Economics of Greenhouse Gas Limitations

HANDBOOK REPORTS

The indirect costs and benefits of greenhouse gas limitations: Mauritius Case Study

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List of Acronyms

BOS	"Balance of System" (costs)
CEB	Central Electricity Board (of Mauritius)
CH_4	Methane
CO_2	Carbon dioxide
CO	Carbon monoxide
FICOSTEF	Financial cost-effectiveness of a GHG limitation project
FUCOSTEF	(Full) economic cost-effectiveness of a GHG limitation project
GDP	Gross domestic product
GHG	Greenhouse gases
GJ	Gigajoule
GWh	Gigawatt hour
GWP	Global warming potential
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent power producers
kWh	Kilowatt hour
LPG	Liquefied petroleum gas
MW	Megawatt
NMVOC	(Non-methane) volatile organic compounds
NO_x	Nitrogen oxides
N_2O	Nitrous oxide
O_3	Ozone
OEM	Original equipment manufacture
PM	Particulates (dust)
PPP	Purchasing power parity
PV	Photovoltaic
Rs	Mauritian rupee
SO_2	Sulphur dioxide
TOE	Tonne of oil equivalent
UHR	Unemployment hardship relief
VOSL	Value of a statistical life
W_p	Watt peak (performance)

Conversion Factors

The following prefixes are used from multiples of joules, watts and watt hours:

kilo (k)	10^3
mega (M)	10^6
giga (G)	10^9
tera (T)	10^{12}

The following table gives the factors used to convert between alternative units of energy:

to: / *from:*	k TOE	TJ	GWh	M therms
	multiply by:			
k TOE	1	41.87	11.63	0.3968
TJ	0.02388	1	0.2778	0.009478
GWh	0.08598	3.6	1	0.03412
M therms	2.52	105.5	29.31	1

The following factors were used to convert between alternative units of volume:

1 litre	= 0.22 imperial gallon (UK gal)
1 UK gal	= 1.201 US gallons (US gal)
1 barrel	= 159.0 litres

The following conversion factors for petroleum products were used:

1 tonne Derv fuel	= 1,182 litres
1 tonne leaded gasoline	= 1,361 litres
1 tonne unleaded gasoline	= 1,351 litres

1 Introduction

1.1 Background to the Case Study

There has been a considerable amount of work carried out on the appraisal of different projects and programmes that reduce greenhouse gases (GHGs)[1]. These studies have focused on the development of appropriate methodologies for estimating of the costs of GHG limitation, and measuring the amount of GHGs abated. These are two of the central issues that need to be considered prior to finalising a policy for GHG mitigation, and ideally one would pursue those policy measures that effectively reduce GHGs at least cost.

Although the cost (when correctly measured) should have a strong bearing on which policies to select, it is not the only consideration. Other factors will influence the decision, such as the impacts of the policies on different social groups in society, particularly on vulnerable groups, the benefits of the GHG limitation in other spheres (e.g. reduced air pollution), and the impacts of the policies on broader concerns such as sustainability. In developing countries these other factors are even more important than they are in the industrialised countries. GHG limitation does not have as high a priority relative to other goals; such as poverty alleviation, reductions in employment, etc. as it does in the wealthier countries. Indeed, one can argue that the major focus of policy will be development, poverty alleviation etc. and that GHG limitation will be an *addendum* to a programme designed to meet those needs. Taking account of the GHG component may change the detailed design of a policy or programme, rather than being the main issue that determines the policy.

In recognition of the importance of these broader social and environmental issues in developing countries, a methodology has been developed which provides a framework for the assessment of the wider impacts arising from GHG limitation projects, and advice on how to incorporate them into the decision-making framework[2]. The purpose of this report is to apply the methodology to a set of selected GHG limitation projects currently being considered for implementation in the Republic of Mauritius.

1.1.1 GHG Mitigation Measures

In total, six GHG limitation projects were selected for application of the methodology; five of the projects are to be implemented in the electricity generation sector, while one project is being applied to the transport sector.

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[1] For example: UNEP (1998), "Mitigation and Adaptation Cost Assessment: Concepts, Methods and Appropriate Use", UNEP Collaborating Centre on Energy and the Environment, Risø National Laboratory, Roskilde, DK.

Haites, E. and Rose, A. (1996), “Energy and Greenhouse Gas Mitigation: the IPCC Report and Beyond”(eds.), **Energy Policy** Special Issue, **24**, 10/11.

IPCC (1996), **Climate Change 1995. Economic and Social Dimensions of Climate Change: Scientific-Technical Analysis**, Contribution of Working Group III to the Second Assessment Report of the Intergovernmental Panel on Climate Change, Cambridge: Cambridge University Press.

UNCCEE (1997), The Economics of Greenhouse Gas Limitation Guidelines, A report of the UNEP Collaborating Centre on Energy and Environment, Methodological Guidelines – Document 04408.02/02, Risø National Laboratory, Roskilde, DK.

[2] Markandya, A. (1998), **The Indirect Costs and Benefits of Greenhouse Gas Limitation**, A report prepared for the UNEP Collaborating Centre on Energy and Environment, Risø National Laboratory, Roskilde, DK.

Specifically, the selected GHG limitation projects involve[3]:

1. Installing a wind farm with 30 MW declared net capacity.
2. Increasing the average annual electricity tariff by 10 per cent per annum relative to the forecast annual value.
3. Replacing 125 streetlights (currently connected to the electricity grid) with 125 photovoltaic (PV) streetlights.
4. Replacing domestic electric water heaters with active solar water heaters.
5. Purchasing (and therefore generating) an additional 50 GWh per year from a mixture of bagasse and coal.
6. Replacing part of the current (diesel-powered) bus fleet with equivalent buses powered by LPG.

With respect to the measures applied to the electricity generation sector, it is assumed that output from the renewable sources will displace electricity generated from oil-fired power stations, namely, Fort George, Fort Victoria or Saint Louis. Likewise, it is assumed that any reduction in demand resulting from the increase in the electricity tariff will be directed towards output from the oil-fired stations.

1.2 Selection Criterion

The full methodology adopted in this case study is presented in Markandya (1998). Following application of the methodology, the information generated needs to be summarised so that different mitigation projects can be compared. This typically involves constructing a measure of the cost-effectiveness of each project. The cost-effectiveness of each project is obviously a function of its cost and environmental performance; it is also influenced by the choice of discount rate and the base case definition. The treatment of these latter two “influences” in this case study is outlined below. First however, the cost-effectiveness criteria are reviewed.

1.2.1 Cost-effectiveness Criteria

The decision as to whether to implement a mitigation measure will depend, for the most part, on its cost-effectiveness in abating GHGs. The cost-effectiveness criterion used in this study defined by the net present value cost per ton of GHG (CO_2 equivalent) removed. If the net cost in period i is C_i and the reduction in emissions in period i relative to the baseline is E_i then the cost-effectiveness criteria for mitigation measure P is $\mathrm{FUCOSTEF}_p$ where:

$$\mathrm{FUCOSTEF_P} = \frac{\sum_{i=0}^{i=T} C_i (1+r)^i}{\sum_{i=0}^{i=T} E_i (1+d)^i} \qquad (1)$$

The cost C_i is the net incremental cost of the mitigation measure, i.e. the incremental direct costs in time period i net of any associated incremental benefits. The term E_i is the carbon-weighted (CO_2 equivalent) reduction in emissions in period i relative to the baseline. FUCOSTEF refers to the fact that the costs are the full (FU) economic costs of the project and not just the direct financial costs, measuring the cost effectiveness (hence COSTEF). It is to distinguish it from FICOSTEF, which represents the direct

[3] The study originally intended to consider energy utilisation in the industrial sector. Due to a lack of suitable data, however, it has not been possible to assess this option.

financial costs (hence FI) of the project. The term *r* is the rate of discount for costs and *d* is the rate of discount for emissions.

Both measures of cost-effectiveness (i.e. FU / FICOSTEF) have been estimated for each of the selected GHG mitigation measures.

1.2.2 Choice of Discount Rate

Markandya (1998) recommends that a central discount rate of 3 per cent be used to determine the present value of the net incremental cost stream; and a sensitivity analysis is carried out for rates of 1 per cent and 10 per cent. The public sector discount rate in Mauritius, however, has been around 10 per cent since 1995. Therefore, the central discount rate used in this case study is 10 per cent, with sensitivity analysis conducted around lower and upper rates of 5 and 15 per cent.

The same rate(s) of discount are used to determine the present value of the emission savings stream.

In order to provide a complete picture of the uncertainties surrounding the choice of discount rate, the FU / FICOSTEF of each measure is computed for the following two combinations:

- the lowest rate applied to the cost stream and the highest rate applied to the emission savings stream; and
- the highest rate applied to the cost stream and the lowest rate applied to the emission savings stream.

In addition the central rate of 10 per cent is applied to both cost and emission saving streams.

1.2.3 Definition of the Base Case[4]

In general, marginal cost curves for a set of GHG limitation projects may be constructed in one of two ways:

1. Projecting a baseline (or "business-as-usual") scenario, from a given base year to some point in the future, projecting a "mitigation" scenario over the same period, and taking the difference between the two.
2. Projecting an "incremental mitigation" scenario (where all cost and environmental performance data is already reported as the difference between those realised under the baseline and those realised when the limitation project is in place.

The second approach has been adopted in this case study. Therefore, the cost-effectiveness of each GHG limitation project has been assessed using "incremental" cost and environmental performance data.

The base year selected for all cost data was 1995 (i.e. all cost data is expressed in 1995 prices). Some of the cost data was originally quoted in United Kingdom pounds (£) or United States dollars (US$) and for years other than 1995. In such cases, all data was first converted to 1995 prices using appropriate national price indices and then converted to Mauritian Rupees (Rs) using the following nominal exchange rates (annual average): £1 is equal to 28.088 Rs and US$1 is equal to 17.800 Rs.

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4 The base case was defined to reflect the best available data.

The base year selected for computing the FU / FICOSTEF of each measure was 1997 (i.e. it is assumed that each measure was implemented in 1997). Hence, if a measure takes a year to implement, annual recurring costs and emission savings will begin to accrue in 1998.

The time horizon for the analysis is specific to each GHG limitation project, and depends on its estimated useful operating life. For example, wind turbines have an average operating life of 15 years and take up to 1 year to plan / design / install / commission. Under these assumptions, the capital costs would be incurred in 1997, and annual recurring costs and emission savings would accrue every year until the end of 2012. All cost data were assumed to remain constant in real terms over the selected time horizon[5]. The same assumption was made regarding the environmental performance of each measure. Both these assumptions are somewhat unrealistic.

1.3 Structure of Report

The remainder of the report is structured as follows: Section 2 outlines the data set used to estimate the emission savings associated with each mitigation measure. The data set, which serves as the basis for the social cost analysis (i.e. the determination of FUCOSTEF), is constructed in Section 3. In Section 4, each of the selected GHG limitation projects is examined in detail. The FICOSTEF and FUCOSTEF are computed for each measure, and sensitivity analysis conducted around key variables. Mitigation cost curves, which summarise the annual emission savings potential and associated costs, for the selected projects applied in Mauritius, are presented in Section 5, along with some conclusions.

[5] Although the spreadsheet model used to perform the calculations is capable of incorporating changes in selected prices over time.

2 Estimating Reductions in Emissions (Data Module)

2.1 Introduction

It is evident from equation 1 that a key determinant of the cost-effectiveness of a GHG mitigation measure is the carbon-weighted reduction in emissions, relative to the baseline, associated with the measure over its useful life. In this section the data used to estimate the emission savings associated with each mitigation measure is outlined.

In general, emissions (E) are estimated as the product of an emission factor (F) and an activity statistic (A): that is,

$$E = F \times A \qquad (2)$$

Equation 2 provides a simple framework for forecasting changes in future emissions, resulting from - in the context of this case study - the introduction of GHG limitation projects. Changes in emissions are computed by simply changing the activity statistic or, less commonly, the emission factor[6]. For example, emissions of CO_2 from oil-fired power stations may be expressed as:

CO_2 = emissions of CO_2 per tonne of oil burned *x* tonnes of oil burned.

By reducing the quantity of oil burned, for example, by displacing electricity generated from oil-fired stations by wind energy, emissions of CO_2 decrease.

To estimate emission savings resulting from the implementation of selected mitigation projects using this framework, two pieces of data are required: relevant activity statistics and emission factors.

2.2 Relevant Activity Statistics

The GHG mitigation measures selected for analysis are relevant to two sectors, the electricity generation sector and the transport sector. Two sets of activity statistics are thus required, one for each sector.

2.2.1 Electricity Generation Sector

The most obvious activity statistic for this sector is the quantity of fuel input to electricity generation. The mass and primary energy content of fuel inputs to electricity generation in 1995, and the resulting quantity of electricity generated, by major type of fuel, are summarised in Figure 1. The corresponding conversion efficiencies are also given.

Each of the selected mitigation measures applicable to this sector reduce the amount of electricity purchased / generated from fossil fuels, thus the effectiveness of a measure can initially to be expressed as a change in electricity output from, for example, an oil-fired station. To simplify the calculations it therefore makes sense to normalise the fuel input to the quantity of electricity generated. Fuel input (in tonnes) per unit of electricity generated, by type of fuel, is given in Figure 2. Again, taking fuel oil as an example, for every 1 GWh of electricity generated from this fuel source, 213 tonnes of fuel oil are burned. A GHG limitation project that displaces 2 GWh of electricity, therefore, saves 426 tonnes of fuel oil. The saving in GHGs associated with this project are found by multiplying the reduction in fuel oil input (i.e. 426 tonnes) by an appropriate set of emission factors (given below).

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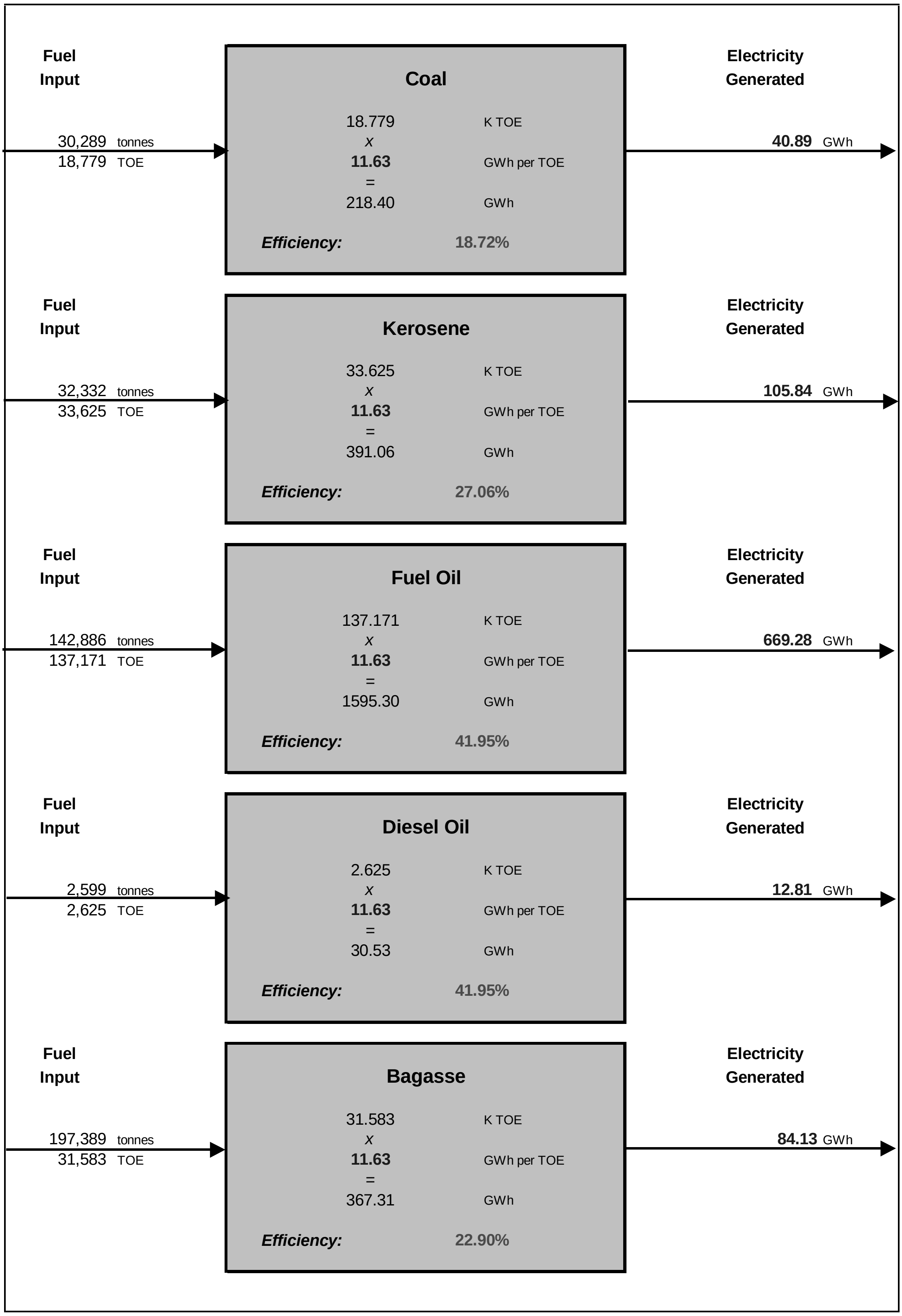
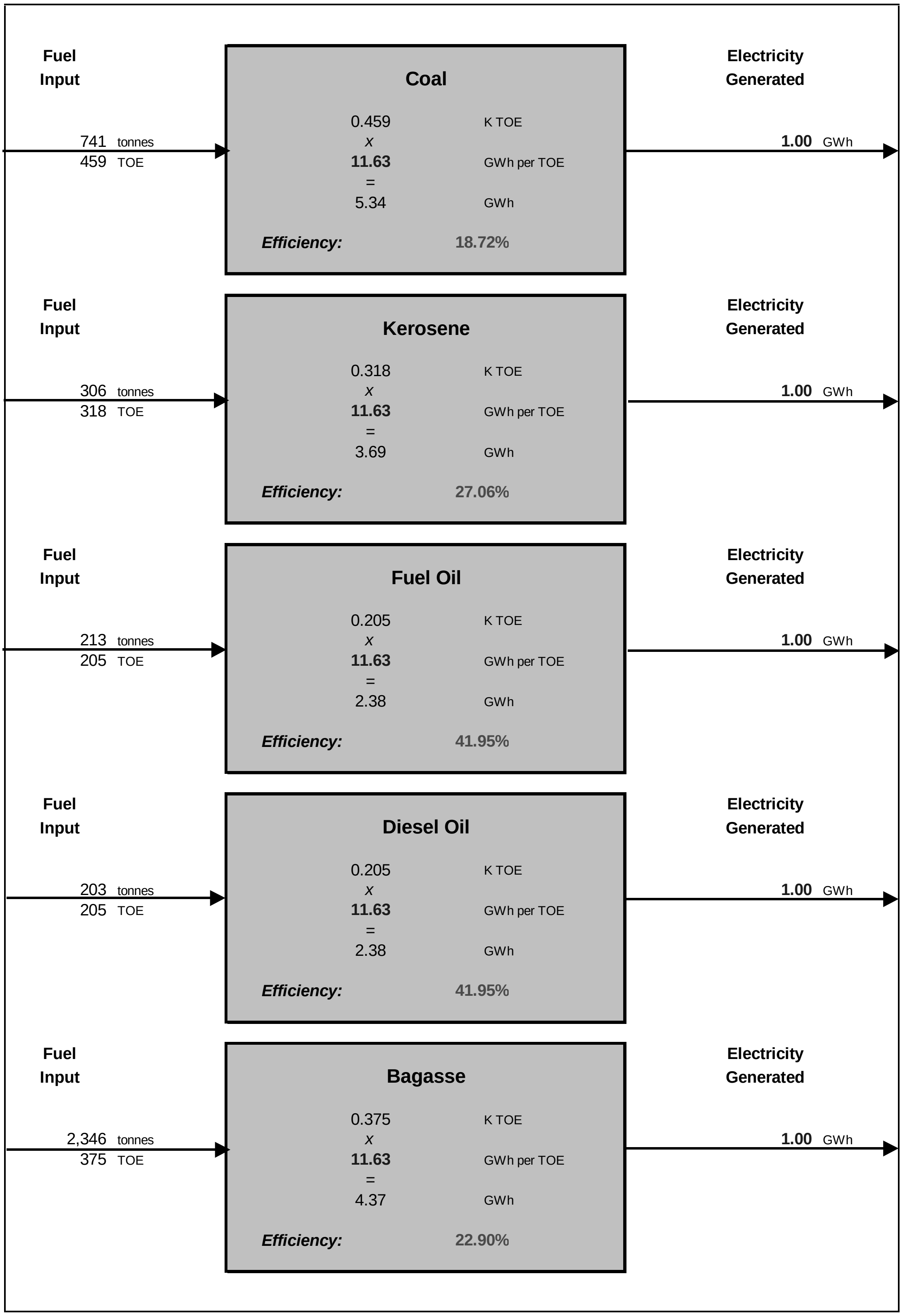
[6] The latter is relevant to situations involving, for example, fuel switching.

Figure 1 Fuel Input, Electricity Generated and Implied Conversion Efficiencies (1995).



Source: "Energy Sector: Baseline Scenario 1995-2020", Mid-term Report, A paper provided by the National Climate Committee, Technical Working Group on the Economics of Greenhouse Gas Limitation.

Figure 2 Estimated Savings in Fuel Input from a Unit Change in Electricity Generation.



Source: "Energy Sector: Baseline Scenario 1995-2020", Mid-term Report, A paper provided by the National Climate Committee, Technical Working Group on the Economics of Greenhouse Gas Limitation.

2.2.2 Transport Sector

The mitigation measure proposed for this sector involves replacing diesel-fuelled buses with LPG-powered buses, which is essentially a form of fuel switching. It is therefore more appropriate to assess changes in emissions by altering the emission factor, as opposed to the activity statistic[7]. (Emission factors are discussed below.) Nonetheless, an activity statistic is still required. With respect to the transport sector two options are widely used: (1) the volume of fuel consumed per vehicle per year; or (2) the number of km travelled per vehicle per year. After reviewing the available data, the latter activity statistic was chosen for the purpose of this study.

The total operational bus fleet in Mauritius (as of June 30th 1995) was 1,767 buses[8]. In total, the fleet made 4,074,000 journeys (trips) in 1995, driving a total distance of 80,736,000 kilometres. Therefore each bus made an average 2,306 trips per annum, with each trip averaging 19.82 km. Each bus thus travelled an average distance of 45,691 km per annum, which is the activity statistic used here to forecast emission savings.

2.3 Emission Factors

As was the case with the activity statistics, two sets of emission factors are required, one for each sector. Furthermore, the purpose of this study is to evaluate GHG mitigation measures in a broader context, including impacts on the environment resulting from secondary emission savings. A set of emission factors, applicable to each sector is therefore also required for other 'classical' air pollutants, including SO_2, NO_x, particulates, CO and NMVOC.

2.3.1 Electricity Generation Sector

For the electricity generation sector the activity statistic chosen to forecast changes in emissions is "the quantity (in terms of tonnes) of fuel burned". Hence, the emission factors used to estimate changes in emission levels must be expressed in terms of "emissions per tonne of fuel burned". In the absence of 'actual' emission factors, it has been necessary to estimate them estimated based on the IPCC default values. The IPCC default values for CO_2 are expressed in terms of "emissions per GJ of fuel". It has therefore been necessary to adjust these factors so that their units are compatible with the selected activity statistic. Taking fuel oil (FO) for example, the required adjustment is as follows:

$$77.4\frac{\text{kg CO}_2}{\text{GJ}}\times 40.20\frac{\text{GJ}}{\text{t}_{\text{FO}}}\times 0.001\frac{\text{tonnes}}{\text{kg}} = 3.11\frac{\text{t CO}_2}{\text{t}_{\text{FO}}}$$

Similarly, emission factors have been computed for all other major fuel inputs to electricity generation in Mauritius, these are reported in Table 1. The factors listed in column IV are used to forecast CO_2 emissions in this study.

The calorific values on which the emission factors given in Table 1 are based have been derived from data on the actual quantity of fuel input to electricity generation in 1995 and the Energy Balance for Mauritius, for the same year. The derivation of the calorific values is illustrated in Table 2.

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7 Although, if the measure changes the price of each passenger-kilometre, it is likely that the activity statistic will change. Modelling "induced" changes in consumer behaviour, however, is beyond the scope of this case study; estimates of "own price" and "substitution" elasticities were unavailable.

8 From Table 1.8 in **Digest of Road Transport and Accident Statistics 1996**, Central Statistical Office, Ministry of Economic Development and Regional Co-operation, Port Louis, Mauritius (August, 1997).

Table 1 Estimated CO_2 Emission Factors: Based on IPCC Default Values.

Fuel Type	Emission Factor[1] (kg CO_2 per GJ fuel)	Calorific Value (GJ per t fuel)	CO_2 Emissions (t CO_2 per t fuel)	Carbon Emissions (kg C per t fuel)
Coal	94.6	25.96	2.46	669.77
Kerosene	71.3	43.54	3.10	846.66
Fuel Oil	77.4	40.20	3.11	848.59
Diesel Oil	74.1	42.29	3.13	854.64
Bagasse	-	6.70	-	-

Source: 1) Halsnæs, K, Callaway J. M. and Meyer, H. J. (1998). The Economics of Greenhouse Gas Limitations. Methodological Guidelines. Main Reports. UNEP Collaborating Centre on Energy and Environment, Risø National Laboratory Denmark.

Table 2 Estimated Calorific Values: Fuels Used in Electricity Generation (1995).

Fuel Type	Primary Energy (from energy balance) (TOE)	Conversion Factor (GJ per TOE)	Fuel Input to Electricity Generation (tonnes)	Calorific Value (GJ per t fuel)
Coal	18,779	41.87	30,289	25.96
Kerosene	33,625	41.87	32,332	43.54
Fuel Oil	137,171	41.87	142,886	40.20
Diesel Oil	2,625	41.87	2,599	42.29
Bagasse	31,583	41.87	197,389	6.70

Source: "Energy Sector: Baseline Scenario 1995-2020", Mid-term Report, A paper provided by the National Climate Committee, Technical Working Group on the Economics of Greenhouse Gas Limitation.

Emission factors for methane, nitrous oxide, and other airborne pollutants are given in Table 3. The latter are used to estimate secondary emission savings resulting from the selected GHG mitigation measures.

As mentioned, the effectiveness of each measure in abating GHGs relative to the baseline is expressed as the carbon-weighted reduction in emissions (i.e. CO_2, CH_4 and N_2O). The weights used to convert the GHG emissions into CO_2 equivalents are the standard Global Warming Potentials (GWP) of the gases; these reflect the greater climate change potential of methane and nitrous oxide, relative to carbon dioxide. Therefore, the total GHG emission saving associated with each limitation project has been calculated as follows (assuming that the project reduces fuel oil input to electricity generation):

$$\Delta \, \mathrm{t\,CO_2\,eq.} = \Delta \, \mathrm{t_{FO}} \times \left[GWP_{\mathrm{CO_2}} \times \frac{\mathrm{t\,CO_2}}{\mathrm{t_{FO}}} + GWP_{\mathrm{CH_4}} \times \frac{\mathrm{t\,CH_4}}{\mathrm{t_{FO}}} + GWP_{\mathrm{N_2O}} \times \frac{\mathrm{t\,N_2O}}{\mathrm{t_{FO}}} \right] \qquad (3)$$

where Δ represents the "change" (reduction) in GHG associated with the measure. The GWPs of CO_2, CH_4 and N_2O are 1, 21 and 310, respectively.

2.3.2 Transport Sector

For the transport sector, the activity statistic chosen to forecast changes in emissions were the number of kilometres travelled per vehicle per year. Hence, the emission factors used to estimate changes in emission levels must be expressed in terms of "emissions per km per vehicle". The factors used to assess the effectiveness of this GHG project are given in Table 4. These are representative of emissions from small to medium size buses, subjected to an adequate maintenance programme, and operating in a variety of road conditions. It must be stressed that these emission factors are "average" figures; ideally it would have been preferable to use different factors for buses of varying age, size, and operating environments. However, such an in-depth analysis is not possible at this stage.

Using the factors given in Table 2.4, the total GHG saving associated with replacing a diesel-fuelled bus with a LPG-powered bus was calculated as follows (assuming that the total number of kilometres travelled per bus per year remains unaffected):

$$\Delta\,\mathrm{t\,CO_2\ eq.} = \frac{\mathrm{km}}{\mathrm{bus} \bullet \mathrm{yr}} \times \left[GWP_{CO_2} \times \partial \frac{\mathrm{g\,CO_2}}{\mathrm{km}} + GWP_{CH_4} \times \partial \frac{\mathrm{g\,CH_4}}{\mathrm{km}} + GWP_{N_2O} \times \partial \frac{\mathrm{g\,N_2O}}{\mathrm{km}} \right] \times 10^{-6}\,\frac{\mathrm{t}}{\mathrm{g}}$$

where ∂ denotes the "difference" in emission factors between a diesel-fuelled bus and a LPG-powered bus, and Δ denotes the "change" in GHGs.

Table 3 Default (Uncontrolled) Emission Factors: Other GHGs and Air Pollutants (Electricity Generation Sector).

Fuel Type	CH_4 Emissions kg CH_4 per t fuel	N_2O Emissions g N_2O per t fuel	NO_x Emissions kg NO_x per t fuel	SO_2 Emissions kg SO_2 per t fuel	PM Emissions kg PM per t fuel	NMVOC Emissions kg NMVOC per t fuel	CO Emissions kg CO per t fuel
Coal	0.264	36.344	4.800	25.100	1.000	0.0691	4.100
Kerosene	0.225	26.124	2.100	0.800	0.007	0.0691	0.160
Fuel Oil	0.135	24.120	7.400	55.500	1.000	0.0592	0.500
Diesel Oil	0.045	25.374	4.500	4.000	0.750	0.0691	0.240
Bagasse	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Source: Salway, A., Goodwin, J. and Eggleston, H. (1996), UK Emission of Air Pollutants 1970 to 1994, A report of the National Atmospheric Emissions Inventory (NAEI), Culham, Oxfordshire: AEA Technology.

Table 4 Default Emission Factors: Other GHGs and Air Pollutants (Average Bus).

Fuel Type	CO_2 Emissions	CH_4 Emissions	N_2O Emissions	CO Emissions (grams per km)	NO_x Emissions	PM Emissions	SO_2 Emissions
Derv Oil: average (A)	731.500	0.085	0.030	10.280	4.880	0.810	0.230
LPG (B)	695.000	0.150	-	4.830	0.880	0.410	-
Differential (A – B)	36.500	-0.065	0.030	5.450	4.000	0.400	0.230

Sources: Salway, A., Goodwin, J. and Eggleston, H. (1996), UK Emission of Air Pollutants 1970 to 1994, A report of the National Atmospheric Emissions Inventory (NAEI), Culham, Oxfordshire: AEA Technology. ExternE (1997b), Externalities of Fuel Cycles 'ExternE' Project: Results of the Transport Project. A draft final report produced for the Commission of the European Communities DGXII (JOULE Programme). Faiz, A., Weaver, C. and Walsh, M (1996), Air Pollution from Motor Vehicles: standards and technologies for controlling emissions, Washington, DC: The World Bank.

3 The Social Cost Analysis (Data Module)

3.1 Introduction

One of the purposes of this case study is to evaluate GHG mitigation measures in a broader context, including the impacts of projects on vulnerable groups, on the environment more generally, on employment and other macroeconomic issues, and the impacts on sustainability in a wider sense. Moreover, if these impacts are to be given equal weight in the decision-making process, then it is helpful to value them in money terms. In the full social cost analysis of each mitigation measure presented in Section 4, an attempt has been made to value impacts associated with secondary emission savings, changes in employment and costs / benefits accruing to different income groups. The assessment of these impacts requires additional data to the financial expenditure on each measure. The additional data, which serves as the basis for the social cost analysis conducted in Section 4, is outlined in this section.

3.2 Secondary Emission Savings

3.2.1 Background

The combustion of fossil fuels to generate electricity or power motor vehicles results in the emission of other air pollutants in addition to GHGs, including SO_2, NO_x, particulates, CO and NMVOC. Links have been documented between each of these pollutants and a number of adverse effects on human health and ecological functions. Projects, which limit GHG emissions by reducing the amount of fuel consumed, will therefore almost certainly have environmental impacts other than those related to climate change. A great deal of work has been undertaken to value some of these impacts in money terms; in particular damages from SO_2, NO_x (and associated ozone) and particulates. A selection of unit damage costs (in terms of US$ per tonne of pollutant) for industrialised countries are presented in Markandya (1998). It was recommended that these damage costs, after making an adjustment for differences in *real* GDP, be used directly to value secondary emission savings.

In the case of Mauritius, however, further adjustment to the unit damage costs is proposed to reflect differences in the physical magnitude of damages resulting from emissions of, say, SO_2 in Mauritius, relative to the damages incurred in the country from which the damage costs were derived. The magnitude of damage from SO_2 (in physical terms) is basically a function of:

1. the 'stock at risk' exposed to SO_2; and
2. the ambient concentration of SO_2.

The unique circumstances of Mauritius, including the fact that it is an island of less than 1,900 km^2 implies that, relative to the UK and Germany where the unit damage costs were derived, both these determinants of the overall scale of damages are likely to be smaller. Consequently, the physical damage per tonne of SO_2 in Mauritius is also likely to be smaller. It therefore seems reasonable to scale the damage costs further to reflect these likely differences in physical magnitude. Several scaling factors are proposed below.

In summary, two adjustments are made to the unit damage costs given in Markandya (1998) prior to their application in Mauritius:

1. the first to reflect differences in income and hence, willingness-to-pay (i.e. regarding the valuation of the damages); and
2. the second to reflect differences in the magnitude of the physical damage per tonne of pollutant.

3.2.2 Proposed Scaling Factors

In order to develop scaling factors which reflect differences in the physical magnitude of damages resulting from the emission of air pollutants in Mauritius relative to the damages incurred in those countries from which the unit damage costs were derived, selected data underpinning the damage cost estimates is required. Since this additional data is only available for those damage costs derived from Germany and the UK, the unit damage costs derived from the US studies and reported in Markandya (1998), are not used in this case study.

The unit damage costs for Germany and the UK reported in Markandya (1998) are reproduced in Table 5. Selected data on which these unit damage cost estimates were based, is given in Table 6, along with similar data for Mauritius.

Table 5 Estimates of Unit Damage Costs (1995 prices).

Pollutant	United Kingdom (US$ per tonne)	Germany (US$ per tonne)
SO_2	9,350	12,350
NO_x (including ozone)	4,860	7,250
Particulates	21,490	23,670

Source: ExternE (1997a), Externalities of Fuel Cycles 'ExternE' Project: Aggregation – External Costs from Electricity Generation in Germany and the UK. A draft final report produced for the Commission of the European Communities DGXII (JOULE Programme).

Table 6 Emission, Population and Area Data for Germany, the UK and Mauritius.

	United Kingdom[1]	Germany[1]	Mauritius[2]
Estimated resident population (million)	57.6	82.0	1.1
Area ('000 km^2)	241.8	367.0	1.9
Density (persons per km^2)	238	230	602
SO_2 emissions: power sector (k tonnes)	2,729	2,232	8.2
NO_x emissions: power sector (k tonnes)	776	411	2.0
PM emissions: power sector (k tonnes)	27	477	0.2

Sources: 1) ExternE (1997a), Externalities of Fuel Cycles 'ExternE' Project: Aggregation – External Costs from Electricity Generation in Germany and the UK. A draft final report produced for the Commission of the European Communities DGXII (JOULE Programme). 2) National Climate Committee (1997), Economics of Greenhouse Gas Limitation, Phase 1, Mid-term Report of the Technical Working Group.

Various scaling factors can be constructed for each pollutant from the data contained in Table 6. A selection of possible scaling factors are presented in Table 7; these have been derived by dividing the magnitude of the parameter for Mauritius by the corresponding value for either Germany or the UK. Taking SO_2 emissions, for example, 11.29 tonnes are emitted per km^2 in the UK, in contrast to 4.39 tonnes per km^2 in

Mauritius. The appropriate scaling factor to be applied to the unit damage cost for SO_2 derived from the UK, is thus 0.3893 (i.e. 4.39 / 11.29). Note: this adjustment is in addition to the suggested adjustment for differences in *real* GDP.

The adjusted unit damage costs, used to value secondary emission savings from the GHG mitigation measures applied to the electricity generating sector, are given in Table 7. The adjustment for differences in the magnitude of physical damages is based on the ratios of population between Mauritius, and Germany and the UK. An income elasticity of 1.00 has been used to adjust for differences in real GDP.

Table 7 Selected Scaling Factors.

	Scaling Factor Based On:					
	persons per km^2	population	kg per person	tonnes per km^2	persons per tonne	person-tonnes per km^2
Relative to the UK:						
SO_2 emissions	2.5274	0.0195	0.1540	0.3893	6.4917	0.0076
NO_x emissions	2.5274	0.0195	0.1295	0.3273	7.7220	0.0064
PM emissions	2.5274	0.0195	0.3325	0.8403	3.0077	0.0164
Relative to Germany:						
SO_2 emissions	2.6194	0.0137	0.2683	0.7028	3.7270	0.0096
NO_x emissions	2.6194	0.0137	0.3483	0.9124	2.8709	0.0125
PM emissions	2.6194	0.0137	0.0266	0.0702	37.299	0.0010

Table 8 Secondary Emission Savings from the Electricity Generation Sector: Adjusted Unit Damage Costs.

	Unit Damage Costs (US$ per tonne)	Real GDP Scaling Factor[1] (%)	Damage Scaling Factor (%)	Scaled Unit Damage Costs (US$ per tonne)
Based on UK:				
SO_2 emissions	9,350	70.78	1.95	129
NO_x emissions	4,860	70.78	1.95	67
PM emissions	21,490	70.78	1.95	297
Based on Germany:				
SO_2 emissions	12,350	65.30	1.37	110
NO_x emissions	7,250	65.30	1.37	65
PM emissions	23,670	65.30	1.37	212

Notes: 1) Based on the following PPP GNPs (94) for the UK, Germany and Mauritius: US$ 17,970, US$ 19,480 and US$ 12,720, respectively.

The adjusted damage costs listed in Table 8 are appropriate for valuing secondary emission savings from GHG mitigation measures applied to the electricity generation sector. (The estimated unit damage costs are based on emissions from the power sector in the UK and Germany). However these values are not appropriate for use in the transport sector. In contrast to emissions from the power sector, emissions from the transport sector tend to be from low level, disperse sources in urban locations, where the density of the 'stock at risk' is relatively high. As one of the mitigation measures considered in this study involves replacing diesel buses with equivalent LPG powered vehicles, unit damage costs have been obtained for emissions from transport sources. These are given in Table 9 and are based on the results of two case studies conducted in the UK as part of the ExternE Transport Project. A figure has been included for CO, in recognition of the significant contribution that the transport sector makes to total CO emissions and to reflect the established links between CO and adverse impacts on human health.

Secondary emission savings resulting from the introduction of LPG buses in Mauritius are valued using the adjusted values reported in Table 9.

Table 9 Secondary Emission Savings from the Transport Sector: Adjusted Unit Damage Costs.

	Unit Damage Costs	Real GDP Scaling Factor[1]	Damage Scaling Factor	Scaled Unit Damage Costs
	(US$ per tonne)	(%)	(%)	(US$ per tonne)
Based on UK:				
SO_2 emissions	11,362	70.78	1.95	157
NO_x emissions	13,800	70.78	1.95	190
PM emissions	23,670	70.78	1.95	327
CO emissions	473	70.78	1.95	7

Sources: ExternE (1997b), Externalities of Fuel Cycles 'ExternE' Project: Results of the Transport Project. A draft final report produced for the Commission of the European Communities DGXII (JOULE Programme).

Notes: 1) Based on the following PPP GNPs (94) for the UK, Germany and Mauritius: US$ 17,970, US$ 19,480 and US$ 12,720, respectively.

Employment Effects

Background

If a mitigation measure creates a job, this has a benefit to society to the extent that the person employed would otherwise have been unemployed[9]. The benefits of employment (as a result of implementing a mitigation measure) are therefore equal to the social costs of the unemployment avoided. These benefits will depend primarily on:

- the period that a person is employed,
- what state support is offered during any period of unemployment, and
- what opportunities exist for informal activities, which generate income in cash or kind.

In addition, unemployment is known to create health problems, which have to be considered as part of the social cost.

The net social benefit / cost of an additional job created / lost as a result of a mitigation measure is therefore the product of two components:

[9] The same logic can be applied to the loss of a job; the arguments are simply in reverse.

1. the number of jobs created / lost by the project (and the period of un / employment); and
2. the net value of an additional job (i.e. the net gain in income minus the value of foregone non-work time plus the value of any health-related benefits).

The derivation of the raw data required to assess the net employment effects of implementing the selected GHG mitigation measures in Mauritius is outlined below.

Estimated Employment Effects

A physical measure of the net employment effects associated with a given mitigation measure is required before it is possible to place some monetary value on them. The guidelines (Markandya, 1998) suggest that data is collected with respect to:

- the number of persons to be employed in the projects;
- the duration of time for which they will be employed;
- the present occupations of the individuals (including no formal occupation); and
- the gender and age (if available).

The development of such a data set, however, would require a survey of potentially affected sectors to ascertain the expected employment impact of the mitigation measures. As it has not been possible to undertake such an exercise at this stage, potential employment effects have been approximated using employment / output ratios for those sectors where employment effects are anticipated. Employment / output ratios for those sectors where *direct* employment effects are likely are given in Table 10. In the construction sector, for example, there were 3.26 employees per Rs million of gross output in 1995. Changes in employment are then estimated by multiplying the employment / output ratios by changes in output resulting from the implementation of the mitigation measures.

Of course, previously unemployed persons will not fill all new jobs, and, equally, a reduction in output will not translate into a proportional loss of jobs. To account for this, it has been necessary to make an assumption regarding the percentage of jobs created / lost, estimated by the employment / output ratios that will actually result in a change in unemployment levels. A figure of 15 per cent is used in the calculations, which does not seem unreasonable given the relatively low unemployment levels in Mauritius.

The approach to estimating net employment effects adopted here is crude, to say the least. The results should therefore be treated as ‘order of magnitude’ estimates only, to be refined when better information becomes available.

Table 10 Employment Intensity in Affected Sectors (1995).

Relevant Sectors	Employment (both sexes)[2] ('000 employees)	Gross Output at Producers' Prices[1] (Rs million)	Employment Intensity (Employees per Rs million)
Sugar Cane	34.5	5,011.0	6.88
Sugar Milling	5.9	7,120.0	0.83
Central Electricity Board[3]	1.9	-	2.12[4]
		-	1.81[5]
Construction	36.8	11,289.2	3.26
Transport (all sectors)	28.4	11,765.7	2.41
Finance, Insurance, Business Services	14.1	12,848.3	1.10

Sources: 1) Table 1.20 in National Accounts of Mauritius 1997, Central Statistical Office, Ministry of Economic Development and Regional Co-operation, Port Louis, Mauritius (January, 1998). 2) Table 1.4 in Digest of Labour Statistics 1997, Central Statistical Office, Ministry of Economic Development and Regional Co-operation, Port Louis, Mauritius (February, 1998). 3) CEB (1997), Annual Report 1996, Central Electricity Board, Curepipe, Mauritius.

Notes: 4) Employees per GWh of electricity sold. 5) Employees per GWh of electricity generated by CEB.

Net Benefit of Additional Job

The net welfare gain of an additional job is defined as:

1) The gain of net income as a result of the new job, after allowing for any unemployment benefit, informal employment, work-related expenses (i.e. the net financial gain to the 'newly' employed person), etc: minus
2) The value of the additional time that the person has at his or her disposal as a result of being unemployed, which is lost as a result of being employed, plus
3) The value of any health related consequences of being unemployed that are no longer incurred.

Hence, the net social benefit / cost of an additional job created / lost as a result of a mitigation measure is equal to (a) minus (b) plus (c). In this section, a value is estimated for each of these elements, for a job created / lost in each of the potentially affected sectors listed above.

Gain of Net Income

The gain of net income depends on the net of tax wage rate, and how much unemployment and other benefits are available. Data were obtained on average (gross) monthly rates of pay, by industrial group, for 1997[10]. These, in turn, were converted to annual figures and deflated to 1995 prices using a Labour Cost Index[11]. The average (gross) annual rates of pay for employees in the sugar cane, sugar milling, electricity / water, construction, transport, and engineering and architectural service

[10] Data were obtained from Table 2.10, Digest of Labour Statistics 1997, Central Statistical Office, Ministry of Economic Development and Regional Co-operation, Port Louis, Mauritius (February, 1998).

[11] The Labour Cost Index was derived from the Unit Labour Cost Index reported in "*Productivity and Competitiveness Indicators 1990 to 1997*", **Economic and Social Indicators**, an Occasional Paper, Issue No. 276, Ministry of Economic Development and Regional Co-operation, Port Louis, Mauritius (August, 1998). The Unit Labour Cost Index is equal to the ratio of the Labour Cost Index to an index of production.

sectors are 49,506 Rs, 64,122 Rs, 100,047 Rs, 99,315 Rs, 55,099 Rs and 95,249 Rs, respectively.

Adjustments for personal income taxes were made based on tax rates estimated from data provided by the Ministry of Economic Development and Regional Co-operation for 1995 (see Table 11). Note: tax rates were only estimated for those gross income ranges that correspond to the gross annual earnings of each of the six industrial groups likely to be affected by the mitigation measures. For example, the gross annual earnings of workers in the construction sector was 99,315 Rs, therefore, the tax rate was estimated for those individuals earning between 90,001 and 100,000 Rs per annum. The estimated tax rate was then used to compute the net annual earnings of construction workers.

Table 11 Individual Income Tax: Analysis by Range of Gross Income Class (1995/96).

Range of Gross Income (Rs per annum)	Gross Income (Rs million)	Chargeable Income (Rs million)	Tax Payable (Rs million)	Estimated Tax Rate (%)
less than 50,000	85.2	4.7	0.3	0.352
50,001 to 60,000	315.8	40.3	2.0	0.633
60,001 to 70,000	409.1	8.6	4.5	1.100
90,001 to 100,000	706.7	187.9	16.7	2.363
100,001 to 125,000	1,557.6	457.2	49.7	3.191

Source: Table 4.11, in Annual Digest of Statistics 1996, Central Statistical Office, Ministry of Economic Development and Regional Co-operation, Port Louis, Mauritius (July, 1997).

Strictly speaking, there is no ‘unemployment benefit’ payable to all unemployed individuals in Mauritius. There is, however, a non-contributory allowance (Unemployment Hardship Relief) payable to the heads of low-income households who can provide evidence that they are unable to find work. The number of beneficiaries of Unemployment Hardship Relief (UHR) was 305 in June 1995. The amount paid to UHR beneficiaries between 1993/94 and 1995/96 averaged one million Rs per annum[12]. Annual payments per beneficiary are therefore about 3,279 Rs. This amount was deducted from the net annual earnings of workers in each sector to provide an estimate of the net annual gain in income from an additional job. However, this is not strictly correct, as not all unemployed individuals receive UHR. Consequently, the net gain in income of an additional job resulting from the mitigation measures is likely to be underestimated.

No information was available on the duration of the UHR allowance. Hence, it was assumed to accrue over the entire period of un/employment resulting from the implementation of the mitigation measure. Also, no data were available on opportunities for the unemployed to partake in informal activities that generate income in cash or kind.

Value of Non-working Time

In moving from unemployment to employment, an individual faces a loss of leisure time, which has some value. In accordance with Markandya (1998), non-working time

[12] “*Social Security Statistics 1991/92 – 1995/96*”, **Economic and Social Indicators**, an Occasional Paper, Issue No. 265, Ministry of Economic Development and Regional Co-operation, Port Louis, Mauritius (February, 1998).

was valued at 15 percent of the gross wage rate. The estimated annual value of non-work time for employees in the sugar cane, sugar milling, electricity / water, construction, transport, and engineering and architectural service sectors is therefore 7,426 Rs, 9,618 Rs, 15,007 Rs, 14,897 Rs, 8,265 Rs and 14,287 Rs, respectively.

Value of Health Related Impacts

It is generally accepted that people in employment are healthier and have greater life expectancy than those who are unemployed. A selection of studies was reviewed in Markandya (1998), where the author concludes that the excess mortality from unemployment in men of employable age may be taken as 75 per cent, with a range from 45 to 110 per cent. In other words, the average death rate of unemployed individuals is about 75 per cent greater than the average death rate for the male population as a whole.

Estimated death rates for persons of working age in the Republic of Mauritius are given in Table 13. Based on the data reported in Table 13, excess death rates for persons of working age were computed, assuming an excess mortality rate of 75 per cent. The results are given in Table 12 below.

Table 12 Excess Mortality Rates among the Unemployed.

	Excess Death Rates		
Age Group	Male	Female	Both Sexes
(Years)	(Deaths per 1,000 persons per year)		
0 to 4	0.6	0.3	0.5
5 to 9	1.0	0.5	0.7
10 to 14	1.0	0.5	0.8
15 to 19	2.1	0.7	1.4
20 to 24	3.2	1.2	2.3
25 to 29	4.1	1.4	2.8
30 to 34	6.4	2.8	4.6
35 to 39	10.3	4.9	7.5
40 to 44	15.8	7.4	11.4
45 to 49	20.9	13.3	16.9
	4.0	2.0	**3.0**

In the environmental economics literature, mortality impacts are valued by multiplying the change in risk of death by a “Value of a Statistical Life” (VOSL). In this case, the change in risk of death, as a result of being made employed, is given by the excess mortality rates shown in Table 12. Based on a VOSL for the United States of US$ 4.0 million (in 1995 prices), and adjusting for differences in *real* GDP, the estimated VOSL for Mauritius ranges from US$ 1.966 million (34.995 Rs million) to US$ 3.120 million (55.536 Rs million), for income elasticities of 1.00 and 0.35, respectively.

As it was not possible to obtain estimates of employment effects by age group and sex, the excess mortality rate for both sexes, averaged over all age groups, was used to estimate the change in risk of death as a result of being made employed. Hence, for an income elasticity of 1.00, the health benefit per person per annum is:

34.995 Rs million *x* 3.03 deaths / 1,000 persons of employable age = 105,860 Rs.

The health benefit increases to 168,274 Rs per person per annum, if the VOSL for Mauritius is based on an income elasticity of 0.35.

Net Value of Additional Job

As noted above, the net social benefit / cost of an additional job created / lost is equal to the net gain in income <u>minus</u> the value of foregone non-work time <u>plus</u> the value of any health related benefits. For each sector likely to experience employment effects as a result of the implementing the selected mitigation measures, the estimated net value of an additional job is given in Table 14.

Table 13 Estimated Death Rates for Persons of Working Age and Sex: Republic of Mauritius (1995).

Age Group	Estimated Resident Population (1995)			Deaths by Age Group and Sex			Death Rates		
	Male	Female	Both Sexes	Male	Female	Both Sexes	Male	Female	Both Sexes
(Years)	(Number)	(Number)	(Number)	(Number)	(Number)	(Number)	(Deaths per 1,000 persons per year)		
15 to 19	56,843	55,578	112,421	49	20	69	0.9	0.4	0.6
20 to 24	48,410	46,478	94,888	64	29	93	1.3	0.6	1.0
25 to 29	51,393	48,136	99,529	71	35	106	1.4	0.7	1.1
30 to 34	52,664	50,049	102,713	146	50	196	2.8	1.0	1.9
35 to 39	46,656	44,663	91,319	201	74	275	4.3	1.7	3.0
40 to 44	40,087	39,015	79,102	217	74	291	5.4	1.9	3.7
45 to 49	28,942	29,599	58,541	247	110	357	8.5	3.7	6.1
50 to 54	20,597	22,089	42,686	283	143	426	13.7	6.5	10.0
55 to 59	16,898	18,704	35,602	356	185	541	21.1	9.9	15.2
60 to 64	13,695	15,283	28,978	382	272	654	27.9	17.8	22.6
	376,185	369,594	**745,779**	2,016	992	**3,008**	5.4	2.7	**4.0**

Source: Table 1.14 and Table 5.5, in Digest of Demographic Statistics 1995, Central Statistical Office, Ministry of Economic Planning and Development, Port Louis, Mauritius (August, 1996).

Table 14 Net Value of Employment Gain (both sexes) by Affected Sector (1995 prices).

Relevant Sectors	Average (Gross) Earnings		Average (Net) Earnings		Value of Leisure Time	Unemployment Hardship Relief	Value of Health Benefits	Net Value of Employment Gain
	Monthly	Yearly	Tax Rate	Yearly				
	(Rs. per month)	(Rs. per annum)	(% of gross)	(Rs. per annum)	(Rs. per annum)	(Rs. per annum)	(Rs. per annum)	(Rs. per annum)
Suger Cane	4,126	49,506	0.352%	49,332	7,426	3,279	105,860	144,487
Manufacturing - Sugar Milling	5,344	64,122	1.100%	63,417	9,618	3,279	105,860	156,380
Electricity/Water	8,337	100,047	3.191%	96,855	15,007	3,279	105,860	184,429
Construction	8,276	99,315	2.363%	96,968	14,897	3,279	105,860	184,652
Transport - buses	4,592	55,099	0.633%	54,750	8,265	3,279	105,860	149,067
Engineering and Arch. Services	7,937	95,249	2.363%	92,998	14,287	3,279	105,860	181,292

Note: 1) The VOSL used to determine the health benefits is based on an income elasticity of 1.00. 2) The value of non-work time is taken as 15 per cent of the gross wage rate.

3.3 Income Distribution

3.3.1 Introduction

The costs of different GHG mitigation measures, as well as any related benefits, belong to individuals from different income classes. It is possible to explicitly incorporate distributional considerations into the social cost analysis by using distribution weights. Basically, this involves converting changes in income into changes in welfare, assuming that an addition to the welfare of a lower income person is worth more than to that of a richer person. A methodology for constructing distribution weights for use in the social cost assessment of GHG mitigation measures was presented in

Markandya (1998). Using this methodology, distribution weights have been developed for application in Mauritius as outlined below.

3.3.2 Estimates of Income Distribution Weights for Mauritius

The weights to be attached to costs and benefits accruing to groups *i* relative to costs and benefits accruing to a person with an average income are given by

$$SMU_i = \left[\frac{\bar{Y}}{Y_i}\right]^{\varepsilon}$$

where SMU_i is the social marginal utility of a small amount of income going to group *i* relative to income going to a person with the average *per capita income*; $\bar{Y}$ is the average per capita income; Y_i is the average income of individual *i*; and ε is the elasticity of the social marginal utility of income (or inequality aversion parameter).

Therefore, in order to construct weights for Mauritius, estimates of $\bar{Y}$ and ε are required. In addition, data is required on the income distribution of households; to facilitate the identification of Y_i. Based on the results of the 1996/97 Household Budget Survey, an income distribution for all households in Mauritius was constructed. This is shown in Table 15. As the table indicates, the average household income from all sources in 1996/97 was Rs 10,179.

Estimates of the inequality aversion parameter (ε) are unavailable for Mauritius. However, the literature has estimates for ε in the range 1 to 2. Although evidence exists for a value of ε of up to 2, Markandya (1998) notes that the implied weights for that number are quite extreme and may be questionable, and therefore suggests that a figure of 1 to 1.75 be used in any GHG limitation exercise. Consequently, income distribution weights for Mauritius have been estimated for inequality aversion parameters of 1, 1.5 and 1.75. The estimated weights are presented in Table 16.

Table 15 1996-1997 Household Budget Survey Results.

Monthly Income Rs. (1996-97)	Number of households in survey	% of total households surveyed	Number of HH in each income band	% of total income (survey)	Total income in each income band	Average income in each income band
< 1,000	26	0.42%	1,043	0.00%	-	-
1,001 to 1,500	148	2.37%	5,935	0.30%	7,634,250	1,286.27
1,501 to 2,000	68	1.09%	2,727	0.20%	5,089,500	1,866.35
2,001 to 3,000	282	4.52%	11,309	1.00%	25,447,500	2,250.21
3,001 to 4,000	385	6.18%	15,440	2.10%	53,439,750	3,461.23
4,001 to 5,000	569	9.13%	22,818	4.00%	101,790,000	4,460.87
5,001 to 6,000	577	9.26%	23,139	5.00%	127,237,500	5,498.78
6,001 to 7,000	613	9.83%	24,583	6.20%	157,774,500	6,418.05
7,001 to 8,000	509	8.16%	20,412	6.00%	152,685,000	7,480.07
8,001 to 9,000	553	8.87%	22,177	7.40%	188,311,500	8,491.38
9,001 to 10,000	367	5.89%	14,718	5.50%	139,961,250	9,509.74
10,001 to 12,000	582	9.34%	23,340	10.00%	254,475,000	10,903.07
12,001 to 14,000	389	6.24%	15,600	7.90%	201,035,250	12,886.93
14,001 to 16,000	294	4.72%	11,790	6.90%	175,587,750	14,892.71
16,001 to 20,000	329	5.28%	13,194	9.20%	234,117,000	17,744.50
20,001 to 25,000	204	3.27%	8,181	7.00%	178,132,500	21,774.08
25,001 >	339	5.44%	13,595	21.30%	542,031,750	39,870.51
Sub-total / Average	6,234	100.00%	250,000	100.00%	2,544,750,000	10,179.00

Source: Table 4 and Table 5, in Household Budget Survey 1996/1997, Central Statistical Office, Ministry of Economic Planning and Development, Port Louis, Mauritius.

Table 16 Income Distribution Weights for Mauritius.

Average income in each income band	Inequality Aversion Parameter		
	1.00	1.50	1.75
-	-	-	-
1,286.27	7.91	22.26	37.34
1,866.35	5.45	12.74	19.46
2,250.21	4.52	9.62	14.03
3,461.23	2.94	5.04	6.60
4,460.87	2.28	3.45	4.24
5,498.78	1.85	2.52	2.94
6,418.05	1.59	2.00	2.24
7,480.07	1.36	1.59	1.71
8,491.38	1.20	1.31	1.37
9,509.74	1.07	1.11	1.13
10,903.07	0.93	0.90	0.89
12,886.93	0.79	0.70	0.66
14,892.71	0.68	0.57	0.51
17,744.50	0.57	0.43	0.38
21,774.08	0.47	0.32	0.26
39,870.51	0.26	0.13	0.09
10,179.00	1.00	1.00	1.00

4 Assessment of GHG Limitation Projects

4.1 Introduction

In this section each of the selected GHG limitation projects is examined in detail. The FICOSTEF and FUCOSTEF are computed for each measure, and sensitivity analyses conducted around key variables. The six selected GHG limitation projects involve:

1. Installing a wind farm with 30 MW declared net capacity.
2. Increasing the average annual electricity tariff by 10 per cent per annum relative to the forecast annual value.
3. Replacing 125 streetlights (currently connected to the electricity grid) with 125 photovoltaic (PV) streetlights.
4. Replacing domestic electric water heaters with active solar water heaters.
5. Purchasing (and therefore generating) an additional 50 GWh per year from a mixture of bagasse and coal.
6. Replacing part of the current (diesel-powered) bus fleet with equivalent buses powered by LPG.

They are considered in turn below.

4.2 Wind Energy Development Programme

This GHG limitation project involves installing a wind farm, with 30 MW declared net capacity, somewhere on Mauritius.

4.2.1 Financial Cost Analysis

Investment Expenditure and Annual Recurring Costs

The capital cost of wind turbines (including the purchase price of the turbines and the direct/indirect installation costs) ranges from approximately £840 to £1,680 (in 1995 prices) per KW of installed capacity[13]. Based on the mid-point of £1,260 per kW, the total capital cost of the 30 MW wind farm is £37.8 million (or 1,061.7 Rs million). The annual operating and maintenance costs are typically expressed as a fraction of the total capital costs. The European Wind Energy Association has estimated this fraction to be 0.025, i.e. 2.5 per cent of the capital costs[14]. Hence, the annual operating and maintenance costs of the wind farm are about 26.5 Rs. million.

Of course, for every unit of electricity generated by the wind farm, a unit of electricity is not generated by one of the oil-fired power stations. This has an annual resource saving which must be deducted from the recurring costs of the wind farm to arrive at the net recurring costs of the mitigation project. For the year ended 31st December 1996, generation expenses (thermal), direct overheads (thermal), and depreciation on generation assets amounted to 1,275.4 Rs million[15]. Over the same period, the thermal stations generated 918.3 GWh. Unit expenses were therefore about Rs 1.38 per kWh.

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13 ETSU (1994), **An Assessment of Renewable Energy for the UK**, A report prepared for the Department of Trade and Industry (DTI) by the Energy Technology Support Unit (ETSU), London, HMSO.

14 EWEA (1991) **Time for Action: Wind Energy in Europe**, European Wind Energy Association.

15 CEB (1997), **Annual Report 1996**, Central Electricity Board, Curepipe, Mauritius.

Analysis of the same data for the oil-fired stations for the year ended 31st December 1997, reveals similar unit costs (total expenses including depreciation of 1,137.3 Rs million were incurred in generating 822.3 GWh of electricity)[16].

Therefore, for every 1 kWh of electricity not generated by the thermal power stations operated by the CEB, it has been assumed that 1.38 Rs is saved[17]. Total annual savings associated with the wind farm thus amount to 90.67 Rs million. Consequently the net recurring costs (savings) of the wind farm are negative 64.12 Rs million. These costs will be incurred for 15 years, which is the typical useful operating life of wind turbines (ETSU, 1994).

Environmental Performance

The electrical output of a wind turbine (in kWh) can be estimated by using the following formula[18]:

$$E = (h \times P_r \times F_C) \times W_T \tag{4}$$

where h is the number of hours in a year (i.e. 8,760); P_r is the rated power output of each turbine in kilowatts; F_C is the net annual capacity factor of the turbines at the site; and W_T is the number of wind turbines at the site. Wind turbines may have power ratings anywhere between 100 and 700 kW; most commercial sites however, have turbines with power ratings closer to 400 kW. Assuming that the turbines to be installed in Mauritius have this power rating, then 75 units are required (i.e. 30 MW divided by 400 kW).

On moderate wind speed sites in the UK, with annual mean wind speeds of about half the turbine's rated wind speed, a capacity factor of 25 per cent is typical. At higher wind speed sites however, capacity factors between 30 and 40 per cent are feasible. Based on a capacity factor of 25 per cent, the average annual output of a 30 MW wind farm is given by

$$65{,}700{,}000\ \text{kWh} = \left(8{,}760\ \text{hours} \times 400 \frac{\text{kW}}{\text{turbine}} \times 0.25\right) \times 75\ \text{turbines}.$$

Therefore, 65.7 GWh of electricity currently generated from fuel oil is no longer required. Recall from Figure 2, for every 1 GWh of electricity generated from this fuel source, 213 tonnes of fuel oil are burned. As the wind farm displaces 65.7 GWh of electricity, the combustion of 14,025 tonnes of fuel oil is therefore avoided. The total annual saving in GHGs is then found by using equation 3, and the appropriate emission factors contained in Table 1 and Table 3. Hence, the annual GHG savings of the wind farm are given by

$$43.8\ \text{kt CO}_2\ \text{eq.} = 14{,}025\ \text{t}_{\text{FO}} \times \left[1 \times 3.11 \frac{\text{t CO}_2}{\text{t}_{\text{FO}}} + 21 \times 0.135 \frac{\text{kg CH}_4}{\text{t}_{\text{FO}}} \times 10^{-3} + 310 \times 24.12 \frac{\text{g N}_2\text{O}}{\text{t}_{\text{FO}}} \times 10^{-6}\right]$$

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16 The unit costs of the wind farm are approximately 2.53 Rs. per kWh; assuming recovery of the capital over 15 years at 10 per cent.

17 In this case, the CEB must still transmit electricity from the wind farm to its customers; therefore (unit) transmission and distribution costs have been excluded from estimates of resource savings.

18 Taylor, D., (1996), "Wind Energy", in Boyle, G. (ed.), **Renewable Energy: Power for a Sustainable Future**, Oxford: Oxford University Press in association with the Open University.

The (Financial) Cost-effectiveness Criterion

The cost-effectiveness criterion used in this study is defined by the net present value cost per ton of GHG (CO_2 equivalent) removed (as calculated by equation 1). Estimates of the (financial) cost-effectiveness of the wind farm are given in Table 17. The central estimate, based on a discount rate of 10 per cent applied to both cost and environmental performance data, is 1,725 Rs per tonne CO_2 eq. abated (or US$ 97 per tonne CO_2 eq.).

Key sensitivities relate to the choice of the following parameters: the unit capital cost; the annual capacity factor; and the average cost of electricity generated from oil-fired stations. For the central case:

- If the capital costs were assumed to be 23,594 Rs and 47,188 Rs per KW of installed capacity, the FICOSTEF changes to 459 and 2,990 Rs per tonne CO_2 eq. abated, respectively.
- If capacity factors of between 30 and 40 per cent are achievable the corresponding measures of FICOSTEF are 1,092 and 301 Rs per tonne CO_2 eq. abated.
- If the average generation cost were to increase or decrease by 10 per cent, the estimate of FICOSTEF changes to 1,517 and 1,932 Rs per tonne CO_2 eq. abated, respectively.

Table 17 Estimated FICOSTEF of Wind Farm.

CO_2 equivalent reductions discounted at:		
5 per cent	454,231	tonnes CO_2 equivalent
10 per cent	332,854	tonnes CO_2 equivalent
15 per cent	255,890	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	396.2	Rs million
10 per cent	574.0	Rs million
15 per cent	686.8	Rs million
FICOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	1,548	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	1,725	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	1,512	Rs per tonne CO_2 equivalent

4.2.2 Social Cost Analysis

The social cost-effectiveness criterion is also defined by equation 1; except now the cost component is expanded to include the valuation of impacts associated with secondary emission savings, changes in employment and costs/benefits accruing to different income groups, where appropriate. Impacts of the measure on other macroeconomic issues and on sustainability more generally, are also considered.

Secondary Emission Savings

Installation of the proposed wind farm will displace 65.7 GWh of electricity currently generated from fuel oil. This, in turn, will result in the combustion of 14,025 fewer tonnes of fuel oil. Not only will this reduce GHG emissions, but emissions of other “classical” air pollutants will also be reduced. Based on the emission factors given in Table 3, estimated annual savings of SO_2, NO_x and PM emissions are 778.4, 103.8 and 14.0 tonnes, respectively. The total annual value of these secondary emission savings is 1.84 Rs million (based on the mid-point between the adjusted unit damage costs for the UK and Germany listed in Table 5). These benefits will accrue over the useful life of the wind farm. The PV of this stream of secondary benefits, by discount rate is:

- 19.1 Rs million (at 5 per cent);
- 14.0 Rs million (at 10 per cent); and
- 10.8 Rs million (at 15 per cent).

Employment Effects

In this case, *direct* employment effects are most likely to be associated with the initial investment expenditure. The purchase and installation of the wind turbines will require the services of the construction and engineering sectors. The employment impact on these sectors is approximated using the employment/output ratios given in Table 10; specifically, changes in employment are estimated by multiplying the employment/output ratios by the total capital expenditure on the wind farm. As explained earlier, it is assumed that only 15 per cent of the estimated number of jobs created/lost will actually result in a change in the level of unemployment[19]. A further assumption is required to distribute the capital expenditure between the construction and engineering sectors. It is assumed that 90 per cent of the costs accrue to the construction sector; the remaining 10 per cent accrue to the engineering sector.

Therefore, the estimated change of employment in the construction and engineering sector are respectively:

$$467 \text{ jobs} = 1{,}061.74 \text{ Rs million} \times 3.26 \frac{\text{employees}}{\text{Rs million}} \times 0.90 \times 0.15 \text{ and}$$

$$18 \text{ jobs} = 1{,}061.74 \text{ Rs million} \times 1.10 \frac{\text{employees}}{\text{Rs million}} \times 0.10 \times 0.15 .$$

The estimated net value of an additional job in each of these sectors was given in Table 14. Based on these values, the total employment benefit (in terms of welfare gains resulting from unemployment avoided) associated with introducing the wind farm is about 89.9 Rs million. This benefit will only accrue in year zero. Clearly, operating and maintaining the wind farm will require labour. It has been assumed, however, that any additional labour required to operate the wind farm will be met by persons currently employed at the oil-fired power stations. (It may be the case that reductions in output from the oil-fired stations gives rise to job losses.)

The Economic (Social) Cost-effectiveness Criterion

Without data on the cost implication for domestic customers, (although it is expected that additional costs incurred by the CEB will be passed onto customers), it is not possible to assess issues arising from impacts accruing to different income groups[20]. In

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[19] To recapitulate this approach to estimating net employment effects is crude, and the results should therefore be treated as ‘order of magnitude’ estimates only.

[20] To weight the impacts accruing to different income groups, one must be able to identify the “additional” cost (in the form of increased electricity tariffs), incurred by each income group. Moreover, it would be desirable to take into account changes in consumption patterns as the cost burden of the wind farms is passed onto customers.

this case, the total economic cost stream is therefore equal to financial cost stream less the value of secondary emission savings and (net) employment benefits. Estimates of the economic (social) cost-effectiveness of the wind farm are given in Table 18. The central estimate is 1,412 Rs per tonne CO_2 eq. abated (or US$ 79 per tonne CO_2 eq.).

It is interesting to note that if no scaling factor is used, the PV of the stream of secondary emission benefits increases dramatically to:

- 1,173.9 Rs million (at 5 per cent);
- 860.2 Rs million (at 10 per cent); and
- 661.3 Rs million (at 15 per cent).

For each of the discount rates considered, the use of these unadjusted values would result in net economic benefits per tonne CO_2 equivalent abated.

Table 18 Estimated FUCOSTEF of Wind Farm.

CO_2 equivalent reductions discounted at:		
5 per cent	454,231	tonnes CO_2 equivalent
10 per cent	332,854	tonnes CO_2 equivalent
15 per cent	255,890	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	287.2	Rs million
10 per cent	470.1	Rs million
15 per cent	586.1	Rs million
FUCOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	1,122	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	1,412	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	1,290	Rs per tonne CO_2 equivalent

Sustainability Indicators

The issue of sustainability arises because environmentalists are concerned that policies implemented should contribute to the longer-term resolution of the conflicts between the protection of the natural environment and economic development. In the context of GHG limitation projects it is the ‘strong’ sustainability notion that is the important one. In developing policies for this area, importance should be given to the achievement of the goals of sustainable resource use and protection of critical natural capital. In addition greater importance should be paid to the long-term implications of any policies introduced today.

Table 2 in Markandya (1998) provides a list of the main sustainability indicators that should be considered for GHG limitation projects in each of the following key areas: energy, forestry, transport and land use / agriculture.

With respect to the proposed wind farm, two key indicators of sustainability are relevant:

- The change in the share of total energy from renewable sources at the beginning and at the end of the policy time horizon.

- Any impacts on biodiversity or natural assets.

In 1995 the thermal power station operated by the CEB burning a combination of diesel, fuel oil and kerosene, generated 788 GWh of energy. This is equivalent to just over 75 per cent of energy produced. Hydropower facilities, operated by the CEB and Independent Power Producers (IPP), generated 134 GWh (just under 13 per cent of energy produced). The sugar factories produced the remaining 125 GWh (or 12 per cent of energy produced); of this amount, 4 per cent was generated from coal and 8 per cent from bagasse. In 1995, therefore, about 21 per cent of all energy produced were from renewable sources; 79 per cent was from non-renewable fossil fuels. The impact of the wind farm, which would generate 68 GWh per annum, would be to increase the relative share of energy produced from renewable sources to 27 per cent (relative to the 1995 base case).

A typical "medium-scale" commercial wind farm in the UK requires between 3 to 5 hectares of land per turbine[21]. This implies that the proposed wind farm in Mauritius (comprising 75 turbines) would cover an area ranging from 225 to 375 hectares. Either of these represent considerably less than 1 per cent of the total area of the Island of Mauritius.

4.3 Change in the Retail Price of Electricity

Predictions of energy demand were made by the Mauritian authorities to provide a basis for forecasting GHG emissions for the country's "business-as-usual" scenario[22]. As part of this exercise, electricity demand was forecast using an econometric model and an energy end-use model. Of particular interest here, the econometric model used predicted levels of GDP and average electricity tariffs (in constant 1995 prices) as explanatory variables. This GHG limitation project involves increasing the average electricity tariffs used in the econometric model by 10 per cent per annum, and observing the change in predicted electricity sales / generation. Savings in GHGs are then calculated from the resulting reduction in fuel oil consumption.

4.3.1 Financial Cost Analysis

Investment Expenditure and Annual Recurring Costs

Electricity was forecast by means of ordinary least squares regression analysis. The model used was of the following form[23]:

$$E_t = c + \alpha Y_t + \beta P_t + \delta E_{t-1} + \mu_t \qquad (5)$$

Where E_t are electricity sales in year *t*; c is a constant (intercept term); Y_t is real GDP (Rs billion) at constant 1995 prices in year *t*; P_t is the real price of a unit of electricity in constant 1995 prices in year *t*; and μ_t is a random error term. Electricity sales are used as a proxy for electricity demand. Using time series data on GDP, unit electricity prices and annual electricity sales, estimates were made of the coefficients in equation 5. These are given in Table 19. Using the estimated coefficients forecasts of electricity sales were made based on the growth assumptions contained in Table 20.

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21 ExternE (1995), **Externalities of Energy – Vol. 6: Wind and Hydro**, European Commission, DGXII, Luxembourg.

22 Energy Sector: Baseline Scenario 1995-2020", Mid-term Report, A paper provided by the National Climate Committee, Technical Working Group on the Economics of Greenhouse Gas Limitation.

Table 19 Coefficients for Electricity Demand Model.

Parameter	Coefficient	Standard Error	t-statistic
c	0.240060	0.059416	4.0404
Y_t	0.500220	0.071674	6.9791
P_t	-0.094768	0.028887	-3.2807
E_{t-1}	0.672930	0.046371	14.5120

Note: The values of the coefficients are based on our own regression analysis, as a result they differ slightly from those found in "Energy Sector: Baseline Scenario 1995-2020", Mid-term Report, A paper provided by the National Climate Committee, Technical Working Group on the Economics of Greenhouse Gas Limitation.

In developing a baseline for Mauritius, output from the econometric model was only used for the period 1997 to 2009, thereafter the energy end-use model was used. As we are assessing the performance of each GHG limitation measure relative the "business-as-usual" scenario, it therefore seems appropriate that we restrict the analysis of this measure, which is based on the econometric model, to the same time period. Hence, the chosen time horizon is 12 years (i.e. 1997 to 2009).

Table 20 Assumptions Underpinning the Electricity Sales Forecasts.

GDP Growth					
Period	1996-2000	2001-2005	2006-2010	2011-2015	2016-2020
(percentage)	5.8	6.0	6.0	5.9	5.7
Evolution of the price of a unit of electricity					
Period	1995-1997	1998-2004	2005-2010	2011-2015	2016-2020
(Rs per kWh)	2.17	2.50	2.88	3.31	3.81

Source: "Energy Sector: Baseline Scenario 1995-2020", Mid-term Report, A paper provided by the National Climate Committee, Technical Working Group on the Economics of Greenhouse Gas Limitation.

The resulting electricity sales forecasts for the period 1997 to 2009 are in Table 21 below. To convert this into generation requirements in each year, the sales estimate needs to be grossed up to account for transmission and distribution losses. It is assumed that current loss levels of 14 per cent will be experienced over the forecast period. For example, the model forecasts electricity sales in 1998 of 1,147.3 GWh. In order to deliver this amount of electricity to customers, 1,334.1 GWh needs to be generated (i.e. 1,147.3 GWh $\div 0.86$), to account for the fact that 186.8 GWh is lost during distribution.

[23] A capital letter denotes the natural logarithm of the variable in question.

Table 21 Electricity Sales and Generation Forecasts.

Year	GDP (Rs billion)	Unit Price Electricity (Rs per kWh)	Electricity Sales (GWh)	Electricity Generation (GWh)
1997	76.6	2.17	1,069.7	1,243.8
1998	81.0	2.50	1,147.3	1,334.1
1999	85.7	2.50	1,237.1	1,438.5
2000	90.7	2.50	1,338.9	1,556.9
2001	96.0	2.50	1,452.8	1,689.3
2002	101.8	2.50	1,580.5	1,837.8
2003	107.9	2.50	1,722.1	2,002.4
2004	114.4	2.50	1,878.7	2,184.5
2005	121.3	2.88	2,023.9	2,353.4
2006	128.6	2.88	2,191.0	2,547.7
2007	136.3	2.88	2,379.3	2,766.6
2008	144.5	2.88	2,589.7	3,011.3
2009	153.2	2.88	2,823.0	3,282.6

This GHG limitation measure involves increasing the average electricity tariffs used in the econometric model by 10 per cent per annum. Hence, the model was re-run with electricity unit prices 10 per cent higher than the values used in the original forecasts. The results are presented in Table 22. The cost and environmental performance of this measure is determined from the difference between the annual generation figures given in Table 21 and those presented in Table 22 below.

Table 22 New Electricity Sales and Generation Forecasts (10 per cent increase in electricity unit price).

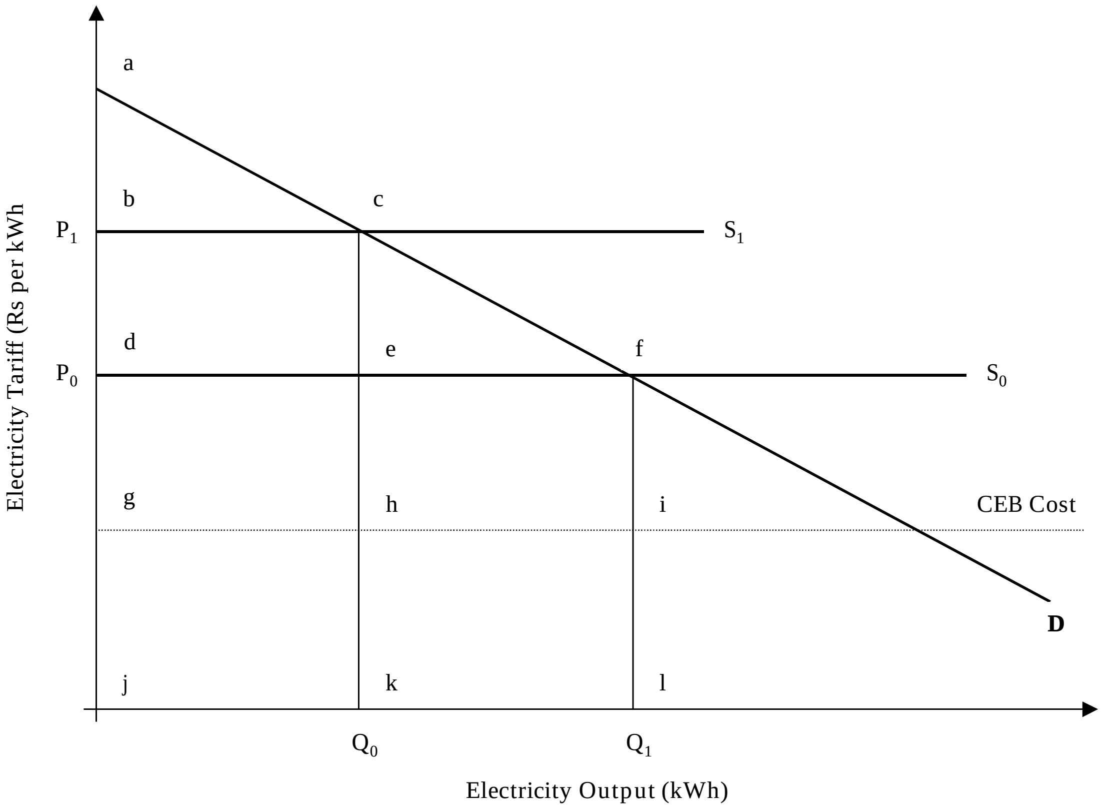
Year	GDP (Rs billion)	Unit Price Electricity (Rs per kWh)	Electricity Sales (GWh)	Electricity Generation (GWh)
1997	76.6	2.39	1,060.0	1,232.6
1998	81.0	2.75	1,137.0	1,322.1
1999	85.7	2.75	1,226.0	1,425.6
2000	90.7	2.75	1,326.9	1,542.9
2001	96.0	2.75	1,439.7	1,674.1
2002	101.8	2.75	1,566.3	1,821.3
2003	107.9	2.75	1,706.7	1,984.5
2004	114.4	2.75	1,861.8	2,164.9
2005	121.3	3.17	2,005.6	2,332.1
2006	128.6	3.17	2,171.2	2,524.7
2007	136.3	3.17	2,357.8	2,741.6
2008	144.5	3.17	2,566.2	2,984.0
2009	153.2	3.17	2,797.4	3,252.8

The (financial) cost of this measure is best illustrated with the use of Figure 3[24]. Under the “business-as-usual” scenario, customers are faced with supply curve S_0, and subject to their demand curve (D), will purchase Q_0 of electricity at price P_0. The area **dflj** represents the total amount paid by customers for Q_0. With this GHG limitation project the price faced by customers is increased from P_0 to P_1 (i.e. the market supply curve shifts from S_0 to S_1). This leads to a fall in the amount demanded from Q_0 to Q_1. Customers now pay an amount equivalent to the area **bckj** for the electricity they consume. The financial cost of the proposed change in unit price is simply the increase in unit price (P_1 minus P_0) multiplied by the size of the market after the price increase has been introduced. This is given by the rectangle **bced** (i.e. **bckj** minus **dflj**), which is basically a measure of the extent to which customers are financially worse-off as a result of the price increase. For example, the (financial) cost of the proposed measure in 1997 is given by

$$233.2\ \text{Rs million} = \left(2.39\frac{\text{Rs}}{\text{kWh}} - 2.17\frac{\text{Rs}}{\text{kWh}}\right) \times 1{,}060.0\ \text{GWh} \times 10^6\ \frac{\text{kWh}}{\text{GWh}}.$$

The (financial) cost for each year of the project, over the selected time horizon, is presented in Table 23.

Figure 3 Costs of Price Increase.



24 This figure will also serve as the basis for deriving a measure of the social costs of this project.

Table 23 Estimated (Financial) Cost per Annum (1995 prices).

Year	Change in Electricity Generation (GWh)	Initial Unit Price of Electricity (Rs per kWh)	New Unit Price of Electricity (Rs per kWh)	Financial Cost to Customers (Rs million)
1997	11.3	2.17	2.39	233.2
1998	12.0	2.50	2.75	284.3
1999	12.9	2.50	2.75	306.5
2000	14.0	2.50	2.75	331.7
2001	15.2	2.50	2.75	359.9
2002	16.5	2.50	2.75	391.6
2003	17.9	2.50	2.75	426.7
2004	19.7	2.50	2.75	465.5
2005	21.3	2.88	3.17	581.6
2006	23.0	2.88	3.17	629.6
2007	25.0	2.88	3.17	683.8
2008	27.3	2.88	3.17	744.2
2009	29.8	2.88	3.17	811.2

Environmental Performance

For every 1 GWh of electricity generated from CEB's oil-fired power stations, 213 tonnes of fuel oil are burned. Therefore, taking 1997 as an example, increasing the retail price of electricity by 10 per cent will ultimately result in an 11.3 GWh reduction in generation. This, in turn, results in 2,407.7 fewer tonnes of fuel oil being combusted. Using the appropriate emission factors contained in Table 1 and Table 3, the corresponding annual GHG savings in 1997 are given by

$$7.5\,\text{kt CO}_2\text{ eq.} = 2{,}407.7\,\text{t}_{\text{FO}} \times \left[1 \times 3.11\frac{\text{t CO}_2}{\text{t}_{\text{FO}}} + 21 \times 0.135\frac{\text{kg CH}_4}{\text{t}_{\text{FO}}} \times 10^{-3} + 310 \times 24.12\frac{\text{g N}_2\text{O}}{\text{t}_{\text{FO}}} \times 10^{-6}\right]$$

Annual GHG savings for each year over the selected time horizon have been calculated in a similar fashion. The results are presented in Table 24.

Table 24 Estimated GHG Emission Savings.

Year	Change in Electricity Generation (GWh)	Change in Fuel Oil Input (tonnes)	GHG Emission Savings (tonnes CO_2 eq.)
1997	11.3	2,407.7	7,512.8
1998	12.0	2,556.6	7,977.5
1999	12.9	2,755.2	8,597.1
2000	14.0	2,978.6	9,294.2
2001	15.2	3,251.6	10,146.1
2002	16.5	3,524.7	10,998.1
2003	17.9	3,822.5	11,927.5
2004	19.7	4,194.9	13,089.3
2005	21.3	4,542.4	14,173.6
2006	23.0	4,914.7	15,335.4
2007	25.0	5,336.7	16,652.1
2008	27.3	5,833.1	18,201.1
2009	29.8	6,354.4	19,827.6

The (Financial) Cost-effectiveness Criterion

Estimates of the (financial) cost-effectiveness of this mitigation measure (as calculated by equation 1) are given in Table 25. The central estimate, based on a discount rate of 10 per cent applied to both cost and environmental performance data, is 37,195 Rs per tonne CO_2 eq. abated (or US$ 2,090 per tonne CO_2 eq.).

The key sensitivity concerning the FICOSTEF relates to the assumed annual increase in the price of a unit of electricity[25]. For the central case:

- If the assumed price increase is only 5 per cent the PV costs and emission savings reduce to 1,661.1 Rs million and 45,700 tonnes CO_2 eq., respectively. The corresponding FICOSTEF is 36,348 Rs per tonne CO_2 eq. abated.
- If the assumed price increase is 8 per cent the PV costs and emission savings reduce to 2,616.5 Rs million and 71,016 tonnes CO_2 eq., respectively. The corresponding FICOSTEF is 36,843 Rs per tonne CO_2 eq. abated.
- If the assumed price increase is 12 per cent the PV costs and emission savings increase to 3,939.0 Rs million and 105,050 tonnes CO_2 eq., respectively. The corresponding FICOSTEF is 37,496 Rs per tonne CO_2 eq. abated.

Clearly, changing this assumption has no significant impact on the FICOSTEF; only the PV of the cost and emission saving streams show any change of note.

[25] And of course, the assumptions underpinning the electricity demand model. However, the accuracy of these parameters is not tested here.

Table 25 Estimated FICOSTEF of Proposed Increase in the Unit Price of Electricity.

CO_2 equivalent reductions discounted at:	
5 per cent	117,488 tonnes CO_2 equivalent
10 per cent	88,294 tonnes CO_2 equivalent
15 per cent	69,135 tonnes CO_2 equivalent
PV of total cost stream discounted at:	
5 per cent	4,426.7 Rs million
10 per cent	3,284.1 Rs million
15 per cent	2,539.9 Rs million
FICOSTEF with costs and GHG reductions discounted at	
5 per cent; 15 per cent	64,030 Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	37,195 Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	21,618 Rs per tonne CO_2 equivalent

4.3.2 Social Cost Analysis

Adjustment to Financial Cost

The financial cost of the proposed change in unit price is given by the increase in unit price (P_1 minus P_0) multiplied by the size of the market after the price increase has been introduced. A measure of the extent to which customers are made financially worse-off, as a result of the price increase, is not the true economic costs of the project. With reference to Figure 3, the true economic cost of the price increase is equal to the value of the output that is lost (Q_0 minus Q_1) because some customers consume less as the price rises. This value is given by the difference between what each unit could have sold for, and what it cost to produce.

The amount a unit could have sold for, is given by the demand curve. For example, the value of the Q_0'th unit is P_0, as this is what the market price would have to be for demand to equal exactly Q_0. The value of the Q_1'th unit is P_1, as the market price would exactly P_1 if the level of output was Q_1. The value of all intermediate units along the demand curve from Q_1 to Q_0 can also be read directly from the demand curve. The total market value of the units that each unit could have sold for (i.e. what each unit could have sold for) is the area **cflk**. The cost of producing the output between from Q_1 and Q_0 is given by the CEB's cost curve; it is given by the area **hilk**. Therefore, the true economic cost of this project is given by the area **cflh** (i.e. **cflk** minus **hilk**).

In the wind farm example, each 1 kWh of electricity generated by CEB's thermal power stations was assumed to cost the CEB 1.38 Rs. In this case, however, the CEB also does not have to transmit the electricity from its thermal stations to its customers. Therefore (unit) transmission and distribution costs should be included. For the year ended 31st December 1996 transmission and distribution expenses amounted to 195.4 Rs million[26]. Unit (distribution and transmission) expenses were therefore about Rs 0.22 per kWh. Resource (cost) savings to the CEB should thus be valued at 1.60 Rs per kWh.

Values for P_0, P_1, Q_0 and Q_1 are given above. Taking 1997 for example, the economic cost of the proposed price increase is given by

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[26] CEB (1997), *op. cit.*

$$6.6\,\text{Rs million} = \left[\left(2.39\frac{\text{Rs}}{\text{kWh}} - 2.17\frac{\text{Rs}}{\text{kWh}}\right)\times 9.7\,\text{GWh}\times 10^{6}\,\frac{\text{kWh}}{\text{GWh}}\times 0.5\right] +$$
$$\left[\left(2.17\frac{\text{Rs}}{\text{kWh}} - 1.60\frac{\text{Rs}}{\text{kWh}}\right)\times 9.7\,\text{GWh}\times 10^{6}\,\frac{\text{kWh}}{\text{GWh}}\right]$$

Similar calculations have been performed for each year over the selected time horizon. The PV of the resulting (economic) cost stream, by discount rate is:

- 106.6 Rs million (at 5 per cent);
- 79.9 Rs million (at 10 per cent); and
- 62.4 Rs million (at 15 per cent).

Secondary Emission Savings

The annual amount of electricity, currently generated from fuel oil, displaced by the proposed price increase, was shown in Table 23. The corresponding reductions in fuel oil use were given in Table 24. Based on the emission factors presented in Section 3, annual savings in SO_2, NO_x and PM emissions were estimated; these are given in Table 26 below. The total annual value of these secondary emission savings is also presented in the table. (Again based on the mid-point between the adjusted unit damage costs for the UK and Germany). The PV of the stream of secondary benefits shown in Table 26, by discount rate is:

- 4.9 Rs million (at 5 per cent);
- 3.7 Rs million (at 10 per cent); and
- 2.9 Rs million (at 15 per cent).

If no scaling factor is used to modify the unit damage costs, then the PV of the stream of secondary benefits becomes, by discount rate:

- 303.6 Rs million (at 5 per cent);
- 228.2 Rs million (at 10 per cent); and
- 178.7 Rs million (at 15 per cent).

Employment Effects

There are no observable capital expenditures associated with this measure, therefore, no direct employment effects are anticipated in the construction and engineering sectors. However, demand for electricity is reduced annually relative to the "business-as-usual" scenario. The resulting reductions in generation may lead to job losses at the CEB. Assuming that this is the case, the employment effect on the CEB has been estimated and valued as above; changes in employment in the CEB are based on the employment intensity per unit of electricity sold (from Table 10). Taking 1997 for example, electricity sales are forecast to decline by 9.7 GWh, as a result of the proposed price increase. The estimated change in employment is given by

$$-3\,\text{jobs} = -9.7\,\text{GWh}\times 2.12\,\frac{\text{employees}}{\text{GWh}}\times 0.15\,.$$

As the quantity of electricity generated declines over time, the estimated number of job losses per annum will increase.

Table 26 Time Profile of Secondary Emission Savings and Benefits: Retail Price Change.

Year	SO_2 Emission Savings	Value of Emission Savings	NO_x Emission Savings	Value of Emission Savings	PM Emission Savings	Value of Emission Savings	Total Value of Savings
	(tonnes SO_2)	(Rs.)	(tonnes NO_x)	(Rs.)	(tonnes PM)	(Rs.)	(Rs.)
1997	133.6	284,681	17.8	20,907	2.4	10,887	316,475
1998	141.9	302,291	18.9	22,200	2.6	11,560	336,050
1999	152.9	325,769	20.4	23,924	2.8	12,458	362,151
2000	165.3	352,183	22.0	25,864	3.0	13,468	391,515
2001	180.5	384,467	24.1	28,235	3.3	14,702	427,404
2002	195.6	416,750	26.1	30,606	3.5	15,937	463,293
2003	212.2	451,968	28.3	33,192	3.8	17,284	502,444
2004	232.8	495,991	31.0	36,425	4.2	18,967	551,384
2005	252.1	537,079	33.6	39,443	4.5	20,539	597,060
2006	272.8	581,102	36.4	42,676	4.9	22,222	646,000
2007	296.2	630,995	39.5	46,340	5.3	24,130	701,464
2008	323.7	689,692	43.2	50,650	5.8	26,375	766,717
2009	352.7	751,324	47.0	55,177	6.4	28,731	835,232

The total employment cost (as we are talking about making previously employed persons unemployed) associated with the proposed increases in the retail price of electricity, by discount rate, are (see Table 27)

- 8.9 Rs million (at 5 per cent);
- 6.7 Rs million (at 10 per cent); and
- 5.3 Rs million (at 15 per cent).

Table 27 Estimated Employment Effects (10 per cent increase in electricity unit price).

Year	CEB Change in Employment (employees)	Value of Change in Employment (Rs million)
1997	5	0.92
1998	5	0.92
1999	5	0.92
2000	6	1.11
2001	6	1.11
2002	7	1.29
2003	7	1.29
2004	8	1.48
2005	8	1.48
2006	9	1.66
2007	10	1.84
2008	11	2.03
2009	12	2.21

Distribution Impacts

With the use of Figure 3 it is possible to dissaggregate the cost of the measures between consumers and producers (i.e. the CEB). Basically, the total annual cost comprises two components:

- the (net) gain by the CEB; and
- the (net) loss by consumers.

Respectively, each of these components is formerly given by

$$[(P_1 - P_0) \times Q_1] - [(P_0 - C_{\mathrm{CEB}}) \times (Q_1 - Q_0)] \text{ and} \tag{6}$$

$$[(P_1 - P_0) \times Q_1] + 0.5 \times [(P_1 - P_0) \times (Q_1 - Q_0)]. \tag{7}$$

The financial cost calculated above is given by the first part of both equations. Since it is simply a transfer of income from consumers to the CEB (i.e. it is a transfer payment), it has no net impact on social welfare. This is only true to the extent that impacts to both groups are weighted equally. The loss to consumers could be weighted using the distribution weights given in Table 16. To do this however, one must be able to dissaggregate domestic electricity demand by income group, and then predict how demand within each income group changes as the price of electricity rises. Data was not available to undertake such an exercise. Nonetheless, to illustrate the distribution of the total annual cost between customers and the CEB, disaggregated cost data is presented in Table 28. Recall, the net economic cost of the projects is given by the difference between equation 6 and 7.

Table 28 Distribution of Annual Costs (1995 prices).

Year	Financial Cost to Customers (Rs million)	Net Gain by the CEB (Rs million)	Net Loss by Customers (Rs million)	Net Economic Cost (Rs million)
1997	233.2	227.7	234.3	6.6
1998	284.3	278.4	385.5	7.2
1999	306.5	300.2	307.9	7.7
2000	331.7	324.9	333.2	8.3
2001	359.9	352.5	361.6	9.1
2002	391.6	383.5	393.4	9.9
2003	426.7	417.9	428.6	10.7
2004	465.5	455.8	467.6	11.7
2005	581.6	571.2	584.3	13.1
2006	629.6	618.4	632.5	14.2
2007	683.8	671.5	686.9	15.4
2008	744.2	730.8	747.6	16.8
2009	811.2	796.7	815.0	18.3

The Economic (Social) Cost-effectiveness Criterion

As it is not possible to quantify distributional issues in this case, the total social cost stream is equal to adjusted financial cost stream less the value of secondary emission savings and (net) employment benefits (which are negative). Estimates of the economic (social) cost-effectiveness of the proposed programme of electricity price increases are given in Table 29. The central estimate is 959 Rs per tonne CO_2 eq. abated (or US$ 54 per tonne CO_2 eq.).

The use of unadjusted values for assessing the benefits of secondary emission savings would result in net economic *benefits* per tonne CO_2 equivalent abated.

Table 29 Estimated FUCOSTEF of Proposed Increase in the Unit Price of Electricity.

CO_2 equivalent reductions discounted at:		
5 per cent	117,488	tonnes CO_2 equivalent
10 per cent	88,294	tonnes CO_2 equivalent
15 per cent	69,135	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	110.6	Rs million
10 per cent	83.0	Rs million
15 per cent	64.8	Rs million
FUCOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	1,632	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	959	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	563	Rs per tonne CO_2 equivalent

Sustainability Indicators

This GHG limitation project is not foreseen to have any significant impact on any of the sustainability indicators contained in Table 2 in Markandya (1998); except that by reducing fuel oil consumption one conserves non-renewable petroleum resources.

4.4 Introduction of PV Street Lighting

In this case the proposed GHG limitation project involves replacing 125 streetlights (currently connected to the electricity grid) with 125 photovoltaic (PV) streetlights. 'Photovoltaic' is the term used to describe the process of converting solar energy directly into electricity in a solid-state device.

4.4.1 Financial Cost Analysis

Investment Expenditure and Annual Recurring Costs

The capital cost of a PV Module ranges from approximately £2.68 to £7.37 (in 1995 prices) per peak watt of output (W_p)[27]. Total investment expenditure will also include the so-called "balance of system" (BOS) costs, i.e. the cost of the interconnection of modules to form arrays, the array support structure, the cost of cabling, charge regulators, switching and inverters, plus the cost of storage batteries. BOS costs are typically 50 per cent of the Module costs[28]. The total investment cost of a PV system is therefore approximately £4.02 to £11.06 per W_p. The total investment cost of the PV streetlight system is estimated using the mid-point of this range, i.e. £7.54 per W_p. It is estimated (see below) that in order to supply the required amount of electricity, the specification of each PV Module should be at least 876 W_p. Given that 125 units are required, the total investment cost amounts to about £825,356 (or 23.2 Rs million).

Annual operating and maintenance costs, typical of small-remote systems, range from 0.26 pence per kWh to 0.96 pence per kWh[29]. Again, annual O & M costs of the PV streetlight system are estimated using the mid-point of this range, i.e. 0.61 pence per kWh. In order to meet the energy requirements of the 125 streetlights, the PV system must supply 182,500 kWh per annum. Hence, annual O & M costs are about £1,113 (or 31,269 Rs).

As with the previous GHG limitation project, the CEB does not have to transmit the electricity from its thermal stations to the modified streetlights. Therefore (unit) transmission and distribution costs should be included in the estimate of resource savings. Resource savings are therefore valued at 1.60 Rs per kWh.

Total annual savings associated with the PV streetlight system thus amount to 292,000 Rs. Consequently the net recurring costs (savings) of this project are negative 260,731 Rs. These cost savings will be incurred for 20 years, which is the typical useful operating life of small-remote PV Modules (ETSU, 1994).

Environmental Performance

The 125 streetlights identified for replacement are currently supplied with an estimated 500 kWh per day (or 1,460 kWh per unit per year). The annual output of the PV streetlight system is therefore 182,500 kWh.

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[27] ETSU (1994), *op cit*.

[28] Boyle, G. (1996), "Solar Photovoltaics", in Boyle, G. (ed.), **Renewable Energy: Power for a Sustainable Future**, Oxford: Oxford University Press in association with the Open University.

[29] ETSU (1994), *op cit*.

The electrical output of a PV Module (in kWh) may be approximated using the following formula[30]:

$$E = \frac{W_p \times I_s}{k \times (1 + l)} \qquad (8)$$

where W_p is the peak watt output of the Module; I_s is the annual average solar insulation; k is a constant reflecting the fact that W_p is measured when the sunlight intensity peaks at 1,000 watts per m^2 at 25 $^{\circ}$C at standard air conditions; and l is the percentage of on-site power losses. Values of I_s, as expected, are highest near the equator, over 2,000 kWh per m^2 per year. Estimates of on-site power losses are variable; a value of 20 per cent is used here, although losses can be as high as 30 per cent. Given that each PV Module must produce 1,460 kWh per annum, equation 6 can be solved for W_p. The required peak watt output of each Module is therefore 876 W_p. This was used to determine the total investment costs of the system (see above).

For every 1 GWh of electricity generated from fuel oil, 213 tonnes of fuel oil are burned. The proposed PV streetlight system displaces 0.183 GWh of electricity, therefore, 39 fewer tonnes of fuel oil are combusted. The total annual saving in GHGs is given by

$$122 \text{ t } CO_2 \text{ eq.} = 39 \text{ t}_{FO} \times \left[1 \times 3.11 \frac{\text{t } CO_2}{\text{t}_{FO}} + 21 \times 0.135 \frac{\text{kg } CH_4}{\text{t}_{FO}} \times 10^{-3} + 310 \times 24.12 \frac{\text{g } N_2O}{\text{t}_{FO}} \times 10^{-6} \right].$$

The (Financial) Cost-effectiveness Criterion

Based on equation 1, estimates of the (financial) cost-effectiveness of the PV streetlight system are given in Table 30. The central estimate, based on a discount rate of 10 per cent applied to both cost and environmental performance data, is 20,256 Rs per tonne CO_2 eq. abated (or US$ 1,138 per tonne CO_2 eq.).

Key sensitivities relate to the choice of the following parameters: the unit capital cost; the unit O & M costs; the on-site power loss factor; and the average cost of electricity generated / distributed from oil-fired stations. For the central case:

- If the investment costs were assumed to be 122.9 Rs and 310.5 Rs per W_p, the FICOSTEF changes to 9,802 and 30,710 Rs per tonne CO_2 eq. abated, respectively.
- If the two end-points for O & M costs were used, i.e. 0.07 Rs and 0.27 Rs per KWh, the FICOSTEF changes to 20,108 and 20,404 Rs per tonne CO_2 eq. abated, respectively.
- If on-site power losses are 10 or 40 per cent (as opposed to 20 per cent) the corresponding measures of FICOSTEF are 18,389 and 22,123 Rs per tonne CO_2 eq. abated.
- If the average generation / transmission cost were to increase or decrease by 10 per cent, the estimate of FICOSTEF changes to 20,016 and 20,496 Rs per tonne CO_2 eq. abated, respectively.

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30 Taylor, D.(1996), "Wind Energy", in Boyle, G. (ed.), **Renewable Energy: Power for a Sustainable Future**, Oxford: Oxford University Press in association with the Open University.

Clearly, the value of FICOSTEF is most influenced by the assumed (unit) investment cost.

Table 30 Estimated FICOSTEF of PV Streetlights.

CO_2 equivalent reductions discounted at:		
5 per cent	1,514.91	tonnes CO_2 equivalent
10 per cent	1,034.91	tonnes CO_2 equivalent
15 per cent	760.88	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	19.9	Rs million
10 per cent	21.0	Rs million
15 per cent	21.6	Rs million
FUCOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	26,198	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	20,256	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	14,226	Rs per tonne CO_2 equivalent

Sustainability Indicators

The proposed PV lighting system affects one key indicator of sustainability. The indicator is the change in the share of total energy derived from renewable sources at the beginning and at the end of the policy time horizon.

In 1995 less than 21 per cent of all energy produced in Mauritius were from renewable sources. Introduction of the 125 PV streetlight units, which would generate 0.183 GWh per annum, would have a negligible impact on the relative share of energy produced from renewable sources (an increase of less than half of one per cent).

4.5 Introduction of Solar Water Heaters

This GHG mitigation project involves replacing electric water heaters in domestic premises with solar thermal water heaters. In contrast to photovoltaics where solar energy is directly converted into electricity, the solar water heating system is a type of active solar heating whereby energy from the sun is first collected, typically by roof panels. The collected solar energy drives a heat engine, which produces mechanical work to drive an electrical generator. The electricity from the generator, in turn, heats the water.

4.5.1 Financial Cost Analysis

Investment Expenditure and Annual Recurring Costs

Based on figures provided by the Mauritian authorities, a new solar water heater (installed) costs between 12,000 Rs and 20,000 Rs[31]. Capital costs are estimated using the mid-point of this range, i.e. 16,000 Rs.

[31] New electric water heaters cost between 2,000 Rs and 4,000 Rs each. In this case study we only consider replacing existing heaters with new solar heaters. Therefore the appropriate capital cost is the full price of a new solar heater (ignoring the value of any residual capital). If we were to consider installing solar water heaters however, as opposed to electric water heaters, in new properties, then the appropriate capital cost is the difference between the two heating systems.

Annual O & M costs are negligible (ETSU, 1994). It is therefore assumed that there is no difference in annual O & M costs between the two heating systems, i.e. incremental O & M costs are assumed to be zero. Nonetheless, the electricity bill of households that install solar water heaters will be reduced by the value of the output of the heaters. It is estimated that each heater will reduce annual purchases of electricity from the CEB by 320 kWh (see below). The average tariff charged to domestic customers in 1995/6 was 2.18 Rs per kWh. Households that install the solar heaters can therefore be expected to save 698 Rs per annum.

The annual saving to households however, is actually a loss to the CEB in terms of reduced turnover[32]. To generate and distribute the electricity the CEB incurs expenses of 1.60 Rs per kWh. The true financial saving associated with supplying 320 fewer kWh annually to each household is therefore 512 Rs per annum (i.e. 320 kWh *x* 1.60 kWh). These savings will be incurred for 20 years, which is the assumed useful operating life of the water heaters.

Environmental Performance

In 1996 the CEB sold about 358 GWh to what it classifies as domestic customers. The domestic customer base for that year was 245,769. Therefore, average annual consumption per customer (household) was 1,456 kWh. Based on surveys conducted in the UK, an estimated 22 per cent of electrical energy delivered to households is used to heat water[33]. Assuming that the same percentage is applicable to Mauritius (no figure was available), it is assumed that the average household uses 320 kWh of delivered electricity per annum for heating water (i.e. 22 per cent of 1,456 kWh).

A single solar water heater is therefore assumed to result in 68.4 fewer kilograms of fuel oil being combusted annually. The corresponding annual saving in GHGs is given by

$$0.2134\ \mathrm{t\ CO_2\ eq.} = 0.0684\ \mathrm{t_{FO}} \times \left[1 \times 3.11 \frac{\mathrm{t\ CO_2}}{\mathrm{t_{FO}}} + 21 \times 0.135 \frac{\mathrm{kg\ CH_4}}{\mathrm{t_{FO}}} \times 10^{-3} + 310 \times 24.12 \frac{\mathrm{g\ N_2O}}{\mathrm{t_{FO}}} \times 10^{-6}\right].$$

The (Financial) Cost-effectiveness Criterion

Based on a discount rate of 10 per cent applied to both cost and environmental performance data, the estimated (financial) cost-effectiveness of a single solar water heater is 6,405 Rs per tonne CO_2 eq. abated (or US$ 360 per tonne CO_2 eq.). Of greater interest however, are the costs and GHG reductions associated with a programme of replacing electric water heaters with solar powered ones.

At present about 20,000 households in Mauritius have solar water heaters; this leaves 225,769 households with electric water heaters. Assuming that 40 per cent of the latter will install solar heaters over a 5-year period (from 1997 to 2001), at the end of the period an additional 90,308 households will have solar heaters. The investment programme implied by these assumptions is illustrated in Table 31. Column II in Table 31 will dictate the total capital expenditure made in any year. Similarly, annual resource savings will be a function the values reported in column III.

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[32] That is, it represents a transfer of wealth between consumers and producers.

[33] Henderson, G. and Shorrock, L. (1989), **Domestic Energy Fact File**, Building Research Establishment: HMSO. Based on a 1993 up-date to the Fact File.

Table 31 Assumed Penetration of Solar Water Heaters.

Year	Penetration per Year[1]	Accumulated Penetration[2]
0	18,062	-
1	18,062	18,062
2	18,062	36,123
3	18,062	54,185
4	18,062	72,246
5	-	90,308
6	-	90,308
↓	↓	↓
20	-	90,308

Notes: 1) Number of (new) units installed by end of year. 2) Accumulated number of (new) units operating from the beginning of the year.

Estimates of the (financial) cost-effectiveness of the penetration programme described above are given in Table 32. The central estimate is 6,722 Rs per tonne CO_2 eq. abated (or US$ 378 per tonne CO_2 eq.).

Key sensitivities relate to the choice of the following parameters: the unit capital cost; the average cost of electricity generated / distributed from oil-fired stations; the percentage of electrical energy delivered to households used to heat water; and the number of years required to achieve the maximum penetration rate. For the central case:

- If the investment costs were assumed to be 12,000 Rs and 20,000 Rs, the FICOSTEF changes to 4,441 and 9,003 Rs per tonne CO_2 eq. abated, respectively.
- If the average generation / transmission cost were to increase or decrease by 10 per cent, the estimate of FICOSTEF changes to 6,165 and 6,963 Rs per tonne CO_2 eq. abated, respectively.
- If the percentage of electrical energy delivered to households used to heat water is 12 or 32 per cent (as opposed to 22 per cent) the corresponding measures of FICOSTEF are 14,326 and 3,871 Rs per tonne CO_2 eq. abated.
- If the period over which the maximum penetration rate is achieved changes to 3 or 10 years, the FICOSTEF becomes 6,556 and 7,210 Rs per tonne CO_2 eq. abated, respectively.

Changing the maximum feasible penetration rate does not effect the value of FICOSTEF. The value of FICOSTEF is most influenced by the percentage of electrical energy delivered to households which is assumed to be used to heat water, as this dictates the magnitude of the annual resource saving to be set against the initial capital outlay. Increasing this percentage is synonymous with assuming that the solar units will produce an amount of electricity in excess of the amount required solely to heat water, and which in turn can be used for other purposes. Restricting the amount of energy generated by the solar units to 320 kWh per annum is probably an unrealistic assumption given the relatively high solar radiation levels in Mauritius.

The previous analysis is based on the assumption that households will voluntarily replace their existing water heaters with solar powered ones, in the absence of external incentives. In reality, this is unlikely. If incentives were used, however, this may have a bearing on the cost data, and should therefore be taken into account.

Table 32 Estimated FICOSTEF of Solar Water Heater Investment Programme.

CO_2 equivalent reductions discounted at:		
5 per cent	205,154	tonnes CO_2 equivalent
10 per cent	132,066	tonnes CO_2 equivalent
15 per cent	91,200	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	821	Rs million
10 per cent	888	Rs million
15 per cent	895	Rs million
FUCOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	9,001	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	6,722	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	4,362	Rs per tonne CO_2 equivalent

4.5.2 Social Cost Analysis

Secondary Emission Savings

The proposed solar water heater investment programme will displace varying amounts of electricity until the maximum penetration target is achieved. Thereafter, the amount displaced will remain constant over the selected time horizon. The changes in the amount of fuel oil combusted will follow a similar pattern. Estimated annual savings in SO_2, NO_x and PM emissions over the 20-year time horizon are shown in Table 33. The total annual value of these secondary emission savings is also shown in the table. The PV of the stream of secondary benefits depicted in Table 33, by discount rate, is:

- 8.6 Rs million (at 5 per cent);
- 5.6 Rs million (at 10 per cent); and
- 3.8 Rs million (at 15 per cent).

Employment Effects

Direct employment effects associated with the proposed investment programme are most likely to be associated with the initial investment expenditures, which accrue over a period of 5 years. Again, the employment impacts associated with installing the water heaters will be felt by the construction and engineering sectors. By the time the target rate of penetration is achieved, domestic customers will demand 43.4 fewer GWh of electricity from the CEB. This may result in a limited number of redundancies. The employment effects on all three sectors have been estimated and valued as above, changes in employment in the CEB are based on the employment intensity per unit of electricity sold from Table 10. The total employment benefit associated with the solar heater investment programme is about 90.5 Rs million (see Table 34).

Operating and maintaining the solar water heaters is not assumed to impose any additional burden on household residents.

Table 33 Time Profile of Secondary Emission Savings and Benefits.

Year	SO_2 Emission Savings (tonnes SO_2)	Value of Emission Savings (Rs.)	NO_x Emission Savings (tonnes NO_x)	Value of Emission Savings (Rs.)	PM Emission Savings (tonnes PM)	Value of Emission Savings (Rs.)	Total Value of Savings (Rs.)
0	-	-	-	-	-	-	-
1	68.6	146,043	9.1	10,725	1.2	5,585	162,353
2	137.1	292,086	18.3	21,450	2.5	11,170	324,706
3	205.7	438,129	27.4	32,176	3.7	16,755	487,059
4	274.2	584,171	36.6	42,901	4.9	22,339	649,412
5	342.8	730,214	45.7	53,626	6.2	27,924	811,765
↓	↓	↓	↓	↓	↓	↓	↓
20	342.8	730,214	45.7	53,626	6.2	27,924	811,765

Distribution Effects

In the situation described above, the full cost of the solar water heater is borne by households. It is therefore possible to make some assessment of the distributional effects of these costs on different income groups. Using the distribution weights given in Table 16, the adjusted cost of a water heater to a household within each income group is provided in Table 35. For example, the adjusted cost of a solar heater to a household with average annual income of 77,017 Rs, ranges from 25,736 Rs to 35,863 Rs, depending on the value adopted for the inequality aversion parameter. To build these adjusted costs into the social cost analysis however, one needs to know the extent of technology penetration per income band. Unfortunately, this information is not available at present. The distributional effects of this project are not therefore reflected in the estimates of FUCOSTEF to follow.

Table 34 Net Employment Effects: Solar Water Heater Investment Programme.

Year	CEB Change in Employment (employees)	Value of Change in Employment (Rs. million)	Construction Change in Employment (employees)	Value of Change in Employment (Rs. million)	Bus. Services Change in Employment (employees)	Value of Change in Employment (Rs. million)	Net Value of Employment Change (Rs. million)
0	-	-	127	23.5	5	0.91	24.46
1	2	0.37	127	23.5	5	0.91	24.09
2	4	0.74	127	23.5	5	0.91	23.72
3	6	1.11	127	23.5	5	0.91	23.35
4	7	1.29	127	23.5	5	0.91	23.17
5	9	1.66	-	-	-	-	1.66
↓	↓	↓	↓	↓	↓	↓	↓
20	9	1.66	-	-	-	-	1.66

The Economic (Social) Cost-effectiveness Criterion

Due to a lack of data to permit further assessment of the distributional effects of the project, the total economic cost stream is equal to financial cost stream less the value of secondary emission savings and (net) employment benefits. Estimates of the economic (social) cost-effectiveness of the solar water heater investment programme are given in Table 36. The central estimate is 5,995 Rs per tonne CO_2 eq. abated (or US$ 337 per tonne CO_2 eq.).

Again, if no scaling factor is used, the PV of the stream of secondary emission benefits increases significantly, thereby reducing the economic cost per tonne CO_2 equivalent abated. For example, the PV of secondary emission savings with no scaling is 341.3 million benefits (discounted at 10 per cent). The corresponding value of FUCOSTEF is 3,453 Rs per tonne CO_2 eq. abated (or US$ 194 per tonne CO_2 eq.).

Table 35 Adjust Cost to Households of Solar Water Heaters.

Average income in each income band	Number of HH in each income band	Adjusted Cost (Rs per HH)		
		1.00	1.50	1.75
(Rs per annum)	(number)			
15,435	5,935	126,617	356,189	597,412
22,396	2,727	87,263	203,792	311,434
27,003	11,309	72,377	153,937	224,499
41,535	15,440	47,054	80,692	105,670
53,530	22,818	36,509	55,150	67,783
65,985	23,139	29,618	40,298	47,004
77,017	24,583	25,376	31,958	35,863
89,761	20,412	21,773	25,399	27,433
101,897	22,177	19,180	21,000	21,973
114,117	14,718	17,126	17,718	18,022
130,837	23,340	14,937	14,433	14,187
154,643	15,600	12,638	11,232	10,589
178,712	11,790	10,936	9,041	8,221
212,934	13,194	9,178	6,952	6,050
261,289	8,181	7,480	5,114	4,229
478,446	13,595	4,085	2,064	1,467
122,148	248,957			

Table 36 Estimated FUCOSTEF of Solar Water Heater Investment Programme.

CO_2 equivalent reductions discounted at:		
5 per cent	205,154	tonnes CO_2 equivalent
10 per cent	132,066	tonnes CO_2 equivalent
15 per cent	91,200	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	718.9	Rs million
10 per cent	791.8	Rs million
15 per cent	804.8	Rs million
FUCOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	7,883	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	5,995	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	3,923	Rs per tonne CO_2 equivalent

Sustainability Indicators

As with the PV street lighting system, one key indicator of sustainability is affected by the solar water heater investment programme; the change in the share of total energy derived from renewable sources at the beginning and at the end of the policy time horizon.

In 1995 less than 21 per cent of all energy produced in Mauritius were from renewable sources. Implementation of the proposed investment programme in solar water heaters, which would generate a minimum of 28.9 GWh per annum (by the time the maximum penetration target had been achieved) would increase the relative share of energy produced from renewable sources to 23.6 per cent (relative to the 1995 base case).

It must be re-stressed that total amount of energy produced from this project depends greatly on the assumptions adopted regarding the number of households converting to solar powered water heaters, and the amount of electricity generated by the solar units.

4.6 Increased Use of Bagasse as Fuel Source

This GHG limitation project involves purchasing an "additional" 50 GWh per year from a mixture of bagasse and coal[34]. The 50 GWh is "additional" in the sense that it is "over and above" the amounts given in the "Power Development Plan", which outlines the CEB's plans to meet future electricity demand[35]. As with the other limitation measures the 50 GWh per year from the mixture of bagasse and coal will displace an equivalent amount of electricity generated from fuel oil.

4.6.1 Financial Cost Analysis

Investment Expenditure and Annual Recurring Costs

In this case, the cost analysis is based on (unit) price differentials between each of the fuel sources, i.e. bagasse, coal and fuel oil. Consequently, there are no directly observable capital expenditures. This is not to say that, in order to produce an additional 50 GWh per annum, the sugar factories will not need to make some investments in capital. Rather, it is assumed that the annual cost (depreciation and interest costs) of any required capital expenditure is recovered through the tariff charged to the CEB.

For every additional unit of electricity purchased from the sugar factories, the CEB can generate one less unit of electricity from its oil-fired power stations. The CEB, in turn, will save 1.38 Rs (the average unit generation expense of the thermal stations) per unit of electricity not generated. Therefore, the CEB will save about 69.0 Rs million annually from its thermal power station operations. At the same time however, the CEB must pay for the 50 GWh of electricity supplied by the sugar factories. For the purpose of this study it is assumed that the average generation costs for a sugar factory (firm supply) are 1.67 Rs per kWh and 1.50 Rs per kWh, for electricity derived from bagasse and coal, respectively[36].

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[34] It is assumed that the 50 GWh will be supplied by a so-called "firm" power facility (i.e. electricity will be available all year, even out of the crop season). To this end, the facility must be capable of burning a combination of bagasse and coal, to ensure that it can operate when bagasse is unavailable.

[35] Energy Sector: Baseline Scenario 1995-2020", Mid-term Report, A paper provided by the National Climate Committee, Technical Working Group on the Economics of Greenhouse Gas Limitation.

[36] These figures are based on a review of output and cost data for Independent Power Producers supplied by the Mauritian authorities.

Clearly, the total cost of electricity supplied by the sugar factories will depend on the relative share of the 50 GWh derived from bagasse and coal respectively. Of the total amount of electricity generated from this source in the base year, approximately 65 per cent were generated from bagasse, while about 35 per cent were generated from coal. For the central case, it is assumed that the same relative shares will be maintained over the selected time horizon, which is 20 years. Therefore, the annual cost of electricity generated from bagasse and coal is, respectively:

$$54.3\,\text{Rs million} = 50\,\text{GWh} \times 1.67\frac{\text{Rs}}{\text{kWh}} \times 0.65 \text{ and}$$

$$26.3\,\text{Rs million} = 50\,\text{GWh} \times 1.50\frac{\text{Rs}}{\text{kWh}} \times 0.35\,.$$

The total annual cost of this GHG limitation project is thus 11.6 Rs million (i.e. 54.3 + 26.3 – 69.0 Rs million). These costs will be incurred for 20 years, starting in year zero.

Environmental Performance

The proposal involves the CEB purchasing an "additional" 50 GWh per year, generated by sugar factories from a mixture of bagasse and coal. Clearly, the combustion of coal produces GHG emissions (see Table 1 and Table 3), and thus increased emissions from the combustion of coal must be deducted from the emission savings resulting from the decrease in fuel oil use, to arrive at the net annual GHG savings from this mitigation project. As was the case with the annual cost of the project, this will depend on the relative share of the 50 GWh derived from bagasse (as opposed to coal). The assumed relative shares of each fuel were given above.

As 50 GWh of electricity from oil-fired stations is displaced, 10,673 fewer tonnes of fuel oil are combusted. The annual GHG savings are thus given by

$$33.3\,\text{kt CO}_2\text{ eq.} = 10{,}673\,\text{t}_{\text{FO}} \times \left[1 \times 3.11\frac{\text{t CO}_2}{\text{t}_{\text{FO}}} + 21 \times 0.135\frac{\text{kg CH}_4}{\text{t}_{\text{FO}}} \times 10^{-3} + 310 \times 24.12\frac{\text{g N}_2\text{O}}{\text{t}_{\text{FO}}} \times 10^{-6}\right]$$

Assuming that 35 per cent of the 50 GWh is generated from coal, an additional 12,963 tonnes of coal are burned per annum (see Figure 2). The annual gain in GHG emissions from the increased coal usage is found by using equation 3, and the appropriate emission factors contained in Table 1 and Table 3. Hence, the annual gain in GHGs is given by

$$32.1\,\text{kt CO}_2\text{ eq.} = 12{,}963\,\text{t}_{\text{C}} \times \left[1 \times 2.46\frac{\text{t CO}_2}{\text{t}_{\text{C}}} + 21 \times 0.264\frac{\text{kg CH}_4}{\text{t}_{\text{C}}} \times 10^{-3} + 310 \times 36.344\frac{\text{g N}_2\text{O}}{\text{t}_{\text{c}}} \times 10^{-6}\right]$$

Net annual GHG savings from this project are therefore equal to 1.2 kt CO_2 eq. These savings will accrue annually over the selected time horizon.

The above estimated GHG savings are based on an observed coal conversion efficiency of 18.72 per cent. Some of the new power facilities will however, have significantly better conversion efficiencies of nearly 24 per cent. If this higher efficiency is achievable, then only an additional 10,112 tonnes of coal input is required to generate 35 per cent of 50 GWh. The annual gain in GHGs is now given by

$$25.0\,\text{kt CO}_2\text{ eq.} = 10{,}112\,\text{t}_{\text{C}} \times \left[1 \times 2.46\frac{\text{t CO}_2}{\text{t}_{\text{C}}} + 21 \times 0.264\frac{\text{kg CH}_4}{\text{t}_{\text{C}}} \times 10^{-3} + 310 \times 36.344\frac{\text{g N}_2\text{O}}{\text{t}_{\text{c}}} \times 10^{-6}\right]$$

The corresponding net annual GHG savings are 8.3 kt CO_2 eq., considerably higher than with the lower coal conversion efficiency.

The (Financial) Cost-effectiveness Criterion

Estimates of the net present value cost per ton of GHG (CO_2 equivalent) removed are given in Table 37. The central estimate, based on a coal conversion efficiency of 24 per cent and a discount rate of 10 per cent, is 1,397 Rs per tonne CO_2 eq. abated (or US$ 78 per tonne CO_2 eq.).

Key sensitivities relate to the choice of the following parameters: the unit generation costs for each fuel; the coal conversion efficiency; and relative shares of total output generated from bagasse and coal. For the central case:

- If the average generation costs (fuel oil) were to increase or decrease by 10 per cent, the estimate of FICOSTEF changes to 561 and 2,232 Rs per tonne CO_2 eq. abated, respectively.
- If the average generation costs (bagasse) were to increase or decrease by 10 per cent, the estimate of FICOSTEF changes to 2,054 and 740 Rs per tonne CO_2 eq. abated, respectively.
- If the average generation costs (coal) were to increase or decrease by 10 per cent, the estimate of FICOSTEF changes to 1,715 and 1,079 Rs per tonne CO_2 eq. abated, respectively.
- If the coal conversion efficiency is 18.72 per cent, the corresponding FICOSTEF is 9,627 Rs per tonne CO_2 eq. abated.
- If the relative share of total output generated from bagasse and coal at the *beginning* of the time horizon is 50 / 50, the corresponding FICOSTEF is 11,541 Rs per tonne CO_2 eq. abated.
- If the relative share of total output generated from bagasse and coal at the *end* of the time horizon is 50 / 50, the corresponding FICOSTEF is 2,495 Rs per tonne CO_2 eq. abated.
- If the relative share of total output generated from bagasse and coal at the *beginning* and *end* of the time horizon is 50 / 50, the corresponding FICOSTEF is negative 4,149 Rs per additional tonne CO_2 eq. emitted (i.e. GHG emissions actually increase under this scenario).

Table 37 Estimated FICOSTEF of Purchasing an Additional 50 GWh from Bagasse/Coal.

CO_2 equivalent reductions discounted at:		
5 per cent	111,173	tonnes CO_2 equivalent
10 per cent	78,564	tonnes CO_2 equivalent
15 per cent	59,949	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	155.3	Rs million
10 per cent	109.7	Rs million
15 per cent	83.7	Rs million
FUCOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	2,590	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	1,397	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	753	Rs per tonne CO_2 equivalent

4.6.2 Social Cost Analysis

Secondary Emission Savings

The proposed project will displace 50 GWh of electricity currently generated from fuel oil. This will result in the combustion of 10,673 fewer tonnes of fuel oil with the corresponding reduction in emissions of other air pollutants. However, increased emissions from the combustion of coal must be deducted from the secondary emission savings resulting from the decreased use of fuel oil, in order to arrive at the net annual savings in SO_2, NO_x and PM emissions. Recall, relative to the baseline, an additional 10,112 tonnes of coal is burned as part of this project (based on the higher efficiency).

Based on the emission factors given in Table 3, estimated (net) annual savings in SO_2, NO_x and PM emissions are 338.6, 30.4 and 0.6 tonnes, respectively. The total annual value of these secondary emission savings, which will accrue over 20 years, is 759,519 Rs. The PV of this stream of secondary benefits, by discount rate is:

- 10.2 Rs million (at 5 per cent);
- 7.2 Rs million (at 10 per cent); and
- 5.5 Rs million (at 15 per cent).

If the lower conversion efficiency is used estimated (net) annual savings in SO_2, and NO_x emissions are 267.0 and 16.8 tonnes respectively, and PM emissions actually increase by 2.3 tonnes. The total annual value of these secondary emission savings is 578,156 Rs, and the PV of this stream of secondary benefits, by discount rate is:

- 8.9 Rs million (at 5 per cent);
- 7.4 Rs million (at 10 per cent); and
- 5.0 Rs million (at 15 per cent).

The above values are probably overestimates, in that secondary emissions from the combustion of bagasse are not included due to a lack of emission factors.

Employment Effects

In this case, as no observable initial investments are required, there are no perceived employment impacts on the construction and engineering sectors. The proposed project involves decreasing output from the CEB, while simultaneously increasing output from the sugar factories. The former may result in a limited number of redundancies at the CEB's thermal stations; whereas the latter may result in some job creation at the sugar factories. The estimated change of employment in each sector is respectively:

$$-14 \text{ jobs} = -50 \text{ GWh} \times 1.81 \frac{\text{employees}}{\text{GWh generated}} \times 0.15 \quad \text{and}$$

$$10 \text{ job} = \left(1.67 \frac{\text{Rs}}{\text{kWh}} \times 32.5 \text{ GWh} + 1.50 \frac{\text{Rs}}{\text{kWh}} \times 17.5 \text{ GWh} \right) \times 0.83 \frac{\text{employees}}{\text{Rs million}} \times 0.15 .$$

The total employment cost (loss in welfare) associated with this project is therefore about 1.01 Rs million per annum. The value of the unemployment created at the CEB is greater than the value of the unemployment avoided by the new positions at the sugar factories. Due to a lack of data, it is not possible to assess indirect employment effects associated with inter-industry demand between sugar milling and sugar cane production. Such indirect employment effects may be significant.

The Economic (Social) Cost-effectiveness Criterion

Domestic customers are unlikely to be affected by the introduction of the project. The distribution of the costs between different income groups is therefore not a concern and the total economic cost stream is equal to financial cost stream less the value of secondary emission savings and (net) employment benefits. Table 38 provides estimates of the economic (social) cost-effectiveness of purchasing an additional 50 GWh from sugar factories. The central estimate is 1,427 Rs per tonne CO_2 eq. abated (or US$ 80 per tonne CO_2 eq.).

If no scaling factor is used, the PV of the stream of secondary emission benefits increases to:

- 627.5 Rs million (at 5 per cent);
- 443.4 Rs million (at 10 per cent); and
- 338.3 Rs million (at 15 per cent).

For each of the discount rates considered, the use of these unadjusted values would result in net economic benefits per tonne CO_2 equivalent abated.

Table 38 Estimated FUCOSTEF of Purchasing an Additional 50 GWh from Bagasse/Coal.

CO_2 equivalent reductions discounted at:		
5 per cent	111,173	tonnes CO_2 equivalent
10 per cent	78,564	tonnes CO_2 equivalent
15 per cent	59,949	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	158.7	Rs million
10 per cent	112.1	Rs million
15 per cent	85.6	Rs million
FUCOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	2,647	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	1,427	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	770	Rs per tonne CO_2 equivalent

Sustainability Indicators

With respect to the proposed project one key indicators of sustainability is immediately relevant: the change in the share of total energy from renewable sources at the beginning and at the end of the policy time horizon. By increasing the annual amount of electricity generated from bagasse by 35 GWh the relative share of energy produced from renewable sources would increase by about 3 per cent, to just over 24 per cent (relative to the 1995 base case). Of course, this change depends on the assumed share of the additional output obtained from bagasse.

Although not quantifiable at present, increasing the generation capacity of the sugar mills will almost certainly place extra demands on the producers of sugar cane. This, in turn, may force sugar cane producers to increase production, which may place additional demands on the natural environment. It is therefore not inconceivable that biodiversity and natural capital indicators may be adversely impacts by this project.

4.7 Introduction of LPG Powered Buses

This GHG limitation project involves replacing part of the current (diesel-powered) bus fleet with equivalent buses powered by LPG. Results of comparative field trials of alternative road transport fuels have shown that the use of dedicated buses, i.e. those that are specifically designed with LPG engines rather than conversions from diesel buses, can result in reductions of direct and indirect GHGs[37]. However, buses converted to use LPG do not necessarily have lower emissions with respect to all pollutants[38]. Therefore, in this case study retrofitting diesel buses to run on LPG is not considered as a viable option; only original equipment manufactured (OEM) LPG buses are considered.

4.7.1 Financial Cost Analysis

Investment Expenditure and Annual Recurring Costs

Based on field trials conducted in the UK, the incremental cost of a new OEM LPG bus, relative to a new diesel bus of similar specification, is £12,500[39]. In the same field trials, the necessary re-fuelling infrastructure was estimated to cost between £300 and £800 per vehicle. All costs are in 1995 prices. Taking the mid-point of this range, the incremental capital cost of purchasing a new OEM LPG bus, as opposed to a new diesel bus, is £13,050.

The incremental annual recurring costs are computed for differences in fuel costs only; maintenance costs of both types of bus are assumed to be the same. Some additional costs may arise from needing to train drivers and maintenance staff, but no data is available on the likely magnitude of these costs.

Previously, it was estimated that each bus in Mauritius travels an average distance of 45,691 km per annum. Based on the field trials eluded to above, the fuel cost of an OEM LPG bus ranges from 3.985 to 9.672 pence per km (mid-point is 6.829 pence per km). Hence, the annual fuel cost per OEM LPG bus is approximately £3,120 (or 87,636 Rs). The fuel economy of a typical diesel bus in Mauritius is 0.284 litres per kilometre[40]. In 1995 a bus thus consumed on average about 12,976 litres of diesel[41]. Given that diesel fuel retailed for 5.50 Rs per litre[42], the annual fuel cost of a diesel bus is about 71,369 Rs. The (net) incremental recurring fuel cost is therefore, 16,267 Rs per bus per annum (i.e. 87,636 Rs minus 71,369 Rs). These net recurring costs are assumed to accrue annually over the useful operating life of typical OEM LPG bus, which is about 18 years.

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37 ETSU, (1997), **Comparative Field Trials of Alternative Road Transport Fuels**. Prepared by the Energy Technology Support Unit (ETSU), July 1997.

38 Greene, D., (1996), **Transportation & Energy**, Eno Transportation Foundation Inc., Lansdowne, VA.

39 ETSU, (1997), o*p cit*.

40 Energy Sector: Baseline Scenario 1995-2020", Mid-term Report, A paper provided by the National Climate Committee, Technical Working Group on the Economics of Greenhouse Gas Limitation.

41 That is, 45,691 km per bus per annum times 0.284 litres per kilometre.

42 From Table 3.1 in **Digest of Road Transport and Accident Statistics 1996**, Central Statistical Office, Ministry of Economic Development and Regional Co-operation, Port Louis, Mauritius (August, 1997).

Environmental Performance

For the transport sector the activity statistic chosen to forecast changes in emissions, was "the number of kilometres travelled per vehicle per year". The emission factors used to estimate changes in emission levels were thus expressed in terms of "emissions per km per vehicle". As noted above, each bus in Mauritius travels an average distance of 45,691 km per annum.

Using the emission factors contained in Table 3, the annual GHG saving associated with using an OEM LPG bus instead of a diesel-fuelled bus is given by:

$$2.03\,\mathrm{t\,CO_2\ eq.} = 45{,}691\frac{\mathrm{km}}{\mathrm{bus}\bullet\mathrm{yr}}\times\left[1\times 36.5\frac{\mathrm{g\,CO_2}}{\mathrm{km}} + 21\times -0.07\frac{\mathrm{g\,CH_4}}{\mathrm{km}} + 310\times 0.03\frac{\mathrm{g\,N_2O}}{\mathrm{km}}\right]\times 10^{-6}\,\frac{\mathrm{t}}{\mathrm{g}}$$

These savings will accrue annually over the operating life of the OEM LPG bus. Of course, this assumes that the total number of kilometres travelled per bus per year remains constant over time.

The (Financial) Cost-effectiveness Criterion

Based on a discount rate of 10 per cent applied to both cost and environmental performance data, the estimated (financial) cost-effectiveness of a single OEM LPG bus is 30,026 Rs per tonne CO_2 eq. abated (or US$ 1,687 per tonne CO_2 eq.). Of greater interest however, are the costs and GHG reductions associated with a programme of replacing diesel buses with OEM LPG buses.

At present, the general consensus is that alternative fuel technology is only cost-effective for commercial fleets, operating from a few central depots, with high annual mileage. Furthermore, inconveniences associated with slow refuelling, bulky storage tanks, and reduced range, tend to limit the appeal of alternative fuelled vehicles in the commercial market[43]. Consequently, the large-scale introduction of OEM LPG powered buses in Mauritius seems applicable only to operators of the four major bus fleets. The analysis is therefore restricted to these operators. The size of the four major bus fleet operators is given in Table 39. For the purpose of this analysis, the assumed objective to replace the current diesel-powered buses of the major operators with OEM LPG buses, following natural replacement rates.

Table 39 Major Bus Fleet Operators in Mauritius (1995).

Fleet Operator	Number of Buses (1995)
National Transport Corporation	460
United Bus Services	250
Triolet Bus Services	100
Rose Hill Bus Services	70
Total all operators	880

Between 1992 and 1996, an average of 174 buses per annum were registered in Mauritius. This figure is for all operators and includes market growth and replacement[44]. As of June 30th 1995, the total size of the bus fleet in Mauritius was 1,767.

43 Faiz, A., Weaver, C. and Walsh, M., (1996), *op cit*.

44 It is assumed that new registrations are a good proxy for new purchases.

Therefore, about 49.8 % of total buses in operation belong to major fleet operators (i.e. 880 ÷ 1,767). Assuming that the same proportion applies to new registrations, then on average 87 new buses were purchased by major fleet operators per annum. Given this replacement rate, it would take 10 years to supersede the majority of the current diesel fleet with an OEM LPG fleet.

The investment programme implied by these assumptions is illustrated in Table 40. Column II in will dictate the total capital expenditure made in any year. Similarly, incremental annual fuel costs and emissions savings will be a function the values reported in column III.

Table 40 Assumed Replacement Programme for OEM LPG Buses.

Year	Penetration per Year[1]	Accumulated Penetration[2]
0	87	-
1	87	87
2	87	173
3	87	260
4	87	347
5	87	433
6	87	520
7	87	607
8	87	693
9	87	780
10	-	867
↓	↓	↓
18	-	867

Notes: 1) Number of (new) OEM LPG buses purchased by end of year. 2) Accumulated number of (new) OEM LPG buses operating from the beginning of the year.

Estimates of the (financial) cost-effectiveness of the bus replacement programme described above are given in Table 43. The central estimate is 32,613 Rs per tonne CO_2 eq. abated (or US$ 1,832 per tonne CO_2 eq.).

Key sensitivities relate to the choice of the following parameters: the unit capital cost; the retail price of diesel oil; the LPG fuel cost per km; and the number of years taken to achieve the replacement target. For the central case:

- If the total incremental investment cost was assumed to increase or decrease by 10 per cent, the FICOSTEF changes to 35,073 and 30,153 Rs per tonne CO_2 eq. abated, respectively.
- If the retail price of diesel fuel were to increase or decrease by 10 per cent, the FICOSTEF changes to 29,097 and 36,128 Rs per tonne CO_2 eq. abated, respectively.
- If the LPG fuel cost per kilometre were 3.985 or 9.672 pence (instead of 6.829 pence) the corresponding measures of FICOSTEF are 14,638 and 50,587 Rs per tonne CO_2 eq. abated.
- If the period over which the entire fleet was to be replaced changes to 5 or 15 years, the FICOSTEF becomes 31,031 and 34,659 Rs per tonne CO_2 eq. abated, respectively.

The previous analysis is based on the assumption that fleet operators will voluntarily replace retired diesel buses with new OEM LPG buses, in the absence of external incentives. If incentives were to be used, however, this may have a bearing on the cost data, and should therefore be taken into account. As evident from the sensitivity analysis, a major influence on the cost-effectiveness of this project is the price differential between diesel and LPG. Given a favourable fuel price differential, this project could offer net (financial) returns, and therefore become a “no-regret” mitigation measure.

Table 41 Estimated FICOSTEF of Diesel Bus Replacement Programme.

CO_2 equivalent reductions discounted at:		
5 per cent	13,908	tonnes CO_2 equivalent
10 per cent	8,727	tonnes CO_2 equivalent
15 per cent	5,822	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	369.0	Rs million
10 per cent	284.6	Rs million
15 per cent	230.0	Rs million
FUCOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	63,378	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	32,613	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	16,535	Rs per tonne CO_2 equivalent

4.7.2 Social Cost Analysis

Secondary Emission Savings

The proposed vehicle replacement programme will save varying amounts of SO_2, NO_x, PM and CO emissions annually until the entire bus fleet is replaced. Thereafter, annual emission savings will remain constant over the selected time horizon, which is 18 years. Estimated annual savings in SO_2, NO_x, PM and CO emissions over the 18-year time horizon are shown in Table 42. The total annual value of these secondary emission savings is also shown in the table. The PV of the stream of secondary benefits depicted in Table 42, by discount rate, is:

- 5.4 Rs million (at 5 per cent);
- 3.4 Rs million (at 10 per cent); and
- 2.4 Rs million (at 15 per cent).

There is less justification for scaling down damages associated with transport emissions however. Most of the impacts on human health and materials resulting from transport emissions (particularly, PM and CO) occur locally, within a few kilometres of the source. The assumption that the majority of pollutants (particularly, SO_2 and NO_x) from point sources will be dispersed to sea therefore seems less applicable in the case of transport emissions. (This was the primary justification for scaling down the unit damage costs resulting from air pollution from power stations in Mauritius.)

If no scaling factor is used, the PV of the stream of secondary emission benefits becomes:

- 275.5 Rs million (at 5 per cent);
- 176.4 Rs million (at 10 per cent); and
- 122.3 Rs million (at 15 per cent).

Table 42 Time Profile of Secondary Emission Savings and Benefits.

Year	SO_2 Emission Savings	Value of Emission Savings	NO_x Emission Savings	Value of Emission Savings	PM Emission Savings	Value of Emission Savings	CO Emission Savings	Value of Emission Savings	Total Value of Savings
	tonnes SO_2	Rs	tonnes NO_x	Rs	tonnes PM	Rs	tonnes CO	Rs	Rs
0	-	-	-	-	-	-	-	-	-
1	0.9	2,514	15.8	53,682	1.6	9,208	21.6	2,509	67,940
2	1.8	5,083	31.7	107,364	3.2	18,415	43.2	5,018	135,880
3	2.7	7,624	47.5	161,046	4.8	27,623	64.7	7,527	203,819
4	3.6	10,165	63.3	214,727	6.3	36,830	86.3	10,036	271,759
5	4.6	12,706	79.2	268,409	7.9	46,038	107.9	12,545	339,699
6	5.5	15,248	95.0	322,091	9.5	55,246	129.5	15,054	407,639
7	6.4	17,789	110.9	375,773	11.1	64,453	151.0	17,564	475,579
8	7.3	20,330	126.7	429,455	12.7	73,661	172.6	20,073	543,519
9	8.2	22,872	142.5	483,137	14.3	82,868	194.2	22,582	611,458
10	9.1	25,413	158.4	536,818	15.8	92,076	215.8	25,091	679,398
↓	↓	↓	↓	↓	↓	↓	↓	↓	↓
18	9.1	25,413	158.4	536,818	15.8	92,076	215.8	25,091	679,398

Employment Effects

It is assumed that direct employment effects associated with the proposed replacement programme are most likely to result from the installation of the re-fuelling infrastructure. This, in turn, is assumed to take place gradually over time, coinciding with annual increases in the OEM LPG bus fleet. Employment effects will therefore occur over the 10-year period required to complete the replacement programme. Again, any employment effects will be felt by the construction and engineering sectors.

Assuming that 90 per cent of the infrastructure investment costs accrue to the construction sector and 10 per cent accrue to the engineering sector, the estimated change of employment in each is respectively:

$$1 \text{ job} = 1.34 \text{ Rs million} \times 3.26 \frac{\text{employees}}{\text{Rs million}} \times 0.90 \times 0.15 \text{ and}$$

$$> 1 \text{ job} = 1.34 \text{ Rs million} \times 1.10 \frac{\text{employees}}{\text{Rs million}} \times 0.10 \times 0.15 .$$

Employment effects in both sectors are negligible. Nonetheless, the total employment benefit associated with installing the required infrastructure is just under 0.2 Rs million per annum. The PV of this benefit stream over ten years at a 10 per cent discount rate is 1.3 Rs million.

Operating and maintaining the OEM LPG bus fleet is assumed to require the same labour input as that required by the diesel fleet. Likewise, purchasing and registering new OEM buses, relative to their diesel counterparts, is not assumed to involve a change in labour input.

As mentioned, bus drivers and maintenance staff may need additional training, which in turn may give rise to short-term employment opportunities. No data is available, however, to permit the estimation of the likely magnitude of these effects.

The Economic (Social) Cost-effectiveness Criterion

Due to a lack of data to permit further assessment of the distributional effects of the project, the total economic cost stream is equal to financial cost stream less the value of secondary emission savings and (net) employment benefits[45]. Estimates of the economic (social) cost-effectiveness of the bus replacement programme are given in Table 43. The central estimate is 32,072 Rs per tonne CO_2 eq. abated (or US$ 1,802 per tonne CO_2 eq.).

If no scaling factor is used, the PV of the stream of secondary emission benefits increases significantly, thereby reducing the economic cost per tonne CO_2 equivalent abated. For example, the PV of secondary emission saving benefits with no scaling is 176.4 Rs million (discounted at 10 per cent). The corresponding value of FUCOSTEF is 12,250 Rs per tonne CO_2 eq. abated (or US$ 688 per tonne CO_2 eq.).

Table 43 Estimated FUCOSTEF of the Diesel Bus Replacement Programme.

CO_2 equivalent reductions discounted at:		
5 per cent	13,908	tonnes CO_2 equivalent
10 per cent	8,727	tonnes CO_2 equivalent
15 per cent	5,822	tonnes CO_2 equivalent
PV of total cost stream discounted at:		
5 per cent	362.2	Rs million
10 per cent	279.9	Rs million
15 per cent	226.5	Rs million
FUCOSTEF with costs and GHG reductions discounted at		
5 per cent; 15 per cent	62,225	Rs per tonne CO_2 equivalent
10 per cent; 10 per cent	32,072	Rs per tonne CO_2 equivalent
15 per cent; 5 per cent	16,286	Rs per tonne CO_2 equivalent

Sustainability Indicators

Some GHG limitation projects involving transport may have impacts on urbanisation and on land available for agriculture. One sustainability concern is that the trends in land use are not sustainable; in other words, as more and more land is taken into urban and suburban use, there is a loss of amenity and of biodiversity. A proxy for that is the change in the percentage of urban/suburban land. The proposed diesel bus replacement programme is not anticipated to have any impact on this indicator. The project essentially involves switching (fossil) fuels, both of which must be imported, and is not foreseen to initiate significant modal shifts. Although the latter will depend

[45] It is likely that the increased cost to operators will ultimately be passed onto consumers in the form of higher fares. As public transport tends to be used more by lower income groups, the distibutional consequences of the replacement programme should be assessed. At present, however, data is not available to perform this assessment.

on the own price and substitution elasticities of various transport modes (assuming the increased cost is eventually passed to commuters in the form of higher fares).

From a global perspective, the use of alternative fuels has the potential to conserve other petroleum products and conserve energy sources. However, a major disadvantage with LPG is its limited supply at present (about 5 to 10 per cent of the amount of petroleum produced and approximately 3 per cent of the quantity of natural gas)[46]. The sustainability of large-scale conversions to LPG is therefore questionable.

[46] Faiz, A., Weaver, C. and Walsh, M., (1996), *op cit*.

5 Summary Analysis of GHG Mitigation Measures

5.1 Context

In recognition of the importance of broader social and environmental issues in developing countries, a methodology has been developed which provides a framework for the assessment of the wider impacts arising from GHG limitation projects, and advice on how to incorporate them into the decision-making process. The purpose of this report is to apply the methodology to a set of selected GHG limitation projects currently being considered for implementation in the Republic of Mauritius.

In total, six GHG limitation projects were selected for application of the methodology. Five of the projects are to be implemented in the electricity generation sector, while one project is being applied to the transport sector. The six selected GHG limitation projects are:

1. Installation of a wind farm with 30 MW declared net capacity.
2. Increasing the average annual electricity tariff by 10 per cent per annum relative to the forecast annual value.
3. Replacement of 125 streetlights (currently connected to the electricity grid) with 125 photovoltaic (PV) streetlights.
4. Replacement of domestic electric water heaters with active solar water heaters.
5. Purchasing (and therefore generating) an additional 50 GWh per year from a mixture of bagasse and coal.
6. Replacement of part of the current (diesel-powered) bus fleet with equivalent buses powered by LPG.

With respect to the measures applied to the electricity generation sector, it is assumed that output from the renewable sources will displace electricity generated from oil-fired power stations. Likewise, it is assumed that any reduction in demand resulting from the increase in electricity tariffs will be directed towards output from the oil-fired stations.

The decision as to whether to implement a mitigation measure will depend, for the most part, on its cost-effectiveness in abating GHGs. The cost-effectiveness criterion used in this study is defined by the net present value cost per ton of GHG (CO_2 equivalent) removed. Two measures of cost-effectiveness have been estimated for each of the selected GHG mitigation projects. One measure is based on direct financial costs (denoted by FICOSTEF); the other measure is based on economic (social) costs (denoted by FUCOSTEF). In determining FUCOSTEF an effort was made to value impacts associated with secondary emission savings, changes in employment, and costs / benefits accruing to different income groups. The impact of the mitigation project on sustainability in a wider sense as also considered.

Some important (general) assumptions underpinning the analysis include:

- The central discount rate used is 10 per cent, with sensitivity analysis conducted around lower and upper rates of 5 and 15 per cent.
- The cost-effectiveness of each GHG limitation project was assessed using “incremental” cost and environmental performance data.

- The base year selected for all cost data was 1995 (i.e. as far as possible all cost data is expressed in 1995 prices).
- The base year selected for computing the FU/FICOSTEF of each measure was 1997 (i.e. it is assumed that each measure was implemented in 1997).

The main results of the study are summarised below.

5.2 Main Results

5.2.1 Financial Cost Analysis

Estimates of the financial cost-effectiveness (i.e. FICOSTEF) of each GHG limitation project are given in Table 44 below. These (central) estimates are based on a discount rate of 10 per cent applied to both cost and environmental performance data. The most cost-effective measure involves generating an additional 50 GWh per annum from a mixture of bagasse and coal (US$ 78 Rs per tonne CO_2 eq.). Increasing the retail price of a unit of electricity by 10 per cent over the current forecast tariffs is the least cost-effective measure (US$ 2,090 Rs per tonne CO_2 eq.).

The "average" total annual mitigation associated with each measure is also shown in Table 44. Where GHG emission savings varied over the useful life of the measure, the PV of the associated stream of emission savings has been annualised using an appropriate annuity factor; hence, the use of the term "average". The greatest annual emission savings by far result from the wind energy development programme, nearly 44 kt CO_2 eq. per annum. Although annual emission savings are typical related to the scale of the project, in this case, the wind energy development programme is also relatively cost-effective (US$ 97 Rs per tonne CO_2 eq.).

If all six measures were implemented the total annual (financial) cost is nearly US$ 40 million. The corresponding total annual reduction in GHG emissions is 82.6 kt CO_2 equivalent. The data presented in Table 44 is summarised in the mitigation cost curve shown in Figure 4.

The mitigation measures considered in this case study are relatively expensive as instruments for reducing GHGs. This is not totally surprising, as some of them involve considerable capital outlay, and achieve relatively small reductions in GHGs. Potentially more cost-effective solutions would involve introducing energy efficiency measures, e.g. "good housekeeping", including better maintenance of boilers, improved insulation, etc. Such measures involve relatively little capital outlay, yet produce significant savings in terms of reduced energy consumption.

5.2.2 Social Cost Analysis

Central estimates of the economic cost-effectiveness (i.e. FUCOSTEF) of each GHG limitation project are given in Table 45. In determining FUCOSTEF the FICOSTEF was adjusted to account for impacts associated with secondary emission savings, changes in employment and costs/benefits accruing to different income groups (where possible). Furthermore, the financial cost of the proposed increases to the price of electricity was adjusted, to better reflect the true economic cost of the measure.

After making these adjustments, the most cost-effective measure is to increase the retail price of a unit of electricity, with an estimated FUCOSTEF of US$ 53 Rs per tonne CO_2 equivalent. Replacing the current diesel bus fleet of the main operators with OEM LPG buses now becomes the least cost-effective measure (US$ 1,802 Rs per tonne CO_2 eq.).

Table 45 also shows the “average” total annual mitigation associated with each measure. As expected, these do not differ from the values given in Table 44; only the cost data varies from FICOSTEF to FUCOSTEF. If all six measures were implemented the total annual (economic) cost would be just over US$ 12 million. The total annual economic cost is therefore considerably less than the estimated annual financial cost, about 70 per cent lower. However, this is more a result of valuing the increase in electricity tariffs appropriately, than including employment and secondary emission savings in the analysis. (As before, the corresponding total annual reduction in GHG emission is 82.6 kt CO_2 equivalent.) The data presented in Table 45 is summarised in the mitigation cost curve shown in Figure 5.

Table 44 Summary of FICOSTEF for the Selected GHG Limitation Measures.

GHG Project		Unit Mitigation Cost	Total Annual Mitigation	Total Mitigation Cost	Accumulated Mitigation Cost	Accumulated Annual Mitigation
		US$ per tonne CO_2 eq.	tonnes CO_2 eq. per annum	US$ '000 per annum	US$ '000 per annum	tonnes CO_2 eq. per annum
1.	Additional 50 GWh from bagasse (higher coal conversion efficiency)	78	9,228	723.7	723.7	9,228
2.	Wind energy (additional 30 MW installed capacity)	97	43,762	4,238.5	4,962.2	52,990
3.	Solar water heaters (40% penetration over 5 years)	378	15,512	5,858.0	10,820.2	68,502
4.	PV streetlights (125 units to displace 500 kWh of electricity per day)	1,140	122	139.1	10,959.3	68,624
5.	Replacement of diesel buses with OEM LPG buses	1,832	1,064	1,949.3	12,908.6	69,688
6.	Ten per cent increase in the current forecast annual electricity tariff	2,090	12,958	27,077.1	39,985.7	82,646

Table 45 Summary of FUCOSTEF for the Selected GHG Limitation Measures.

GHG Project		Unit Mitigation Cost	Total Annual Mitigation	Total Mitigation Cost	Accumulated Mitigation Cost	Accumulated Annual Mitigation
		US$ per tonne CO_2 eq.	tonnes CO_2 eq. per annum	US$ '000 per annum	US$ '000 per annum	tonnes CO_2 eq. per annum
6.	Ten per cent increase in the current forecast annual electricity tariff	53	12,958	683.6	683.6	12,958
1.	Additional 50 GWh from bagasse (higher coal conversion efficiency)	79	43,762	3,471.5	4,155.0	56,720
2.	Wind energy (additional 30 MW installed capacity)	80	9,228	739.8	4,894.8	65,948
3.	Solar water heaters (40% penetration over 5 years)	337	15,512	5,224.4	10,119.2	81,460
4.	PV streetlights (125 units to displace 500 kWh of electricity per day)	1,035	122	126.2	10,245.5	81,582
5.	Replacement of diesel buses with OEM LPG buses	1,802	1,064	1,917.2	12,162.6	82,646

Figure 4 FICOSTEF Curve for GHG Limitation Measures in Mauritius.

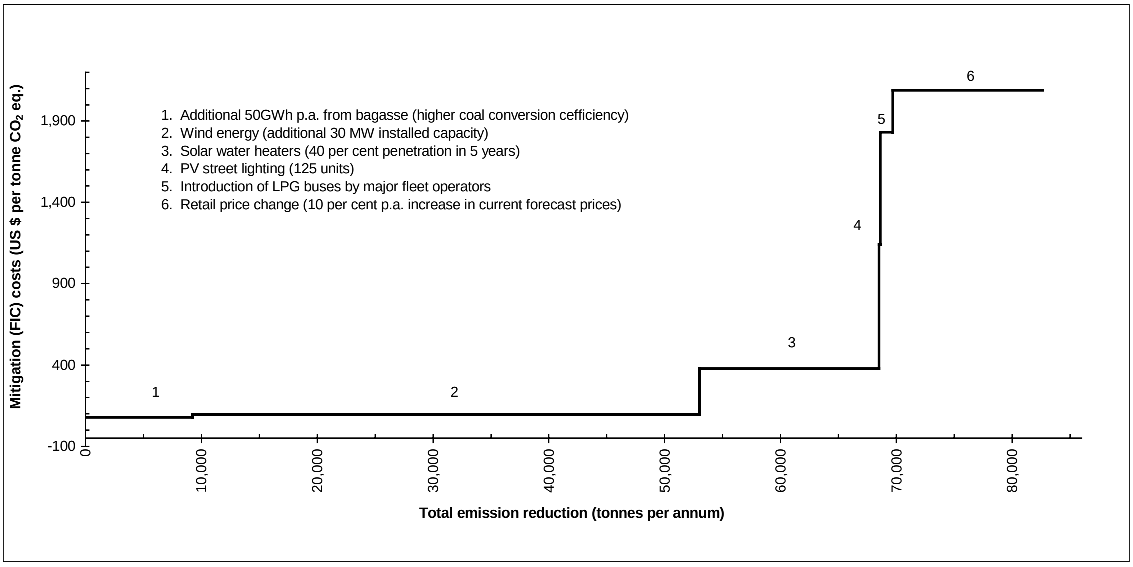
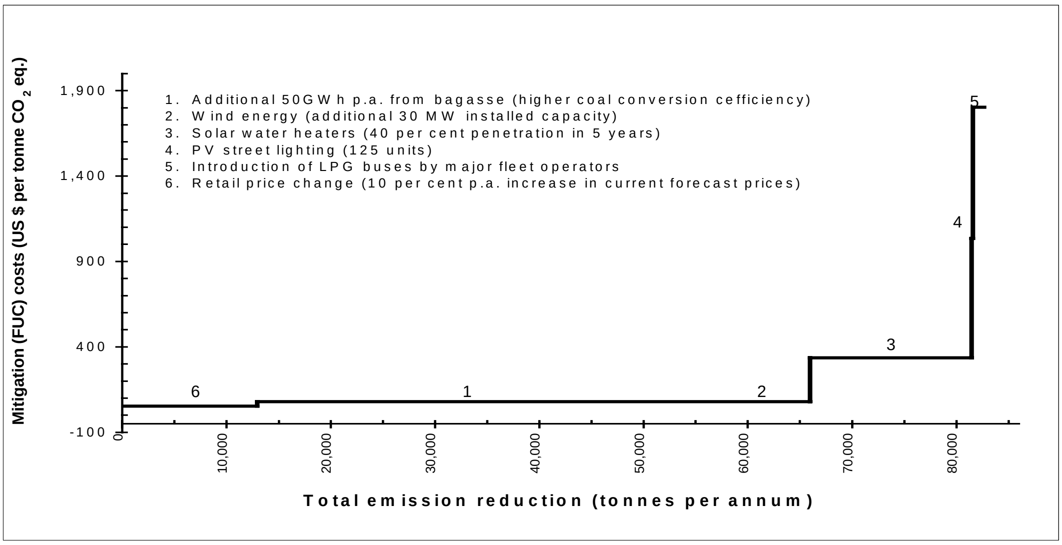


Figure 5 FUCOSTEF Curve for GHG Limitation Measures in Mauritius.



5.2.3 Uncertainty in the Results

For each GHG limitation project, a number of "key" input parameters to the analysis were identified, and their influence on the cost-effectiveness of the measure assessed. Those parameters which were found to have a significant effect on the cost-effectiveness of each measure are listed below. The sensitivity analysis was conducted for the central case only.

- Wind energy development programme - key sensitivities relate to the choice of the following parameters: the unit capital cost and the annual capacity factor.
- Proposed increase in the unit electricity tariff – no key sensitivities were found, however, the accuracy of the assumptions underpinning the electricity demand model was not tested.
- PV streetlights – the key sensitivity relates to the choice of the unit capital cost.

- Solar water heater investment programme - key sensitivities relate to the choice of the following parameters: the unit capital cost and the percentage of electrical energy delivered to households used to heat water.
- Additional electrical output from a mixture of bagasse and coal - key sensitivities relate to the choice of the following parameters: the unit generation costs for each fuel, the coal conversion efficiency and the relative shares of total output generated from bagasse and coal.
- Diesel buses replacement programme - key sensitivities relate to the choice of the following parameters: the unit capital cost, the retail price of diesel oil and the LPG fuel cost per km.

Efforts should therefore be made to establish the most accurate values for each of the above input parameters prior to reaching any concrete conclusions regarding the relative merits of each GHG limitation project.

It should also be noted that the assessment of the solar water heater investment and the diesel bus replacement programmes, were based on the voluntary up-take of the technology. It was assumed, for example, that fleet operators would voluntarily replace retired diesel buses with new OEM LPG buses, in the absence of external incentives. If incentives were to be used to encourage the penetration of the technology, this may have a bearing on the cost data. Any such effects should be taken into account when determining the cost-effectiveness of these two measures.

Other key uncertainties relate to the valuation of secondary emission savings, changes in employment and costs / benefits accruing to different income groups. Firstly, the approach to estimating net employment effects adopted here is crude. It was necessary to make an assumption regarding the percentage of jobs created / lost, estimated by the employment / output ratios, that would actually result in a change in unemployment levels. A figure of 15 per cent was used in the calculations. There is no real justification for this assumption. The results should therefore be treated as 'order of magnitude' estimates only, to be refined when better information becomes available. Furthermore, the analysis was restricted to direct effects in a few sectors. Indirect employment effects can be just as significant, if not more so.

It was found that the use of unadjusted values for assessing the benefits of secondary emission savings resulted in a significant improvement in the FUCOSTEF of each measure; in some case the use of unadjusted values resulted in net economic *benefits* per tonne CO_2 equivalent abated. The use of no scaling factor seems most reasonable regarding air pollution (in particular local impacts) from transport sources.

Finally, it should be noted that several of the measures impose additional costs directly on households, and therefore potentially on vulnerable income groups. The cost burden to households should be weighted using the distribution weights given in Table 16. To do this however, one must be able to dissaggregate domestic electricity demand by income group, and then predict how demand within each income group changes as the price of electricity rises. Alternatively, in the case of the solar water heaters, it is necessary to be able to predict the up-take of the technology within each income group. Data was not available to undertake such analyses. The true welfare cost of each of these measures is therefore not accurately represented in the estimated FUCOSTEF.