Project No 518294 SES6
CASES
Cost Assessment of Sustainable Energy Systems

Instrument: Co-ordination Action

Thematic Priority: Sustainable Energy Systems

Deliverable No. 10.1
[Assessment of policy instruments to internalise environmental related external costs in non-EU Member States]

Due date of deliverable: 31/05/2008
Actual submission date: 17/07/2008

Start date of project: 1st April 2006 Duration: 30 Months

Organisation name of lead contractor for this deliverable: **University of Bath**

Revision: **FEEM**

Project co-funded by the European Commission within the Sixth Framework Programme (2002-2006)		
Dissemination level		
PU	Public	X
PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential, only for members of the consortium (including the Commission Services)	

Assessment of policy instruments to internalise environmental related external costs in non-EU Member States

Wan-Jung Chou [a]
Anil Markandya [a]
Alistair Hunt [a]

[a] University of Bath

Table of contents

List of tables

1. Introduction

In the developing countries selected in CASES, the governments have been implementing policy instruments to promote renewable energy in power generation, with an aim to: 1) mitigate GHG emissions, 2) foster economic development of rural areas, and 3) enhance the energy security by diversify the energy matrix and by reducing the dependence on imported energy sources. In recent years, rapid economic growth has been widely observed in these developing countries. In 2006, Turkey achieved GDP growth rate by 6.1%, 10.7% for China, and 9.2% for India (World Bank Statistics). In this momentum of economic growth, these countries have been undergoing increasing electricity consumption. Given that the power sector is characterised by its high greenhouse gas (GHG) emissions, a cleaner energy matrix is necessary to support sustainable economic development. Lack of access to electricity has been a crucial contribution to economic and social inequality amongst areas within a country, such as in Brazil, China, and India. Whilst grid extension to these off-grid remote areas is not always economically plausible, electrifying these areas by means of local renewable resources can be an alternative. Energy security or security of supply of a country is its ability to supply energy to meet demand at a price that protects economic growth. Long-term measures to increase national energy security are to decrease the dependence on one energy source or imported sources and to exploit local fossil fuels or renewable resources.

Governments have a number of options that they can use to promote renewable energy. The first is to support the voluntary measures, particularly through education and dissemination. The second type refers to environmental standards or energy taxes. The third option is to promote renewable energies through direct support. Generally, a mix of policy instrument is essential to success. (Sawin, 2004) This report will focus on the investigation of policy instruments that offer direct support to renewable energy projects, in the developing countries of Brazil, China, India, and Turkey.

Section 2 briefly reviews the policy instruments that are currently active in the four countries. Assessment of the policy instrument will be carried out in section 3 for each of the four countries, by using criteria that are also applied in assessing policy instruments in the EU countries (WP9). Conclusion will be made in section 4.

2. Policy instruments

2.1. Brazil

As of year 2005, Brazil had installed power generation capacity of around 100GW. Hydroelectricity accounted for over 70% of the capacity, mainly from large-scale hydro power, and gas fired power plant ranked the second, 10.07%. By contrast, the share of installed capacity of coal-fired power is around 1.4%. In terms of electricity production, hydropower, both large- and small-scale, contributed more than 80% of the domestic power production in that year. See Table 2.1 below for more information. By year 2005, the installed capacity of renewables-based power plants was only 5% of the total capacity; given its abundant renewable resources, Brazil has a great potential in further fostering renewables energy technologies.

Table 2.1: Installed capacity and electricity generation by technologies as of year 2005

	Installed capacity (MW)	% of capacity	Electricity production (GWh)	% of production
Coal	1,415	1.41	9,971	2.47
Oil	5,251	5.24	11,737	2.91
Gas	10,085	10.07	18,813	4.67
Nuclear	2,007	2.00	9,855	2.45
Large hydro	68,400	68.29	337,457	83.73
Small hydro	1,740	1.74		
Wind	28.6	0.03	93	0.02
Biomass	3,068	3.06	14,361	3.56
Other sources	8,170	8.16	745	0.18
Total	100,164.6	100	403,032	100

Source: Brazilian Ministry of Mines and Energy (MME) and IEA statistics

The earliest renewable energy projects are dated back to mid 1970s. Since 1990s, government programmes commenced to electrify off grid rural areas through renewable energy technologies. A federal programme, the Programme for Energy Development in State and Municipalities (PRODEEM), during the years 1994-2001, was launched, in order to electrify remote villages through locally available renewable sources and thereby to promote self-sustainable social and economic development of these areas. In general, flaws in the execution were revealed. Firstly, the programme only installed 18% of the systems planned, 46% of systems installed were mislaid, and 36% were installed correctly but soon stopped working. Secondly, the target of diversifying energy resources was not met as photovoltaic technology prevailed, whereas wind systems and small hydroelectric stations were excluded. (Ruiz, Rodríguez, and Bermann, 2007)

During 2001-2004, two programmes were launched to promote electricity generation by using wind power and small hydroelectric power. These are the Emergency Energy Programme (PROEÓLICA) for the wind power and the Programme for the Commercialisation and Development of Small Hydroelectric station (PCH-COM) for the latter source. PROEÓLICA aimed to install capacity of 1050MW with wind turbines to connect them to the electrical network, and a purchase of the generated electricity (up to 1050 MW) was guaranteed over a period of 15 years, at a price fixed by regulatory authority. Upon enactment of this programme, this price lay at R$

112/MWh. In May 2002 a new reference price of R$ 72.35/MWh was determined by ANEEL (Resolution No. 248), which, however, was reckoned unable to cover the emerging cost[1] of the power generation from wind energy. This programme later on was transferred to the Alternative Energy Source Incentive Programme (PROINFA). The PCH-COM programme aimed to commercialise small hydroelectric stations. Capacity of 1200 MW was planned to be installed during the years 2001-2003. Loans were provided to the enterprise; also, generated electricity by private sectors was guaranteed a purchase from the utility at a fixed price. However, four months after it launched, this programme became inactive as the prices did not provide enough incentives to the private investors.

Regulated by Law 10438/02 and later revised by the Law No. 10762/03 and Decree 5025 in March 2004, the Alternative Energy Source Incentive Programme (PROINFA) enacted in 2002 and became the main programme operating to promote electricity generation from renewable energy sources. In the first phase (year 2002-2006[2]), this programme required installation of 3300 MW of electricity capacity from wind turbine, small hydropower stations, and biomass plants, with 1100 MW for each source. A tendering system was introduced to contract this capacity. Long-term purchase guarantee was offered to independent power generators: produced electricity will be purchased by Eletrobrás[3] at fixed feed-in prices for 20 years. The fixed purchase prices vary amongst renewable sources and are determined by the economic value of the referential competing energy source[4], as shown in Table 2.2. The PROINFA-tariffs are adjusted annually by the IGP-M, the General Market Price Index[5]. The unadjusted economic values (feed-in tariffs) and adjusted purchase prices of electricity contracted in the first phase of PROINFA are shown in Table 2.2.

[1] The emerging cost was estimated to be between R$ $_{2001}$ 101.40/MWh and R$ $_{2001}$ 218/MWh. (Wachsmann and Tolmasquim, 2003)
[2] Later, the deadline of the first phase was postponed from December 2006 to December 2008 (Decree MME 452/2005). This is the deadline for start-up of operation of contracted power generators.
[3] Eletrobrás is currently a holding company that links directly the Ministry of Mine and Energy. Several utility companies that generate and transit companies in the country are under its holding.
[4] The Law 10436 initially defined the economic values of three types of RETs at 80% at least of the average national rate of supply to the end users, but the temporary measure 127/03 amended this value of 50%, 70%, and 90% of the average national rate for electricity generated from biomass, small hydro, and wind power, respectively. Average national rate of supply is measured as the ratio of income from electricity supply to end users in the past 12 months to respective electricity consumed, shown in R$/MWh.
[5] The General Market Price Index is composed of three elements: (1) Wholesale Trade Market Price Index (IPA-M) (60%), (2) Consumer Market Price Index (IPC-M) (30%) and (3) National Construction Cost Index (INCC-M) (10%). (Kissel and Krauter, 2006)

Table 2.2: Feed-in tariffs by different renewable energy technology

Renewable Energy Technology	Feed-in tariffs R$/MWh (March 2004)	Feed-in tariffs €cents/kWh (March 2004)	Adjusted tariffs €cents/kWh (July 2005, adjusted by IGP-M index)
Small-scale hydro	117.02	4.50	5.1
Wind power	180.18 – 204.35	6.93-7.86	7.8-8.9
Biomass			
Sugarcane	93.77	3.61	4.1
Wood residues	103.20	3.97	4.5
Rice husks	101.35	3.90	4.4
Landfill biogas	169.08	6.50	7.3

Note: 1€ = R$ 2.60. Source: do Valle Costa et al, 2008

In the first phase, the programme established a *minimum equipment nationalisation index*[6] at 60% of the equipment value, and this index will increase to 90% in the second phase of the programme due to expected larger scale of long-term projects (Dutra and Szklo, 2008). This index aimed at developing the manufacturing industry of renewable energy technologies that produce durable goods and create employment opportunities.

Notified by the Law 10438/2002, the second phase of PROINFA aims to achieve the target that the gross electricity consumption from wind energy, biomass, and small hydro power will achieve 10% of the total electricity consumption by 2022. In 2004, a new regulatory framework for the power sector was introduced by the Law 10848, and as understood, the second phase of PROINFA will have to operate in compliance with this new model. The new model introduces a bidding system to replace previous wholesale energy market to contract new electricity generation capacity from both conventional and non-conventional fuels. This aims to control excess rise of the electricity tariffs as contracts will be given to the projects which generate electricity at lower prices. In order to keep promoting the use of renewable energy, a share of electricity amount to be contracted in the bidding processes will be reserved to these sources. The share will be defined by the Ministry of Mines and Energy (MME), under the condition that the bidding prices from renewable sources shall not exceed 0.5% of the final tariff in any year, when compared to a power generation expansion based on conventional sources. Moreover, the accumulated tariff impact due to renewables shall not exceed 5% of the tariff if it was formed only by conventional sources. The capacity of new renewables projects will be capped to limit their impact on the final electricity tariffs. Despite the broad guidelines mentioned above, the implementation date of the second phase is still unknown.

[6] This index refers to a mandate that a minimum percentage of total equipment in value must be manufactured domestically.

2.2. China

China, as a growing economy, has roughly 9.4% of the world's installed electricity generation capacity and is predicted to be responsible for up to 25% of the increase in global electricity generation over the next three decades. For the purpose of power production, coal has been a dominant source in China. In 2005, it was used to generate almost 79% of China's electricity, whereas renewable resources – hydro power (mainly large scaled) and biomass - accounted for 16%, of which hydro power has a dominant share. See Table 2.3 for more information.

Table 2.3: Power generation by sources in 2005

	Electricity production (GWh)	% of total production
Coal	1,972,267	78.97
Oil	60,634	2.43
Gas	11,931	0.48
Biomass	2,504	0.1
Nuclear	53,088	2.13
Hydro power	397,017	15.9
Total	2,497,441	100

Source: IEA energy statistics

In 1970s and 1980s, demand of electricity grew in rural areas. In order to meet this trend, China provided financial incentives to promote using renewable sources, such as biogas, fuel wood, and small hydropower, to generate electricity. These incentives included low interest loans, financial grants, and subsidies. China emitted 10.6% of global carbon emission from fossil fuels in 1990 and 14.2% in 2003, and this share is projected to rise to 22.2% by 2020 (IEA, 2006). In correspondence with this, since 1990s, environmental protection and sustainable development have also become targets for government policies to promote electricity generation from renewable sources, in particular solar energy, wind power, and biomass.

Several executive programmes have commenced since 1990s to promote electricity generation from renewable resources. The Brightness Programme, implemented in 1996, is an umbrella program that includes the Township Electrification Programme (TEP) (implemented 2001-2003), and the Village Electrification Programme (2005-2010). The TEP contracted 20 MW of solar PV and 840 kW of wind, and 200 MW of small hydro through public biddings, to provide electricity for more than 1000 townships. The Wind Power Concession Programme, implemented in 2002, has been the main programme to develop large-scale on-shore wind projects to connect to the grid. As of 2005/2006, the installed capacity of each RET nationwide is reported in the second column of Table 2.4. The Renewable Energy Law, a latest regulatory framework for renewable energy projects, took effect on January 1, 2006. By encouraging investment in wind, solar, water, biomass, and other renewable resources, the Law notifies that installed capacity of renewables-based generation shall reach

15% of total generation capacity by 2020 and the projected capacity by different renewable energy technologies (RETs, hereafter), as shown in Table 2.4, shall be achieved. Moreover, the Chinese government's Eleventh Five-year Plan, dating from 2006 to 2011, specifies measures in detail to increase the shares of renewable energy: 1) the construction of 30 large-scale wind farms with a 100MW capacity; 2) the provision for grid-connected wind and biomass to reach 5 GW and 5.5 GW respectively; 3) to achieve biomass and waste fuelled generation of more than 5.5 GW by 2010.

Table 2.4: Realised and projected installed capacity of different RETs in China

RET	Current installed capacity (2005/2006) (MW)	Projected installed capacity in 2020 (MW)
Small hydro power	2850	300,000 [7]
Biomass	1880	30,000
Wind power	1260	30,000
Solar PV	65	1,800

Source: Fang and Zeng (2007)

Supported by various programmes, the major policy instruments that are currently active for renewables-based power generation include renewable portfolio standards (see blow), market regulating mechanisms, fiscal incentives, and grants for research development. In late 2007, the Renewable Portfolio Standard (RPS) mandates were announced (Renewables global status report, 2007). Firstly, the share of non-hydro renewable energy should be 1% of total power generation by 2010 and 3% by 2020. Secondly, any power producer in China with capacity greater than 5GW must increase its actual ownership of power capacity from non-hydro renewables to 3% by 2010 and 8% by 2020. Market regulatory mechanisms are employed for biomass and wind power technologies connected to the grid. Favourable tax rates and custom duties reductions are provided to the renewable technologies. Other financial incentives are also available: 1) renewable energy development fund is provided to encourage studies in renewable energy in rural areas, to cover early-stage research and development costs for projects in all areas, and to help fund construction of renewable projects on islands; 2) low interest loans are provided for renewable energy project[8].

In 2006, the National Development and Reform Commission (NDRC) announced the feed-in tariffs policy for different renewables technologies. As shown in Table 2.5 below, the tariffs vary with different technologies. For per unit of electricity generated by biomass technology, a fixed premium of 0.25 Yuan, around 2.33 €cent/kWh, is provided. Since 2002 when the Wind Power Concession Programme was implemented, a government tendering system has been introduced to contract generation capacity from large-scale on-shore potential projects (100-200MW), and a power purchase agreement at winning bidders' prices was guaranteed by state-owned

[7] This also includes large hydro power.
[8] Interest rate subsidy is provided to the banks that provide low-interest loans.

utilities for 25 years. In 2006, it was modified as that the winning bidder's price is the feed-in tariff for the first 10-15 years, and after that, the purchase price will be the average local feed-in price on the market. For other renewables-based technologies, tariffs will be determined case by case.

Table 2.5: Feed-in tariffs for different RETs announced in 2006

Renewable energy technology (RET)	Feed-in Tariffs (Yuan/kWh)
Biomass	0.25 Yuan + coal fired power price
Wind power	Following the Wind Concession Programme, the lowest bidder's price as the fixed power purchase price for the first 30,000 full load hours. The duration of the purchase depends on individual plant's load factor, ranging between 10-15 years. After 30,000 full load hours, the project generator will receive the average local feed-in-tariff on the power market at that time.
Solar and other RETs	Project-based approval price

Source: Renewable global status report (2007)

As shown in Table 2.6, the technologies of small hydro power, biogas, wind power, and municipal wastes have favourable VAT rate at 6%, 13%, 8.5%, and 0% respectively (the standard rate is 17%). Biogas, including biogas production and related equipment production costs and purchases, has the favourable VAT rate. Since 2001, the VAT for municipal waste-generated electricity had been refunded in total, and in 2004, the regulation further clarified that this VAT refund is only applicable for municipal waste electricity with more than 80% fuels stemming from municipal waste, which gives a strong incentive for municipal power generation. These VAT exemptions are considered significant reduction in power generation costs of these technologies and help to level the playing field so that renewable energy are better able to compete at the cost basis (Sawin, 2004). Take wind power for example, the reduction is about 0.05-0.07 Yuan/kWh, around 0.47-0.65 €cent/kWh, according to the difference in cost in the various wind farms (Li, Shi, and Ma). Moreover, further income tax reduction by 15% are applicable for the biogas and wind power technologies, and this should encourage power generators to invest further on technology improvement, which, in turn, will lower generation cost.

Table 2.6: Favourable tax rates for renewable technologies (issued in 2001)

Technologies	VAT	VAAT (Value-Added Annex Tax)	Income Tax
General	17%	8% of VAT	33%
Small hydro power	6%	8% of VAT	33%

Biogas	13%	8% of VAT	15%
Municipal waste	0	0	33%
Wind	8.5%	8% of VAT	15%

Source: Li, Shi, and Ma[9]

2.3. India

Conventional fuel cycles, especially coal-fired power, have been the main power supply in India. As on April 30, 2008, official statistics show that 64.6% (92,156.84) of the total installed capacity is from thermal power, 24.7% (35,908.76 MW) from large hydroelectric power, 7.7% (11,125.41 MW) from other renewable sources, and 2.9% (4,120 MW) from others. As on December 31, 2007, total renewable-based electricity generation capacity in India is 11478.36 MW, including 11272.13 MW (98.2%) of grid connected and 205.23 MW from captive/distributed generators[10]. Of the grid-connected capacity, as shown in Table 2.7, nearly 70% of the total capacity is accounted by wind energy, 18.15% by small-hydro power, 6.39% by cogeneration-bagasse, and 5.37% by biomass power. Comparing the installed capacity with the estimated potential shown in the same table refers to the fact that India still has considerable renewable resources unexploited.

Table 2.7: Estimated potential and cumulative achievement of electricity capacity of renewables in India (as on December 31, 2007)

RET	Estimated potential (MW)	Cumulative Achievement (MW)	% of total installed capacity
Wind power	45,195 (53.31)	7,844.52	69.59
Biomass	16,881 (19.91)	605.80	5.37
Small Hydro power (Up to 25MW)	15,000 (17.69)	2,045.61	18.15
Bagasee cogeneration	5,000 (5.9)	719.83	6.39
Waste	2,700 (3.18)	55.25	0.49
Solar power		2.12	0.02
Total	84,776	11,272.13	100

Source: Ministry of Non-conventional energy Source, Annual report 2007-08

The Indian renewable energy programme was launched primarily as a response to the perceived rural energy crisis in the 1970s. Cash subsidies were provided for promoting renewable energy technologies. In the early 90s, the focus of programmes shifted from purely subsidy-driven dissemination to technology promotion, through a commercial route. Aiming to promote investment in renewable technologies, this technology push approach embodied fiscal and financial incentives such as subsidised

[9] The published year of this reference is not available.
[10] This figure comprises 95 MW from biomass cogeneration, 86.53 MW from biomass gasifier, and 23.70 from waste.

interest rates (low interest loans), capital subsidies, long repayment schedule, tax concessions, low import tariffs, duty waivers and accelerated depreciation. (Ghosh, Shukla, Garg, Benkata, and Ramana, 2002)

The India Alternate Energy Project was launched in 1991, aiming to achieve commercialisation of wind power and solar PV technologies. Feed-in tariffs and purchase guarantee were applied at the state level. The effectiveness in the dissemination of wind power technology turned out to be more significant than that for solar PV technology, due to massive investment cost of solar PV technology[11]. In the 10th Five-Year Plan starting from April 2002, solar technology was targeted as the main means to electrify 5000 villages[12]. Even though low cost financing was provided, the massive investment cost of solar technology and low possibility of return made this project unattractive for private sector[13] (Thakur, Deshmukh, Kaushik, Kulshrestha, 2005).

In 2003, the Electricity Act[14] took effect, which has been serving as a regulatory framework for Indian power sector reform as well as for efficient and environmentally benign policies. In accordance with the Electricity Act 2003, the Indian government released the National Electricity Policy in February 2005 in which the need for the promotion of non-conventional energy sources was emphasised. Specifically, the Policy notes the need to reduce the capital cost of projects based on renewable energy and stresses the importance of promoting competition amongst renewables projects. Based on this broad policy mandate, State Electricity Regulatory Commissions (SERCs) ought to increase the share of electricity from non-conventional resources and guarantee a purchase of such electricity at prices as a result of competitive bidding procedures. In practice, it is completely left to the individual SERC to enact detailed policy measures to promote development of renewable technologies. More recently, the Integrated Energy Policy, released in August 2006, further requires power regulators to mandate feed-in laws for renewable energy, where appropriate, as provided under the Electricity Act 2003, as well as to provide alternative incentive structure for utilities to integrate renewables into their systems.

Currently, a combination of policy instruments - Renewable Portfolio Standard and feed-in tariffs, at the state level, is the main market mechanism. The RPS ratios and feed-in tariffs are state-specific (See Table 2.8 for the details). Renewable electricity as a proportion of total procurement power by the distribution licensees is determined by respective SERC. These ratios range from 0.5% to 10% (Singh, 2007) and are guided by the potential for renewable energy resources, existing utilisation and expected investment in each state. The tariffs at which distribution companies

[11] This was due to the initial incentives based on capital subsidies and tax benefits due to 100% depreciation. However, because these incentives did not relate to generation, it ended up with the situation that many unviable wind machines were installed in a hurry to avail tax benefits without considering wind sitting issues. (Banerjee, 2006)
[12] It was planned that 18000 villages would be covered by the year 2012.
[13] Through Electricity Act 1991, Indian power sector was open for Independent Power Producers (IPPs).
[14] The Act has deepened the power sector reform in India and enabled competition in this sector.

guarantee to purchase also vary amongst areas, as well as technologies. These buy-back prices under the RPS are measured mainly in a cost-based nature and determined by investment cost and rate of return[15] (Singh, 2007). More recently, in January 2008, with a view to harness the vast solar energy potential in the country for power generation, a new initiative on developing grid interactive solar power generation has been announced. A maximum capacity of 10 MW from each Indian state will be eligible under the scheme and 5 MW per developer. A fixed premium of 12 Rs/kWh, around 20.68 €cents/kWh, for solar photovoltaic power and 10 Rs./kWh, around 17.23 €cens/kWh, for solar thermal power are provided for electricity fed to grid. Developers will sell electricity to state-run utilities and the premium will be paid to them on top of the tariff the utilities offer. The subsidy is valid for a period of 10 years (MNRE, 2007/08).

In addition, fiscal and financial incentives are also available in each state to encourage investment in technology development.

[15] Despite being notified in the National Electricity Policy, the measure of price bidding exercises has not been adopted to contract renewables-based projects.

Table 2.8: RPS and feed-in tariff in large states of India as of 31/07/2007

State	RPS (%)	Feed-in Tariffs (Rupee/kWh)			
		Wind	Small hydro	Biomass	Bagasee cogeneration
Andhra Pradesh	5 (2005/06, 2007/08) 0.5 from wind energy	3.37 with 5% annual increment (base price as on 01/04/2004)		2.63 (2005-06) with 1% annual increment for 5 yrs	2.63 (2005-06) with 1% annual increment for 5 yrs
Chattishgarh	Available			2.67 (2004-05)	2.67 (2004-05)
Gujarat	1 (2006/07) 1 (2007/08) 2 (2008/09)	3.37 for new wind mills for up to 20 years		3	3
Haryana	3 (2007/08)	4.08 with 1.5% annual increment (base year 2007-08)		4	3.74 with 2% annual increment (base year 2007-08)
Karnataka	Min 5 Max 10	3.4 fixed for 10 yrs	2.8 for 10 yrs	2.88 (2004-05) with 1% annual increment on base year for 10 yrs	2.8 with an annual increment by 2%
Kerala	Available	3.14 fixed for 20 yrs		Incentives only up to 2005-06	Incentives only up to 2005-06
Madhya Pradesh	0.5	1st year: 3.97 2nd year: 3.80 3rd year: 3.63 4th year: 3.46 5th – 20th yr: 3.3		3.33 – 5.14 for 20 yrs, with increment of 3 - 8 praise.	3.33 – 5.14 for 20 yrs, with increment of 3 - 8 praise.
Maharashtra	3 (2006/07) 4 (2007/08) 5 (2008/09)	New project: 3.5 in the first year, with an annual increment by Rs. 0.15, for 13 years		3.04 – 3.43 with 1% annual increment for 13 yrs	3.05 (commission year)

	6 (2009/10)				
Orissa	3 (2007/08) 3.5 (2008/09) 4 (2009/10) 4.5 (2010/11) 5 (2011/12)	N A			
Punjab	1 (2007/08)	3.66 with 5% annual increment till 2012		3.59 (2007-08) with five annual increment of 3% till 2012.	3.59 (2007-08) with five annual increment of 3% till 2012.
Rajasthan	*Wind*: 2 (2006/07), with an annual increment by 0.3, till max 4. *Biomass*: 0.37 (2006/07), and 0.83 (2007/08), with annual increment by 0.3, till max 2. *Solar*: up to 50MW *Others*: 25 MW	Projects commissioned after 3/02/06: 3.31 for the first 10 yrs; 3.79 from 11 to 20 yrs. Updated tariffs: 3.59/3.67, depending on areas (base year 2008-09)	Projects commissioned in 2004/05: 3.32 with annual increment by 2%, up to year 2013/14.	Projects commissioned in 2004/05: 3.32 with annual increment by 2%, up to year 2013/14. 3.60–3.96 (2007/08)	Projects commissioned in 2004/05: 3.32 with annual increment by 2%, up to year 2013/14. 3.60–3.96 (2007/08)
Tamil Nadu	10	2.90		2.73 (2000-01) with 5% annual increment for 9 yrs	2.73 (2000-01) with 5% annual increment for 9 yrs
Uttar Pradesh	7.5		3.39 – 1.90 for the 1st to 20th year of operation.	2.86 for existing and 2.98 for new with 4 praise increment per year.	2.86 for existing and 2.98 for new with 4 praise increment per year.

Source: Singh (2007); Ministry of New and Renewable Energy, Annual report 2007-08

2.4. Turkey

Currently, electricity is mainly generated from thermal power plant, geothermal energy and hydro power plants. As shown in Table 2.9, electricity generated from conventional thermal sources comprises the largest share of Turkey’s electricity supply, contributing 75 % in 2005. Hydroelectricity generation takes up almost all of the remainder, 24.43%. Turkey has abundant hydraulic resources and currently identified gross potential and energy production capacity are nearly 50GW and 112 TWh/year (Bilgen et al, 2008), and the government hopes to expand the hydroelectric power plant capacity to 35GW by year 2020 (Kaya, 2006). Currently, Turkey is heavily dependent on imported energy sources, such as natural gas and oil, and hydropower capacity will be fully exploited. Therefore, to increase the dependency on domestic energy source and to expand the use of other renewable resources to diversity energy sources become main driving forces for the development of renewable energy.

Table 2.9: Electricity generation by fuel sources in 2005

	Generation (GWh)	% of total generation
Coal	43192	26.67
Oil	5483	3.39
Gas	73445	45.35
Biomass	34	0.02
Waste	88	0.05
Hydro	39561	24.43
Geothermal	94	0.06
Wind	59	0.04
Total	161956	100.00

Source: IEA statistics

Turkey has favourable natural conditions to develop biomass, geothermal power, wind power, and solar power generation technologies. Biomass used to be an important source of energy consumption in Turkey, mainly for heating and cooking. However, since 1980s, its contribution to total energy consumption has dropped from 20% to 8% in 1995. Despite this, Turkey still has rich agricultural potential. The total agricultural residues amount calculated in dry base has been measured approximately between 40 and 53 million tons, and this is considered having a high potential to replace lignite (40 million tons) and hard coal (1.3 million tons) used in electricity production. Also, Turkey has significant potential in geothermal energy. In 2005, geothermal ranked the second main renewable resource after hydropower in electricity generation (see Table 2.9), and its installed capacity is 20.4 MW as of 2006 (Bilgen et al, 2008). Provided with Turkey’s natural condition (owning coast), Turkey's technical wind energy potential is around 88,000 MW. By 2006, the installed capacity of wind power was 50 MW (Ben Jannet Allal and Vigotti, 2007) and 40 new wind farm projects (totalling approximately 1400 MW) already obtained licences. (Guner Law Office, 2008). In spite of that Turkey has high solar potential, the development of solar technology, particularly electricity generation, is still in an early stage.

Market deployment policies for renewables started in 1984 [16] with third-party financing and excise and sales tax exemptions. In 2001, the Electricity Market Licensing Regulation of the Electricity Market Law took effect and contained two regulations to promote the use of renewable energy. Firstly, the legal entities applying for licences for construction of renewable energy facilities are required to pay only 1% of the total licence fee. Secondly, renewables-based generation facilities are exempted from paying the annual licence fees for the first eight years following the facility completion date as specified in the licence. Meanwhile, priority of connection to the transmission and/or distribution systems is given to the renewables based generating facilities. The real beginning for a national renewable policy took place in the decree of Modification of the License Regulation in the Electricity Market in 2003 but the Regulation was not considered sufficient to overcome high investment cost, risk and lack of security associated with the entrance of renewable power generators into the electricity market. (Bilgen et al, 2008)

The Law on Utilisation of Renewable Energy Resources for the Purposes of Generating Electricity Energy took effect on May 18, 2005. Providing the primary regulatory platform, the Law focuses on expanding the use of renewable energy sources for generating electrical energy by establishing the necessary legal and regulatory framework. Meanwhile, the Law also ensures that the increase in the use of renewable energy sources shall not disturb free market conditions.

In accordance with the Law, several policies related to fostering renewables-based electricity generation are specified. To begin with, certificates are issued by the authority as a mean of regulating and monitoring. Private legal entities that generate electricity from renewable resources are granted a certificate that specifies the type of resource utilized to generate electrical energy, as well as the incentives with which each entity is entitled. A mandatory purchase scheme is provided to these generators under which the electricity generated from renewables will be purchased by legal retail sale licensees, on the basis of bilateral agreement. Each retail licensee is obliged to purchase the certified electricity[17] from renewables at the ratio of its total energy sales within the previous calendar year to total electrical energy amount offered by all legal retail licensees. In case that the total certified electricity amount is sufficient, the ratio for each retail entity shall not be lower than 8% of its sales in the previous year. The guarantee to buy the electricity energy generated from renewable energy resources was for 7 years but in 2006 it was extended to 10 years. The feed-in price of a specific year shall be the Turkish average wholesale electricity price in the previous year as determined by EMRA (Energy Market Regulatory Authority), but it should lie within the range of Turkish Lira equivalent to 5 to 5.5 €cents/kWh[18]. For example, the buy-back price for renewables based electricity was 9.13 YKr/kWh, around 5.2

[16] The build-own-transfer (BOT) and the build-own-operate (BOO) schemes were put in place in 1984 and financed major power projects (not limited to renewables) with the main objective of attracting private investors. The BOT and BOO financing schemes ended in 2000 and were replaced in 2001 by financial incentives within the framework of the Electricity Market Law. (Bilgen et al, 2008)
[17] The relevant information on the amount of certified electrical energy from RE will be issued by EMRA (Energy Market Regulatory Authority).
[18] However, legal entities that hold licenses based on renewable energy resources and which have the opportunity to sell above the limit of 5.5 eurocent/kWh in the market shall benefit from this opportunity.

€cent/kWh in 2007. Moreover, the Council of Ministers is entitled to raise this price up to 20 %, i.e. approximately 1 €cent/kWh, at the beginning of each year. This feed-in incentive is applicable for plants put into operation by December 31st, 2011, which may be extended for two years.

Financial incentives are offered to energy projects during their investment period. Firstly, low-interest loans can be taken up to 45% of the capital cost. Secondly, tax credit is offered for up to 20% of R&D expenses for three years. Thirdly, the sale price, rent, rights of access and usage permissions of state owned land are subject to an 85% reduction, provided that the property is used for the purpose of generating electrical energy from RER (Gunner Law Office, 2008). Finally, national funds are available to promote R&D.

2.5. Summary

The review above suggests that legal and political frameworks exist to promote RETs in all four countries. Most of policy instruments consist of a mixture of command-and-control and economic instruments. A feed-in pricing system is commonly employed in all four countries. Table 2.10 provides a summary of feed-in prices by countries and technologies. Mandate of renewable portfolio standard is employed in China, India, and Turkey. In China, the policy instruments vary by technologies, such as a tendering system for wind power and a fixed feed-in premium for biomass. In compliance with RPS and feed-in tariffs as broad commands by law, each state in India defines the ratio of RPS and the prices to be employed to different types of technologies. Brazil employs respective feed-in incentive for different RETs, but on the contrary, Turkey only specifies one universal feed-in price. Financial incentives in various forms, such as favourable tax rates, duty exemption, and subsidies to encourage investment and R&D are available in China, India, and Turkey.

Table 2.10: Summary of feed-in tariffs in the four developing countries (€cent/kWh)

	Brazil (March 2004)	**China**	**India**	**Turkey**
Wind power	6.93-7.86	3.4 (Varies with bidding results)	5-7.03	5-5.5
Small hydro	4.5	No fixed price	4.83-5.84	-
Biomass	3.61-6.5	4.37 (fixed premium of 2.33)	4.53-8.86	-
Solar PV	--	No fixed price	25.42 (fixed premium of 20.68)	-
Solar thermal	--	No fixed price	21.97 (fixed premium of 17.23)	-

Note: 1€=10.75 Yuan; 1€=58.03 Indian Rupees; 1€=1.47 US$

3. Assessment of policy instruments

To achieve success in fostering renewable energy in electricity production requires input of efforts from a combination of policy instruments. The assessment to be carried out will mainly focus on the market regulatory mechanisms, i.e. feed-in prices, tendering system, that are currently active in the four countries. The policies instruments will be analysed regarding a list of pre-defined performance criteria. The criteria and their definitions are listed in Table 3.1. Later, a multi-criteria decision analysis can be carried out based on the assessment outcomes.

Table 3.1: Criteria of assessment

Criterion	Definition
Effectiveness of externality internalisation	The extent to which the policy instrument achieves the stated objective of internalising externalities with a high degree of effectiveness and certainty within a specified period of time.
Cost-efficiency	The extent to which the policy instrument achieves the stated objective at the lowest possible cost for economic actors (businesses, households, and government), within the specified period of time and with a high degree of certainty. The relevant cost components are the fulfilment costs and the compliance costs (resources needed to comply with the monitoring and general administrative requirements) incurred by economic agents and regulatory costs incurred by the regulator.
Flexibility	This refers to the extent to which the policy instrument will retain its effectiveness under a range of changing environmental, economic, technological and social conditions. That is, will the instrument automatically adjust or if not, how easily is the policy instrument, once implemented, modified, either by government or by regulated actors, to accommodate changes.
Predictability	This refers to the extent to which the policy instrument provides power generators with a dependable incentive (‘carrot’ or ‘stick’), with known duration. An instrument with a high degree of predictability should reduce ‘market risk’, so that generators feel confident enough to modify their investment plans and to innovate and reduce costs.
Dynamic Efficiency	This refers to the extent to which a policy instrument provides continuing incentives for innovation and diffusion that will lead to improved performance – in environmental quality or cost – through the development and adoption of new environmental cleaner and economically more efficient practices or technologies.
Equity	This refers to the extent to which the policy instrument does not yield disproportionate burdens or benefits - financial or environmental – to particular groups, or unduly limit the options of future generation. This criterion includes fairness to actors and environmental justice.
Ease of introduction	This refers to the extent to which the policy instrument is relatively easy to implement, and does not require significant changes – by either government or generators – to existing legal, managerial, and technological (e.g. IT) systems.

	If new legislation is necessary, how feasible is it? Are the information requirements for setting the policy instrument manageable?
Ease of monitoring and enforcement	This refers to the extent to which reliable compliance monitoring the enforcement can be implemented at an acceptable cost. Monitoring and enforcement costs will depend on the informational requirements and the institutional and human resources requirements.
Diversification	This indicates the extent to which the policy instrument will lead to a diversified electricity generation system, by encouraging investment in a range of technologies, at different scales and at geographically dispersed sites.
Acceptability	This indicates the extent to which the policy instrument is understood by the public, acceptable to generators, and sellable to decision-makers in government. If an instrument has been used with any success in the past, political resistance may be low. The acceptability of an instrument will also depend on whether it avoids negative and creates positive impacts in other important policy areas (e.g. employment).

3.1. Brazil

For the projects contracted under the first phase of the PROINFA, the feed-in tariffs are expected to remain unchanged in real terms and will adjust in relation to inflation for 20 years. Together with this, a 20-year of purchase guarantee provides generators with high degree of predictability which reduces perceived market risk and creates a stable environment for further development in technology improvement and innovations. Nevertheless, a fixed tariff for a long period causes a concern in that a continuous favourable incentive is likely to turn out economically inefficient in the long term. This is because: 1) it may not push generators to invest in technology improvement, increases in productivity, and reduction of costs (Teixeira and da Graça Carvalho, 2007); 2) this, in turn, will slow down the progress of RETs becoming economically competitive; 3) end users will not benefit as they eventually will be paying for extra cost as a result of non-competitive power generators. Therefore, it is reckoned that a feed-in tariff that remains favourable over a long period is not a dynamically efficient policy instrument to foster renewables-based electricity generation.

One determinant of the success of a pricing law is whether a designated tariff is high enough to remove the barrier of high investment cost and of entrance to a competitive electricity market. The feed-in tariffs of biomass, small hydro, and wind power, respectively, are determined by regulatory authorities at the levels which reflect the economic feasibility of the three RETs. The PROINFA aimed to contract 1100 MW from biomass, small-hydro power, and wind power, respectively, summing up to 3300 MW. However, by the end of 2006[19], as can be seen in Table 3.2, the contracted capacity from small-scale hydro power and wind energy exceeded the programme's expectation, whereas the contracted capacity from biomass was significantly lower than planned.

[19] This was the first deadline of the PROINFA phase I.

Table 3.2: Contracted electricity capacity by source in the first phase of PROINFA

Renewable energy source	As planned by the policy (MW)	Realised final contraction (MW)
Biomass	1100	685
Small-scale hydro	1100	1191
Wind	1100	1422
Total	3300	3298

Source: Dutra and Szklo (2008)

Such an outcome strongly implies that the pricing incentives for wind power and small hydro power had higher acceptability amongst potential generators than that for biomass power generation. Regarding this, Dutra and Szklo (2008) proposed three explanations. Firstly, the tariffs applied to the biomass technology were considered too low to guarantee the economic feasibility of new biomass projects. Secondly, using biomass, sugarcanes in particular, to produce bio-fuel has been a prosperous business in Brazil, and this put a high opportunity cost for the investment in sugarcane bagasse fired-thermal power generation. Finally, the internal return rate of such cogeneration investment was lower than that of ethanol and sugar production, 15% p.a. versus 18% p.a.

Moreover, the feed-in prices for bagasse generation, ranging from 3.61 to 3.91 €cents/kWh, were lower than the new bidding prices of new thermo power generation projects held in 2005 - around 4.9 eurocent/kWh for thermal power (do Valle Costa et al, 2008). This strongly indicates the fact that the price for the bagasse generation technology was too low to recognise the environmental benefit of this technology against conventional thermal power technology. On the other hand, the high acceptability in the cases of wind power and small hydro power can be explained by the recent experience that feed-in tariffs were once implemented to promote these two technologies in two previous programmes, PROEÓLICA and PCH-COM.

In Brazil, hydroelectricity contributes 80% of the total domestic electricity production and most of it is supplied by large hydro power plants. In order to gauge private cost of current hydro power generation, this report adopts the average price of bidding results to sell electricity generated by existing hydropower plants[20]. A weighted average private cost for existing hydro power plants is calculated at around 2.02 €cents/kWh, as shown in Table 3.3.

Table 3.3: Bidding results of electricity generated by existing hydropower plants in Brazil in 2004/2005

	Period	Average capacity (MW)	Production (TWh/year)	Price US$/MWh	Price €cents/kWh
First bidding	2005-2012	9054	79.3	25.88	1.76
	2006-2013	6782	59.4	30.3	2.06
	2007-2014	1172	10.3	33.96	2.31
Second bidding	2008-2015	1325	11.6	37.41	2.55
Third bidding	2006-2008	102	0.9	28.33	1.93
Fourth bidding	2009-2016	1166	10.2	42.71	2.91

[20] This is under the assumption that during auctions the offers converged to marginal costs.

Average price[21]	29.69	2.02

Source: Dutra and Szklo (2008)

It is important to know that large hydropower projects produce a very small amount of greenhouse gas emissions or air pollutants in the operational phase, and the main concern relates to damages on human health in the fuel cycle. The identified potential impact of the large hydro-electric life cycle on human health comprises: 1) a significant increase in the population during the construction of the power plant, which results in the need to expand basic sanitation and public health services of the region; 2) an increase in water-borne diseases and infectious diseases and parasite vectors due to the change in hydric system and the synergy with the increase in the population, during the operation stage (Brazil country report, CASES). Recently in Brazil, under the requirement of environmental feasibility, mitigating measures for the second type of impact need to be defined and programmes need to be established a certain period before construction takes place, to reduce the incidence rate of these diseases. Hence, the externalities related to the second type of impact have gradually become a part of private cost. Nevertheless, some externalities do remain.

The Brazil country report of CASES provides estimation of externalities of large hydro power plant which was carried out on the Rio Madeira hydroelectric complex[22] located in the state of Rondônia in the Amazon Region, as a case study. The estimated external cost of the first type of impact is US$1.03/MWh, equivalent to 0.07 €cents/kWh and the estimated externalities avoided cost of the second type of impact is US$ 0.87/MWh, equivalent to 0.059 €cents/kWh[23]. The total external cost is 0.129 €cents/kWh. Adding this external cost to the private cost mentioned above yields a total social cost of hydropower generation at 2.149 €cents/kWh.

The estimated external cost per unit of electricity production from a gas-fired fuel cycle is 1.2 €cent/kWh. Taking the bidding results of new thermoelectric plants which start operate in 2008 as the proxy for current private cost of power generation from thermal power, the private cost is 59.52 US$/MWh, around 4.05 €cent/kWh. Summing private cost and external cost yields the total social cost of 5.25 €cent/kWh.

To gauge the generation cost of different fuel cycles in the long term, this report refers to the estimates in the literature. Under a long-term scenario forecast study carried out by IAEA (International Atomic Energy Agency), forecasts of levelised cost of different fuel cycles are provided and exhibited in Table 3.4 below. For the listed RETs, the life time is assumed to be 20 years with a discount rate of 15%. The figures are of year 2001. As suggested above, private cost of new large hydro projects shall gradually cover the cost resulting from measures of avoiding externalities, and this in turn will lower external cost related to hydro power fuel cycle. In accordance with this, considering 0.07 €cents/kWh the proxy for estimate of long-term external cost for

[21] The average price is the production-weighted average of the bidding prices.
[22] This complex comprises two power plants, with total capacity of 6450 MW. These power plants are scheduled to commence operation in 2012 and 2013.
[23] Another estimation of the second type of impact was carried out on another hydro-electric power plant in operation – Tucuruí Plant. It was not regulated by environmental legislation by the time it was constructed. The estimated external cost of the second type of impact was US$ 0.64/MWh, equivalent to 0.044 €cents/kWh.

large hydro power generation and 1.2 €cents/kWh[24] for thermal power generation, estimates of total social cost of these two types of fuel cycles are shown in the right-most column of Table 3.4. Similarly for the wind power, biomass, and small-scale hydro generation, the estimates of levelised cost, which are available for years 2010, 2015, and 2020, are taken as private cost; assuming that externalities of RETs are zero, estimates of total social cost are derived and shown in the rightmost column of the table.

Table 3.4: Forecast of private cost by fuel cycle types for years from 2010 to 2020

Type of fuel cycle	Private cost (US$/MWh)	Private cost [25] (€cents/kWh)	External cost (€cents/kWh)	Social cost (€cents/kWh)
Large hydro	36.65	2.49	0.07	2.56
Thermoelectric	42.68	2.90	1.2	4.1
Wind[26]	89.7 (2010) 85.5 (2015) 77.11 (2020)	6.10 (2010) 5.82 (2015) 5.25 (2020)	0	6.10 5.82 5.25
Biomass[27]	45.49 (2010) 45.49 (2015) 45.49 (2020)	3.10 (2010) 3.10 (2015) 3.10 (2020)	0	3.10 3.10 3.10
Small hydro[28]	54.40 (2010) 54.40 (2015) 54.40 (2020)	3.70 (2010) 3.70 (2015) 3.70 (2020)	0	3.70 3.70 3.70

1€=1.47 US$; source of private cost estimates: Dutra and Szklo (2008)

In this report, the effectiveness of a policy instrument to be examined refers to the extent to which externalities are able to be internalised[29] for per unit of electricity production. The effectiveness of feed-in tariffs is analysed for the case of renewable energy technologies against large hydro power generation as well as gas-fired thermal power during only the period from 2007 to 2015, due to limitation on information availability. In Table 3.5, the second row exhibits the estimates of total social cost of large hydro power generation, and the estimation method has been addressed above. Tariffs of RETs are feed-in prices guaranteed by the PROINFA programme and in the level unadjusted by the IGP-M index. The indicator of measured internalisation

[24] This is the external cost estimate based on a gas-fired fuel cycle.
[25] Estimates of private cost here is the levelised costs per kWh of electricity generation, in which the annualised capital costs plus fuel and maintenance costs over the year are divided by annual kWh output.
[26] Construction period of a wind project is assumed to be 1 year and the capacity factor is 25%.
[27] The construction period of a biomass project is 1.5 years and the capacity factor is 65%. Biomass fuel cost is assumed to be null.
[28] Construction period of a small hydro project is 2 years and the capacity factor is 65%.
[29] The concept of internalising externalities is defined as that energy price signals are provided to value any damages or, conversely, to recognise specific benefits. Such signals can be explicit, in the form of new taxes, user fees, or surcharges, or implicit, in the form such as caps on use. (Pershing and Mackenzie, 2004)

indicates the degree of internalisation, which is shown as the ratio of $\left(Tariff_{RET} \big/ SocialCost_{LH} \right)$, where $Tariff_{RET}$ denotes feed-in prices of respective RET and $SocialCost_{LH}$ denotes the social cost resulting from large hydro power generation. Results show that the feed-in tariffs for all three RETs promoted by the PROINFA outweigh social cost of large hydro power and this suggests that the feed-in prices more than fully recognise the environmental benefit of RETs, for a unit of generated electricity from large hydro power, during year 2007 and 2015.

Table 3.5: Level of externality internalisation for the case of large hydro power generation

		2007	2010	2015
Large hydro	Social cost (€cents/kWh)	2.149	2.56	2.56
Wind	Tariffs (€cents/kWh)	6.93 - 7.86	6.93 - 7.86	6.93 - 7.86
	Indicator for internalisation (%)	322 - 366	271 - 307	271 - 307
Small hydro	Tariffs (€cents/kWh)	4.5	4.5	4.5
	Indicator for internalisation (%)	209	176	176
Biomass (bagasee)	Tariffs (€cents/kWh)	3.61-3.97	3.61-3.97	3.61-3.97
	Indicator for internalisation (%)	168 - 185	141 - 155	141 - 155

For the case of gas-fired thermal power generation, the current indicator of measured internalisation indicates the degree of internalisation, which is shown as the ratio of $\left(Tariff_{RET} \big/ SocialCost_{Gas} \right)$, where $Tariff_{RET}$ denotes feed-in prices of respective RET and $SocialCost_{Gas}$ denotes the estimated social cost per unit of electricity production from gas-fired thermal fuel cycle. Results exhibited in Table 3.6 show that the feed-in tariffs can fully internalise externalities per unit of electricity production from a gas-fired fuel cycle from year 2007 to 2015. The feed-in price for small hydro can fully internalise the externalities from year 2010 onwards. By contrast, externalities can only be partially internalised in the case of biomass technology.

Table 3.6: Level of externality internalisation for the case of gas-fired thermal power generation

		2007	2010	2015
Gas-fired thermal	Social cost (€cents/kWh)	5.25	4.1	4.1
Wind	Tariffs (€cents/kWh)	6.93-7.86	6.93-7.86	6.93-7.86
	Indicator for internalisation (%)	132-150	169-192	169-192
Small hydro	Tariffs (€cents/kWh)	4.5	4.5	4.5
	Indicator for Measured internalisation (%)	85.7	110	110
Biomass (bagasee)	Tariffs (€cents/kWh)	3.61-3.97	3.61-3.97	3.61-3.97
	Indicator for internalisation (%)	68.8-75.6	88-96.8	88-96.8

Alternatively, degree of internalisation can be measured by the extent to which additional cost of each respective RET - its total cost minus generation cost - outweighs external cost caused by large hydro power generation per unit of electricity production. The environmental benefit from respective RET is calculated as $(Tariff_{RET} - PC_{RET})$, where PC_{RET} denotes the private cost of respective RET. The degree of internalisation can be realised by comparing the environmental benefits of each RETs with the external cost of large hydro power. As shown in Table 3.7, environmental benefits of three RETs all exceed external costs of large hydro power generation, and this confirms the effectiveness of internalising externalities of the RETs. Having said so, compared with small hydro power and wind power, the biomass technology comes as the least-cost option.

Table 3.7: External benefit in relation to large hydro power generation

		2007	2010	2015
Large hydro	External cost (€cents/kWh)	0.129	0.07	0.07
Wind	Tariffs (€cents/kWh)	6.93-7.86	6.93-7.86	6.93-7.86
	Environmental benefits	0.83-1.76	0.83-1.76	1.11-2.04
Small hydro	Tariffs (€cents/kWh)	4.5	4.5	4.5
	Environmental benefits	0.8	0.8	0.8
Biomass (bagasee)	Tariffs (€cents/kWh)	3.61-3.97	3.61-3.97	3.61-3.97
	Environmental benefits	0.51-0.87	0.51-0.87	0.51-0.87

For the case of gas-fired thermal generation, as shown in Table 3.8, environmental benefits of the wind power is capable of outweighing externalities of gas-fire thermal power generation, and this depends on the capacity factor of a wind power plant. On the contrary, environmental benefits of small hydro and biomass technology are lower than the external cost of gas-fired thermal power.

Table 3.8: External benefit in relation to gas-fired thermal power

		2007	2010	2015
Gas-fired thermal	External cost (€cents/kWh)	1.2	1.2	1.2
Wind	Tariffs (€cents/kWh)	6.93-7.86	6.93-7.86	6.93-7.86
	Environmental benefits	0.83-1.76	0.83-1.76	1.11-2.04
Small hydro	Tariffs (€cents/kWh)	4.5	4.5	4.5
	Environmental benefits	0.8	0.8	0.8
Biomass (bagasee)	Tariffs (€cents/kWh)	3.61-3.97	3.61-3.97	3.61-3.97
	Environmental benefits	0.51-0.87	0.51-0.87	0.51-0.87

The analyses above suggest that the feed-in tariffs specified in the first phase of the PROINFA are able to fully recognise the estimated externalities resulting from large hydro power per unit of electricity production. By contrast, the degree of internalisation for gas-fired thermal power by different RETs is in general lower than that for hydro power, and this is because gas-fired thermal power generation causes higher externalities than hydro power generation. Provided with the bidding outcomes in the first phase of PROINFA, wind power production is predicted to take up a higher share of total electricity production of the three RETs, with small hydro following as the second. Such a combination of renewables-based power production is effective in internalising externalities, but not the least cost option. Moreover, the goal of energy diversification is achieved.

As mentioned above, in the second phase of PROINFA, the capacity of renewables-based technologies will be contracted through a tendering system and will be capped by its impact on final electricity price. However, this may lead to several undesirable outcomes. Firstly, the regulated price caps will inevitably limit the degree of the effectiveness of internalisation of externalities resulting from electricity generation from conventional fossil fuels, unless new conventional power generation plants will start to follow a full-cost pricing mechanism. Secondly, despite being cost-efficient, this may not be able to encourage continuous development of less competitive technologies as only the most competitive technologies will be able to take a share of this market. Thirdly, this may not achieve the target of energy diversification. Dutra and Szklo (2008) carried out simulations of electricity generation scenarios up to 2020. Three possible scenarios of electricity generation from renewable resources in the second phase were considered: 1) exclusive use of a specific renewable resource, i.e. wind power only, biomass only, or small hydro power only; 2) equal division of generated electricity amongst the three sources; 3) equal installed capacity division amongst the sources. The simulation outcome suggested that the only scenario that satisfied the original broad target of the PROINFA phase two was the one in which biomass power generation option had exclusive participation in the bid. However, the barrier faced by biomass fired thermal power generation in phase one might happen again in the phase two (Dutra and Szklo, 2008). Also, an exclusive focus on biomass technology would make the domestic electricity supply vulnerable to crop yields which characterise seasonal fluctuations, as well as cause environmental concerns regarding biomass plantation[30]. Having said so, the implementation date of the second phase is still not foreseeable. Moreover, the new regulatory model is criticised for being unable to attract private investment. (do Valle Costa et al, 2008)

The PROINFA establishes a minimum *equipment nationalisation index* at 60% of the equipment value in the first phase and 90% in the second stage. This index is set in order to encourage the development of related manufacturing industry; however, it is observed especially in wind power industry that this index cannot be met by the low installed manufacturing capacity. In the case of wind power, national manufacturing capacity of wind turbine components are very low[31] and this has given rise to the slow progress of construction of contracted capacities in the first phase of PROINFA (do

[30] Firstly, the erosion is a problem related to the cultivation of annual crops. Secondly, the use of pesticides can affect the quality of groundwater and surface water, which in turn has an impact on animals and plants. Thirdly, biomass plantation supports a narrower biological species than natural forests would do. Finally, the collection, transportation, and use of biomass increase the use of vehicles and infrastructure, which causes emissions to the environment. (Johansson et al, 2004)

[31] By the end of 2006, there are only two manufacturers that produce wind turbine component, with total capacity of producing 550 MW/year. (Dutra and Szklo, 2008)

Valle Costa et al, 2008). The fact that wind power technology is largely made available by international manufacturers is considered to be considerably disadvantageous to fostering the technology and reducing related investment costs, and in turn results in slowing down the progress of technology dissemination. (Cavaliero and Silva, 2005; Goldemberg et al, 2005)

It is predictable that the introduction of electricity generated from renewable resources will increase the electricity price and will have an impact on the end users. It thus becomes an important issue that whether the promotion policies will cast negative impact on the degree of consumers' affordability to electricity, especially for those low-income households or enterprises. According to the Law 10762/03, the expenditures resulting from the feed-in-tariffs are transferred to the consumers in proportion to their electricity consumption, with the exception of low-income households that consume less than 80 kWh per month[32] and a second group under special conditions to be defined by ANEEL - up to 220 kWh per month. Therefore, low income consumers are protected from the price increase.

Under the Law 10438/02, the Energy Development Bill (CDE) was created, aiming at the energy development of the Brazilian States and the competitiveness of generated energy from wind sources, small hydro, biomass, natural gas and national mineral coal in areas attended by the national network system and the promotion of generalisation of electric energy services in all areas of the country. The resources come from: 1) annual payments to the use of public well being, 2) payments of fines by ANEEL, and 3) payments of annual quotes from all agents that sell electricity to final consumers.

With a 25-year duration, the funds in CDE can be used on payment for the difference between the economic values (feed-in prices) for renewables-based power production [33] and the economic value of power production from conventional competitive technologies (da Silva et al, 2005). It is stated that none of the fuel source may receive yearly funds whose total value exceeds 30% of the annual collection of the account (Cavaliero and Da Silva, 2005). It rules out the possibility that funds would be spent exclusively on one source and limits the opportunities of other sources.

Electrifying the rural areas helps the development of local communities and renewable energy provides the best solution for this goal, as grid extension is technically and economically unfeasible for these areas (Goldemberg et al, 2005). The development of renewable energy in these areas shall lead to sustainable development of local communities, job opportunities, and related industries. Under the PROINFA phase I, the indicator for an increase in off-grid households' accessibility to electricity is low. However, the PROINFA programme focuses exclusively on promoting renewables-based electricity transmitted via grids, whereas generating off-grid electricity by using renewable energy resources areas do not benefit much from this programme.

[32] According to the IEA statistics in 2005, the electricity consumption is 2013 kWh/capita in Brazil. Accordingly, the monthly average is 167.75 kWh per capita.
[33] In addition to RETs, natural gas power generation is also supported by this fund.

3.2. China

In China, as can be seen in section 1.2, different policy instruments are employed with respect to the development status of each RET. For biomass technology, a feed-in price is clearly specified, which is a fixed premium at 0.25 Yuan/kWh, approximately equivalent to 2.33 €cents/kWh. However, the length of period during which this pricing law will be remaining active is not clearly defined and this is considered both an advantage and a disadvantage. From the positive point of view, this provides investors with a long-term guarantee of purchasing and hence reduces uncertainty in the long-term future, especially when most of biomass generation projects are still small-scale and would find it difficult to bear high transaction cost of case-by-case price setting or a tendering system (Hu et al, 2005). On the other hand, a subsidy without a known duration may not motivate generators to invest in technology innovations to reduce operational cost, and this as a consequence, can slow down the process of technology dissemination as well as produce financial burden on the government and end users. Therefore, the unknown duration weakens the predictability and the continuous favourable feed-in incentive scores low in the criterion of dynamic efficiency.

Before the introduction of the Wind Concession Programme, feed-in tariffs were employed to promote wind power, and they ranged from 0.46 to 1.2 Yuan/kWh, with an average of 0.72 Yuan/kWh, equivalent to 6.72 €cents/kWh (Lewis, 2004). Aiming to further foster this technology at the lowest possible cost, the Chinese government introduced a bidding process together with a purchase guarantee under the Programme. The price for wind power is determined under a tendering system and the lowest bidding result will be the purchase price. As modified in 2006, the purchase will be applicable for the first 30,000 hours of full load generation, which, depending on the site's wind resource, could cover about 10-15 years (IEA).

The bidding results of the two pilot projects were priced at 4.06 €cents/kWh and 4.66 €cents/kWh. Majority of the concession rounds following these two pilot projects, in the Programme, were won by state-owned companies, at a price around 3.4 €cents/kWh (Liu, 2006). It is noted that these prices are lower than the current levelised cost of wind power in China that lies between 4.29 and 5.44 €cents/kWh (Liu, 2006). There is a possibility that the bidding results reflected the situation that continuous improvement in technology will reduce the levelised cost in the future. On the other hand, this refers to the situation that state-owned companies tend to underbid because of the prestige of winning a project, whereas these prices may be too low for projects run by private and foreign companies (Sequeira, 2006). Underbidding is likely to lead to inadequacy of overall project quality as well as low level of realised projects. The other problem relates to the government-run concession procedure as this incurs large transaction costs (Sinton et al, 2005).

By contrast, feed-in prices for solar power and other renewable energy technologies remain rather general and this leaves room for prices to be set by the authorities. Somehow, price set on a case-by-case basis will inevitably cause high transaction costs and administrative cost, which may discourage project developers. This thus does not lead to cost efficiency.

Technology-specific promotion policies are more likely to fulfil the goal of energy source diversification, to develop different technologies at different scales, because there exist no crowd-out effects amongst different technologies.

The effectiveness of externality internalisation of the policy instruments mentioned above will be discussed below. It is shown in Jiang et al (2007) that, for a coal fuel power plant, the estimated external cost of the power generation stage is 2.54 €cents/kWh[34]. The generation cost of a typical coal-fired power plant is around 0.22 Yuan/kWh (Li, 2007), equivalent to 2 €cents/kWh. Currently, the provision of estimated private cost of different RETs is not available, however, it is suggested that the private cost of small hydro power is approximately 1.2 times the cost of coal-fired power, 1.5 times for biomass, 1.7 times for wind power, and 11-18 times for solar PV (Fang and Zeng, 2007). Accordingly, the private cost of different RETs can be worked out as shown in Table 3.9 below.

Table 3.9: Elaborated current private cost of different generation technology

Generation technology	Yuan/kWh	€cents/kWh
Coal-fired	0.22	2
Small hydro power	0.264	2.5
Biomass	0.33	3.1
Wind power	0.374	3.5
Solar PV	2.42 - 3.96	22.5 – 36.8

Note: 1€=10.75 Yuan

The total social cost of coal-fired power generation can be estimated as shown in Table 3.10. With the coal-fired power price assumed to be at the average generation cost, i.e. 0.22 Yuan/kWh, the current feed-in tariff for biomass technology, according to Table 2.5, works out as 0.47 Yuan/kWh, equivalent to 4.37 €cents/kWh. Whilst feed-in tariff for biomass will vary with the coal-fired power price, the recognised environmental benefit of biomass generation, i.e. the price premium, is fixed. This benefit and the external cost resulting from coal-fired power generation will be put into comparison, in order to gauge the degree of externality internalisation. The fixed premium, as shown in Table 2.5, is 0.25 Yuan/kWh, equivalent to 2.33 €cents/kWh, and this internalise 96.3%, i.e. the ratio of $4.37/4.54$, of the estimated externalities.

Table 3.10: Externality internalisation of biomass against coal-fired power

[34] This figure is estimated based on the emission rates of a power plant with a capacity of 100 MW and annual plant load of 6000 hours in a fully utilised condition.

	Private cost (€cents/kWh)	External cost (€cents/kWh)	Social cost (€cents/kWh)	Feed-in tariff (€cents/kWh)	Indicator of internalisation (%)
Coal-fired power	2	2.54	4.54	--	--
Biomass	3.1	0	3.1	4.37	96.3

For the case of wind power, tariffs are determined by biddings and the prices are expected to decline with respect to reduction in generation cost over time. In this report, current feed-in prices for wind power projects adopt the average price from winning bidders - 3.4 €cents/kWh - in the concessions following the two pilot projects. Currently, as demonstrated in Table 3.11, the level of externality internalisation is measured as $\left(Price_{FeedIn} / SocialCost_{coal} \right)$, i.e. $3.4/4.54$ = 74.9%. In comparison, the effectiveness of externality internalisation is lower in the case of wind power than in the case of biomass, 74.9% versus 96.3%.

Table 3.11: Externality internalisation of wind power against coal-fired power

	Private cost (€cents/kWh)	External cost (€cents/kWh)	Social cost (€cents/kWh)	Feed-in tariffs (€cents/kWh)	Indicator of internalisation (%)
Coal-fired power	2	2.54	4.54	--	--
Wind power	3.5	0	3.5	3.4 (2007)	74.9

For the case of solar and other renewable technologies, analysis is not able to be carried out in this report. Moreover, estimates of costs – private and social – based on the electricity scenarios in year 2010, 2020, and 2030 are not available, and this limits the scope of analysis of this report.

The extra cost associated with developing renewable energy will be shared by all citizens, through a grid cost sharing system. It is reported that an extra ‘renewable energy’ charge of 0.001 Yuan (0.009 €cents) for every unit of electricity has been added to household utility bills since June 2006 (Li, 2007). As of year 2006, the annual electricity consumption per capita of households in China is 249.4 kWh, and the average increase in charge amounts approximately to 0.2494 Yuan per capita, around 2.32 €cents. As of year 2006, per capita annual disposable income of urban households is 11,759.5 Yuan, and it is 3,587 Yuan for rural households. On a per capita basis, the renewable energy charge is around 0.002% of the income for urban households, and 0.007% for rural households, which suggests that the impact of this incremental change on rural households is more than three times in scale the effect on people living in urban areas. Having said so, the realised impact on rural households may be limited because many of them live in off-grid areas. To appropriate address this issue, further investigations are required.

Currently, the electricity purchase prices for electricity generators are determined through bilateral agreement between utilities and suppliers[35]. However, the electricity prices have been criticised for being unable to reflect total costs. Firstly, transaction and distribution costs of electricity from coal-fired power may not accurately reflect in the electricity price. As coal sources are primarily located in the north of China, transaction costs of electricity to the demand centre in eastern and south-eastern coastal areas can be high. Secondly, electricity prices from old coal-fired plants exclude capital costs, and the Chinese electricity industry has been characterised by a high proportion of old generation plants (Cherni and Kentish, 2007). These make the electricity generated from RETs more costly than that from coal-fired power. These are reckoned as the barriers for the dissemination of renewable technologies.

3.3. India

The feed-in tariffs in the states which employ such a pricing system are determined based on a cost-plus-return approach; hence, the feed-in incentives for different RETs are higher than the upper-bound generation cost[36] of corresponding RETs reported in the second column of Table 3.12, provided that private cost considers generation cost as well as capital investment. In most of the states, the purchase guarantee is set to be valid till a certain time in the future or for a certain period, e.g. 20 years. Besides, the annual increases in tariffs are also clearly specified. This provides high predictability for investors.

Table 3.12: Generation cost and capital cost of various RET

RET	Generation cost (Rs./kWh)	Capital cost (million Rs./MW)
Small hydro	1.00-2.00	30-60
Wind energy	2.00-2.75	35-40
Biomass power	1.75-2.00	30-40
Bagasse cogeneration	1.75-2.00	25-30
Biomass gasification	1.25-1.50	25-30
Solar PV	10.00-12.00	250-300

Source: Varun and Singal (2007)

However, a concern relates to the cost-plus-return nature of the feed-in tariffs as such incentives measure will not prove to be cost-efficient. The basis for determination of tariff by respective SERC includes: 1) a justifiable investment in an appropriate technology, 2) a normative debt-to-equity ratio and a reasonable rate of return on equity, and 3) an inflation indexed variable cost. A rate of return on equity is often criticised for overinvestment and lack of incentive for improvement in efficiency in operation (Singh, 2007). In many states, the buy-back prices are either at a flat price or in an ascending trend with a rate of 1.5-5% over time. By contrast, only a few states employ a pricing mechanism which decreases over time, e.g. the incentives for

[35] Wholesale markets for conventional fossil fuels have been just piloted in some provinces, whereas electricity from renewable technologies has not been included in the markets.
[36] The average levelised cost of respective technologies should lie above the generation cost specified in the table.

wind power energy in the state Madhya Pradesh and for small hydro power in Uttar Pradesh. A non-descending pricing system gains criticism for its lack of incentive for improvement in efficiency of operations to reduce generation cost as well as that eventually, consumers will tend to pay more than they should as a result of inefficient feed-in incentives. Such a pricing mechanism scores low in the criterion of dynamic efficiency.

To explore the effectiveness of externality internalisation, estimation of total social cost of a coal fuel cycle needs to be made. According to the estimation of Working Package 7, the valuated impacts of coal-fired power generation on the general public, namely the final external cost, is estimated to be Rs 3.15/kWh, around 5.43 €cent/kWh. Adding the private cost, i.e. Rs 2.50-3.00/kWh (4.31-5.17 €cent/kWh), to the generation cost yields the social cost of thermal power at around Rs 6.00/kWh[37] (10.33 €cent/kWh).

Under the feed-in pricing system of every state, the extent to which the externalities of electricity generation from conventional fossil fuels is internalised or to be internalised, is discussed below. Feed-in tariffs of different states as of December 31, 2007 for grid-connected electricity from wind power vary from 2.9 to 4.08 Rs./kWh, which averagely lie above the generation cost of coal-fired power production. The feed-in prices for small hydro power range between 2.8 and 3.39 Rs./kWh, between 2.63 and 4 Rs./kWh for biomass, and between 2.63 and 5.14 Rs./kWh for bagasee cogeneration. As can be seen in Table 3.13, the lowest feed-in prices for biomass and bagasee cogeneration are even below the private cost of coal-fired power. This raises the concern that these prices, adopted in some states, are not high enough to recognise the environmental benefits of the subsidised renewables technologies. It is commonly observed that the feed-in prices for different technologies are all lower than the total social cost per unit of electricity. The indicator for internalisation can be measured as $\left(Price_{FeedIn} / SocialCost_{coal} \right)$, and the indicators of respective RETs are shown in the rightmost column of Table 3.13.

Table 3.13: Externalities internalisation as of year 2007 of various RETs

	Private cost (Rs./kWh)	External cost (Rs./kWh)	Social cost (Rs./kWh)	Feed-in Tariff[38] (Rs./kWh)	Indicator for Internalisation (%)
Conventional:					
Coal-fired power	2.75	3.15	6	--	--
Renewable:					
Wind power	--	--	--	2.9-4.08	48.3 - 68
Small hydro	--	--	--	2.8-3.39	46.7 – 56.5
Biomass	--	--	--	2.63-4	43.8 – 66.7
Bagasee cogeneration	--	--	--	2.63-5.14	43.8 – 85.7

[37] This is from the country report.
[38] This refers to the feed-in prices of the year 2007 for newly-commissioned projects.

In the promotion programme for solar PV power and solar thermal power announced in 2008, the feed-in premiums mentioned above offered prices from utilities as well as subsidised capacity are both clearly stated. Assumed that the purchase price offered by utilities is around the private cost of coal-fired power, effective feed-in prices – private cost of coal-fired power plus fixed premium - shall recognise the RETs' environmental benefits or alternatively, internalise the externalities. The indicator for internalisation is measured as $\left(Tariffs_{FeedIn} / SocialCost_{coal} \right)$, and this is 246% ($14.75/6$) for solar PV and 213% ($12.75/6$) for solar thermal power technology. It can be seen that the feed-in tariffs are more than two times the current social cost for both technologies. A high premium will favour long-term project development, especially for solar power generation which is a highly capital-intensive technology. The impact of high premiums on electricity price for end users are limited because of the subsidised capacity of solar PV/solar thermal power is restricted within 10 MW in each state.

Table 3.14: Externality internalisation of solar PV/solar thermal technology

	Private cost (Rs./kWh)	External cost (Rs./kWh)	Social cost (Rs./kWh)	Feed-in tariffs[39] (Rs./kWh)	Indicator for Internalisation (%)
Conventional:					
Coal-fired power	2.75	3.15	6	--	--
Renewable:					
Solar PV	--	--	--	14.75	246
Solar thermal	--	--	--	12.75	213

To sum up, it is seen that the effectiveness of internalisation varies amongst states. It is worth noting that some states in India do not have potential to develop renewables-based power generation and these areas inevitably contribute more to the externalities than the others. Provided that there isn't a well-organised mechanism to distribute environmental benefits from renewable energy, inequity in environmental benefits can easily emerge.

A Renewable Portfolio Standard (RPS) mandates the minimum amount of capacity or generation that must come from renewables and the mandated amount in general increases over time (Sawin, 2004). As exhibited in Table 2.8, minimum ratios of electricity from renewable resources have been specified in many states, and the standards are applicable to captive and open access consumers as well in such states: Andhra Pradesh, Maharashtra, and Rajasthan. The participation of captive and open access consumers is reckoned helpful in promoting competition in the market as well as an encouragement for captive and independent producers to use renewable resources rather than fossil fuels to generate electricity.

[39] This is calculated as: private cost of electricity from coal-fired power + fixed premiums – 12 Rs./kWh for solar PV and 10 Rs./kWh for solar thermal.

Steady growth in RPS requirement over time is observed in the states of Gujarat, Maharashtra, Orissa, and Rajasthan, whereas some states only apply a fixed standard which is applicable either for a specific year or continuously over time. The continuity and stability of targets mandate are important in that this provides predictability over a long time horizon and hence encourages electricity buyers and sellers to enter long-term supply contracts (Berry and Jaccard, 2001). Moreover, Berry and Jaccard (2001) mentioned an important issue in standard setting, that is, whether or not there should be one target for which all renewables will compete or a separate target for different types or classes of renewables. Under the first approach, the least-cost options would be developed but the aim of supply diversity or that of promoting newly emerging technologies may not be achieved. Both approaches are seen to be carried out in India. Andhra Pradesh has rate of 0.5% for wind energy and Rajasthan employs respective targets for wind power, biomass, solar power, and a class of other renewable technologies. By contrast, most of the states have a single target for all renewables.

One indicator for the effectiveness of technology dissemination is the level of increases in installed capacity of a given type of renewable technology. The installed capacity of wind power in each year since 2001 is shown in Table 3.15, Table 3.16 for small hydro power, and Table 3.17 for biomass and bagasee generation. As can be observed, in wind power, several states demonstrated progressive growth of wind power during the years 2004-2007, such as Gujarat, Karnataka, Maharashtra and Tamil Nadu. In mid-1990s, together with some financial and fiscal incentives, an electricity buy-back policy had been employed by some states on wind power projects, i.e. government had to purchase electricity at a tariff no lower than 2.54 Rs./kWh, and hence this price had been commonly employed by these states during late 1990s and the first couple of years of the new century. The feed-in tariffs were later increased under the mandate of the Electricity Act. This has provided project developers with a better incentive as well as is more capable of internalising externalities and this policy is more acceptable by the generators as well as decision makers in the government. These thus can explain the rapid dissemination of wind power in India, particularly as it is employed together with a RPS. For small hydro power, continuous and substantial increases in installed capacity are only observed in Karnataka from 2003 up to the end of 2007, whereas in other states, new installation only took place intermittently. Installed capacity of biomass and bagasse cogeneration nationwide demonstrates a steady growth since year 2003, especially in the states of Andhra Pradesh, Karnataka, Maharashtra, Tamil Nadu, and Uttar Pradesh.

Currently, statistics of electricity generation from thermal power and wind power are available only for the year 2003-2004 and the year 2004-2005. As shown in Table 3.18, the shares of electricity generated from wind power grew over time in most of the listed states, and substantial increases were observed in Rajasthan and Tamil Nadu. The state of Rajasthan has policy instruments – feed-in tariffs and RPS - for wind power, hydro power, and biomass technology, respectively. For wind power, a RPS of 2% in the year of 2006-2007 was mandated, with an annual increment by 0.3, till it reaches 4%. Table 3.18 shows that the electricity production has reached 1.58% in the year 2004-2005. Provided the increase of around 180 MW in installed capacity of wind power during the years 2004-2005 and 2005-2006, the RPS of 2% in 2006-07 is certainly achievable. In the state of Tamil Nadu, the wind power plants generated more than 50% of the electricity production from wind power in the country in the year 2004-2005, and 7.5% of the aggregate production within the state. Amongst the states with incentives, the purchase prices for renewables-based electricity employed in Tamil Nadu provides are the lowest and given the installed capacity up to now, the RPS of 10% shall be able to be fulfilled by the wind power alone. This suggests a high level of cost-efficiency of the policy instruments applied in Tamil Nadu.

Table 3.15: Installed capacity (MW) of wind power by state in each fiscal year in India

	Up to 31/03/2002	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08	Total
Andhra Pradesh	93.2	0.0	6.2	21.8	0.5	0.8	0.0	122.5
Gujarat	181.4	6.2	28.9	51.5	84.6	284.0	238.2	874.8
Karnataka	69.3	55.6	84.9	201.5	143.8	266.0	96.1	917.2
Kerala	2.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0
Madhya Pradesh	23.2	0.0	0.0	6.3	11.4	16.4	13.0	70.3
Maharashtra	400.3	2.0	6.2	48.8	545.1	485.3	158.6	1646.3
Rajasthan	16.1	44.6	117.8	106.3	73.3	111.8	25.9	495.7
Tamil Nadu	877.0	133.6	371.2	675.5	857.6	577.9	218.8	3711.6
Others	4.3	0.0	0.0	0.0	0.0	0.0	0.0	4.3
Total	1666.8	242.0	615.2	1111.7	1716.2	1742.1	750.6	7844.5

Source: MNES Annual report, 2007-08

Table 3.16: Installed capacity (MW) of small hydro power by state in each fiscal year in India

	Up to 31/12/2001	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	Total
Andhra Pradesh	145.91	4.8	13.55	14.55	0	0	0.29	179.1
Chattisgarh	1	0	5	7.5	0	4.5	0.05	18.05
Gujarat	7	0	0	0	0	0	0	7
Haryana	48.3	0	14.4	0	0	0	0	62.7
Karnataka	156.9	0	56.48	55.45	31.8	83	80.37	464
Kerala	69.52	0	15.1	0	0	14	0	98.62
Madhya Pradesh	38.16	0.8	0	2.2	0	0	10	51.16
Maharashtra	200.33	6	0.75	0	0	1.5	2.745	211.325
Orissa	1.3	6	0	0	0	0	0	7.3
Punjab	102.2	1	5.2	3	2	9.15	1.35	123.9
Rajasthan	23.85	0	0	0	0	0	0	23.85
Tamil Nadu	73.9	0	2.5	1.3	0	0	12	89.7
Uttar Pradesh	21.5	0	0	0	0	3.6	0	25.1
Other	533.26	21.72	26.87	6	23.38	39.21	33.865	684.305
Total	1423.37	40.07	139.88	90.02	54.64	157.46	140.17	2045.61

Source: MNES, Annual Reports, 2001/02, 2002/03, 2003/04, 2004/05, 2005/06, 2006/07, and 2007/08

Table 3.17: Installed capacity (MW) of biomass/bagasee cogeneration by state in each fiscal year in India

	Up to 31/12/2001	2002-2003	2003-2004	2004-2005	2005-2006	2006-2007	2007-2008	Total
Andhra Pradesh	101.2	42.85	53.27	47.88	56.05		33	334.25
Chhattisgarh	0	11	0	0	77.5		57.8	146.3
Gujarat	0.5	0	0	0	0		0	0.5
Haryana	4	0	0	2	0		0	6
Karnataka	72.6	36.78	26	16.62	102.28		8	262.28
Madhya Pradesh	11	-11	1	0	0		0	1
Maharashtra	12.5	12	0	11.5	26		46	108
Punjab	12	10	0	0	6		0	28
Rajasthan	0	0	7.8	0	15.5		0	23.3
Tamil Nadu	98	8	44.5	22	43		57	272.5
Uttar Pradesh	46.5	0	12.5	14	48.5		22	143.5
Total	358.3	109.63	145.07	114	140.53	234.3	223.8	1325.63

Source: MNES, Annual Reports, 2001/02, 2002/03, 2003/04, 2004/05, 2005/06, 2006/07, and 2007/08

Table 3.18: Generated electricity (utilities only) by fiscal year

	2003-04			2004-05		
State	Wind (GWh)	Total (GWh)	Ratio (%)	Wind (GWh)	Total (GWh)	Ratio (%)
Andhra Pradesh	92.81	32913.93	0.28	160.79	37305.14	0.43
Gujarat	251.5	38269.84	0.66	350	44230.8	0.79
Karnataka	322.14	22996.43	1.40	489.53	23515.43	2.08
Kerala	2.49	5629.02	0.04	2.5	6514.95	0.04
Madhya Pradesh	1.24	15802.08	0.01	38.76	15975.24	0.24
Maharashtra	1269.02	66390.48	1.91	495.36	67078.27	0.74
Rajasthan	15	18614.08	0.08	331.53	20985.8	1.58
Tamil Nadu	1447.65	30353.93	4.77	2426.3	32229.72	7.53
West Bengal	0.47	23508.42	0.00	0.45	24888.26	0.00
Total	3402.32	565101.7	0.60	4295.22	594456.2	0.72

Source: Central Electricity Authority, Ministry of Power, Government of India, Annual report 2003-04, 2004-05

The availability of renewable resources varies widely across the regional climates and geographies of India, and the lowest-cost resources may not be accessible within any particular RPS state. Besides, distribution licensees are allowed to purchase renewable-based electricity from other states, which, however, involves high transmission cost. As suggested, a national market of renewable energy certificates is one effective mechanism for tapping into the best resources (Cory and Swezey, 2004). At the moment, such a market does not exist in India. It is strongly recommended that a nationally tradable renewable energy credits for achieving the renewable portfolio standard (RPS) is necessary to enhance the policy efficacy (Singh, 2007). First of all, provided that renewable resources are not evenly distributed across sates, credits will help redistribute renewables electricity across states via a trading mechanism, with no electricity transmission involved. Secondly, government agencies can provide more effective support by purchasing such credits annually and thus complement financial subsidies or fiscal incentives. Please see Singh (2007) for more discussions in detail.

Some existent policies in the power sector are considered to be negative on the development of RETs, which is going to be discussed below. It is well known that, in India, the overall electricity tariffs structure for the end users has been severely distorted by the cross-subsidisation. Agricultural and residential electricity prices have been heavily subsidized as the government considers universal access to electricity a social and political objective. By contrast, industrial consumers are charged more to subsidise agricultural and residential consumers. Please see Table 3.19 for illustration.

Table 3.19: Electricity subsidies in India

	Average price (Rs./kWh)	Supply cost (Rs./kWh)	Rate of subsidy (%)
Residential	1.5	3.56	57.9
Agricultural	0.25	3.42	93.0
Industrial	3.5	3.56	Not applicable

Source: Karki, Mann, Salehfar, and Hill (2005)

Owing to strong political compulsion, the situation of cross-subsidy is unlikely to be phased out in a short or medium term, and it has shown significant negative economic impacts (Karki et al, 2005). To begin with, low prices, especially for the residential and agricultural sectors, leave utilities without sufficient finances to improve the quality and reliability of electricity supply. For instance, the state utilities are operating with heavy financial deficits (around €3.95 billion an year). Secondly, these cross-subsidies benefit mainly those who are economically better off, whereas the majority of really poor people have no access to electricity due to the high connection fee to electricity as well as low electricity consumption. Thirdly, owing to high cost and unreliable supply of electricity, industrial consumers have chosen to have their own back up supplies, normally diesel generators. Numerous stand-alone diesel generators contribute to more GHG emissions. Moreover, it is possible that the costs as a result of developing renewables technologies have been passed onto the end users disproportionately as a result of the cross-subsidisation nature, leading to social inequity as well as high financial burden for the government as well as for the industrial sector.

Subsidising conventional fossil fuels – coal mainly - used to apply in developed and are still applied in developing countries, as this aims to boost economic growth by lowering energy costs. The Indian government has been subsidizing the price of coal. The condition of relative low prices of coals makes coal-fired power generation competitive and favourable. Moreover, under the pressure of increasing demand of electricity in India, the government may prefer choosing conventional thermal power generation owing to its low gestation time, to using RETs (Karki, Mann, Salehfar, and Hill, 2005). These factors inevitably create a higher barrier for RETs which usually have higher private costs to become competitive in the electricity market.

It is notified in the Electricity Act that electricity tariffs need to be rationalised, e.g. to adjust to reflect electricity full cost, as well as that cross-subsidisation levels ought to be lowered and ultimately eliminated. As suggested in Pershing and Mackenzie (2004), if a renewable energy technology is to become cost-effective, market impediments need to be overcome. This can be achieved through the removal of subsidies to fossil fuels, i.e. coal, and through measures to ensure full cost pricing of electricity, that is, the electricity prices reflect their social cost – private production cost and environmental cost. To meet the target of eliminating cross-subsidies requires not only economic but also political reforms (Cust et al, 2007).

The Indian Government outlined an ambitious plan for total household electrification by 2012, which ought to be met by measures of grid extension, distribution reforms, and de-politicisation of tariffs (Cust et al, 2007). Regarding supply cost of electricity, studies suggest that the supply cost of electricity through grid to rural areas can be around three times generation cost of that for areas close to grid (Barnes and Sen, 2002). A recent estimate for a case study puts the cost of delivery to rural areas at over Rs.9/kWh (Hansen and Bower, 2003). Therefore, to electrify rural areas via distributed generation systems[40]/decentralised generation system becomes another niche for the development of renewable energy, as the high cost of on-grid electricity has made some renewable technologies the least-cost options for household electrification, e.g. biomass gasification (Rs. 4-7/kWh) and micro-hydro power (Rs.3-6/kWh) (Cust et al, 2007). Under the Electricity Act, the Rural Electrification Policy has been notified by the Ministry of Power in 2006 to permit stand-alone generation systems to use renewable resources. This provides guidelines for setting up off-grid systems in rural areas and specifies tariffs forbearance of electricity supply to consumers in rural areas (Singh, 2007). However, at present, there still exist barriers for electricity generation and distribution in rural areas. First of all, there is still a lack of clarity in legislation regarding allowing IPPs to generate and distribute electricity. Moreover, some factors crowd out decentralised distributed renewable energy projects, such as: 1) state-controlled power sector, 2) aforementioned subsidised conventional energy, 3) non-payment culture, and 4) distorted support for renewable energy technology programme (Cust et al, 2007).

[40] Decentralised generation (DG) system is defined as the installation and operation of electric power generation units connected directed to the distribution network or connected to the network on the customer site of the meter. (Ackerman et al, 2001)

3.4. Turkey

Turkey distinguishes itself from the previous three countries in that there is only one universal feed-in tariff, ranging between 5 to 5.5 €cents/kWh, provided by the government. This leaves completely to the market to decide which technology by its cost advantage and future prospect will develop. It turns out that the tariff is only sufficient for wind power energy; however, it is noted by the World Wind Energy Association that this tariff is still much lower than the average remuneration in the leading European wind markets. By contrast, the tariff is not sufficient to promote the development of other renewable energy technologies of solar energy, small hydro, and biomass.

In contrast with such developing countries as China and India, Turkey is not heavily dependent on coal to generate electricity. Around 26% of the generated electricity is from coal-fired power plants, whereas over 70% is supported by fuel cycles with relatively low external costs - large hydro and gas power generation. Approximately, the external cost per kWh electricity from fossil fuels is 2.5 times that from natural gas and 28 times that from hydro power (Topcu and Ulengin, 2004). For a Turkish lignite fuel cycle, the externalities is estimated at 3.35 eurocent/kWh (please see the D.7.2 for further details), which presumably is not taken into account in the wholesale price of a unit of electricity generated. An estimate of total social cost in the case of lignite fuel cycle, which considers both private cost - around 2.10 €cent/kWh[41] - and external cost, shall be 5.45 €cent/kWh. As of year 2007, the level of externality internalisation is measured as $\left(FeedInPrice / SocialCost_{lignite} \right)$, i.e. 95.4%. For natural gas and large hydro, the indicators of 132 and 205, suggesting that the feed-in price can more than fully internalise per kWh electricity generated from natural gas and large hydro (See Table 3.20).

Table 3.20: Externality internalisation as of 2007

	Private cost (€cent/kWh)	External cost [42](€cent/kWh)	Social cost (€cent/kWh)	Feed-in tariff (€cent/kWh)	Indicator of Internalisation (%)
Conventional:					
Lignite fuel cycle	2.10	3.35	5.45	--	95.4
Natural gas	2.6	1.34	3.94	--	132
Large hydro	2.42	0.12	2.54	--	205
Renewable:					
Wind onshore	2.84	--	2.84	5.2	

Source: Topcu and Ulengin (2004) and Köne and Büke (2007)

[41] This calculation was done in OECD/NEA (2005) and used in Köne and Büke (2007), containing investment cost, fuel cost, and operation and maintenance cost, at 5% discount rate. In the same paper, estimates of private cost of other types of fuel cycle are also available.

[42] Based on the estimated external cost of lignite-fired power, the estimated external costs of natural gas and large hydro are derived with respect to the relative scales suggested in Topcu and Ulengin (2004).

The feed-in pricing law and mandatory purchase offered by distribution utilities are guaranteed for 10 years. Compared with policies enacting in the three other countries, this time period is not long; even though, it provides project developers with high predictability. Whilst the feed-in price is determined by wholesale market prices which are largely for electricity from mature and competitive fuel cycles, an issue remains in the matter that whether the purchase price will be adequate to foster the electricity generation and to provide generators with incentives to invest further on technology innovation in order to reduce operation cost. Moreover, the government has not addressed further regarding any continuous incentives available after the policy of feed-in tariff comes to the end. Whilst a period of 10 years is possibly not long enough for a technology to become fully competitive, the lack of incentives beyond 10 years inevitably creates uncertainty with long-term development of RETs.

The Turkish electricity market has been going through a process of vast restructuring in core activities ranging from generation to distribution. Since 2001, reform on liberalisation of Turkey's electricity market has taken place. The main purpose of the market liberalisation is to achieve lower tariffs[43] by increasing overall system efficiency. Years 2006-2010 is considered the transitory period to a cost-based tariff structure[44]. During this transition period, a national tariffs scheme remains to avoid price fluctuations and the revenue imbalance across regions will be equalised through revenue transfer. The cost as a result of feed-in incentives to the RETs will be reflected in the basket price of the energy purchased by a distribution company. Currently, the feed-in tariff is capped by the wholesale electricity price in the previous year. If the feed-in tariffs would be increased by 20%, such increase would be borne by the whole population because, at least during the years 2006-2010, a cross-region revenue transfer mechanism is in place to balance the price fluctuations.

3.5. Summary

Comparisons of policy instruments – primarily market regulatory mechanism - are made amongst the four countries and are summarised below. Details are exhibited in Table 3.9.

The level of effectiveness of externality internalisation is dependent on the main fuel sources of power production in each country. Turkey and Brazil are highly dependent on fuel sources which cause low externalities, i.e. large hydro and natural gas. Theses two countries have greater effectiveness of internalisation than China and India which rely heavily on coal-fired generation.

The feed-in price for the wind power in China and that in Turkey are considered to be more cost-efficient than those in the other two countries. In China, the amount of

[43] Accordingly, a new tariff structure has been developed and the electricity tariffs are calculated as 'cost-reflective' based on predetermined operating and loss/theft improvement targets.
[44] This structure contains four tariff components: 1) retail sales, 2) distribution, 3) retail services, and 4) transmission.

incentive is determined through market competition and in Turkey, the incentive follows the electricity price in the wholesale market. But these prices could be low.

A mechanism which allows feed-in prices to adjust with respect to any changes in economic conditions, e.g. inflation, production cost, etc., is implemented in Brazil, India, and Turkey. Predictability related to the feed-in prices is observed in all the four countries. In China, it varies amongst different technologies and amongst different states as well as technologies in India. Dynamic efficiency is more likely to emerge in the case that a tendering system is employed to contract capacity or when a feed-in price is decreasing to encourage generators to improve production efficiency and reduce cost. This can be observed in China (wind power) and in some states of India. To some extent, inequity exists in all the four countries, e.g. disproportionate distribution of environmental benefits/cost amongst the states in India; the impact as a result of the increase in electricity price on rural households is on average three times the impact on urban households. In all the four countries, a legal framework enacted before the introduction of the policy instruments, which makes it easy for actors to comply.

Finally, diversification of electricity generation is more easily to be achieved when: 1) targets of capacity to be contracted by RETs are set in advance, like in Brazil and China and 2) RPS is set by RETs, like in some states of India. By contrast, the degree of diversification is not achieved by current policy instruments in Turkey.

Table 3.21: Summary of assessment outcomes

Country / *Criterion*	**Brazil**	**China**	**India**	**Turkey**
Effectiveness to internalise externalities	High internalisation (>100% by some measures)	Only partly: 91.7% by biomass and 74.9 % by wind power	Partly internalisation Degree of internalisation varies from state to state	High internalisation for lignite fuel cycle and more than complete internalisation for large hydro
Cost-efficiency	Not the least cost policy option The target of capacity contraction was not met by the original deadline of PROINFA phase I.	Cost efficient for wind power but with lower internalisation	The nature of cost plus return of feed-in tariffs is criticised for its lack of efficiency Relative high cost efficiency is found in the state of Tamil Nadu	Cost efficient as the incentive is determined by the wholesale prices of the power sector
Flexibility	Feed-in prices are adjusted annually according to the IGP-M index	--	Feed-in prices are adjusted annually according to inflation in some states	The feed-in price is allowed to be raised by the council of ministry by 20% in the beginning of each year.
Predictability	High predictability in the first phase The implementation of the phase II is still not foreseeable.	Higher predictability for the wind power than for the biomass Incentives are vague for other RETs.	High predictability majority of the states	High predictability
Dynamic Efficiency	Inconsistency exists between first and the second phase of PROINFA. In the second phase, the competitive nature is aimed to be introduced.	It is the case of wind power, but not for biomass or other RETs.	Some states have dynamically efficient incentives, i.e. decreasing feed-in tariffs together with RPS	This policy has not addressed a continuous incentive to be provided after the period of 10 years.
Equity	Leaves out rural area electrification	Low participation of private project investors in the wind concession programme, favouring state-owned	State-specific incentives and requirement benefit each state, but some states without potential renewable resources	The feed-in price turns out to be sufficient only for wind power and has an implicit crowd-out effect on other

		companies The increase in electricity bill may have higher impact on rural households than on urban households.	will not benefit.	RETs.
Ease of introduction	Introduced by a law. The second phase will need to adjust in compliance with the new electricity regulatory framework.	Introduced by a law	Introduced by a law	Introduced by a law
Ease of monitoring and enforcement	--	Government-run concession programme for the wind power and case-by-case permission for other RETs involve high transaction costs.	--	Each renewables-based generator is issued a certificate and this allows authority to monitor.
Diversification	In the PROINFA phase I, contracted capacity was distributed amongst three RETs. Phase II may crowd out less competitive technologies.	Diversification of electricity production is targeted. The policy of RPS is recently announced in late 2007.	The level of diversification varies from state to state.	Low diversification: only wind power generation emerges.
Acceptability	The acceptability of feed-in price is relatively low in the biomass industry because biomass, especially sugarcane, has been highly promoted to produce biodiesel. The acceptability amongst wind power and small hydro generators are comparatively high. This is because two previous programmes, PROEÓLICA and PCH-COM, were implemented to promote these two technologies by feed-in tariffs.	High acceptability in the case of wind power	High acceptability because a buy-back mechanism for wind power had been employed previously.	A similar instrument has not been employed in the nation before.

4. Conclusion

This report provided an assessment on policy instruments that are currently employed to promote renewable energy in electricity generation, in Brazil, China, India, and Turkey. Section 2 started with reviewing on policy instruments that provided direct support to renewable energy generators. The reviewing found that command-and-control measures and economic incentives were both available in the four countries. This refers to the fact that these countries have implemented to promote and disseminate renewable energy technologies in power production.

Section 3 exhibited assessment of the policy instrument – mainly the market regulatory mechanisms – on their performance in the aspects of pre-defined criteria. One crucial task was to investigate the extent to which the policy instruments can effectively internalise externalities per unit of electricity production. Together with this, other aspects of the policy instruments were also examined, such as their acceptability, equity, ease of introduction, etc. Following conclusions can be made.

Firstly, the differences in effectiveness of externality internalisation amongst the four countries are dependent on the main fuel sources of power production in each country. Turkey and Brazil mainly rely on fuel sources that cause low externalities, i.e. large hydro and natural gas, and they have greater effectiveness of internalisation than China and India where coal is the main energy source of power generation.

Secondly, state-specific policy instruments in India may yield disproportionate distribution of environmental benefits/cost across the country and cause regional inequity. As suggested, a mechanism to mitigate this inequity is required, e.g. a national market for renewable credit (Singh, 2007). Thirdly, market impediments in the power sector need to be removed, e.g. subsidies to conventional fuel cycles and cross subsidies between sectors amongst end users, and electricity pricing ought to comply with a full-cost based mechanism.

The perceived risk of investing in renewable energy projects in developing countries is high due to uncertainty with political, regulatory, and market stability (Frost, 2003). This refers to the fact that, in addition to the provisions of policy incentives to renewable energy generators, fundamental soundness of the power sector of these developing countries is reckon to be crucial for the dissemination of renewable energy technologies.

Bibliography

- Ackerman, T., Andersson, G., and Sodder, L. (2001), 'Distributed generation: a definition', *Electric Power Systems Research*, 57, pp. 195-204
- Ben Jannet Allal, H. and Vigotti, R. (2007), 'Renewable Energy in Southern and Eastern Mediterranean Countries: Challenges for a sustainable development in the region', *Global Energy for the Mediterranean*, No. 1
- Barnes, D. F. and Sen M. (2002), 'Energy Strategies for Rural India: Evidence from Six States' ESMAP/UNDP
- Berry, T and Jaccard, M (2001), 'The renewable portfolio standard: design considerations and an implementation survey', *Energy Policy*, pp. 263-277
- Bilgena, S., Keleş, S., Kaygusuz, A., Sarı, A. and Kaygusuz, K. (2008), 'Global warming and renewable energy sources for sustainable development: A case study in Turkey', *Renewable and Sustainable Energy Reviews*, 12, pp. 372–396
- Cavaliero, C. K. N. and Da Silva, E. P. (2005), 'Electricity generation: regulatory mechanism to incentive renewable alternative energy sources in Brazil', *Energy Policy*, 33, pp. 1745-1752
- Cherni J. A. and Kentish, J. (2007), 'Renewable energy policy and electricity market reforms in China', Energy Policy, 35, pp. 3616-3629
- Cory, K. S. and Swezey, B. G. (2007), 'Renewable Portfolio Standards in the States: Balancing Goals and Implementation Strategies', *NREL Technical Report*
- Cust, J., Singh, A., and Neuhoff, K. (2007), 'Rural Electrification in India: Economic and Institutional aspects of Renewables', [http://www.electricitypolicy.org.uk/pubs/wp/eprg0730.pdf]
- Claudia do Valle Costa, Emilio La Rovere, and Dirk Assmann (2008), 'Technological innovation policies to promote renewable energies: lessons from the European experience for the Brazilian case', *Renewable and Sustainable Energy Reviews*, 12, pp. 65-90
- Johansson, T. B., McCormick, K., Neij L., and Turkenburg, W. (2004), 'The potentials of renewable energy', Thematic background paper, International conference for renewable energies, Bonn
- Köne, A. Ç. and Büke, T. (2007), 'An analytical network process (ANP) evaluation of alternative fuels for electricity generation in Turkey', *Energy Policy*, 35, 5220-5228
- Wachsmann U. and Tolmasquim, M.T. (2003) 'Wind power in Brazil—transition using German experience', *Renewable Energy*, 28, pp.1029–1038
- Dutra, R. M. and Szklo, A. S. (2008), 'Incentive policies for promoting wind power production in Brazil: Scenarios for the Alternative Energy Sources Incentive Programme (PROINFA) under the new Brazilian electric power sector regulation', *Renewable Energy*, 33, pp 65-76
- Frost, T. (2003), 'Novel funding for renewable energy developments', *Asian Energy Supplement*, September, pp. 25

- Hansen, C. J. and Bower, J. (2003), 'An economic evaluation of small-scale distributed electricity generation technologies', Oxford Institute for Energy Studies
- Hu R., Li, J., and Wang, Z. (2005), 'China's renewable energy law and biomass energy', *Industrial biotechnology*, Winter
- Ghosh, D., Shukla, P.R., Garg, A., and Venkata Ramana, P. (2002), 'Renewable energy technologies for the Indian power sector: mitigation potential and operational strategies', *Renewable and Sustainable Energy Reviews*, 6, pp. 481-512
- Guner Law Office, 2008: Turkey: Renewable Energy / Market Opportunities And Legislation In Turkey
- NREL (2004) 'Renewable Energy in China – Grid connected wind power in China'
- Liu, Y. (2006), 'Behind the Chilly Air: Impacts of China's New Wind Pricing Regulation', Worldwatch Institute, http://www.worldwatch.org/node/3904
- Li J., Shi J. and Ma L. (??), 'China: Prospect for renewable energy development' [http://www.hmtreasury.gov.uk/media/5/2/final_draft_china_mitigation_renewables_sector_research.pdf]
- Lewis, J. I. (2004), 'Conceding too much? Conflicts between the government and developers in promoting the China "Wind Concession" project model', World Renewable Energy Congress VIII
- Cavaliero, C. K. N. and Silva, E. P. D. (2005), 'Electricity generation: Regulatory mechanisms to incentive renewable alternative energy sources in Brazil', *Energy Policy*, 33, pp.1745–1752
- Marcos Alexandre Teixeira, M.A. and da Graça Carvalho, M. (2007), 'Regulatory mechanism for biomass renewable energy in Brazil, a case study of the Brazilian Babassu oil extraction industry', *Energy*, 32, pp. 999–1005
- Maceddo da Costa, M., Cohen, C., and Schaeffer, R. (2007), 'Social features of energy production and use in Brazil: Goals for a sustainable energy future', *Natural Resources Forum*, 31, pp.11-20
- Li, L. (2007), 'China Urges Electricity Suppliers to Buy 'Green' Power', Worldwatch Institute, http://www.worldwatch.org/node/5330
- Pershing, J. and Mackenzie, J. (2004), 'Removing subsidies: levelling the playing field for renewable energy technologies', Thematic Background Paper, International Conference for Renewable Energies, Bonn
- Sawin, J. L. (2004), 'National policy instruments: policy lesions for the advancement & diffusion of renewable energy technologies around the world', Thematic background paper, International Conference for Renewable Energies, Bonn
- Topcu, Y.I. and Ulengin, F. (2004), 'Energy for the future: an integration decision aid for the case of Turkey', *Energy*, 29, pp 137-154