussions of greenhouse gases on our climate. Yet, despite their acquiescence, emissions continue to rise. There are several reasons that might explain their reluctance. Firstly, because CO_2 emissions are so directly related to the Gross Domestic Product, it is often believed that in order to decrease emissions, output would have to decrease as well. Secondly, with technology such as fuel cells and photovoltaics, all sectors of the economy can feasibly replace fossil fuels with a more environmentally benign energy, but at a high cost. Third, when the benefits to avoiding anthropogenic CO_2 induced climate change only occur in the distant future while the costs would have to be incurred today, it is often deemed 'uneconomical' to take any action to curb emissions at even a slight positive discount rate. Research undertaken for this paper however, will attempt to demonstrate that substantial abatement can be achieved without a drastic drop in output, or by incurring an exorbitant cost.

There are several different types of fossil fuels being used today for electricity generation. Some emit more CO_2 than others. If the power generation sector can be encouraged to use those with lower emissions, this would go a long way to attaining the Kyoto target. Furthermore, this abatement method would presumably be affordable since conventional steam facilities can be made to accommodate different types of energy inputs. This premise thus raises the following question: How much of a carbon fee would be needed to induce Ontario's conventional steam facilities to switch to cleaner energy and hence lower CO_2 emissions sufficiently to comply with the Kyoto Protocol?

Given that the intensity of CO_2 emissions remains constant with the type of fuel burned, having a measure for the substitutability of energy inputs also provides us with a measure for the substitutability of emissions. In other words, the demand equations drawn from the translog procedure can provide a means to estimate the carbon fee needed to alter the relative price of fossil fuels enough to entice the use of cleaner energy and attain the Kyoto target. In the end, the price of fossil fuels will increase disproportionately and the magnitude of the increase will dictate how costly a carbon fee policy will be. This gives rise to the second question to be addressed: What would be the cost of using a carbon fee policy as a means to satisfy the Ontario power generation sector's Kyoto commitments?

2 The translog function

Prior to the 1970s, empirical studies on the structure of production were confined to analysing the trade-off between two inputs, labour and capital. The functional form used in these studies assumed constant elasticity of substitution (CES) which proved to be excessively restrictive to extend to accommodate more than two factors of production. It wasn't until the breakthrough work of Christensen, Jorgenson and Lau [5], who presented a fundamental deduction of the generalised translog functional form, that there was an allowance for the non-restrictive estimation of substitution possibilities with several factors of production. Their novel approach inspired numerous studies on production incorporating labour and capital inputs, several differing energy inputs and raw materials [6–10].

Earlier uses of the translog functional form have been to examine the relationship between pairs of factor inputs in the production process. Where most were concerned with determining the complementarity or substitutability of energy and capital and energy and labour, the emphasis here is on the substitutability of the three main energy types (Coal, oil and natural gas). It is the position of this paper that interfuel substitution can and will occur in response to relative energy price changes without a discernible effect to capital and labour and so their role will not be considered. It stands to reason that in an inconstant fossil fuel market, industrial consumers can make adjustments in their energy mix without a significant impediment to production [11,9,12]. It is hoped that their interactions will provide invaluable information on the substitutability of CO_2 intense fuels for those that are more environmentally benign. Furthermore, since interfuel substitution is assumed to occur independent of labour and capital and prices are assumed to be exogenous, the translog functional form allows for non-homotheticity and variable returns to scale [13,9] and is written as:

$$S_i = a_i + \sum_j b_{ij} \ln P_j + b_{iQ} \ln Q \tag{1}$$

where

S_i	*Budget share of fuel i*
i, j	*Coal, oil and gas*
P_j	*Price of fuel j, i ≠ j*
Q	*Output*
a_i	*Constant term*
$b_{i,Q}$	*Parameters to be estimated measuring sensitivity*

and $S_i = \partial \ln C / \partial \ln P_i$, represents the change in the cost of energy with respect to the change in the price of fuel *i*. Equation (1) is the standard framework to analyse energy demand, but to fashion the model for the particulars of this study and improve the overall efficiency of the coefficients, additional explanatory variables will be added as follows:

$$S_i = a_i + \sum_j b_{ij} \ln P_j + b_{iQ} \ln Q + d_i S_{it} + \sum_k g_{ik} \ln Z_k \tag{2}$$

where

S_{it}	*Budget share of fuel i in time period t*
Z_k	*A set of exogenous variables of interest*
d_i, g_{ik}	*Parameters to be estimated*

Of the system of *n* equations above, only *n* – 1 of the share equations are estimated since the demand shares must respect the adding-up criterion (*∑Si=1*). It should be noted however, that the cost function, from which these share equations are derived, must be linear homogeneous and its underlying production function must be well behaved. Given these conditions, the following parameter restrictions become necessary:

$$\sum_i a_i = 1,$$
$$\sum_i b_{ij} = \sum_j b_{ij} = 0,$$
$$\sum_i b_{iQ} = 0,$$
$$b_{ij} = b_{ji}, \forall i \neq j$$

A set carbon fee will provoke a one time disproportionate increase in the price of fossil fuels. On the whole, profit-maximising producers will react by substituting their higher emission fuels for an energy source that is cleaner and relatively cheaper. With data on Ontario's power generation industry, the above translog procedure will attempt to model this substitution by predicting where the quantity demanded for individual fuels will settle in response to a one time carbon fee induced price increase. In the end, it becomes a simple matter to make a quantitative assessment of the ensuing drop in CO_2 emissions.

3 The structure

3.1 Overview of Ontario's power generating sector

Ontario's conventional steam power generation sector was chosen as the subject of this study for its dynamic involvement of all three types of fuels and for its sheer CO_2 abatement potential. As is the case with other provinces and even other countries, coal will account for the bulk of the fuel utilised in Ontario's mixed fuel portfolio. Considering that the CO_2 emission factors from burning coal are at the upper end of the scale at 88 tonnes of CO_2 per terajoule (t/Tj) of energy generated and emission factors from natural gas stand at 49 t/Tj [14,15], it isn't hard to imagine the environmental benefits of substituting away from coal. It stands to reason that altering the fuel in conventional steam burners will go a long way to cutting emissions and at a palatable cost to society.

Up until April 1999, Ontario Hydro was the crown-corporation governing power generation in Ontario. In the process of deregulation, this responsibility has since shifted to a separate provincially owned company named Ontario Power Generation. Despite the name change, this new corporate identity maintains the same diversity of technologies to meet the province's electricity demand, comprised of steam nuclear, hydro and fossil fuel powered conventional steam. Two thirds of the province's energy needs will be met with their baseline hydrologic and nuclear capacity while the remaining third belongs to conventional steam, which was responsible for more than 26 million tonnes of CO_2 emissions in 1990.

Conventional steam power generation is the process of burning, either coal, natural gas or HFO to turn liquid water into vapour to drive a generator and produce electricity. Historically, Ontario hydro has made considerable use of all three fuels. Due to the volatile nature of fuel prices however, electricity generating costs will operate under the Merit Order Dispatch system (MOD) where Ontario Hydro and now, Ontario Power Generation, rank each fuel's operating cost and make a choice of what fuel to utilise given prevailing market conditions [16]. So, for instance, if the relative price of HFO is low for a given period of time, Ontario Power generation will rank the HFO burning facilities above others. This is analogous of a cost minimising process where fuels can be substituted for one-another in response to relative price changes.

However, because conventional steam burners cannot accommodate perfect substitution of fossil fuels, the power generation sector, guided by the MOD system, is not poised to make immediate fuel mix adjustments in response to the day to day spot price. Instead, this industry will make its decisions based on the trend of relative fuel prices. This is suggestive of a longer-term relationship between prices and the expenditure share of individual fuels. A matter that further lends itself to this premise is the nature of natural gas based electricity. It is wholly generated by independent producers and purchased on a contractual basis. Ontario Power Generation is hence committed to acquire a predetermined amount of natural gas based electricity for an inflexible period of time.

Given the industrial structure described above, the power generation sector's fuel switching, cost minimising behaviour, which is hoped to be captured in this study's translog procedure, is best suited for long-run analysis. This is consistent with prior studies of this nature [12,8,10].

3.2 Methodology

The translog specification involves a system of equations that are simultaneous in nature. Simultaneity results in a cross-equation correlation of the disturbance terms and hence independent OLS estimation of single equations yields biased and inconsistent parameter estimators. It becomes necessary then, to rely on a more sophisticated estimation method, which can account for the close conceptual relationship between parameters across equations. The Seemingly Unrelated Regression (SUR) model has become common practice when estimating a system of related equations. The SUR method involves generalised least square estimation and improves the overall efficiency of the model by accounting for the cross-equation correlation of the error terms and for the situation where some of the explanatory variables across equations are identical, as is the case in the present analysis.

In effect, the SUR procedure uses single equation OLS to derive an estimate of the error covariance matrix and once obtained, performs generalised least square estimation. During this process, estimates of the error covariance matrix can be updated and the Zellner procedure iterated until sequential changes in both the covariance matrix and the estimated parameters between iterations become negligible. This is termed the iterative Zellner-efficient estimator (IZEF) and is the choice methodology in the present context, to ensure that the parameter estimates are invariant to the exclusion of one of the equations under the conditions of the adding-up criterion ($\sum Si = 1$). When the error term is normally distributed, the IZEF procedure is equivalent to maximum likelihood estimates in multivariate regression models [17].

3.3 The variables

The data consists of a time series of quarterly observations on Ontario's electric power industry spanning the years 1981 to 1999. In the years prior to 1981, the techniques used to compile the statistics were different [18] and therefore, less compatible with the present statistics so their inclusion here might unnecessarily introduce a bias to the estimation procedure.

The translog model of energy demand describes the breakdown of electric utility production costs into expenditures on individual fuels and, from before, takes on the following form:

$$S_i = a_i + \sum_j b_{ij} \ln P_j + b_{iQ} \ln Q + d_i S_{it} + \sum_k g_{ik} \ln Z_k \qquad \text{for i, j = coal, nat. gas and HFO}$$

Where S_i is the expenditure share of fuel i, P_j are the prices of each fuel, Q the output, S_{it} lagged dependent and Z_k a set of exogenous variables of interest. These variables will be represented in this study as follows:

Scoal = expenditure share of coal

Sgas = expenditure share of natural gas

Shfo = expenditure share of HFO

All shares are expressed as a percentage of the total fuel cost that was faced by Ontario hydro's conventional steam capacity and must hence add to unity.

lnPcoal3 = price of coal

lnPgas3 = price of natural gas

lnPhfo3 = price of HFO

Prices are natural logarithm transformations of the original prices expressed in dollars per terajoule (Tj). They are lagged by three years to account for the long term input adjustments in response to relative price changes.

lnQ = output produced by conventional steam facilities

Scoal3 = equation 1's dependent variable lagged by three years

Sgas3 = equation 2's dependent variable lagged by three years

The lagged dependent variables were included to account for the momentum in demand for a particular fuel and for potential serial correlation in the error. Their inclusion basically states that part of today's expenditure share level is related to the last period's level and ideally, should only be lagged by one quarter [19,20]. Unfortunately, since one of this study's main purposes is to set up a simulation model, the lag had to be consistent with the price lags. Otherwise, the predictions would be limited to quarter by quarter estimates and hence during simulation, the error would be compounded with each additional projection and so longer term forecasts would essentially yield meaningless results. This approach increases the ease and reliability in the forecasting procedure which more than offsets the possible loss of efficiency associated with a longer lagged dependent.

Finally, the notation for the variables which comprise Z_k are:

lnH = output produced by hydro facilities

lnN = output produced by nuclear facilities

d1 to d4 = dummy variables for quarters 1 to 4 respectively

All output data are in logarithmic form for Ontario's electric power industry and are expressed in terajoules.

All data were obtained from various energy Statistics Canada publications and through CANSIM, their online time series service [21–23]. The data sources collected for Ontario's electric power sector are described in detail in Seres [20].

4 Empirical results

In the previous sections, it was hypothesised that conventional steam electric utilities remain responsive to relative fuel price changes and will substitute one fuel input for another in order to minimise production costs. The translog model, which attempts to capture this behaviour, was estimated with restrictions imposed and the results are summarised below.

As explained earlier, the adding-up criteria (∑Si=1) forces the exclusion of one of the equations from the three equation system and so the expenditure shares for coal and natural gas were arbitrarily chosen to produce the estimated coefficients. Judging from the summary statistics in Table 1, the model seems to perform quite well. The expenditure share equations for coal and natural gas yielded the respective R^2 of .86 and .91, which would confirm a good fit for the variables chosen and lend credence to the model's forecasting ability. Also, the Breusch-Pagan test of independence confirms the simultaneous nature of the expenditure share equations and substantiates the appropriateness of the IZEF methodology [24].

Table 1

	Const.	*d2*	*d3*	*d4*	*InPcoal3*	*InPgas3*
Scoal	-1.0647	0.0041	0.0345	-0.0133	-0.4637	0.3452
	(-0.949)	(0.244)	(1.672)	(-0.906)	(-9.702)	(-8.153)
Sgas	1.4763	-0.0553	-0.0741	-0.0176	0.3452	-0.3261
	(1.668)	(-4.088)	(-4.566)	(-1.511)	(8.153)	(-6.762)
	InPhfo3	*InC*	*InH*	*InN*	*Si3*	R^2
Scoal	0.1185	0.0595	0.1585	-0.0652	0.3743	0.86
	(4.318)	(3.043)	(2.179)	(-2.023)	(5.482)	
Sgas	-0.0192	-0.1318	-0.0600	0.0506	0.5851	0.91
	(-0.836)	(-8.45)	(-1.039)	(2.014)	(10.455)	

Note: Breusch-Pagan test of independence: chi2(1) = 12.761, Pr = 0.0004

On the whole, the model yielded results for the coefficients in both share equations that were consistent with expectations [25]. First and foremost, all but one of the coefficients for the lagged price variables ($\ln p_i 3$) coincided with the anticipated interfuel substitution behaviour. This is readily apparent by their signs, magnitudes and t statistics. However, the coefficient for the price of HFO variable proved insignificant in the natural gas share equation. Moreover, its negative sign is suggestive of a slight complementarity between HFO and natural gas rather than substitutability. At peak load capacity, when the demand for electricity is highest, Ontario Power Generation will meet this short-term demand with its HFO and natural gas facilities [16]. Under these circumstances, the importance of minimising fuel is outweighed by the immediate necessity to extend the power generation capacity. The expenditure shares for both fuels will hence climb together, giving the appearance of complementarity. In any case, there would seem to be two forces influencing the relationship of HFO and natural gas. In normal times, they will act as substitutable inputs, but during peak loads, their apparent complementarity prevails. These two forces will serve to increase the standard error for the price of HFO coefficient in the natural gas share equation, which would explain its non-significant t statistic.

Secondly, the coefficients for the production of conventional steam electricity (lnQ) are significant in both equations. Fuss [9] showed that if $b_{iQ} = 0$ the underlying production structure is homothetic. The significant coefficients then, despite their opposing signs, would confirm non-homotheticity in Ontario's conventional steam sector.

The opposing signs merely suggest that when output from conventional steam facilities increases, coal fired plants are responsible for the increase, which inevitably causes the share of natural gas to fall.

Third, the lagged dependent variables are significant and positive in both share equations. A direct interpretation of these coefficients would state that part of today's demand share of each fuel can be explained by past demand. Although this is undoubtedly true, causality between periods should not be inferred. Rather, the inflexibility of the power generation sector's infrastructure will restrict the demand for each fuel in both periods. Ontario Power Generation will have some latitude on what types of fuels to use to generate power, but coal burners, which very often cannot accommodate any other type of fuel, remain prevalent. Short of additional investments, this establishes a floor for coal's expenditure share and a ceiling for the shares of other fuels. Fuel purchase commitments will in turn be affected by this rigidity, which accounts for the significance of the lagged dependent variables.

Fourth, even though the remaining variables have no direct bearing on the objective of this study and serve mainly to enhance the quality of the model, a brief mention of their interpretation might be of interest. The quarterly dummies are indicative of a fair degree of seasonal variation with natural gas and only slight variation with coal. This stands to reason since coal seems to be more of a staple fuel input than natural gas or HFO. The coefficient for nuclear energy in the coal share equation is negative which suggests that there is a trade-off between nuclear energy and coal based energy. Perhaps this is due to a cost minimisation process or because the recent loss of output from the shutdown of some of Ontario's reactors is being offset by an increase in coal fired generation. In any event, for the same reasons as before, this negative relationship in the coal share equation should induce a positive relationship between the same variables in the gas share equation, which is indubitably the case.

On a final note, even though it is evident in Table 1 that some of the coefficients are clearly insignificant, none of them will be discarded from the model in order to prevent undue bias on the remaining coefficients. All variables then, will be employed in the simulation procedure and the results thereof can be seen in the following section.

5 Simulation

5.1 The model

The objective of this research is to form reasonable estimates of the demand for the three fuel inputs in the conventional steam sector. In so doing, the response to carbon fee induced price changes can be gauged to make some well educated predictions for short-run CO_2 abatement.

In the previous section, Table 1 enumerated the coefficients obtained by the regression procedure. They can now be fitted into a set of expenditure share equations to forecast the changes in demand in response to an increase in fuel input prices (see Table 2). Remember that HFO's share equation was not directly estimated in order to preserve the adding-up criterion ($\sum Si= 1$). Its coefficients, however can be derived from the restrictions given in Section 1. For the purposes of simulation though, the parameters for HFO's share equation serve no function and are hence omitted from the Table.

Table 2 Expenditure share equations

Equation	*Coefficients:* *Constant*	*InPcoal3*	*InPgas3*	*InPhfo3*	*InQ*
Scoal	-1.1429	-0.4637	0.3452	0.1185	0.0595
Sgas	1.5516	0.3452	0.3261	-0.0192	-0.1318
Latest observation		7.8284	7.7983	8.6298	10.5884

Equation	*Coefficients:* *InH*	*InN*	*Scoal3*	*Sgas3*	*Predicted* $\sum Si = 1$	*Actual* *Shares 1999*
Scoal	0.1585	-0.0652	0.3743		76%	76%
Sgas	-0.0600	0.0506		0.5851	19%	18%
Shfo					5%	6%
					100%	100%
Latest observation	10.2039	11.0205	0.7708	0.1576		

Before assessing the effects of imposing a carbon fee on Ontario's conventional steam sector, it might be useful to first predict where the demand for fuel will stabilise, given today's market conditions. The latest observations in the data set will hence serve as the parameters to complete the model. Because the industry's structure imposes a 3 year time lag to fully adjust to fuel prices, 1999's observations will yield predictions for 2002's expenditure shares for coal and natural gas, while HFO's share is educed from the difference between 100% and the shares of the other two. However, in order for the share predictions to be meaningful, the proportion of conventional steam, hydro and nuclear power, are assumed to be fixed. In other words, the lnQ, lnH and lnN variables will remain constant throughout the forecasting period. Given the relative inflexibility of the power generating infrastructure and Ontario hydro's past behaviour, this would not seem to be an unrealistic assumption.

The model predicts shares for coal, natural gas and HFO of 76%, 19% and 5% respectively. Considering that 1999's actual shares were almost identical to these, there will be little interfuel substitution at prevailing market conditions.

5.2 The carbon fee

As stipulated earlier, carbon fees disproportionately raise the prices of various fossil fuels provoking their consumers to both, lower the quantity demanded of all fuels and switch to those with lower CO_2 emissions. To understand how carbon fees will affect the prices of fuel, the concept of CO_2 emission factors must first be introduced. Since carbon dioxide emissions are relatively constant to the type of fuel burned, emission factors measure the quantity of CO_2 produced per unit of energy generated. Smith [15] estimated the CO_2 emission factors for the various fuels used in industrial processes in Canada and the ones relevant here, can be seen in Table 3 [26]. So, for instance, if a consumer of coal now faces a \$10 /tonne carbon fee, the price of coal will increase by \$882 /Tj, assuming the consumers bear the total brunt of the price increase [27]. Similarly, the price of natural gas and HFO would increase as well, but in accordance with their respective emission factors.

Table 3 Effects of carbon fee on CO_2 emissions

Carbon fee: $10.00 \$/t. of CO_2

	CO_2 emission		Prices		*Predictions 2002*						
					Shares (with carbon fee)		*Output in Terajoules*			*CO_2 emissions in tonnes*	
	Factors t./Tj	*PΔ \$/Tj*	*\$/Tj*	*PΔ %*	*ΣSi = 1*	*Dollars*	*No C. fee*	*With C. fee*	*QtyΔ Tj*	*No C. fee*	*With C. fee*
Coal	88.2	\$882.00	\$3,392.98	35.13%	70%	901,637,860	296,503	265,737	-10%	26,151,550	23,437,963
Nat. gas	49.68	\$496.80	\$2,933.19	20.39%	23%	296,134,816	75,772	100,960	33%	3,764,334	5,015,691
HFO	74	\$740.00	\$6,336.04	13.22%	7%	95,275,720	9,459	15,037	59%	699,979	1,112,746
				λ =	0.43651	1,293,048,396	381,734	381,734	0%	30,615,863	29,566,401

Gross cost increase: \$310,993,611

Cost increase net of revenue: \$15,329,603.03

Percent change in CO_2 from current levels: -3%

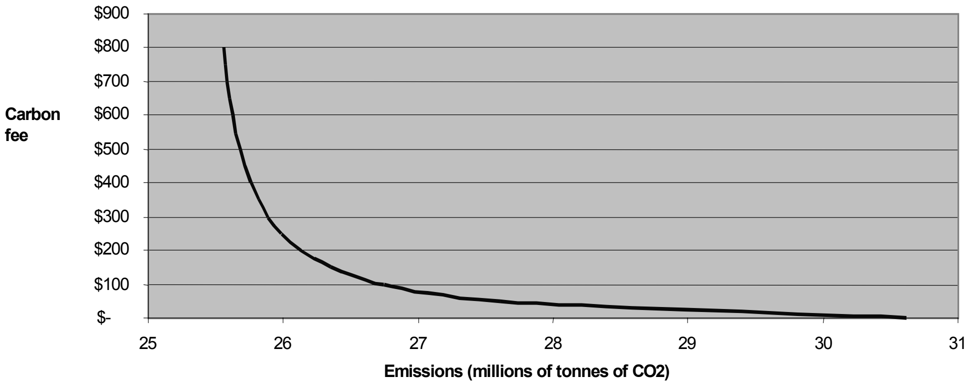
In keeping with the example, the effects of the price increase can be traced through with the expenditure share equations. By inputting the new prices into the model, the share of coal would drop down to 70%, while the shares of natural gas and HFO would increase to 23% and 7% respectively. If the total energy generated by the conventional steam sector is held constant, the fuel price increase would automatically drive up the industry's input costs. The total fuel costs in 1998 were just over 982 million dollars. With a $10/tonne carbon fee, total expenditures would have to rise to over 1.293 billion dollars, a 32% increase (see Seres [20] for details of the calculation).

In all likelihood however, total output by conventional steam facilities would decrease as the relative cost of alternative energy sources goes down. But for the purpose of illustrating the interfuel substitution effect, total output is held constant. Once total expenditures on fuel are known, it becomes a simple matter of breaking it down into dollar value expenditures on each fuel given the predicted percentile shares. From there, dividing through by prices yields the quantity consumed of each fuel in natural units, which translates easily into predicted CO_2 emissions. The demand share equations predict that a one time $10/tonne carbon fee, levied on the consumers of the three fuels in Ontario's conventional steam sector, would abate CO_2 emissions by 3% from the baseline scenario.

There is one final element that should be considered before assessing the true cost of a carbon abatement policy. Carbon fees will generate revenue which will largely offset the higher expenditures associated with a fuel price increase. In the case of a carbon tax, revenues generated are directly proportional to total CO_2 emissions. For an emission permit policy, the initial auction of the pollution certificates would serve to generate revenue as well. Under cost-minimising behaviour, the proceeds from either economic policy should be equivalent [4] and to the benefit of the public sector. Furthermore, from society's perspective, regardless of how the revenue is allocated, for the most part it counterbalances the higher input costs faced by the fuels' consumers. The difference between the two can be viewed as the net cost to society for imposing a set carbon abatement policy. As elicited from Figure 1, a $10/tonne carbon fee would result in a net cost increase of over 15 million dollars.

With the existing framework of the expenditure share model, it might be revealing to forecast emissions at incremental changes of the carbon fee. By then plotting the predicted emissions response to increasing carbon fees, an ad hoc curve could be derived, analogous to the marginal abatement cost curve (MAC). Figure 1 illustrates the negative relationship that exists between carbon fees and CO_2 emissions in Ontario's conventional steam sector. The most prevalent feature of this curve is its curvilinear shape. This is consistent with environmental economic theory whereby abatement incentives are subject to diminishing marginal returns [28]. This product of industrial consumer behaviour suggests that, ceteris paribus, there is a limit to a carbon fee's effectiveness.

Figure 1 The marginal abatement cost curve



5.3 The Kyoto target

The Kyoto Protocol prescribes a 6% overall reduction in greenhouse gases for Canada below 1990 levels. This may be an ambitious target as the conventional steam sector, congruent with other sectors, has steadily increased their emissions over the last decade. As of 1990, total annual CO_2 emissions by Ontario's power generating sector stood at 26,184,945 tonnes. By applying the same convention that Kyoto decrees on Canada to this sector, the emissions goal would be in the order of 24,618,848 tonnes. Considering that in 1999, CO_2 emissions from this sector stood at 30,615,863 tonnes, the Kyoto target would necessitate a 20% reduction in emissions from current levels. It is evident, however, from Figure 1, that a carbon fee alone cannot induce sufficient fuel substitution to achieve the objective, barring any significant capital adjustments. Concessions will need to be made elsewhere.

If Ontario Power Generation is to cut its emissions to a level equivalent to that mandated by the Kyoto Protocol, reducing total output from its conventional steam facilities could be a solution.

However, at the onset of this study, it was hypothesised that significant abatement could be achieved simply by changing the relative prices of fossil fuels and hence altering the fuel mix so that the total energy was maintained but with lower emissions. This would be ideal, as it would satisfy environmental pressures by taking the first steps to thwarting climate change, as well as the economic pressures, by keeping costs low. The expenditure share equation models the demand for the three fossil fuels and simulation indicates that substantial interfuel substitution would occur in response to a carbon fee, but not enough to achieve the set target. It is natural to infer from this that, under these particular circumstances, a typical carbon fee cannot provoke a sufficient change in the relative prices.

Of the three fuels being considered here, natural gas is the 'cleanest' in terms of CO_2 emissions and thus, a relative increase in its utilisation, holds the greatest potential to curtailing emissions in the near future. It follows then, that if a carbon fee policy were to be applied to coal and HFO, while exempting natural gas, the relative prices would change even further, enhancing the interfuel substitution effect. Simulation was hence carried-out under this scenario and the results can be seen in Table 4. As anticipated, the model predicts a much greater contribution of natural gas in the generation of electricity.

Table 4 Effects of a coal and HFO specific carbon fee

Carbon fee: $27.00 $/t. of CO_2

	CO_2 *emission*		*Prices*		*Predictions 2002*						
					Shares (with carbon fee)		*Output in Terajoules*			*CO_2 emissions in tonnes*	
	Factors t./Tj	*PΔ $/Tj*	*$/Tj*	*PΔ %*	*ΣSi = 1*	*Dollars*	*No C. fee*	*With C. fee*	*QtyΔ Tj*	*No C. fee*	*With C. fee*
Coal	88.2	$2,381.40	$4,892.38	94.84%	48%	656,707,883	296,503	134,231	-55%	26,151,550	11,839,161
Nat. gas	49.68	$0.00	$2,436.39	0.00%	41%	558,430,660	75,772	229,204	202%	3,764,334	11,386,858
HFO	74	$1,998.00	$7,594.04	35.70%	10%	138,960,996	9,459	18,299	93%	699,979	1,354,104
				λ =	1.84386	1,354,099,539	381,734	381,734	0%	30,615,863	24,580,123

Gross cost increase: $372,044,754

Cost increase net of revenue: $15,826,596

Kyoto target: 24,613,848

Percent change in CO_2 from current levels: -20%

Revenue (,000s): $356,218

Now, the conventional steam sector's cost minimising behaviour would prescribe a \$27/tonne fuel specific carbon fee in order to attain the Kyoto target. Furthermore, output by this sector would not need to be reduced and the net cost of the policy would be marketable at \$15,826,596. In effect, this policy indirectly subsidises natural gas, but considering the options, it would be the least cost method for this sector to attain its desired short term CO_2 emissions goal.

Before concluding this section, there are a couple of important features of the model that should be addressed. Firstly, in Table 4, the expenditure share equations predict that coal's share would drop to 48%. This would involve the reduction in output from existing coal-fired facilities. Perhaps more importantly though, the model predicts that natural gas's share would rise to 41% and electrical output would triple from current levels. At present, natural gas facilities do not have the capacity to meet this potential demand and so the province would need to invest in new facilities. Presumably though, these facilities would share a similar cost structure with existing natural gas facilities. This study's estimated coefficients would hence remain applicable for rendering predictions in the absence of cost data from 'unbuilt' natural gas electric facilities. Secondly, by construction, the expenditure share equations attempt to make long term predictions for the demand of fuel inputs. The exogenous influences on fuel prices are not taken into account. In other words, the only price changes being considered in the simulation process, are those caused by the adoption of a carbon fee. However, this is less than likely as there are constant supply and demand factors perpetually changing the prices of fuel. Therefore, when interpreting the results, it is important to keep this level of uncertainty in mind. The numerical predictions for carbon fees and total abatement should thus only be taken as illustrative estimates.

On the other hand, relying on historical precedent, the exogenous real fuel price changes of coal and natural gas have not been substantial and would pale in comparison to those induced by a carbon fee. HFO, however, is susceptible to much greater fluctuations, but as is the case with all three fuels, the general tendency is for prices to rise. Unless the market for coal experiences a complete collapse, this would only serve to slightly overshoot the abatement target.

On a final note, it would seem that a fuel specific carbon fee policy imposed on coal and HFO would be the ideal solution for this sector to attain its Kyoto objectives as it could maintain its conventional steam infrastructure. The price of coal faced by energy producers would almost have to double to stimulate substitution to natural gas. The share of HFO wouldn't change very much despite its price increase, which would seem to confirm its independent role as a peak load fuel. It is important to reiterate, though, that the emissions abatement is estimated from a baseline scenario where total energy is assumed to remain fixed at current levels. This, in itself, would require Ontario Power Generation to voluntarily halt the yearly increase in output from the conventional steam sector for the carbon fee to be as effective as predicted.

5.4 Discussion

Climate change is a global phenomenon requiring a global initiative. In the absence of a world governing body with the ability to sanction individual nations, the onus will ultimately lie on the domestic ratification of international agreements such as the Kyoto Protocol. This has profound implications for the role that individual nations must play to limit CO_2 emissions. At present, there is very little incentive for one country to comply with Kyoto when other nations choose to ignore it. But eventually, this apathy will subside and Canada will need to make concrete decisions on how to curtail its emissions.

In the climate change debate, there is one school of thought that firmly believes that CO_2 abatement must stem from the massive introduction of renewable technologies. Hoffert *et al*. [29] clearly illustrate that due to the unrelenting increases in the demand for energy the world over, stabilisation of CO_2 emissions at 1990 levels will require an enormous injection of non-fossil fuel based energy by the mid 21st century. Although these findings are not in dispute here, it is hoped that this research demonstrates that substantial emissions reduction can be achieved for the more pressing near future by simply switching to less carbon intense fuels. This is, admittedly, a smaller step toward a more sustainable economy, but it might nevertheless be an easier step to take and pave the way to the mass adoption of renewable energy.

The most likely economic tool to induce this level of fuel switching is the market based carbon fee. It should not be inferred though, that the response to a $27/tonne fuel specific carbon fee prescribed for Ontario's conventional steam sector can be extended to other sectors on a national scale. Since the fossil fuel power generation facilities predominantly rely on coal as an input fuel, there is more room for abatement by substituting that input for a cleaner burning fuel such as natural gas. This industry then, holds the greatest potential for CO_2 abatement from interfuel substitution, which is reflected in the relatively modest carbon fee needed. At this point, one could speculate that in industries that have a similar dependence on coal, equivalent results could be achieved. However, this is not the case for most of Canada's commercial and industrial emitters of CO_2 who only have a trivial reliance on coal. Refined petroleum, electricity and natural gas make up the bulk of the non-power generation sector's energy input and so it is doubtful that a $27/tonne carbon fee would be met with the same results.

In any case research undertaken here holds promising results for CO_2 abatement from the power generation sector in Ontario as well as other regions and in other nations that utilise coal to produce electricity. It should be mentioned though, that if such a, natural gas friendly, fuel specific carbon fee policy were implemented across Canada and beyond its borders, the assumption made earlier, where the price of natural gas is exogenously determined, would most probably not hold true. Widespread use of such a policy would forcibly increase the demand for natural gas and unless its supply increased proportionally, its price would inevitably rise. This would reduce both interfuel substitution by the utilities and CO_2 abatement unless counter measures were taken to increase the supply and distribution of natural gas and effectively sterilise this supply side effect.

6 Conclusions

Since the signing of the Kyoto Protocol in December 1997, there have been a number of follow-up conferences for the signatory nations to collaborate on operational policies for the abatement of CO_2. The most recent of these was held in Marrakech, where negotiators for Canada and other countries convened to discuss options to achieve Kyoto's objectives. Time, however, is slowly running out. Although Canada recognises the climate altering potential of anthropogenic CO_2, its decision-makers have yet to ratify the protocol or make any serious commitments to cutting emissions. This complacency is shared by several other Parties.

Policy makers are legitimately hesitant for three reasons. Firstly, not all countries face reduction commitments under the Kyoto Protocol. If one country was obligated to reduce emissions significantly whilst its large trading partners have no such obligations, the economic relationship of these countries would change. The country with the commitment would be facing higher costs than its trading partners. In an unrestricted market, this position may alter the competitive structure unfavourably and provoke capital flight. This is certainly the dilemma that Canada faces when its largest trading partner has declined to ratify the Protocol. Secondly, the degree of climate change and the ensuing ecological and economic repercussions that it would entail are uncertain which makes it difficult to justify the sacrifices that would have to be made by enacting an abatement policy. Thirdly, the costs associated with this policy are often estimated to be higher than the benefits of thwarting climate change. Consequently, several nations have expressed their reluctance to ratify and the fate of Kyoto is left in limbo.

It was hoped to be demonstrated here that the cost of emissions reduction need not be that high. It has been hypothesised that if consumers of fossil fuels can be induced to substitute coal and oil for cleaner fuels such as natural gas, then substantial abatement can be achieved without incurring too high a cost. The policy instrument best suited for this task is the carbon fee, which makes use of market mechanisms to attain the least cost method of CO_2 emissions reduction. Its effectiveness would be maximised in Canada's conventional steam power generation sector where coal remains the dominant fuel input, leaving plenty of room for interfuel substitution. For the scope of this paper, the heterogeneous energy infrastructure in Canada required a province specific focus and Ontario was chosen as the subject for this study. However, the modelling framework proposed here can easily be extended to accommodate other sectors in other regions.

To analyse the effects of a carbon fee, details of fossil fuel demand had to be ascertained. The translog cost function is a well established methodology for modelling producer's cost minimising, input substitution behaviour with more than two factors of production. It thus lends itself ideally to this study's three-fuel input model. This functional form was chosen because of its firm theoretical basis that assures a well-behaved production function and for the ease with which measurement of input substitution can be derived. The translog modelling procedure produces a system of expenditure share equations which sets up the framework to simultaneously test the fuel demand response to relative price changes and make quantitative predictions on CO_2 abatement.

The simulations undertaken indicated that the effect of typical application of a carbon fee was diminishing marginal returns, which would ultimately prevent Ontario's power generating sector from achieving its allotted emissions target. An alternative scenario was then presented where additional concessions were made to enable this sector to attain a CO_2 abatement level in line with Kyoto's objectives. By imposing a fuel specific carbon fee of \$27/tonne, but exempting natural gas, the change in the relative prices would be sufficient to induce the desired interfuel substitution effect and attain the 20% emissions reduction necessary, without having to restrict output. This policy comes at a palatable net cost of under 16 million dollars.

Further research is needed in other high emissions sectors that have access to a broader range of energy inputs. Although these sectors do not rely on coal as a staple fuel such as in the power generation sector and so only limited inter-fossil fuel substitution would be expected, they do, however, have the option to consume electricity and potentially eliminate their direct CO_2 emissions. In consequence, it would be fair to assume that the substitution effect would differ among these sectors and almost certainly from the one observed in this study. By estimating each sector's response to a carbon fee and its associated costs, decision makers would thus be better equipped to design a policy that would account for this intersectoral heterogeneity.

In addition, there is a need to research the distributional impacts that the unilateral imposition of a carbon fee would entail. For instance, as already noted in Canada's power generation sector, provinces have vast differences in their reliance on fossil fuels to produce electricity. A carbon fee will raise the cost of production disproportionately and those provinces that have a greater dependence on fossil fuels would be subject to higher costs. This in turn may affect one province's competitiveness relative to another and may lead to a redistribution of income. At present however, there is no telling how significant this effect might be and it is only with further study that this issue and others, can be addressed to alleviate some of the uncertainties faced by policy makers today.

Next to transportation, the power generation sector is the single largest emitter of CO_2 in Canada. Ideally, its fossil fuel fired facilities should be entirely replaced with more renewable sources of energy. Given Canada's abundance of resources relative to its population, this might be a feasible option in the long term, but not likely in the near future. Much like other industrialised nations then, Canada is forced to contend with its present infrastructure to eliminate a growing portion of its CO_2 emissions. The purpose of the present study was to demonstrate that this can be accomplished without having to sacrifice energy consumption. The scope, however, was limited to Ontario, but the framework could easily be extended to accommodate a region by region analysis and paint a more comprehensive global picture. If similar low cost results can be foreseen internationally, it might set the ball in motion for planned emissions abatement and lift the air of complacency that is pervading several policy makers today.

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26 See [20] and [15] for details on the emission factor estimates for coal.

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