PERGAMON

Energy Conversion and Management 44 (2003) 3247–3265

ENERGY CONVERSION & MANAGEMENT

www.elsevier.com/locate/enconman

Greenhouse gas emission mitigation in the Sri Lanka power sector supply side and demand side options

Priyantha D.C. Wijayatunga [a,*], W.J.L.S. Fernando [b], Ram M. Shrestha [c]

[a] *Department of Electrical Engineering, Centre for Energy Studies, University of Moratuwa, Moratuwa 10400, Sri Lanka*

[b] *Sri Lanka Energy Managers Association, 71/4 Gregory's Road, Colombo 7, Sri Lanka*

[c] *Energy Program, Asian Institute of Technology, P.O. Box 4, Klong Luang, Pathumthani 12120, Thailand*

Received 30 May 2002; received in revised form 21 November 2002; accepted 12 May 2003

Abstract

Sri Lanka has had a hydropower dominated electricity generation sector for many years with a gradually decreasing percentage contribution from hydroresources. At the same time, the thermal generation share has been increasing over the years. Therefore, the expected fuel mix in the future in the large scale thermal generation system would be dominated by petroleum products and coal. This will result in a gradual increase in greenhouse gas (GHG) and other environmental emissions in the power sector and, hence, require special attention to possible mitigation measures.

This paper analyses both the supply side and demand side (DSM) options available in the Sri Lanka power sector in mitigating emissions in the sector considering the technical feasibility and potential of such options. Further, the paper examines the carbon abatement costs associated with such supply side and DSM interventions using an integrated resource planning model, which is not used in Sri Lanka at present. The sensitivities of the final generation costs and emissions to different input parameters, such as discount rates, fuel prices and capital costs, are also presented in the paper. It is concluded that while some DSM measures are economically attractive as mitigation measures, all the supply side options have a relatively high cost of mitigation, particularly in the context of GHG emission mitigation. Further it is observed that when compared with the projected price of carbon under different global carbon trading scenarios, these supply side options cannot provide economically beneficial CO_2 mitigation in countries like Sri Lanka.

Keywords: Greenhouse gas emission; GHG mitigation; CO_2 abatement

* Corresponding author. Tel.: +94-1-650-279; fax: +94-1-650-622.

E-mail addresses: priyanth@elect.mrt.ac.lk (P.D.C. Wijayatunga), shavi@sltnet.lk (W.J.L.S. Fernando), ram@ait.ac.th (R.M. Shrestha).

0196-8904/$ - see front matter
doi:10.1016/S0196-8904(03)00100-6

1. Electricity supply industry

1.1. Conventional generation

The Sri Lanka electricity generation sector has been dominated by hydroelectricity for many years. The installed capacity and energy supply from hydroelectric stations in Sri Lanka have been progressively increased through commissioning of hydropower stations since Sri Lanka's first large scale hydropower station was commissioned in 1950. By the year 2000, the total installed capacity of hydropower stations totalled about 1140 MW. Depending on the rainfall in different years, the proportion of electricity generated at hydropower plants has been varying from about 40% to 70% during the last five years. For instance, out of the total generation of 6964 GW h in 2000, hydroplants supplied only 3197 GW h (46%), while in 1998, hydroplants supplied 3915 GW h (69%) out of a total generation of 5675 GW h. The shortfall is always provided by thermal power stations fuelled by petroleum products, such as fuel oil and auto Diesel. The hydropower and thermal generation contributions during the last 30 years are shown in Fig. 1. An important feature, which can be identified from this figure, is that after 1995, the level of self generation by consumers has become significant, mainly due to power shortages experienced during those years [1]. A large majority of the self generation plants are powered by auto Diesel driven Diesel engines.

1.2. Alternative energy

In addition to the large hydropower plants, renewable energy based electricity generation has been a focus in Sri Lanka for the last two decades, both by the state and private sectors. The Ceylon Electricity Board (CEB), which is the state owned utility controlling a major share of the power system, initiated popularising solar photovoltaic systems for rural domestic lighting in

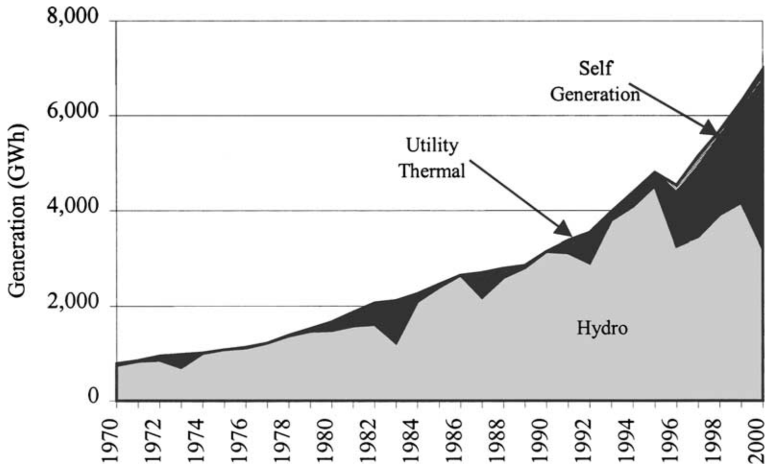

Fig. 1. Historical hydro and thermal energy share in Sri Lanka power system.

the early 1980s. Presently, under the World Bank funded Energy Services Delivery Project, the private sector has taken over installation of domestic solar home systems in a large scale. Under the same scheme, a large number of grid connected, as well as isolated, small hydropower plants are now being developed by the private sector, although their total contribution still remains small in comparison to conventional large hydropower development. The use of dendro power plants (fuel wood fired plants) supplied by fuel wood from dedicated energy plantations is still under experimentation in Sri Lanka. A 3 MW pilot scale grid connected wind power plant has been in operation since 1999 in the southern part of the country, but its annual plant factor has been less than 20% on average.

1.3. Energy conservation

Energy conservation has also been a major focus in the electricity sector for many years in Sri Lanka. The energy conservation fund was established in the mid 1980s to coordinate activities in this area, and later, in the early 1990s, a separate unit for demand side management was established in the CEB, mainly to focus on energy conservation activities in the electricity sector. This unit has been pursuing several utility sponsored DSM programmes, such as popularisation of compact fluorescent lamps (CFLs), development of an energy efficient building code and energy labelling of electric appliances. Several private, and non-governmental organisations too, pursue energy conservation and management activities by offering expert services and training programmes.

2. Electricity sector and environment

The impacts of the electricity generation sector on the environment in any country could be in the form of

- particulate emissions,
- gaseous emissions, such as CO_2, SO_x, NO_x,
- warm water discharges into surrounding water bodies, such as the lakes, rivers and sea,
- inundation of land in the case of large hydroreservoirs and,
- changes in land use patterns.

Although many of these factors are common to any development project, the particulate and gaseous emissions are of primary importance in the case of electricity generation using fossil fuels.

2.1. Power sector emissions

Suspended particulate matter (SPM) consists mainly of ash with minute quantities of unburned carbon particles. There are three major gaseous emissions released as a result of fossil fuel burning, viz. carbon dioxide (CO_2), sulphur dioxide (SO_2) and oxides of nitrogen (NO_x). It is mainly the CO_2 emission that has drawn special attention of scientists world over in recent times, since it poses a major threat to the global environment in the form of the greenhouse effect.

Though there are proven mitigatory measures available for controlling SO_x and NO_x emissions effectively, there is no effective way of controlling CO_2 emissions other than limiting fuel use. One of the solutions to this problem is to improve the efficiency of the burning process. However, even with major modifications in the burning processes, the improvements achieved to date have not been attractive enough to offset the associated cost differentials.

In Sri Lanka, it is mandatory for new thermal power projects exceeding 25 MW and new hydropower projects exceeding 50 MW in capacity to get environmental clearance from the relevant Project Approving Authority by conducting an environmental impact assessment (EIA) prior to commencement of the project.

2.2. Emission standards

Since late 1994, Sri Lanka has approved ambient air quality standards, but there is only a proposed set of emission standards with which the projects are expected to comply, if approved. At present, all new thermal power projects above 25 MW have to comply only with the air quality standards given in Table 1 [7].

When compared with standards specified by the World Bank and World Health Organisation given in Table 2, it can be seen that Sri Lanka has more stringent ambient air quality standards for NO_x and SO_x emissions. The standard for particulate matter is also lower than the existing World Bank standard [7]. A comparison of proposed emission standards with those of the WB and some Asian countries is shown in Table 3. It can be seen that the proposed Sri Lankan standards are between the proposed World Bank standards and the standards of some neighbouring Asian countries, such as the Philippines, India and Indonesia [7].

3. Objective and limitations of the study

The objective of this study is to determine the economics of technically feasible electricity generation options and demand side management options available for reduction of GHG emissions in the Sri Lanka electricity sector. For this purpose, both the traditional resource planning (TRP) and integrated resource planning (IRP) techniques have been used. Such technically feasible options will be further screened to determine the carbon abatement costs in relation to specific carbon reduction targets.

Table 1
Ambient air quality standards and proposed stack emission standards of Sri Lanka

Pollutant type	Ambient air quality standards (g/m^3)		Stack emission standards (mg/MJ)	
	24-h level	1-h level	Coal	Liquid fuel
Nitrogen oxides (NO_x)	100	250	300	130
Sulphur oxides (SO_x)	80	200	520	340
Total suspended particles	300	500	40	40

Source: Energy for sustainable development [7].

Table 2
Comparison of ambient air quality standards of different countries and organisations

Pollutant	Averaging time	Ambient air quality standards (mg/m^3)					
		World Bank (existing)	World Bank (proposed)	WHO	Indonesia (proposed)	Thailand	Sri Lanka
Nitrogen dioxide	Annual	0.10	0.05	0.05	0.10	–	–
	24 h	–	0.125	0.15	0.15	0.32	0.10
	1 h	–	0.35	0.32	0.40	–	0.25
Sulphur dioxide	Annual	0.10	–	–	0.06	0.10	–
	24 h	0.50	0.15	0.09	0.30	0.30	0.08
	1 h	–	0.40	0.35	0.90	0.10	0.20
Suspended particulate	Annual	0.10	0.07	0.075	0.09	–	0.10
	24 h	0.50	0.11	0.15	0.23	–	0.30
	1 h	–	–	–	–	–	0.50

Source: EIA Study Report, West Coast Coal Development Project, Sri Lanka [10].

Table 3
Comparison of emission standards of different countries and organisations

Pollutant	Emission standards (mg/MJ)					
	Sri Lanka (proposed)	World Bank (proposed)	India	Indonesia (proposed)	Philippines	European commission
Nitrogen oxides	300	260	–	590	350	225
Sulphur dioxide	520	700	–	200	540	140
Suspended particulate	40	17	120	140	140	17

Source: EIA Study Report, West Coast Coal Development Project [10].

The study only analyses cases that are more suited for the Sri Lanka electricity industry. Hence, technologies such as nuclear power as a GHG mitigation option are not considered. Further, the renewable energy based options are offered as candidate plants only in a realistically achievable time scale and are not offered as candidate plants in large blocks. A liquefied natural gas (LNG) based plant is offered as a large plant option due to the economies of scale required for this technology to be feasible. Hence, a LNG based plant may not be considered by the model until such large plants are demanded by the system.

Similarly, only DSM measures that can be practically implemented and those that are presently being discussed at the local level are offered as options. Highly sophisticated end use equipment, such as infrared sensitive control devices and other technologies, which may be commercially available but not very appropriate in the local situation, are not considered.

As in any study of this nature, there is a degree of uncertainty in the input data, but the supply side and demand side data are those used in the power industry and, hence, are considered to be reasonably accurate. However, data at a disaggregated level for the demand categories and end use devices are derived using best estimates, based on surveys and studies conducted by various agencies.

4. Methodology

The IRP model and the related software developed by the Asian Institute of Technology (AIT), Bangkok, for long term electricity generation expansion planning is used in this study. This model determines the optimum generation expansion plan for a given planning period considering not only the different generation technologies but also the DSM options available for implementation in a given system [9]. It accommodates any demand side management measure that can be adopted in the concerned power system in addition to all types of thermal, hydro and other renewable energy options for electricity generation in its objective function. The same model can used for TRP based studies by omiting the DSM options and having only the supply side options in the objective function. This model has been well documented and accepted as a tool for IRP, and later, it has been modified to obtain GHG emission related outputs [9].

During the study discussed in the paper, all technically feasible generation options for Sri Lanka are included in the objective function along with a list of selected DSM options. The optimisation is performed to determine the generation expansion plan and its costs under different scenarios. All these scenarios are further analysed to determine the carbon abatement costs in relation to specific carbon reduction targets. The sensitivities of the output to variations in the calculation parameters, such as the discount rates, capital costs, fuel costs and electricity demand are also studied.

5. Input data

5.1. Electricity demand

All data used in this study are based on actual 1998 data and the others are derived or forecasted using nationally published data sources such as the Department of National Planning and the Department of Census and Statistics. The demand forecast is derived by econometric analysis. Generally, the results of these econometric forecasts are used to assess the future requirement of both capacity and energy of the system for the next 20 years. In order to analyse the effects of any variation in the demand forecast, at least two additional demand forecasts are considered with a lower growth rate and higher growth rate compared to the base case [1].

The total or gross system losses calculated based on gross generation and 'as billed' sales figures have, on average, increased by about 2–3% but have remained within 15–19% in the past few years. However, the Transmission Planning and Distribution Planning divisions of the CEB anticipate reductions in the system losses due to planned improvements in the system. These anticipated loss reduction schemes are shown in Table 4, and the load forecast using these loss reduction schemes is shown in Table 5. The study uses the modified demand forecast, including these loss reduction targets and other interventions already planned, in a scenario that is considered to be the business as usual case (BAU).

Table 4
Transmission and distribution losses as a percentage of generation with the anticipated loss reduction scheme

	Year												
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Transmission (%)	4.0	4.0	4.0	4.0	4.0	3.8	3.6	3.4	3.2	3.0	3.0	3.0	3.0
Distribution (%)	12.6	12.4	11.8	11.3	10.8	10.4	10.4	10.2	10.3	10.3	10.2	10.1	10.0
Total (%)	17.6	17.4	16.8	16.3	15.8	15.2	15.0	14.6	14.5	14.3	14.2	14.1	14.0

Source: Long term generation expansion plan [1].

Table 5
Load forecast with anticipated loss reduction programmes—1998

Year	Demand (GW h)	Growth rate (%)	Losses (%)[a]	Generation (GW h)	LF (%)	Peak load (MW)
1999	5100	10.0	17.4	6174	55.0	1282
2000	5600	9.8	16.8	6731	55.0	1397
2001	5671	1.3	16.3	6776	55.0	1406
2002	6082	7.2	15.8	7224	55.0	1499
2003	6515	7.1	15.2	7682	55.0	1594
2004	6970	7.0	15.0	8200	55.0	1702
2005	7451	6.9	14.6	8724	55.0	1811
2006	7961	6.9	14.5	9312	55.0	1933
2007	8502	6.8	14.3	9921	55.0	2059
2008	9073	6.7	14.2	10575	55.0	2195
2009	9676	6.6	14.1	11264	55.0	2338
2010	10313	6.6	14.0	11991	55.0	2489
2011	10991	6.6	14.0	12780	55.0	2653
2012	11711	6.5	14.0	13617	55.0	2826
2013	12473	6.5	14.0	14504	55.0	3010
2014	13281	6.5	14.0	15443	55.0	3205
2015	14136	6.4	14.0	16438	55.0	3412
2016	15048	6.4	14.0	17497	55.0	3632
2017	16014	6.4	14.0	18621	55.0	3865
2018	17039	6.4	14.0	19812	55.0	4112

Source: Long term generation expansion plan [1].
[a] Losses include technical losses at generation, transmission and distribution and any non-technical losses.

5.2. Existing and committed electricity generation

The data on the fuel types used and their costs, data on existing and committed plants and data on existing and candidate thermal plants are given in Tables 6–9 [1,3,4,6]. The energy output quantities of all hydroplants have been separated into season 1, "wet season", and season 2, "dry season". "Wet season" represents three months of the year when the hydroreservoirs have a heavy inflow of water due to monsoon rains while the "dry season" consists of the remaining nine months. Being a country in the tropical region, the Sri Lanka hydropower system is subject only to these two seasonal variations.

Table 6
Fuel types used

Fuel type	Cost (US$/GJ)
Fuel oil	2.82
Residual	2.25
Diesel	3.95
Coal	1.78
Fuel wood	2.04
LNG	4.27

Source: Long term generation expansion plan [1].

Table 7
Data on existing and committed hydroplants

	Capacity (MW)	Earliest available year	Availability	Operating cost (US$/MW h)	Retire-ment year	Fixed O&M '000 (US$/MW h)	Energy in season 1 (MW h)	Energy in season 2 (MW h)
All existing	1115	1	0.98	0	50	0.3286	1,767,980	2,123,100
Kukule	70	1	0.98	0	50	0.3286	131,710	171,550
Upper Kotmale	150	4	0.98	0	50	0.3286	179,220	350,580

Source: Long term generation expansion plan [1].

Table 8
Data on candidate thermal plants

	Plant name				
	Diesel	Coal	GT 35	GT 105	CCY
Fuel type	Residual	Coal	Diesel	Diesel	Diesel
Fuel consumption '000 (kg/MW h)	0.1944	0.364	0.2899	0.2707	0.1694
Calorific value (MJ/kg)	42.09	26.38	44.20	44.20	44.20
CO_2 emission factor (kg/MW h)	595.28	845.62	892.45	833.31	521.57
SO_2 emission factor (kg/MW h)	6.023	1.871	0.86	0.86	1.631
NO_x emission factor (kg/MW h)	2.705	1.23	0.773	0.773	1.008
Capacity (MW)	10	300	35	105	300
Minimum operating level (MW)	0	0	0	0	0
Available year	7	2	1	1	2
Availability	0.79	0.87	0.84	0.84	0.84
Capital cost '000 (US$)	13,316	372,900	19,687.5	40,173	211,440
Non-depreciable capital '000 (US$)	0	0	0	0	0
Heat rate (MJ/MW h)	8181	9601	12,812	11,962	7486
Operating cost '000 (US$/MW h)	0.00736	0.00279	0.00381	0.00285	0.00233
Annual maintenance (h)	720	960	720	720	720
Life time (years)	25	30	20	20	30
Fixed O&M '000 (US$/MW per month)	0.92	0.561	0.475	0.359	0.272

Source: Long term generation expansion plan [1].

Table 9
Data on existing thermal plants

	Units	Plant name							
		GT	Diesel eng.	Diesel ext.	New GT	Diesel IPP	CCY	Barge	CCY
Fuel type		Diesel	Residual	Residual	Diesel	Residual	Diesel	Fuel oil	Diesel
Fuel consumption	'000 kg/MW h	0.3399	0.2334	0.1944	0.2707	0.2165	0.1864	0.2107	0.1864
Calorific value	MJ/kg	44.20	42.09	42.09	44.20	42.09	44.20	42.31	44.20
CO_2 emission factor	kg/MW h	1046.44	714.7	595.28	833.31	662.91	563.69	639.37	573.97
SO_2 emission factor	kg/MW h	0.86	6.023	6.023	0.86	6.023	1.631	6.023	1.631
NO_x emission factor	kg/MW h	0.773	2.705	2.705	0.773	2.705	1.008	2.705	1.008
Capacity	MW	120	72	40	115	63.5	300	60	150
Minimum operating capacity	MW	0	0	0	0	0	0	0	0
Available year		1	1	1	1	1	1	1	1
Availability		0.71	0.8	0.78	0.84	0.88	0.84	0.8	0.84
Heat rate	MJ/MW h	15,023	9823	8181	11,962	9111	8240	8914	8240
Operating cost (without fuel cost)	'000 $/MW h	0.00244	0.00563	0.00702	0.00349	0.00823	0.00308	0.00362	0.00419
Annual maintenance	h	960	960	720	720	600	720	528	720
Year of retirement		15	7	19	14	19	28	22	30
Fixed O&M	'000 $/MW per month	0.261	6.806	1.641	0.39	4.03	0.36	6.33	0.488

Source: Long term generation expansion plan [1].

The emission factors associated with different gases for each type of thermal plant given in Table 8 are based on the guidelines of the Intergovernmental Panel on Climate Change (IPCC) [3,4].

5.3. Supply side options for mitigation of GHG emissions

The supply side options considered are mainly categorised into three groups. They are the advanced cleaner technologies available on conventional fossil fuel systems, renewable energy based plants and efficiency improvement on existing generating plants. These are offered as candidate plants or options for substitution in place of traditional fossil fuel based systems when GHG emission mitigation is required in any of the scenarios analysed.

5.3.1. Clean coal technologies

In this study, the integrated gasified combined cycle (IGCC) and the pressurised fluidised bed combustion (PFBC) technologies associated with coal power plants are considered as candidates

Table 10
Data on candidate clean coal plants

	Plant name	
	IGCC	PFBC
Fuel type	Coal	Coal
Fuel consumption (kg/MW h)	0.32166	0.34091
Calorific value (MJ/kg)	26.38	26.38
CO_2 emission factor (kg/MW h)	746.13	790.79
SO_2 emission factor (kg/MW h)	0.094	0.308
NO_x emission factor (kg/MW h)	0.308	0.431
Capacity (MW)	300	300
Minimum operating level (MW)	0	0
Available year	3	3
Availability	0.9	0.9
Capital cost '000 (US$)	396,000	396,000
Non-depreciable capital '000 (US$)	0	0
Heat rate (MJ/MW h)	8483	8994
Operating cost '000 (US$/MW h)	0.002	0.002
Annual maintenance (h)	960	960
Life time (years)	30	30
Fixed O&M '000 ($/MW per month)	1.667	1.667

Source: Final report, Asian regional research project on energy environment and climate change—phase III [11].

in which GHG emission mitigation can be achieved through more efficient fuel burning processes. Since Sri Lanka does not have any coal power plants in its existing generation system and is planning to add those plants in the future, these technologies provide an opportunity for GHG mitigation. The main characteristics of these clean coal technologies that are used in the study are given in Table 10 [3,4].

5.3.2. Renewable energy technologies

5.3.2.1. Hydropower. Sri Lanka still has a total of about 800 MW of additional hydropower potential that can be developed in the future. Of this potential, the candidate plants given in Table 11 are considered to be the next most viable plants that cannot be justified at present solely on economic grounds, but when GHG emission mitigation is required under certain scenarios, these plants may replace fossil fuel plants at a cost.

5.3.2.2. Wind power. Some studies have been undertaken on the assessment of wind energy potential in the country by the CEB. Data on the southeastern part of the country has already been collected, and currently, data collection in the northwestern part of the country is in progress. Also, there appears to be a considerable wind power potential in the central mountain region. The northern and northeastern regions too are expected to have a good wind regime, though not quantified to date. Based on the already available data, reasonable estimates have been made on the total wind power potential in the country. This is estimated to be around 1800 MW, and its development is assumed to be in the form given in Table 12 [5].

Table 11
Data on candidate hydroplants

	Project name			
	Ginganga	Broadlands	Uma Oya	Moragolla
Unit capacity (MW)	49	40	150	27
Available year	2	2	3	2
Maximum number of units	1	1	1	1
Availability	0.98	0.98	0.98	0.98
Capital cost ’000 (US$)	139,703.9	134,112	431,475	108,491.4
Operating cost ’000 (US$/MW h)	0	0	0	0
Life time	50	50	50	50
Fixed O&M ’000 (US$/MW per month)	0.3286	0.3286	0.3286	0.3286
Available energy in season 1 (MW h)	68,020	41,370	185,360	26,500
Available energy in season 2 (MW h)	144,050	103,850	261,340	84,150

Source: Long term generation expansion plan [1].

Table 12
Data on candidate wind plants

	Wind-30	Wind-3	Wind-60	Wind-75	Wind-150
Unit capacity (MW)	30	3	60	75	150
Available year	2	2	2	2	2
Maximum number of units	5	1	3	3	3
Availability	0.2	0.2	0.2	0.2	0.2
Capital cost ’000 (US$)	33,000	3300	66,000	82,500	165,000
Operating cost ’000 (US$/MW h)	0	0	0	0	0
Life time	30	30	30	30	30
Fixed O&M ’000 ($/MW per month)	0.75	0.75	0.75	0.75	0.75
Available energy in season 1 (MW h)	18,568	1857	37,130	46,426	92,640
Available energy in season 2 (MW h)	36,250	3626	72,500	70,618	181,260

Source: Long term generation expansion plan [1].

5.3.2.3. Dendro thermal. The other renewable option considered in the study is fuel wood fired power plants called dendro thermal power. Dendro thermal power generation largely depends on the availability of land to establish dedicated energy plantations to supply the fuel wood requirement of the power plants. Of the total land area of 6.5 million hectares in the country, around 1.2 million hectares of marginal land in all districts may be considered for energy forestry.

Such plantation grown biomass can be used for power generation in three general applications. These include

- stand alone, grid connected biomass based power plants using plantation grown feedstocks or mixed with agricultural residues;
- cogeneration in agriculture (e.g. sugar mills and rice mills) and forestry processing facilities for on site heat and power needs with export of excess power to the grid using mill wastes (rice hull, bagasse, wood waste) and plantation grown biomass;
- cofiring at fossil fuel fired electric generation facilities.

Table 13
Data on candidate dendro thermal plants

Fuel consumption '000 (kg/MW h)	1.2
Calorific value (MJ/kg)	15.91
CO_2 emission factor (kg/MW h)	0
SO_2 emission factor (kg/MW h)	0
NO_x emission factor (kg/MW h)	0
Capacity (MW)	10
Minimum operating level (MW)	0
Available year	2
Availability	0.86
Capital cost '000 (US$)	12,000
Non-depreciable capital '000 (US$)	0
Heat rate (MJ/MW h)	19,093
Operating cost '000 (US$/MW h)	0.0025
Annual maintenance (h)	960
Life time (years)	25
Fixed O&M '000 (US$/MW per month)	1.8

Source: Feasibility of dendro power based electricity generation in Sri Lanka [2].

For each of these applications, the current conversion technology of choice is the simple steam turbine cycle. However, at the scale appropriate for biomass, the technology is expensive and relatively inefficient when compared with fossil fuel power plants.

A total of 1700 MW of dendro thermal plants, which is expected to be developed in 10 MW units due to present technical constraints, is considered in the study. The cost and other characteristics are given Table 13 [2–4].

When certain study scenarios require GHG emission mitigation, dendro power plants can replace fossil fuel based systems even though they are expensive to establish and operate since the net life cycle of CO_2 emissions in dendro power is considered to be zero when the plants are fuelled with dedicated energy plantations.

5.3.3. Retrofitting of existing thermal plants and T&D loss reduction

There are only a few thermal plants in the Sri Lanka power system at present. Of these few, one thermal plant, which is already 40 years old, is considered for retirement in 2003. Therefore, no modifications or retrofitting is considered in the study as an emission mitigation option. A more rigorous transmission and distribution loss reduction programme, over and above what is proposed under the business as usual scenario (BAU), is considered in the study.

5.4. Demand side options

There are a large number of DSM measures that can be adopted in a given power system, but what can be finally implemented depends heavily on the economics, awareness and acceptability of those measures by the consumers. There have been a few successful programmes involving

Table 14
Data on demand side management options considered

	DSM option				
	DSM1	DSM2	DSM3	DSM4	DSM5
Cost per 1000 units (US$ '000)	4.32	4.81	5.91	244.58	1596.03
Available year	1	1	1	1	1
Life time (yrs)	7	7	7	10	10

DSM1: domestic 40 W incandescent bulbs are replaced by 11 W CFL; DSM2: domestic 60/75 W incandescent bulbs are replaced by 15 W CFL; DSM3: 60–100 W Incandescent bulbs in industrial and commercial institutions are replaced by 20 W CFL; DSM4: commercial refrigerators are replaced by efficient refrigerators; DSM5: air conditioners in industrial and commercial institutions are replaced by efficient air conditioners.

popularisation of the use of CFLs to replace incandescent lamps in the Sri Lanka domestic sector. Therefore, there is a very good potential of using CFLs as a DSM measure. Though there have been no attempts in the past, the use of efficient refrigerators and air conditioners in commercial and industrial installations seems to be the next DSM measure that is likely to be acceptable if it is financially attractive to the consumers. Considering these, the DSM options given in Table 14 are used in the study.

6. Results

The study is conducted using the data given in Section 5 with IRP and without DSM TRP measures in place.

6.1. Base case

In this scenario, all the supply side options are considered in the TRP along with already planned transmission loss reduction targets. The only modification in the IRP study is that the DSM options are included in the objective function in addition to the supply side options. The output plant sequence in the base case scenario for both the TRP and IRP are given in Table 15.

6.2. Sensitivity analysis

The sensitivities of the outputs of the TRP and IRP studies to the variations in certain input parameters, such as the capital cost, fuel prices, demand growth rate, plant efficiencies, discount rate and CO_2 emission constraints that are likely to deviate from the base case values under different market conditions, are observed in the analysis. The specific details of the cases are the following:

Scenario	Description
20% capital cost increase	Capital costs of all the future power plants are increased by 20% of the base values
20% capital cost decrease	Capital costs of all the future power plants are decreased by 20% of the base values
40% capital cost decrease	Capital costs of all the future power plants are decreased by 40% of the base values
20% increased load growth rate	Rate of load growth is increased by 20% of the base load growth rate
20% decreased load growth rate	Rate of load growth is increased by 20% of the base load growth rate
Fuel price decreased	Prices of oil and LNG decrease by 25% of the base value, while the price of coal decreases by 10% from the base value
Fuel price increased 1	Prices of oil and LNG increase by 25% of the base value, while the price of coal increases by 10% from the base value
Fuel price increased 2	Prices of oil and LNG increase by 50% of the base value, while the price of coal increases by 10% from the base value
2% increased plant efficiency	All the power plants become 2% more efficient in operation against their existing operating efficiency
5% increased plant efficiency	All the power plants become 5% more efficient in operation
2% decrease in base load growth	Lowered demand growth by 2% to account for rigorous loss reduction targets in transmission and distribution systems
10% CO_2 emission reduction	CO_2 emissions constrained to 10% below the base case value
20% CO_2 emission reduction	CO_2 emissions constrained to 20% below the base case value
30% CO_2 emission reduction	CO_2 emissions constrained to 30% below the base case value
15% discount rate	Discount rate used in the economic analysis increased to 15% from the base case value of 10%
5% discount rate	Discount rate used in the economic analysis decreased to 5% from the base case value of 10%

The outputs of the sensitivity analyses are given in Table 16 for both the TRP and IRP studies, along with their base case values.

7. Analysis

7.1. Base case

It can be seen from Table 15 that the base case scenario of the TRP model leads to the selection of 1800 MW of coal steam plants, 560 MW of gas turbines and 20 MW of Diesel based on residual oil. Similarly, under the IRP model, 1500 MW of coal steam plants, 35 MW of gas turbines and 20 MW of Diesel based on residual oil are selected. None of the clean coal technologies or renewable

Table 15
Selection of plants in the base case scenario

Year of commissioning	Type of plant	Capacity (MW)
Panel A—TRP		
2005	Coal steam	(1×300)
2009	Coal steam	(1×300)
2011	Coal steam	(1×300)
2012	Coal steam	(1×300)
2014	Coal steam	(1×300)
2015	Diesel–residual oil	(2×10)
2015	Gas turbine 105 MW	(1×105)
2016	Coal steam	(1×300)
2016	Gas turbine 105 MW	(1×105)
2017	Gas turbine 35 MW	(1×35)
2017	Gas turbine 105 MW	(3×105)
Total		2380
Panel B—IRP		
2008	Coal steam	(1×300)
2010	Coal steam	(1×300)
2013	Coal steam	(1×300)
2015	Coal steam	(1×300)
2016	Gas turbine 35 MW	(1×35)
2017	Diesel–residual oil	(2×10)
2017	Coal steam	(1×300)
Total		1555

energy plants, including the large hydroelectric plants given in Section 5, is selected in the base case, mainly due to the high costs associated with their installation and operation. This means that none of these cleaner technologies will be in use under normal circumstances where only economic feasibility is considered.

It is important to note that the total installed capacity of new plants goes down by 825 MW (300 MW of coal and 525 MW of gas turbines) when the DSM options are included under IRP. This has resulted in the IRP model giving a reduction in overall costs as well as emissions, which can be seen in Tables 16 and 17. This means that the use of DSM measures not only is economically advantageous under normal circumstances but also reduces GHGs about 22% and other harmful emissions by about 15%, creating a win–win situation in power system planning.

7.2. Capital cost and load changes

The plant capital cost increase has resulted in increased generation costs and a significant reduction in GHG (about 8%) and other harmful emissions. This is mainly due to the replacement of capital intensive and relatively more polluting coal power plants with oil fired plants under these circumstances. Similarly, the decrease in capital costs resulted in a higher contribution of coal power with increased emissions. The increase and decrease in load growth rates (20% of the

Table 16
Generation costs and emissions associated with different scenarios in sensitivity analysis

Case study—sensitivities	Generation cost ($ billion)		CO_2 (Gg '000)		SO_2 (Gg)		NO_x (Gg)		LRAC (USCts/kW h)	
	TRP	IRP	TRP	IRP	TRP	IRP	TRP	IRP	TRP	IRP
1. Base case	1.57	1.25	102.64	80.32	327.63	279.74	189.05	157.4	2.47	2.23
2. 20% capital cost increase	1.65	1.30	94.57	77.91	317.28	273.35	181.52	153.59	2.59	2.32
3. 20% capital cost decrease	1.48	1.20	104.47	81.3	328.13	281.15	190.23	158.44	2.32	2.14
4. 40% capital cost decrease	1.37	1.12	108.77	88.56	322.96	281.58	190.24	162.02	2.15	2.00
5. 20% increased load growth rate	1.60	1.28	104.76	81.99	330.24	282.93	191.31	159.65	2.48	2.26
6. 20% decreased load growth rate	1.54	1.28	99.98	77.99	323.28	273.31	185.86	153.48	2.44	2.26
7. Fuel price decreased	1.33	1.05	76.82	64.06	304.25	262.97	169.39	144.06	2.09	1.87
8. Fuel price increased 1	1.72	1.39	107.86	85.81	326.94	284.73	191.34	161.92	2.7	2.49
9. Fuel price increased 2	1.79	1.45	109.77	90.49	316.19	265.3	188.15	156.78	2.81	2.58
10. 2% increased plant efficiency	1.56	1.24	103.16	80.32	328.12	279.74	189.5	157.4	2.44	2.21
11. 5% increased plant efficiency	1.53	1.23	103.51	80.32	326.68	279.74	189.18	157.4	2.4	2.19
12. 2% decrease in base load growth	1.48	1.16	96.71	74.25	313.13	264.67	179.91	147.87	2.41	2.16
13. 10% CO_2 emission reduction	1.63	1.32	90.23	69.35	317.86	261.03	180.42	145	2.53	2.34
14. 20% CO_2 emission reduction	1.71	1.39	80.63	60.63	298.2	215.66	167.88	121.33	2.66	2.48
15. 30% CO_2 emission reduction	1.80	1.47	71.57	55.7	278.27	229.95	155.32	125.72	2.82	2.61
16. 15% discount rate	0.98	0.76	76.82	64.06	303.97	262.97	169.28	144.06	2.49	2.20
17. 5% discount rate	2.55	2.08	108.26	88.05	325.62	284.3	191.01	162.81	2.3	2.14

Table 17
Percentage change in costs and emissions under CO_2 emission mitigation scenarios

% change against TRP base case	% increase in generation cost (US$ billion)		% reduction in emissions						% increase in LRAC (US-Cts/kW h)	
			CO_2 (Gg '000)		SO_2 (Gg)		NO_x (Gg)			
	TRP	IRP	TRP	IRP	TRP	IRP	TRP	IRP	TRP	IRP
Base case	0.00	−20.38	0.00	21.75	0.00	14.62	0.00	16.74	0.00	−9.72
10% CO_2 emission reduction	3.82	−15.92	12.09	32.43	2.98	20.33	4.56	23.30	2.43	−5.26
20% CO_2 emission reduction	8.92	−11.46	21.44	40.93	8.98	34.18	11.20	35.82	7.69	0.40
30% CO_2 emission reduction	14.65	−6.37	30.27	45.73	15.07	29.81	17.84	33.50	14.17	5.67

base value of 6.4–7.2% annually) have only a marginal impact (±2%) on emissions. Further, the 2% decreased load growth introduced to account for rigorous transmission and distribution loss reduction programmes results in only about 5% reduced emissions. These are mainly because the plant sequence is not affected by this level of load variation, and only the plant outputs vary.

7.3. Fuel cost changes

The historical patterns show that while coal prices are relatively stable, oil prices are highly variable. Further, the prices of LNG are generally linked to oil prices. Therefore, when examining the sensitivity of the study output against fuel prices, this difference in price variations has been taken into consideration.

The decrease in fuel prices (coal by 10% and oil and LNG by 25%) has clearly resulted in more utilisation of oil based plants, giving lowered emissions, while the increased fuel prices (coal by 10% and oil and LNG by 25% or 50%) resulted in more coal based plants, with increased emissions, being in use. As a result, the overall GHG emissions vary by about −25% to +7% of that of the BAU case.

7.4. Plant efficiencies

Increased plant efficiencies finally have only an insignificant impact on emissions, mainly due to a lowered loss of load probability and, hence, increased energy supply. Therefore, the total cost is also reduced only marginally. Therefore, the benefit of increased plant efficiencies is directly translated into increased supply reliability.

7.5. Discount rates

Most countries in this region, including Sri Lanka, use discount rates around 10% in generation expansion planning studies. Therefore, this rate was selected in the base case, while the sensitivities are observed for the 5% and 15% discount rates.

When the discount rate is changed to 15% from the base case value of 10%, capital intensive plants, such as coal plants, are less favoured over others, such as oil fired plants. This results in lowered emissions under this scenario, while it is exactly the opposite under a reduced discount rate of 5%, where more capital intensive plants with low operational costs are preferred over the others.

7.6. CO_2 emission control

The cost and other implications of CO_2 emission control are given in Table 17 for both the TRP and IRP cases. All the comparisons are made against the BAU case, which is the TRP base case. It can be seen that switching to the DSM options automatically reduces the CO_2 and other emissions. For instance, the cost of the IRP base case is 20% less than that of the BAU case at a CO_2 emission reduction of about 22%. Even a 46% reduction in CO_2 (against BAU) can be achieved in the IRP model at a 6% reduction in overall costs.

Under the CO_2 emission control scenarios of the TRP based model, where approximately 10%, 20% and 30% reductions in CO_2 are achieved, the average cost of these reductions amounts to US$46, US$57 and US$67, respectively, for a tonne of carbon. In the IRP based model, these values become a little more expensive than those of the TRP case, since a certain level of CO_2 reduction has already been achieved with the DSM measures in the IRP case. These values are US$55, US$66 and US$80, respectively, per tonne of carbon against the IRP base case. The tighter the emission control regime, the higher is the cost of achieving it, particularly due to the requirement to select more expensive renewable energy based technologies, such as wind, hydro and dendro plants, for the purpose of reducing CO_2 in a large scale. It is important to note that renewable energy based plants (wind and dendro) are selected only in scenarios where forced CO_2 emission reduction targets are imposed.

Unconstrained world trading of carbon is expected to fetch only US$24 a tonne of carbon [8]. Carbon abatement costs in Sri Lanka become less than this figure only in the case of IRP against the TRP base case, where even 46% overall CO_2 reduction can be achieved at a negative cost.

7.7. Correlations

The emissions of CO_2, NO_x and SO_2 are highly correlated with each other (above 80% correlation), while the generation cost is only weakly correlated to emissions (approximately a maximum of 30% correlation). In general, a greater percentage of CO_2 reduction can be achieved at a lesser percentage increase in generation costs. The long run average cost (LRAC) increases only by about 14% when making attempts to reduce CO_2, even by 30% under the TRP case. Even a 46% reduction in CO_2 (against BAU) can be achieved at only a mere 6% increase in LRAC under the IRP case.

8. Conclusions

This study was mainly focussed on examining the supply side and demand side options available for greenhouse gas (GHG) emission mitigation in the Sri Lanka power system, but the results obtained in the study are equally applicable to countries having similar resource utilisation in the power sector.

It is concluded that there are technically feasible and economically viable options for mitigating GHG emissions in the Sri Lanka power sector by as much as 46% from the business as usual scenario when the traditional generation planning process is used. These options include both DSM measures as well as renewable energy technologies, such as wind, hydro and dendro power, in addition to clean coal technologies. While some of the DSM measures are negative cost options, all the renewable energy and clean coal technologies impose a cost penalty in GHG mitigation. Further, it is also concluded that none of the available supply side options can mitigate GHG emissions at the expected carbon prices under an unrestricted world carbon trading scenario, where price of carbon is expected to be US$24 ton^{-1} [8].

It is important to note that these results should not be taken in isolation, especially because of the underlying assumptions of the availability of commercially proven clean coal technologies at economically competitive prices. Further, there are also very optimistic renewable based energy sources, which need evaluation of their true potential in the country, and the long term viability of maintaining hitherto untested primary energy sources and systems associated with power generation in Sri Lanka require further study. Further, some of these GHG emission reductions cannot be effected within the first few years, as some clean coal technologies and renewable options have their own lead times.

Acknowledgements

The authors are grateful to the Asian Institute of Technology, University of Moratuwa, Sri Lanka Energy Managers Association, Ceylon Electricity Board and Swedish International Development Cooperation Agency (Sida) for providing technical, financial and other resources to conduct this research work.

References

[1] Ceylon Electricity Board, Long Term Generation Expansion Plan (2000–2016). Generation Planning Branch, Ceylon Electricity Board, Sri Lanka, 1999.
[2] Daranagama U, Wijayatunga PDC, Ariyadasa KP, Kumarasiri HK. Feasibility of dendro power based electricity generation in Sri Lanka. Energy Forum, Sri Lanka, 1998.
[3] Greenhouse Gas Inventory Workbook. Revised 1996 IPCC guidelines for National Greenhouse Gas Inventories, vol. 2, London, UK, 1996.
[4] Greenhouse Gas Inventory Reference Manual. Revised 1996 IPCC guidelines for National Greenhouse Gas Inventories, vol. 3, London, UK, 1996.
[5] Wind energy resources assessment—southern lowlands of Sri Lanka—Final Report. Ministry of Power and Energy, Sri Lanka, 1992.
[6] Thermal Generation Options Study—Final Report. Ceylon Electricity Board and Electrowatt Engineering Services Ltd., 1996.
[7] Fernando WJLS, Wijayatunga PDC, Shrestha RM. Least cost supply-side options for mitigating greenhouse gas and other harmful emissions from the power sector: Sri Lanka case study. Energy Sustainable Develop, J Int Energy Initiative 2002;VI(1):74–84.
[8] Ellerman AD, Jacoby HD, Decaux A. The effects on developing countries of the Kyoto protocol and CO_2 emissions trading. Report no. 41. Joint Program on the Science and Policy of Global Change, Massachusetts Institute of Technology, Boston, 1998.
[9] Shrestha RM, Marpaung COP. Supply and demand-side effects of power sector planning with CO_2 mitigation constraints in a developing country. Energy 2002;27:271–86.
[10] Ceylon Electricity Board, Environmental Impact Assessment Study Report. West Coast Coal Development Project, Ceylon Electricity Board, Sri Lanka, 1998.
[11] Asian regional research project on energy environment and climate change—Phase III. Final Report on Power Sector, Asian Institute of Technology, Bangkok, August 2002.