TERI REPORT

to CERC

on

Pricing of power from Non-Conventional Sources

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Abbreviations

AAD	Advance Against Depreciation
ABT	Availability Based Tariffs
AP	Andhra Pradesh
APERC	Andhra Pradesh Electricity Regulatory Commission
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CUF	Capacity Utilization Factor
C-WET	Centre for Wind Energy Technology
EA 03	Electricity Act 2003
EPS	Electric Power Survey
ERC	Electricity Regulatory Commission
EU	European Union
GOI	Government of India
IPP	Independent Power Producer
IREDA	Indian Renewable Energy Development Authority
KERC	Karnataka Electricity Regulatory Commission
LRMC	Long Run Marginal Cost
MERC	Maharashtra Electricity Regulatory Commission
MNES	Ministry of Non-conventional Energy Sources
MOP	Ministry of Power
MSW	Municipal Solid Waste
MW	Mega Watt
NABARD	National Bank for Agriculture and Rural Development
NFFO	Non Fossil Fuel Obligation
NGO	Non Government Organization
NHB	National Housing Bank
O&M	Operation and Maintenance
PLF	Plant Load Factor
PTC	Production Tax Credit
PURPA	Public Utilities Regulatory Act
PV	Photo Voltaic
REC	Renewable Energy Credit
RES	Renewable Energy Source
RET	Renewable Energy Technology
RGGVY	Rajiv Gandhi Grameen Vidyutikaran Yojana
ROE	Return on Equity
ROR	Run off the River
RPO	Renewable Purchase Obligation
RPS	Renewable Portfolio Standard
SEB	State Electricity Board
SERC	State Electricity Regulatory Commission
SHP	Small Hydro Power
SRMC	Short Run Marginal Cost
TTRC	Tradable Tax Rebate Certificates
UI	Unscheduled Interchange
UK	United Kingdom
UPERC	Uttar Pradesh Electricity Regulatory Commission
US	United States

Abbreviations used in annexes

APGENCO	Andhra Pradesh Generating Company
APTRANSCO	Andhra Pradesh Transmission Company
CCL	Climate Change Levy
CEB	Ceylon Electricity Board
CPC	Ceylon Petroleum Corporation
DNO	Distribution Network Operator
DTI	Department of Trade and Industry
EEG	Erneuerbare-Energien-Gesetz
EFL	Electricity-Feed-in-Law
EGAT	Electricity Generating Authority of Thailand
ESC	Energy Supply Committee
EVN	Electricity of Vietnam
FFL	Fossil Fuel Levy
GHG	Green House Gas
GOC	Government of China
MOI	Ministry of Industry
MPERC	Madhya Pradesh Electricity Regulatory Commission
NFPA	Non-Fossil Purchasing Agency
OFFER	Office of Electricity Regulation
OFGEM	Office of Gas and Electricity Markets
PPP	Pool Purchase Price
PSP	Pool Selling Price
REAP	Renewable Energy Action Plan
RO	Renewable Obligation
ROC	Renewable Obligation Certificate
SPP	Small Power Producer
SPPA	Small Power Producer Agreement
SMP	System marginal Price
TNERC	Tamil Nadu Electricity Regulatory Commission
TNO	Transmission Network Operator
TOU	Time of Use
UERC	Uttaranchal Electricity Regulatory Commission
VSREPP	Very Small Renewable Energy Power Producer

SECTION 1

Background

The positive attributes of generating electricity from renewable energy sources are widely accepted, although some of these technologies may not be currently competitive commercially with conventional fuels. Renewable energy technologies can help solve energy issues related to electricity generation, namely, environmental concern, energy security, rural electrification and applications in niche markets where conventional electricity supply is not feasible. In case of India, all the above mentioned issues are important, however, the most critical issue is that of energy shortages. Almost all the states in India are facing energy shortages in the range of 3% to 21% with national average energy shortage of about 10%. Renewable energy sources can supplement the present power generation and at the same time address the environmental and energy security issues. Renewable energy technologies have a good potential in India and considerable progress has been achieved. The table 1 below shows the potential for major renewable energy technologies for power generation and the installed capacity.

Table 1: Renewable energy potential and installed capacity as on 31/03/2006

Renewable energy source	Potential (MW)	Installed capacity as on 31.03.2006 (MW)
Wind	45000	5340.6
Small Hydro	10477*	1826.4
Biomass	21000**	912.5
Urban & Industrial Wastes	1700	45.7

*- potential for the 4404 identified sites

** 16000 MW potential for the biomass power with current availability of biomass and 5000 MW potential for the bagasse cogeneration

Source: Annual Report 2005-06, Ministry of Non Conventional Energy Sources

The renewable energy technologies are being promoted through various policies and programmes of the Ministry of Non Conventional Energy Sources (MNES) and the above mentioned achievements are result of such promotional policies. However, it has been observed that in the overall power generation scenario, the utilization of renewable energy for electricity generation has remained marginal. The present installed capacity of renewable energy based electricity systems is about 8100 MW whereas the total installed capacity in India is about 1,26,000MW. Some of the other limitations and barriers that have been faced for promoting renewable energy based electricity generation are (a) pricing of power generated from the renewable energy sources, (b) intermittent nature of electricity from wind and small hydropower, (c) barriers such as restrictions on siting, access to grid and (d) market barriers such as the lack of access to credit. Out of these issues the pricing of power generated from renewable energy sources remains the most critical issue and various policies have been implemented to overcome this issue in India. These policies are generally related to the stage of development of the technology e.g. capital subsidies in the early stages of development.

In India, MNES, in 1993 prepared policy guidelines for promotion of power generation from renewable energy sources which included provisions such as accelerated depreciation, concessions regarding the banking, wheeling and third party sale, among others. Further, the Electricity Act 2003 (EA 03) that was notified by the Ministry of Power in June 2003 along with the National Electricity Policy recognized the role of renewable energy technologies and stand-alone systems. The EA 03 has accorded significant responsibilities to the State Electricity Regulatory Commissions (SERCs) that are now key players in setting tariffs for renewable energy based electricity generation and have also been mandated to set quotas for renewable energy as a percentage of total consumption of electricity in the area of the distribution licensee. The National Tariff Policy that was notified by the Ministry of Power in January 2006, in continuation with the EA 03 and the National Electricity Policy also emphasizes the importance of setting renewable energy quotas and preferential tariffs for renewable energy procurement by the respective SERCs.

At present, there exists a large amount of experience at the international level in terms of strategies that are being used to promote renewable energy sources for power generation through pricing interventions. Some countries are introducing targets requiring that a certain share of electricity generation be based on renewables. Policies seeking to internalize the environmental costs and other externalities associated with electricity generation will attempt at making renewable energy more competitive. The international experience across different countries highlights the fact that the implementation of favourable energy policies has been helpful in promoting and expanding renewable energy technologies to their technical limits. However, these interventions are required to be adopted keeping into view the Indian power sector scenario and priorities.

Thus, with about 8000MW of installed capacity based on renewable energy sources and with the provisions of the EA 03 and other national policies for power generation, it is imperative to prepare a long term strategy for power procurement from renewable energy sources. It would also be useful to review the international experience with regard to renewable energy based electricity generation policies in the context of current Indian legal and regulatory environment. The subsequent sections of this paper deals with these issues; section 2 reviews the international policies and draws the pricing methodologies; section 3 reviews the regulations and tariff orders issued by different states in India; section 4 reviews various provisions in the EA 03 and other relevant policies; section 5 analyses different pricing options to develop a long term strategy and short term pricing guidelines which are discussed in section 6.

SECTION 2

Policies for renewable energy development: International best practices

Based on various stages of their development, different countries have used different policy instruments to promote renewables. These have been documented in the sub-sections given below. This section gives an overview of the policy instruments in the US, the EU Member States of Germany and UK. Some of the other international policy initiatives for promoting renewable energy that have been adopted in the countries of China and Sri Lanka from the South Asian region, Thailand and Vietnam from the South East Asian region, to increase the contribution of electricity from renewable energy sources to the national energy mix, have been discussed in greater detail in Annex 1. Although renewable energy policies in each of the identified countries have some elements of commonality in them, specific emphasis has been laid on the following:

- Feed-in Tariffs
- Renewable Portfolio Standards (RPS) and Renewable Energy Credits (RECs)
- Tendering Schemes
- Other incentive mechanisms
  - Production and Investment Tax Credits in the US
  - Rebates
  - Low interest loan and loan guarantees
  - Production payments

The policy instruments adopted by identified countries are briefly summarized in the table below:

Table 2: Policy Instruments used by different countries

Renewable Energy Technologies/ Countries	Feed-in tariffs	RPS and Renewable Obligation	Green Certificates	Production/ Investment Tax Credits	Subsidies / rebates	Fiscal Measures
Germany	*				*	*
UK		*	*			*
US		*	*	*		*
China					*	*
Sri Lanka						*
Thailand					*	*
Vietnam					*	*

The policy instruments that are in place in the different countries may be categorized on the basis of two identified principles. The instruments would broadly affect either the demand or supply of renewable electricity, and would focus either on electricity generation or on the installed capacity of renewable electricity plants (1):

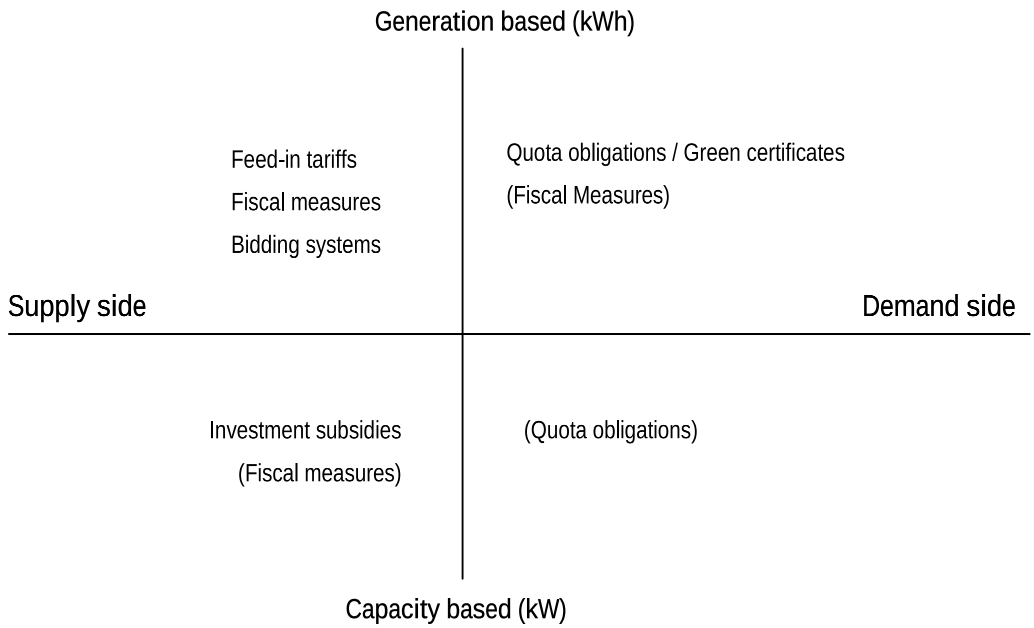

Figure 1: Categorization of policy instruments

From this categorization, there emerge 4 main instruments to promote renewable electricity – Feed-in tariffs, quota obligations in combination with a green certificate system, renewable energy credits and tendering/ bidding schemes. Apart from these instruments, some of the complementary initiatives (on the part of the government) that emerge are fiscal measures and investment subsidies. In this regard, some of the country specific case studies that have been discussed in Annex 1 are: **German** Feed-in tariffs and the Renewable Energy Sources Act (RES), 2000; the **UK** policy initiative in terms of the Non Fossil Fuel Obligation and quota obligations/ green certificates and tendering schemes; quotas and Renewable Portfolio Standards (RPS), in the context of renewable energy technology (RET) policies in **US;** the **Chinese** government's Fiscal measure initiatives for promoting RETs along with Investment and Production Tax Credit examples in US. The other countries' policy initiatives that have been discussed are **Thailand, Vietnam,** and **Sri Lanka**.

International Renewable Energy based Policy Instruments

In this section, the dominant renewable energy based policy instruments that have an important bearing on the pricing of renewable energy power, is discussed. In this context, the international best practices with regard to Feed-In-Tariffs, Quotas/ Renewable

Portfolio Standards/ Renewable Energy Credits and Tendering Schemes have been discussed in considerable detail.

A. Feed-In Tariffs

Feed-in tariffs are a commonly used policy instrument for the promotion of renewable electricity production. The term feed-in tariff can be used either in the context of a minimum guaranteed price per unit of produced electricity as approved by the regulator, to be paid to the producer, or as a premium in addition to market electricity prices. Regulatory measures are usually applied to impose an obligation on electricity utilities to pay the (independent) renewable energy power producer a price as specified by the government.

The level of the tariff is commonly set for a number of years to give investors security on income for a substantial part of the project lifetime. Many different adaptations of the instrument are applied. However, the level of the tariff need not have any direct relation with either cost or price, but can be chosen at a level to motivate investors for green power production.

Country specific examples – Germany

The German federal government, as well as the state and district governments, has put in place a number of measures for promoting renewable sources of energy. The main financial promotion measure on the national level was the Electricity Feed-in Law from 1990 to 2000, targeted at all renewable energy technologies with the objective of increasing the share of electricity produced from renewable energy sources. This law obliged utilities to buy electricity from producers of renewable energy sources and guaranteed a fixed price in combination with a digressive price element.

The regulatory authority fixed the tariffs for a one-year period based on the value of the average utility revenue per kWh sold. The measure stimulated particularly the development of wind energy, however a few identified problems with this law were:

a) The feed-in tariffs were not financed from taxes but from revenues of utilities, which distorted the competition among the utilities;
b) The guaranteed premiums were applicable only to the non-utility sector;
c) Since tariffs were based on utility revenues, tariffs would go down once electricity prices would go down.

Recognizing these difficulties, the Electricity Feed in Law was replaced by the Act on Granting Priority to Renewable Energy Sources (Renewable Energy Sources Act) on 1st April 2000. Further amendments to the tariff rates were announced in 2004.

The new legislation on renewable energy builds upon the "Act on the Sale of Electricity to the Grid" passed in the Bundestag in 1990. That law obliged grid operators to buy electricity generated from renewable sources of energy at a minimum price.

Some of the main features of the new Act are highlighted below:

- Under the new Act, electricity utilities are no longer required to pay the feed-in tariffs, but it obliges the grid operators to pay a minimum price for purchase of electricity from renewable energy sources. The utilities however, still have the legal obligation to take off the electricity produced from renewable energy sources.
- The grid operator having grid closest to the location of the renewable energy source installation has the obligation to pay the tariffs.
- The Act states that the electricity from renewable energy must be transported and charged to the customer.
- The prices under the new Act are based on a fixed price scheme combined with a decreasing price element, in order to allow for technological progress and the expected reduction of costs. From 2002 on, new installations of biomass (minus 1.5%), wind (minus 2%) and PV (minus 5%) receive lower tariffs. From 2003 on, new installations of these types receive tariffs lowered by a further, 1.5, 2 and 5%, and so on for the next following years. For every installation, the expiry date is in 20 years time from the installation. A summary of the feed-in tariff rates as per the new Act (along with revised announced rates of 2004) is summarized in the table below:

Table 3: Feed-in tariffs for electricity produced from renewable energy sources in Germany

Source	Tariff/kWh, January 2000	Tariff/kWh, July 2004	Digressive Element
Hydropower	7.67 cts. up to 500kW 6.65cts. over 500kW	9.67cts. up to 500kW 6.65cts. over 500kW and up to 5MW	Fees shall be reduced 1% annually.
Landfill gas, sewage treatment plant gas, mine gas	7.67 cts. up to 500kW 6.65cts. over 500kW	7.67cts. up to 500kW 6.65cts. over 500kw and up to 5 MW	Fees shall be reduced 1.5% annually.
Biogas	10.23 cts. up to 500kW 9.21cts. up to 5MW 8.70 cts. Up to 20MW	11.5cts. up to 150kW 9.9cts. up to 500kW 8.9cts. up to 5MW 8.4cts. up to 20MW	Fees shall be reduced 1.5% annually.
Geothermal	8.95cts. up to 20MW 7.16cts. over 20MW	15cts. up to 5MW 14cts. up to 10 MW 8.95cts. up to 20MW 7.16cts. over 20MW	Fees shall be reduced 1%annually.
Wind	9.10 cts. for the first 5 years 6.19 cts. after reaching a certain reference revenue	8.7cts. for the first 5 years 5.5cts. after reaching a certain reference revenue	Fees shall be reduced 2% annually. The reference revenue is based up on the amount of electricity fed-in during the first 5 years. This means a

Source	Tariff/kWh, January 2000	Tariff/kWh, July 2004	Digressive Element
			quicker reduction in tariffs for those sites, which have more wind.
Solar radiation	For plants using Photovoltaic energy: 50.62 cts	For plants using solar radiation: 45.7cts. For plants attached to or integrated on top of building: 57.4cts. up to 30kW 54.6cts. up to 100kW 54.0cts. over 100kW	Fees shall be reduced 5% annually.

s o u r c e: 2004 Renewable Energy Sources Act

Country specific examples – California PURPA Experience

California enacted the U.S. Public Utilities Regulatory Act (PURPA) in 1978. The law required utilities to interconnect with and buy energy from "qualifying facilities," including renewable energy plants, at incremental or avoided costs of production. That is, the utilities purchased renewable energy for the price that they would have otherwise had to pay if they installed additional capacity. In California, the implementation of PURPA involved the use of standardized long-term contracts. The costs of the contract were covered through higher electric rates for customers. While these contracts proved costly, it is widely believed that the alternative (nuclear power) would have been even more expensive. The time length of the contracts (15 to 30 years for wind projects), combined with fixed energy prices for much of the time, assured producers of a market for their product and finally gave them something they could take to the bank to obtain financing.

The primary difference between the U.S. PURPA policy and the European feed-in laws was that the PURPA price was based on the wholesale cost of power to the utility while the feed-in price is based on a predetermined fixed tariff.

B. Quotas/ Renewable Portfolio Standards/ Renewable Energy Credits

While pricing laws establish the price and let the market determine capacity and generation, quotas (or mandated targets) work in reverse — the government sets a target and lets the market determine the price. Typically governments mandate a minimum share of capacity or generation of electricity, or a share of fuel, to come from renewable sources. The share required often increases gradually over time, with a specific final target and end-date. The mandate can be placed on producers or distributors.

Country Specific Example - US

The Renewable Portfolio Standard (RPS), widely used in U.S. states, is based on the obligation/certificate system. Under an RPS, a political target is established for the minimum amount of capacity or generation that must come from renewables, with the amount generally increasing over time. Investors and generators then determine how they will comply, the type of technology used, the developers to do business with, the price and contract terms. At the end of the target period, electricity generators must demonstrate, through the ownership of credits that they are in compliance in order to avoid paying a penalty. Producers give credits — in the form of “Green Certificates,” “Green Labels” or “Renewable Energy Credits” (RECs) — for the renewable electricity they generate. Such credits can be tradable or sellable, to serve as proof of meeting the legal obligation and to earn additional income. Those with too many certificates can trade or sell them; those with two few can build their own renewable capacity, buy electricity from other renewable plants, or buy credits from others. Once the system has been established, government involvement includes the certifying of credits, and compliance monitoring and enforcement. Box 1 below gives an explanation of the operation of RECs.

Box 1: Characteristics and operation of RECs

A REC is the aggregation of non-energy and socially beneficial attributes (e.g. environmental and socio-economical benefits) of a quantifiable unit of renewable energy power production – usually a MWh, represented as a tradable product. Tradable RECs are used to represent the renewable energy element of electricity generation. Essentially, a renewable energy generator produces two products: a MWh of electricity for sale and a renewable energy certificate demonstrating that a MWh of renewable energy power has been produced and delivered into the grid. If the regulations governing the renewable energy obligation allow utilities to use RECs to satisfy their renewable energy obligation, the utilities can buy the RECs from the generators. Through such a system, a utility needing to demonstrate compliance with a Renewable Purchase Obligation (RPO) needs to own a certain number of certificates. For example, if the RPO sets the utility’s renewable energy obligation at 1,000 MWhs it would need to own 1,000 one-MWh certificates. The trades can either be bi-lateral (between the buyer and seller) or they can be facilitated through a central trading market. The REC trading system gives the renewable energy generator two separate revenue streams, one from selling MWhs of electricity and the other from selling RECs.

Tradable RECs are essentially a certificate of proof that a unit of electricity has been produced from a renewable energy source. A REC trading system has several characteristics:

- It provides additional financing for renewable energy generators because they can earn money by selling RECs in addition to energy.
- It facilitates the development of a regional renewable energy market to meet RPO requirements.
- It reduces the cost of the RPO by providing easy access to a geographically diverse array of generating resources.
- It reduces the need to build new transmission specifically to serve renewable energy production.
- It makes it possible for states in which there are no renewable energy producers to nonetheless have an RPO in place that a utility can meet by acquiring RECs from outside the state.
- The REC tracking system provides assurance and verification that a REC actually represents real renewable generation; it prevents fraud and promotes confidence in the renewable energy market.

Tradable RECs have been used extensively as a successful market based policy instrument to promote renewables in Australia, Japan, US (Texas, Arizona, Wisconsin, Nevada), Netherlands, Denmark and UK.

As with the feed-in law, the additional costs of renewable energy under quota systems are paid through a special tax on electricity or by a higher rate charged to all electricity consumers.

RPS policies are expanding at the state/ provincial level in the United States and Canada. Six new US states enacted RPS policies in 2004 and early 2005, bringing the total number of states with RPS policies to eighteen. Canada has ten provinces with RPS policies. India has 6 states with RPS and more are expected to follow. Most RPS polices are in the range of 8-20%, typically by 2010 or 2012, although few contain smaller or larger percentages (2).

There are also five countries with national RPS policies, all enacted quite recently. Australia's RPS (2001) requires utility companies to submit a certain number of renewable energy certificates each year (1.25% of generation was required for 2004, or about 2,600 GWh total); this requirement will be adjusted each year to eventually lead to Australia's national target of 9,500 GWh by 2010. UK's RPS (2002) will lead to 10% by 2010 and then to 15% by 2015, continuing to 2027. Japan's RPS (2003) also requires a certain percentages from utilities, which increases over time to reach 1.35% by 2010. Poland's RPS (2004) will reach 7.5% by 2010. Thailand's RPS is 4%. In Netherlands, Dutch Utilities have voluntarily adopted an RPS, based on targets of 5 per cent of electricity generation by 2010, increasing to 17 per cent by 2020. In Brazil, the Energy Policy enacted during 2001, requires national utilities to purchase over 3,000 MW of renewable energy capacity by 2016 (3).

C. Tendering Schemes

Under tendering systems, regulators specify an amount of capacity or share of total electricity to be achieved, and the maximum price per kWh. Project developers then submit price bids for contracts.

Country Specific Example - UK

The UK's Non-Fossil Fuel Obligation (NFFO) was an early example of this type of policy. Governments set the desired level of generation from each resource, and the growth rates required over time. The criteria for evaluation are established prior to each round of bidding. In some cases, governments will require separate bids for different technologies, so that solar PV is not competing with wind projects, for example. Generally, proposals from potential developers are accepted starting with the lowest bid and working upwards, until the level of capacity or generation required is achieved. Those who win the bid are guaranteed their price for a specified period of time; on the flip side, electricity providers are obligated to purchase a certain amount of renewable electricity from winning producers at a premium price. The government covers the difference between the market reference price and the winning bid price. Each bidding round is a one-time competition for funds and contracts.

Five tender rounds were organized during the 1990's, the last being called in 1998. For the first two rounds, the purchase contracts with Regional Electricity Companies were guaranteed for eight years. For the last three rounds the contract guarantee extended to fifteen years. The guaranteed contract price emerged as a result of the tendering process and was made up of two components – the pool price and a technology-specific premium, which came from the Non-Fossil Fuel Levy Fund.

After 2000, a new system was shaped to support commercial viability of RES, consisting of three elements. The first and central element of the new support system is a quota Renewable Obligation (RO) on electricity supply companies with a 25-year horizon. The second element is the exemption from the Climate Change Levy (CCL) for renewable electricity consumed by industrial and business consumers. The third is a governmental subsidy program to support the more expensive technologies and those that still need technical improvements. The purpose of the Renewable Obligation imposed on suppliers of energy is to reach 10% renewable electricity share by 2010. This policy is envisaged to be in place until March 2027.

D. Other Incentive Instruments

Apart from the dominant renewable energy policy instruments, some of the other complementary initiatives on the part of the government, primarily to support development of renewable energy technologies are fiscal measures such as investment tax credit, production tax credit, low interest loans, loan guarantees and investment subsidies. The key features of these incentive mechanisms are summarized in box 2 below.

Box 2: Other incentive mechanisms used across different countries to promote renewable energy

1. **Investment Tax Credits**

Investment tax credits can cover just the cost of the system, or the full costs of installation. They have been used extensively for the promotion of water and space heating systems based on biomass and geothermal energy. They can be helpful early in the diffusion of a technology, when costs are still high, and to encourage their installation in off-grid, remote locations. They directly reduce the cost of investing in renewable energy systems and reduce the level of risk.

2. **Production Tax Credits (PTC)**

It provides tax benefits against the amount of energy actually produced and fed into the electric grid, or the amount of biofuels produced, for example. They increase the rate of return and reduce the payback period, while rewarding producers for actual generation of energy. A PTC can be used as the central mechanism for the support of renewables as part of a national or regional mechanism, or it can be used in support of other mechanisms, such as a quota mechanism.

3. **Rebates**

As an alternative to investment and production credits against taxes, some states and countries have subsidized renewable energy through production payments or rebates. Rebates are refunds of a specific share of the cost of a technology, or share of total installation costs (for example, 30 percent of total costs), or refunds of a certain amount of money per unit of capacity installed (for example, $3.00 per peak Watt (Wp) of PV capacity).

4. **Production Payments**

Production payments reward energy generation through a certain payment per unit of output. For example, California has enacted a production incentive that awards a per kW payment for some existing and new renewable energy projects. It is financed through a small per kW charge on electricity use, meaning that Californians share the cost of the program according to the amount of power they consume

5. **Low-Interest Loans and Loan Guarantees**

Worldwide, one of the major barriers to renewable technologies in the high initial capital costs of renewable energy projects. Thus, the cost of borrowing plays a major role in the viability of renewable energy markets. Financing assistance in terms of low-interest, long-term loans and loan guarantees can play an important role in overcoming this obstacle. Lowering the cost of capital can bring down the average cost of energy per unit and reduce the risk of investment.

Alternative approaches for Tariff Determination

The analysis of the pricing mechanisms of renewable energy based electricity generation from the various international experiences, there emerges, two main pricing options for setting generation tariffs from renewable energy based power plants.

i) Cost-based approach
   - Benchmark pricing approach

ii) Marginal cost/ Avoided cost based approach
   - Long-run marginal cost (LRMC)
   - Short-run marginal cost (SRMC)

Cost based approach

The cost based approach relies on the availability of requisite station-wise information for the generating stations, and thereafter builds up the tariffs from the costs. The exercise for tariff setting in the cost based approach is adjusted for performance standards set by regulators, where rate of return on the capital investments is regulated and a cap is imposed on clear profit earned by the generator. This methodology of tariff computation takes into account the recovery of fixed cost components such as interest on debt, operation and maintenance costs and also assures a fixed return on an investor's equity. This is similar to the pricing of conventional power projects with Power Purchase Agreements.

This approach necessitates validating each element of costs with the historical data/past trends and other supporting information. This approach is, therefore, practically difficult when applied to such large number of tiny and widely distributed generating stations.

Benchmarking Approach

The Benchmarking approach is another alternative but it is highly dependant on a broad based and reliable data for defining the benchmarks or norms. Benchmark pricing typically adopts a representative station for determination of tariffs. In this method typically all cost elements are considered for this benchmark determination. The benchmark costs could result in unattractiveness of projects that are above the cost benchmark but are nonetheless viable from an economic perspective, considering the low losses involved in such local generation, social benefits and also the higher avoided costs of alternative sources.

Marginal Cost/ Avoided Cost Approach

The Marginal cost or the Avoided cost based approach considers the unit cost of energy displaced at the margin by the energy generated at the margin by the renewable energy based power plant. The avoided costs thus become payable for the energy generated by the renewable energy plant.

Avoided cost is the price that is equal to the incremental cost that a particular utility would have incurred if it had to produce the power itself or obtained the power from some another source.

An issue that comes up in this approach relates to what is actually the avoided cost in such cases. One view is that the avoided cost is the cost that the licensee would have incurred in procuring the same energy from another existing source at the top end of the merit order. Another view is that the avoided cost should be the cost of supply to the licensee's consumer at the place and at the voltage on which power from such tiny generating stations is injected into the grid. As this marginal power varies from cheapest to costliest generating station throughout the different months of a year, the ideal approach would be to run a daily or at least a monthly merit order for determination of cost of this replaced power. However, looking at the small quantities of and impact of such power and also the complexity in computation, such approach could run into difficulties. For practical reasons a less specific approach like the average procurement costs of power would seem desirable. In case of the cost of supply approach, the problems of working out precisely the cost of supply at a particular place and on a specified voltage arise with no easy solutions. Another issue which arises in this connection is whether the cost of inefficiency of carrying such power on low voltage resulting in avoidable losses should be thrust on the licensee or should it be compensated for the same while computing such avoided costs. An avoided cost based tariff would need periodic revision arising out of changes in the other (marginal) generating stations' tariffs. However, the advantage of this method is that it would cover the inflationary increases as well as other changes, which would have to be periodically addressed in the tariff determination exercise.

Long Run Marginal Cost (LRMC)

Long-run marginal costs are the 'incremental cost of optimal adjustments in the system expansion plan and system operation attributable to a small increment of demand which is sustained into the future' (4). The major components of LRMC are: (a) Energy Cost Component (fuel and operation costs) and (b) Capacity Cost Components (new generation, transmission and distribution costs). The energy cost component is the Short-run marginal cost, which is described below. In the capacity cost component, the two factors that influence their level are the depreciation and discount rates. The capacity cost has to be annualized in order to make adequate financial planning. The depreciation rate represents the loss of value of installed capacity over the years and the discount rate is the opportunity cost of capital that is used for the investment in new capacity.

Short Run Marginal Cost (SRMC)

The short-run marginal cost represents the cost of producing an additional unit of electricity when the capacity is fixed. It includes the fuel and operation costs related to the production of the additional unit of energy. Hence, SRMC relies on the current fuel and operation cost data.

SECTION 3

Review of Indian Legislation and Policies

Ministry of Non Conventional Energy Sources Initiatives

In India, the utilization of renewable energy technologies for electricity generation has a long history. The wind demonstration projects set up in early 80's e.g. in Tamil Nadu, Gujarat, and Maharashtra are example of this. This phase was followed by development of policy measures, including financing and institutional measures to support the renewable energy technologies. The Ministry of Non-Conventional Energy Sources (MNES), in 1993 prepared policy guidelines for promotion of power generation from renewable energy sources. Some of the salient features of this policy guideline are - buy back price of Rs. 2.25 per kWh with 5% annual escalation, with 1993 as base year, concessions regarding the banking, wheeling and third party sale and fiscal incentives like allowing 100% accelerated depreciation for renewable energy projects were also given. The MNES guidelines were valid for a period of 10 years.

Power being a concurrent subject between the central and the state governments in India; different states adopted the MNES guidelines to varying degree. Further, there have been modifications in the state level policies with on one hand, some states giving additional benefits to renewables while on the other hand, some states have even diluted the benefits that were proposed in the MNES guidelines.

Ministry of Power Initiatives

With an objective of enhancing the operations of the power sector entities in the country as well as creating a conducive environment for investments, Ministry of Power, has taken a number of initiatives in the past. These initiatives have been characterized on the basis of major legislative changes, policy measures and administrative actions and have been highlighted as follows:

Major Legislative Initiatives

Legislative framework in the past

Prior to the EA 03, the power sector in India was governed by three important legislations viz. The Indian Electricity Act, 1910; The Electricity (Supply) Act, 1948 and The Electricity Regulatory Commission (ERC) Act, 1998. Prior to the enactment of the ERC Act, 1998, the regulatory function at the central level was performed by the Central Electricity

Authority (CEA) / GoI and at the state level was performed by the SEBs / state government. The authority of the CEA was exercised through the process of grant of techno-economic clearance and the stipulation of various norms. GoI was responsible for the tariff setting of central generating stations. At the state level, the state governments and the SEBs were responsible for the regulatory function of the sector.

The key features of the ERC Act, which is relevant in the context of pricing of renewable energy based power generation, are as follows:

The ERC Act, 1998

- Provision for setting up of Central Electricity Regulatory Commission (CERC) / State Electricity Regulatory Commission (SERC) with powers to determine tariffs;
- Constitution of SERC optional for states; and
- Distancing of government from tariff setting process.
- Rationale for change in legislative framework

The key reasons for devising a new legislation governing power sector were:

- Requirement for harmonizing and rationalizing provisions in the existing laws to
- Create a competitive environment which would result in enhancing quality and reliability of supply to consumers; and
- Distance regulatory responsibilities of the government.
- Obviate the need for individual states to enact their own reform laws;
- Introduce newer concepts like power trading, open access, Appellate Tribunal etc.; and
- Providing special provisions for rural areas.

Electricity Act 2003

In order to formulate a comprehensive legislation imparting renewed thrust to coordinated development of the power sector in the country, the Electricity Act, 2003 (EA 03) has been enacted. The EA 03 provides a comprehensive yet flexible legislative framework for power development and envisions a sector characterized by a competitive market in power where the regulators and the power utilities play increasingly significant roles.

Key objectives of the EA 03

The important objectives of the EA 03 are as follows:

i) To consolidate the laws relating to generation, transmission, distribution, trading and use of electricity and generally for taking measures conducive to development of the entire electricity industry;
ii) Promoting competition in the industry;
iii) Protecting the interest of consumers and supply of electricity to all areas;

iv) Rationalization of electricity tariff;
v) Ensuring transparent policies regarding subsidies;
vi) Promotion of efficient and environmentally benign policies;
vii) Constitution of CEA, Regulatory Commissions and establishment of an Appellate Tribunal; and
viii) For other related matters

The EA 03 also had its impact on the renewable power sector and recognized the role of renewable energy technologies in the National Electricity Policy and in stand-alone systems. Some of the important provisions in the Act with regard to the promotion of renewable energy are given below.

Section 3 (1)
"The Central Government shall from time to time, prepare the National Electricity Policy and tariff policy, in consultation with the State Governments and the Authority for development of the power system based on optimal utilization of resources such as coal, natural gas, nuclear substances or materials, hydro and renewable sources of energy."

Section 4
"The Central Government shall, after consultation with State Governments, prepare and notify a national policy, permitting stand alone systems (including those based on renewable sources of energy and other non-conventional sources of energy) for rural areas."

The state electricity regulatory commissions (SERCs) are now crucial players in the context of state level policies for renewable.

Section 61 (h)
"The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the promotion of co-generation and generation of electricity from renewable sources of energy."

Further the EA 03 has made it mandatory for SERCs –

Section 86 (1) (e)
"to promote co–generation and generation of electricity through renewable sources of energy by providing suitable measures for connectivity with the grid and sale of electricity to any persons, and also specify, for purchase of electricity from such sources, a percentage of the total consumption of electricity in the area of a distribution licensee."

Policy measures and initiatives

National Electricity Policy

In pursuance of the provisions of the Act, the Government of India has notified the National Electricity Policy vide MOP notification No. 23/40/2004-R&R (Vol-II) dated 12.2.2005. National Electricity Policy also stresses the need for the promotion of Non-Conventional Energy Sources. The extract of the relevant provisions of the National Electricity Policy is given below -

"*5.12 Cogeneration and Non-Conventional Energy Sources*

5.12.1 Non-conventional sources of energy being the most environment friendly there is an urgent need to promote generation of electricity based on such sources of energy. For this purpose, efforts need to be made to reduce the capital cost of projects based on non-conventional and renewable sources of energy. Cost of energy can also be reduced by promoting competition within such projects. At the same time, adequate promotional measures would also have to be taken for development of technologies and a sustained growth of these sources.

5.12.2 The Electricity Act 2003 provides that co-generation and generation of electricity from non-conventional sources would be promoted by the SERCs by providing suitable measures for connectivity with grid and sale of electricity to any person and also by specifying, for purchase of electricity from such sources, a percentage of the total consumption of electricity in the area of a distribution licensee. Such percentage for purchase of power from non-conventional sources should be made applicable for the tariffs to be determined by the SERCs at the earliest. Progressively the share of electricity from non-conventional sources would need to be increased as prescribed by State Electricity Regulatory Commissions. Such purchase by distribution companies shall be through competitive bidding process. Considering the fact that it will take some time before non-conventional technologies compete, in terms of cost, with conventional sources, the Commission may determine an appropriate differential in prices to promote these technologies.

5.12.3 Industries in which both process heat and electricity are needed are well suited for cogeneration of electricity. A significant potential for cogeneration exists in the country, particularly in the sugar industry. SERCs may promote arrangements between the co-generator and the concerned distribution licensee for purchase of surplus power from such plants. Cogeneration system also needs to be encouraged in the overall interest of energy efficiency and also grid stability."

National Tariff Policy

In compliance with Section 3 of the EA 03, the Central Government notified the Tariff Policy vide MOP notification No.23/2/2005-R&R (Vol. III) dated January 6, 2006 in continuation with the National Electricity Policy. Some of the important provisions with regard to non-conventional energy generation are highlighted below –

Section 6.4

(1) Pursuant to provisions of section 86(1)(e) of the Act, the Appropriate Commission shall fix a minimum percentage for purchase of energy from non-conventional sources taking into account availability of such resources in the region and its impact on retail tariffs. Such percentage for purchase of energy should be made applicable for the tariffs to be determined by the SERCs latest by April 1, 2006.

It will take some time before non-conventional technologies can compete with conventional sources in terms of cost of electricity. Therefore, procurement by distribution companies shall be done at preferential tariffs determined by the Appropriate Commission.

(2) Such procurement by Distribution Licensees for future requirements shall be done, as far as possible, through competitive bidding process under Section 63 of the Act within suppliers offering energy from same type of non-conventional sources. In the long-term, these technologies would need to compete with other sources in terms of full costs.

(3) The Central Commission should lay down guidelines within three months for pricing non-firm power, especially from non–conventional sources, to be followed in cases where such procurement is not through competitive bidding.

Implementation of Section 86 (1) (e) of the EA 03 and Section 6.4 (1) of the National Tariff Policy are underway and different SERCs are in the process of issuing tariff orders for renewable energy based electricity generation and specifying quota/share for power from renewable energy.

Integrated Energy Policy

The Prime Minister and the Deputy Chairman, Planning Commission, Government of India, took the decision for an effective and comprehensive energy policy as an urgent imperative in the year 2004. An expert committee was constituted under the leadership of

Dr. Kirit Parekh, to prepare an integrated energy policy linked with sustainable development that covers all sources of energy and addresses all aspects including energy security, access and availability, affordability and pricing, efficiency and environment. The committee was constituted on 12th August 2004. The draft integrated energy policy was circulated in December 2005 and the final policy was notified in August 2006.

The broad vision behind the energy policy is to reliably meet the demand for energy services of all sectors including the lifeline energy needs of vulnerable households, in all parts of the country, with safe and convenient energy at the least cost in a technically efficient, economically viable and environmentally sustainable manner.

The integrated energy policy has outlined some ambitious tenets. These are summarized below.

- Renewable energy may need special policies to encourage them. This should be done for a well-defined period or up to a well-defined limit and should be done in a way that encourages outcomes and not just outlays.
    - Phase out capital subsidies, which only encourage investment without ensuing outcome, by the end of the 10th Plan linked to creation of renewable grid power capacity
    - Power regulators must seek alternative incentive structures that encourage utilities to integrate wind, small hydro, cogeneration, etc., into their systems. All incentives must be linked to energy generated as opposed to capacity created.
    - Respective power regulators should mandate feed-in laws for renewable energy, where appropriate, as provided under the Electricity Act and as are mandated in many countries.

The following specific policies to promote various renewables have been recommended in the policy:

- *Mini Hydro:* A detailed survey should be carried out to identify potential sites. Identified sites should be auctioned. For plants which are not connected to grid bid for lowest tariff with a pre-specified premium in the form of Tradable Tax Rebate Certificates (TTRC) should be invited. For village level plants, the entrepreneurs should be encouraged to supply power to meet other requirements such as agro processing and milling. If the plant can feed into a grid, the grid should be required to accept power at the going time of day tariff, and the plant site should be auctioned off for minimum premium in the form of TTRC linked to output. The responsibility for investments for connecting to the grid should be fixed in advance before the bidding.

- *Wind Power:* For wind power, site selection is freer than hydro-power and wind plants can be set-up on private land. Thus there may be need to auction only sites on public property. The same two types of auctions may be followed as described above for hydro-power plants.
- *Fuel-wood Plantation:* Cooperatives should be encouraged and facilitated to grow tree plantations in villages. Cooperatives which are open to all members of the community and which are non-discriminatory should be given government land on long-term lease. Women should be encouraged to set-up and manage such plantations so that the time they now spend in gathering fuel can be spent productively in a way that empowers them. They should also be provided finance. If organized and managed properly, such plantations are economic and successful. Field based NGOs could also be involved in this activity. To encourage large-scale plantations, contract farming should be facilitated.
- *Electricity from Wood Gasification:* This can provide electricity based on gasification of wood and can be very useful especially in remote villages. The same set of policies, indicated for micro hydel and wind power plants should be followed here.
- *Bio Gas Plants:* The real potential of bio gas is in community level plants. To encourage private or community entrepreneurs to set these up, they need to be provided land and finance. Also to have the willing participation of all the cattle owners in the community requires an appropriate operating strategy. The essential policy required is provision of land and finance.

SECTION 4

Review of tariff orders for renewable energy power

Tariff determination for power from renewable sources in India

The Ministry of Non-Conventional Energy Sources (MNES) prepared tariff guidelines for power procurement from renewable energy sources in early 90's. These guidelines were based on the tariffs given to IPPs (independent Power Producers) at that time. The guidelines were technology neutral i.e. they prescribed single tariffs for different renewable energy technologies. Different state utilities adopted these guidelines with varying degree of deviations. Subsequent to the Electricity Regulatory Commissions (ERC) Act 1998, the state electricity regulatory commission (SERC) became responsible for determination of tariffs as per the section 22(1)(c). The ERC Act also provided principles for tariff fixation. Some of the SERCs initiated action of determining tariffs for power generation based on renewable sources. The tariff order of Maharashtra Electricity Regulatory Commission (MERC) for bagasse power projects was the first such tariff order. This was followed by various renewable energy technology specific tariff orders by different state regulatory commissions. A summary of all these tariff orders, as on June 2006, is given in annex 2.

It is also clear from a review of the tariff orders issued by the various SERCs for purchase of power from renewable energy based plants, that the 'cost based tariff' methodology has been adopted by all the commissions. However, even though the overall approach followed by all the SERCs is the 'cost based tariff' approach, there are different issues specific to each renewable energy technology. The tariff orders for the five main renewable energy technologies viz. wind, biomass, bagasse-based cogeneration, small hydro and municipal solid waste are reviewed in this section.

Wind

Tariff order for wind power has been issued by SERCs of Maharashtra, Madhya Pradesh, Andhra Pradesh, Karnataka and Tamil Nadu. Within the overall principle of cost based tariffs different states have used different benchmarks for costs and performance parameters appropriate for that particular state. The critical parameters are capital cost, Operation and Maintenance (O&M) expenses, Return on Equity (RoE), the capacity utilization factor (CUF). Table 4 gives the benchmarks used by the different SERCs for determining the tariffs for wind power along with the tariffs approved.

Table 4: Wind benchmarks set by different SERCs for determining the generation tariff

State	Capital cost Rs./ MW	O&M costs	RoE	CUF	Tariff
Maharashtra	Rs. 4Cr/MW	1.5% for first 3 Yrs 2% in 4th year and 5% escalation after 4th year	16%	20%	Rs. 3.50 /kWh with annual increase of Rs. 0.15/kWh
Karnataka	Rs. 4.24 Cr/MW	1.25 with 5% annual escalation	16%	26.5%	Rs. 3.40/ kWh for 10 years
Andhra Pradesh	-	-	-	-	Rs. 3.37 /kWh with 5% simple escalation*
Tamil Nadu	5 Cr/MW for new plants	1.1% with 5% annual escalation	16%	25.29% for old plants and 26.7% for new plants	Rs 2.75/kWh for old plants Rs 2.90/kWh for new plants
Madhya Pradesh	Rs. 4.5Cr/MW	1% for first 5years and 5% simple escalation after that	16%	22.5%	First year Rs. 3.97 / kWh drops till Rs. 2.43/ kWh in 11th year and gradual increases to Rs.2.60/ kWh in 20th year

* -Based on MNES guidelines

It is clear that the CUF and intermittency are two critical issues specific to wind power. The CUF for wind power is primarily dependent on the wind resource available at a particular location and to a lesser extent on the wind turbine technology or efficiency. The benchmark CUF used in the tariff determination are based primarily on the CUFs achieved in the states, in the existing wind farms in the state. There is variation in the assumption of CUF across different states since the wind resource availability varies from state to state. The tariff is then estimated based on the CUF and the tariff is applicable for full actual generation.

Another critical issue in case of wind power projects is availability of 80% accelerated depreciation benefit. This incentive is used by the investors to reduce the tax liability. The actual benefit varies from project to project depending upon the capability of the investor to absorb the depreciation benefit. Further depending upon the date of commissioning of project this benefit is availed fully in first year, if the project is commissioned before 30th September, or used over 2 years, if the project is commissioned after 30th September. In case of wind tariff estimated by MERC, due to variations in actually availing the depreciation benefit, the accelerated depreciation benefit over five years has been used for tariff estimation. In case of other states the accelerated depreciation benefit has not been considered while estimation of tariffs.

While recognizing the importance of intermittency and non-dispatchability, there is no specific bearing on the tariffs offered in different states i.e. the wind power is 'must buy'. This implies that the wind projects will dispatch 100% of available capacity without being subjected to the merit order dispatch.

In case of the Madhya Pradesh, a front loaded tariff was determined for wind power with annual reduction in tariff, whereas in the case of other states the tariffs have annual escalation factors and are offered in different slabs. This is primarily to address the cash flow issue for the wind power producers.

Small Hydro

The main components of tariff setting with regard to small hydropower (SHP) are the capital cost, CUF, O&M charges, water royalty charges and grid connectivity. SERCs have come out with tariff orders taking into consideration the topology and the resource availability of their particular state. Table 5 gives the tariffs, which are being offered by different states with differing stands taken with regard to royalty charges.

Table 5: Small hydro benchmarks set by different SERCs for determining the generation tariff

State	Capital cost (Rs./ MW)	O&M costs	Royalty	CUF	Tariff
Andhra Pradesh	Rs. 3.6 Cr/MW	1.5% with 4% annual escalation	Royalty charges will be paid by APTRANSCO and Discom's to GoAP. Rs. 0.39 /kWh till 5 years. Rs. 0.78 /kWh from 5th till 10th year. Rs. 1.17 /kWh beyond 10 years.	35%	Rs 2.60/unit for the first year, which reduces by Rs.0.08/unit every year till the 10th year.
Karnataka	Rs. 3.9 Cr/MW	1.5 with 5% annual escalation	No Royalty charges	30%	Rs. 2.80/ unit for the first year with no escalation
Uttar Pradesh	Rs. 4.5 Cr/MW	2.5% with 4% annual escalation	Royalty Charges will be paid by distribution licensees to GoUP	35%	Rs 3.39/unit
Uttaranchal	Rs. 5.5Cr/MW	3% with 4% annual escalation		45%	Case to case basis
Maharashtra	Rs. 4.4Cr/MW	2.5% with 4% annual escalation	Royalty charges are passed through.	30%	Rs 2.84/Unit in the first year, which increases by Rs.0.03/unit every year till the 10th year. Fixed tariff of Rs 3.11/unit from 10th to 15th year. Annually escalation at Re 0.03/unit subsequently
Himachal Pradesh	-	-	-	-	Rs.2.50/kWh with the base year 2001. The tariff shall be indexed at 50% of the annual inflation rate of the consumer Price Index.

A potential site is the most important factor in case of small hydro. These potential sites are usually in far-flung areas with no connectivity. The capital cost hence becomes a major factor. It varies from the technology being used. The run off the river (ROR) and the canal-based systems have different technology requirements and hence differ in terms of costs. SERCs have taken into account the costs involved for capital costs and O&M costs from the existing plants.

Commissions have also reassured themselves of the operating CUF in the existing plants. In case of small hydro projects, CUF has always been a parameter, which is of most importance. As seen from different state experiences, the CUF differs from canal-based projects to the run off river projects. As in the case of wind, the benchmark CUF are based on the CUF of existing small hydro plants in the state. Uttaranchal has indicated that a CUF of 45% has been taken into consideration to promote higher efficiencies. States have also introduced performance-based incentives for SHP's.

Two part tariff vis a vis Single part tariff

Andhra Pradesh (AP)

In AP, a single part tariff has been designed and approved by the Commission since it has been felt that a two-part tariff which is implemented for large hydro power projects will be difficult for SHP projects since the number of small hydro plants in the state is large. The threshold CUF has been taken as 35% in the state. The Commission is also of the opinion that that developer should only get the variable cost (if any) and the incentives if the plant operates above the threshold CUF. An incentive of 25 paise is being given to the developer for every unit generated above the threshold CUF.

Maharashtra

The MERC opines that if strictly two part tariff is adopted for SHP projects, including interest, depreciation, advance against depreciation (AAD) and 16% ROE, then the tariffs will be front loaded, thus burdening the licensee and hence the consumers. The MERC also suggests that the two part tariff cannot be implemented for small hydro projects since the tariff cannot be made to follow the cost curve on a year to year basis. This could also be analyzed as the uncertainty in generation from year to year. The MERC is also of the opinion that a single part tariff would offer high level of investment certainty by guaranteeing a fixed price for every unit delivered.

Uttaranchal

Uttaranchal Electricity Regulatory Commission (UERC) has also issued SHP tariff setting order, which approves a single part tariff, and it relates to the difficulties in working out the design energy of the plant, in terms of adequate water discharge all through out the year. However incentives for plants operating above the normative CUF are being offered to developers.

Karnataka

Karnataka Electricity Regulatory Commission (KERC) has also taken into consideration the practical difficulties in implementing a two-part tariff for a large number of SHP projects with low capacity, seasonal variation in water discharge and monitoring of projects.

Bagasse based Cogeneration

The power from cogeneration projects mainly bagasse based cogeneration has been treated separately by different state regulatory commissions and specific tariff orders have been issued. The initial order which goes into detailed analysis of bagasse based cogeneration was issued by MERC. Bagasse based cogeneration basically involves cogeneration of power and steam, where steam is used in the plant itself and part of power generated is exported to the grid. The critical issues related to cogeneration and its treatment by different tariff orders are discussed below:

Definition and eligibility

In case of Maharashtra the different technologies used of cogeneration have been differentiated and any ‘incidental cogeneration’ is not allowed whereas in case of other states there is no such differentiation.

Use of conventional fuel in off-season

Use of conventional fuel in off-season was allowed earlier as per the MNES guidelines. However with the new tariff orders of MERC, UPERC, APERC and KERC the use of conventional fuel and its ‘pass through’ is not allowed. The recent order of TNERC, however allows use of conventional fuel up to 25%.

Fuel cost and consumption

Bagasse is a by-product in the sugar industry, and thus available free of cost for the bagasse based cogeneration plant. However it has alternate usages, primarily in paper production. It has been observed by the commissions that price discovery is difficult in this case. An alternative of proxy pricing was used initially In the MERC order. The price of coal in equivalent heat terms was used as cost of bagasse. Other commissions while considering the fuel price also followed a similar approach. Another fuel related issue is specific fuel consumption or station heat rate. APERC used the similarity between the bagasse based cogeneration and biomass based power used heat rates equivalent to biomass based power projects. Similar specific fuel consumptions were used by commissions in Karnataka and Tamil Nadu.

The loading of fuel cost on steam and power is also a critical issue for cogeneration plants. In case of Maharashtra, based on the study of different projects in the state, MERC has considered 30% loading of variable cost on power. In other states there is no specific mention of this issue.

Capacity Utilization Factor

The CUF for a bagasse based cogeneration plant is dependent on the sugarcane crushing season. Different states have different average days of crushing seasons. Since conventional fuel consumption is not allowed in most of the states, the CUFs are estimated based on crushing season and additional days of operation in off-season, by using stored bagasse or procuring bagasse from other plants.

Accelerated depreciation

The accelerated depreciation for some of the equipments required for cogeneration plants is available. However this benefit has not been considered while dealing with the depreciation issue for cogeneration projects.

Tariff and Control period

As shown in table 6, the tariffs estimated for bagasse based cogeneration projects are designed either as single part tariffs or two part tariffs. The control period for these tariffs varies from three years, as in Andhra Pradesh to ten years, as in case of Karnataka. In case of Tamil Nadu the fixed costs are further divided in to escalating and non-escalating components. The escalating component comprises of O&M costs and its annual escalation. Further the Uttar Pradesh Electricity Regulatory Commission (UPERC), through amendment of its original order, also allowed escalation in capital cost. In the Andhra Pradesh Electricity Regulatory Commission (APERC) order, full tariff i.e. fixed cost and variable cost is given till the benchmarked CUF (55%) is achieved. The fixed cost component is then replaced with an incentive and hence the tariff contains the incentive component and the variable cost component.

Table 6: Bagasse based Cogeneration benchmarks set by different SERCs for determining the generation tariff

State	Capital cost (Rs./ MW)	Fuel cost	Fuel consumption	CUF	Tariff
Maharashtra		Rs 559/ton with 8% escalation		90% with 240days as operating period	Rs 3.05/ kWh with 2% escalation
Karnataka	Rs 3.75 Cr/MW	Rs 800/ton	1.6kg/kWh	60%	Rs. 2.87/ kWh in 1st year with escalation reaching Rs.3.06/ kWh in 10th year
Andhra Pradesh	Rs. 3.25 Cr /MW	Rs 575/ton	1.6 kg/kWh	55%	Fixed cost Rs. 1.72/unit in 1st year reducing to 0.90 in 10th year+ variable cost Rs.1.02 in

State	Capital cost (Rs./ MW)	Fuel cost	Fuel consumption	CUF	Tariff
					2005-05 escalating to Rs.1.24 in 2008-09
Tamil Nadu	Rs. 3.5 Cr/MW	Rs 575/ton with 5% escalation	1.6 Kg/kWh	55%	Rs 3.15 /kWh
Uttar Pradesh	Rs. 3.50 Cr/MW	Rs 740 /ton With 4% escalation	1.45 kg/kWh (Based on station heat rate of 3300kCal/kWh and calorific value of 2275 Kcal/kg)	60%	Tariff (fixed cost, non escalating and escalating component, and variable cost depend on year of commissioning) i.e. different tariffs for plants commissioned in different financial years

Biomass

The detailed tariff orders for biomass based power has been issued by the regulatory commission in Maharashtra, Andhra Pradesh, Karnataka, and Tamil Nadu. The important issues with regard to biomass and its treatment by different commissions are discussed below.

Fuel consumption and cost

The calorific value and hence the specific fuel consumption changes for one type of biomass to another. The Andhra Pradesh government had constituted a committee of experts, which also evaluated the fuel consumption issue. The APERC tariff order considers the fuel consumption indicated by this committee. The MERC order on biomass power uses station heat rate as basis for estimating the variable cost as the specific fuel consumption can change with the type of biomass.

The fuel cost issue has been addressed by the APERC and MERC in a similar manner. The fuel cost considered for tariff estimation is based on weighted average (with calorific value in case of MERC and ratio of 60:40 for rice husk and other biomass in case of APERC) of the cost of different biomass used in the power plants in the state. In case of Maharashtra, usage of coal up to 25% is considered while estimation of the fuel cost. The cost of coal used is the pithead cost to discourage use of coal in biomass based power plants.

Table 7: Biomass power plant benchmarks set by different SERCs for determining the generation tariff

State	Capital cost (Rs./ MW)	Fuel cost	Fuel consumption	CUF	Tariff
Maharashtra	Rs. 4.0 Cr/MW		Heat rate 3650 kCal/kWh	80%	Rs. 3.04/ kWh in first year escalating to 3.34 in 10th year.
Karnataka	Rs. 4.0 Cr/MW	Rs 1000/ton with 5% annual escalation	1.16 kg/kWh	65%	Rs. 2.93/ kWh in first year escalating to 3.10 in 10th year
Andhra Pradesh	Rs. 4.0 Cr/MW	Rs 1000/ton with 5% annual escalation	1.16 kg/kWh	80%	Fixed cost Rs. 1.61/ kWh in 1st year decreasing to 0.87 in 10th year. The variable cost for 2004-05 Rs.1.27 escalating to Rs.1.54 in 2008-09
Tamil Nadu	Rs. 4.0 Cr/MW	Rs 1000/ton with 4% annual escalation	1.16 kg/kWh	80%	Rs 3.15 / kWh

Capacity Utilization Factor

Higher CUFs can be achieved in case of biomass based power plants with possible use of different types of biomass as well as of coal. Thus the CUFs used for tariff determination are in the higher range of 75-80% across different states.

Tariff and control period

All the state commissions have estimated two-part tariff for biomass power with an exception of Tamil Nadu. The control period varies from three years, as in case of Tamil Nadu to ten years as in case of Karnataka. The control period is a critical issue since the fuel cost can vary over a large range and a shorter control period gives flexibility of adjusting any such variations. Further the fixed cost components are linked with the year of commissioning of plant whereas the variable costs are linked with the financial year. The tariff after the achievement of benchmarked CUF consists of variable cost and an incentive component. It does not include the fixed cost component.

Given the high CUF in case of biomass based power plants in the state of Maharashtra, these projects are subject to scheduling. With these plants being subject to the scheduling, they are also entitled for 'deemed generation' benefit i.e. recovery of fixed charge up to the benchmarked CUF of 80%.

Municipal Solid Waste (MSW)

The municipal solid waste based power plants are relatively new and still in development and demonstration stage in India. The APERC has considered tariffs for such power plants with MNES guidelines as basis. In case of MERC, the issue has been dealt with at the conceptual level looking at various regulatory provisions. In view of MERC, the MSW plants have local benefits in terms of waste treatment and thus development of such plants is in the interest of local bodies. Further, MERC treats them as captive plants for the sole use of local bodies and has thus provided guidelines for the tariff determination allowing development of these projects through private developers. Though the local bodies do not have the right for open access, MERC has made an exception of allowing open access for local bodies.

Issue of Merit order dispatch and firm power

The renewable energy based power plants are generally of smaller capacities compared with the conventional thermal or hydro plants. The tariffs are based on cost plus method and the tariffs estimated are generally higher than the conventional power generation plants. Further, these plants, except the biomass based plants, are dependent on resource which is variable in nature e.g. wind or small hydro. The review of the tariff orders for different renewable energy technologies in different states indicates that the merit order dispatch principals are not applied to renewable energy based power plants because of a) variable resource dependency and/or b) small size and large number of individual plants. In other words the energy generated by the renewable energy projects should be purchased by the licensees at the rates fixed by the respective commissions.

SECTION 5

Analysis of Pricing options and Pricing of Non-firm power

The broad principles of pricing power from non-conventional energy sources has been discussed in Section 2, in the section on Approaches for tariff determination. The selection of a pricing methodology depends on number of factors like the demand supply gap, the importance given to issues like the environmental benefits, energy diversity as well as overall objective of promotion of renewables, long term strategy of development of renewable energy technologies. As mentioned earlier, many of the states in India do have peak as well as energy shortages for instance, up to 21% energy shortage in case of Maharashtra during April-May 06. At national level, the average energy shortage was about 10.7% during April -May 06 (5). The selection of pricing methodology needs to take into account all these factors. Further the provisions of the EA 03 and the national tariff policy provides guidance for pricing of power from non-conventional energy sources. This section discusses the applicability of different pricing options in the context of the above-mentioned issues.

Marginal cost/ avoided cost

The long run marginal cost (LRMC) takes into account the impact of power from renewable energy on the power replaced in short run as well as the impact over the investments in the long run. A detailed exercise at the state level needs to be undertaken to arrive at LRMC which requires detailed data for load projections and capacity addition details. Further the state level energy and power shortages indicate that the inclusion of small size renewable energy plants would not have an impact on capacity addition plans as they are lagging behind and the demand supply gap is projected to remain or increase. Thus the analysis of impact of power generation from renewable sources, with smaller capacities, would not make any impact in terms of capacity additions planned.

Similarly in case of short run marginal cost (SRMC) and avoided cost, the present costs would make the renewable energy based power projects unviable. The actual analysis of the short run marginal cost is difficult given the peak and energy shortages across almost all the states. There are approximations of avoided cost method, which is being followed in Sri Lanka (details given in annex 3). In this method instead of actual estimation of avoided cost, an approximation is made to estimate the avoided cost based on the time for which a particular power plant is operating in the margin. The avoided cost is then the weighted average of variable costs of all plants operating in margin with the time for which they are operational in the margin used as ‘weighting factor’. An analysis carried out in the case of Andhra Pradesh, one of the states where the actual energy shortage is relatively less (4.5% during April – May 06), shows that the ‘approximate avoided cost’ in case of Andhra Pradesh is Rs 2.21/kWh for FY 2005-06. The details of the avoided cost estimation in Andhra Pradesh are given in annex 4.

In this method, the sixteen thermal power plants that are presently operational in the state of Andhra Pradesh have been analyzed. The variable cost of these thermal power plants and the annual generation from each of the thermal plants for the FY 2005-06 has been obtained from APTRANSCO. Based on the annual generation and the installed capacity of each of the thermal power plants, the annual plant load factor of each thermal power plant is estimated. The time for which a particular plant operates at the margin is then estimated by stacking the power plants with increasing order of variable costs. The avoided cost in the state during FY 2005-06 is then estimated as the weighted average of avoided variable costs of the thermal power plants. The details of the avoided cost estimation in Andhra Pradesh are given in annex 4.

An alternative mechanism of pricing power in an electricity market is the concept of System Marginal Procurement Price that was used in UK during the operation of the Electricity Pool in early 1990[1]. In the British electricity market, licensed generators (Declared Net Capacity (DNC) greater than 50 MW) were obliged to become members of the Electricity Pool, and they could sell all, or part, of their generated power into the Pool. These large generators were usually connected directly to the national grid.

Large centrally-dispatched generators (export over 100MW) wishing to sell to the Pool submit bid prices on a half hourly basis and receive the Pool Purchase Price (PPP) (units p/kWh) for their power. Smaller generators who were part of the Pool (50-100MW), but were not centrally dispatched, could operate at any time and receive PPP for their generated output. They could not receive additional payments above the PPP, unlike centrally-dispatched generators.

All generators who were Pool members bid a price for their electricity at half hourly intervals each day. This bid price (units p/kWh) would include the costs of generation and profit. The Pool managers would rank the bids in order of price, with the cheapest first, and buy electricity from the lower priced generators which are required to meet demand. The price bid by the final (and most expensive) generator which was needed to meet demand is the called the System Marginal Price (SMP) (units p/kWh) and PPP is a function of SMP.[2]

In India, an ancillary pool market in the form of the Unscheduled Interchange (UI) mechanism exists. However, this is in complementary with the bilateral contracts that

[1] The detailed explanation of the Operation of the Electricity Pool in UK is explained in Annex 1

[2] PPP = SMP + Capacity

exist between the generator and the distributor. In such a scenario, in addition to the SRMC, a comparative assessment can be done between the total power procurement (fixed and variable) cost of the most expensive power plant and the renewable energy generator. For instance, an analysis carried out in the state of Andhra Pradesh, shows that the 'approximate marginal cost of power purchase' in case of Andhra Pradesh in 2006-07 is Rs. 3.32/ kWh, which is the total power procurement cost of the most expensive power plant. The details of the total power procurement costs of all the generating stations in Andhra Pradesh is given at Annex 5.

Cost based tariff

The cost based tariffs are being provided in many countries as 'preferential' or 'green' tariffs for power generation from renewable energy sources. This method guarantees a fair return on investment for the investor after recovering all the costs. Thus the tariffs are technology specific, and for a large number of small renewable energy based plants, cost and performance benchmarks are used for estimation of tariffs. The advantages of the cost based tariff methodology is that it takes in to account the technology specific issues such as capacity factor and technology cost etc. which are required for any new technology to develop and subsequently compete with other technologies. Further the tariffs can be set for a longer period, giving a signal for security to the investors. In India, as explained earlier, all the tariffs estimated by different SERCs for various renewable energy sources are cost based tariffs. The tariffs as per the cost based methodology can be designed to suit the requirement of the technology as well as taking into account the sensitivity to specific issues related to technology and geographic locations. The tariffs estimated for different renewable energy technologies such as wind, biomass, bagasse and small hydro based power projects by different SERCs clearly shows the variations in tariffs as a result of variations in technology and state specific parameters. Table 8 gives a comparative chart of the renewable energy technology specific tariffs announced by different SERCs.

Table 8: Comparative renewable energy tariffs set by different SERCs

S. No.	States	Wind	Small hydropower	Bagasse based cogeneration	Biomass
1	Andhra Pradesh	Rs. 3.37 /kWh with 5% simple escalation	Rs 2.60/unit for the first year, which reduces by Rs.0.08/unit every year till the 10th year.	Fixed cost Rs.1.72/unit in 1st year reducing to Rs.0.90 in 10th year+ variable cost Rs.1.02 in 2005-05 escalating to Rs.1.24 in 2008-09	Fixed cost Rs. 1.61/ kWh in 1st year decreasing to Rs.0.87 in 10th year. The variable cost for 2004-05 Rs.1.27 escalating to Rs.1.54 in 2008-09
2	Maharashtra	Rs 3.50/kWh with annual increase of Rs. 0.15/kWh	Rs 2.84/Unit in the first year, which increases by Rs.0.03/unit every year till the10th year. Fixed tariff of Rs 3.11/unit from 10th to 15th year. annually	Rs 3.05/ kWh with 2% escalation	Rs. 3.04/ kWh in first year escalating to 3.34 in 10th year.

S. No.	States	Wind	Small hydropower	Bagasse based cogeneration	Biomass
			escalation at Re 0.03/unit subsequently		
3	Madhya Pradesh	First year Rs.3.97/ kWh drops till Rs.2.43/ kWh in 11th year and gradual increase to Rs.2.60/ kWh in 20th year	-	-	-
4	Karnataka	Rs.3.95/ kWh with annual decrease of Rs 0.13/kWh	Rs. 2.80/ unit for the first year with no escalation	Rs. 2.87/ kWh in 1st year with escalation reaching 3.06 in 10th year	Rs. 2.93/ kWh in first year escalating to 3.10 in 10th year
5	Tamil Nadu	Rs2.75 /kWh (old plant) Rs 2.90/kWh (New plants)	-	Rs 3.15 /kWh	Rs 3.15 / kWh
6	Uttar Pradesh		Rs 3.39/Unit	Tariff (fixed cost, non escalating and escalating component, and variable cost depend on year of commissioning) i.e. different tariffs for plants commissioned in different financial years	-
8	Himachal Pradesh	-	Rs.2.50/kWh with the base year 2001. The tariff shall be indexed at 50% of the annual inflation rate of the consumer Price Index.	-	-

A key disadvantage of this method of tariff calculation is that the tariffs are heavily dependent on cost and performance parameters as input data, which might be difficult to obtain or verify. The cost related data is specifically very difficult to verify. Further the cost based tariffs, need to be adjusted for technological improvements resulting in cost reduction and/or efficiency improvement. The cost based tariff help the new technologies to establish and it is expected that through such preferential tariffs, the costs would come down due to technological improvements, economies of scale etc. However there is no direct incentive to reduce costs or improve efficiency. This is also of critical importance since the states also have to fulfill the renewable energy quota obligation. Thus with a protected market and preferential tariffs, the expected cost reductions may not occur on its own. The National Tariff Policy, while recognizing the need for preferential tariffs, stresses that in the long term the non-conventional technologies should compete with other technologies. The regulatory pressure for the cost reduction and bringing about competitiveness is essential in case of cost based tariff methodology is adopted.

Pricing of Non firm power

Definition and concept

The national tariff policy indicates that the issue of non-firm power especially from non-conventional sources needs to be addressed in the context of pricing. The definitions of ‘non firm power’ and firm power available from common literature, as given below, are generic.

1.a) Non-Firm Power: Power or power producing capacity supplied or available under a commitment having limited or no assured availability.

1.b) Non-Firm Power - Electric power which is supplied by the power producer at the producer's option, where no firm guarantee is provided, and the power can be interrupted by the power producer at any time.

2. Firm Power - Power available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Purchase Agreement from the Customer's facilities with an expected or demonstrated reliability which is greater than or equal to the average reliability of the Company's firm power sources.

These definitions basically indicate that the power generation, which cannot be guaranteed at any particular time, is non-firm power. In case of renewable energy sources such as wind and small hydro the power generation is dependent on resource availability, which is variable in nature, and hence the generation cannot be guaranteed. Thus these could be categorized under non-firm power. The power generation from other renewable energy sources like biomass, bagasse and waste is not variable in nature. For such plants the fuel availability and the power generation can be predicted and thus can be considered as capable of supplying firm power. However there is another issue of the possibility of scheduling such power plants. The individual capacity of biomass, bagasse and waste to energy plants, typically in the range of 5-20MW, is comparatively much smaller than the conventional thermal or hydro power plants. Further there could be large number of such small capacity plants, which due to practical considerations cannot be brought under scheduling. As per the present practice, except the biomass power plants in Maharashtra, the load dispatch centres do not schedule such plants. Thus going by the strict definition, only wind and small hydro plants supply non-firm power. However in the context of planning and scheduling, all the renewable energy plants supply non-firm power. Hence, there are two options to deal with this issue, which is related to pricing of non-firm power.

Option I: treat the wind and small hydro as *non-firm power* and treat biomass, bagasse based cogeneration and waste to energy plants as *firm power*. In this scenario, such power plants would be subject to scheduling and the general pricing principles like any thermal power plant of fixed cost and variable cost can be applied. This would require establishing communication infrastructure with all the power plants and scheduling the generation from such large number of small plants.

Option II: treat power from all renewable energy technologies such as, wind, small hydro, bagasse, biomass and waste to energy, non-conventional energy based power plants as *non-firm power.*

Examining the practical considerations mentioned above it may be argued that *option II* of treating power from all the non conventional energy based power plants as non firm power seems practical. Thus for the present discussion all the non-conventional energy power plants are considered to be supplying non-firm power.

Pricing options for non-firm power

The options for pricing of power from renewable energy discussed above do not consider the availability or dispatchability of such power plants. The utilities while scheduling the power generation are guided by 'supply the cheapest power' principle, however the non-conventional power plants are kept out of the purview of 'merit order dispatch principles'.

There are limited options of treating the non-firm power with higher cost like power from non-conventional energy sources. These options and the applicability is discussed below,

A. Short run marginal costing / avoided cost

The assumption here is that since the power supplied is non-firm, it would only affect the short term marginal cost which take in to consideration the variable cost component. Another similar approach is cost determined based on avoided cost i.e. cost of power from non-conventional source is equal to the power being replaced it. Estimation of the SRMC would need detailed operating data regarding load generation costs of different generation options. The actual avoided cost would need identification of which power plants are being displaced as a result of generation from non-conventional energy sources and would again require detailed exercise involving detailed demand and generation projections. The tariffs thus estimated, as seen in the case of Andhra Pradesh with approximate avoided cost, would not provide enough revenues to make the power generation for renewable energy technologies economically viable. The National Tariff Policy guidelines on the non-firm power indicates that the pricing should be such the generation for renewable energy technologies becomes economically viable but at the same time should not put excess burden on consumers and result in excessive profits for power generators. *In this context the short run marginal costs may not be an appropriate option in the present context*.

B. UI mechanism formulated under ABT

Another approach for pricing non –firm power from non-conventional sources could be based on the UI charges under the Availability Based Tariff (ABT) mechanism. Under the ABT, the tariff is divided into three parts

1. Capacity charge
2. Energy charge and
3. Unscheduled interchange (UI) charge

The first two components are well known in the power tariff, however the third component is new and linked with the deviations from schedule (of drawal or generation). The UI charge becomes applicable in case of any deviation from the scheduled generation or drawal of power. All the regional grids have adopted the ABT mechanism however it may be noted that this is applicable to central sector power plants and the state utilities only. The UI charge is linked with the frequency of the grid. The frequency of the grid is used as an indicator of system loading and hence the requirement of generation/ backing down etc. The presently applicable UI charges as per the CERC regulations are given in table 9.

Table 9: Frequency linked UI rates announced by CERC and applicable from October 2004 onwards

Average frequency of time block (Hz)		UI Rate (Paisa per kWh)
Below	Not below	
----	50.50	0.0
50.50	50.48	6.0
50.48	50.46	12.0
-----	-----	-----
-----	-----	-----
49.84	49.82	204.0
49.82	49.80	210.0
49.80	49.78	219.0
49.78	49.76	228.0
-----	-----	-----
----	-----	-----
49.04	49.02	561.0
49.02	-----	570.0

(Each 0.02 Hz step is equivalent to 6.0 paisa/kWh in the 50.5-49.8 Hz frequency range, and to 9.0 paisa/kWh in the 49.8-49.0 Hz frequency range.)

UI rates are worked out for each 15-minute time block. Charges for all UI transactions are to be based on average frequency of the time block.

As the UI charge at any instance indicates the requirement of power in the grid it can be used to price the non-firm power from any source including non-conventional energy sources. The assumption here is that all the power supplied by the non-conventional energy based power plants is non-firm (and not scheduled) it can be treated as an unscheduled generation and out of the three components of tariff mentioned above only the UI charge becomes applicable.

The ABT mechanism has been introduced to improve the grid discipline and reduce the deviation in the frequency. Further, the UI charges can be used as an approximation of short run marginal cost and thus technically this could be the best available option for treating the purchase from any non-firm power. Applicability of the UI charges for purchasing power from non-conventional energy sources, however needs to be critically analyzed. There are essentially two aspects of application of UI charges to non-conventional energy as discussed below

1. *Impact on viability*

As mentioned above, at present the UI mechanism is applicable for the large sized central sector power plants (from generation side) and all the three components of tariff are applicable. The UI charge is applicable only to the deviation from scheduled generation. These two factors put together forms a small component of total tariff and thus would have a limited impact on the overall revenue from sale of power in case of large capacity conventional power plants. In case of power plants based on non-conventional sources the complete generation is treated as unscheduled and only the UI charge becomes applicable. There is large variation and unpredictability of the frequency in the grid. Table 10 depicts the weighted average monthly UI rate based on frequency variations in the northern region. As it can be seen from table 10, even with monthly averaging, there is considerable variation in the UI charges.

Table 10: Monthly Average UI rate for FY 2005-06

Months	**Average UI Rates (Rs./ kWh)**
April 05	2.57
May 05	2.82
June 05	3.12
July 05	3.09
August 05	4.12
September 05	3.45
October 05	3.47
November 05	3.57
December 05	3.93
January 06	3.68
February 06	3.38
March 06	2.75

This unpredictable UI charge combined with the unpredictable generation from a renewable energy plant, mainly in case of wind and small hydro, would result in highly unpredictable revenues. And with such unpredictable revenues the financing and planning of such projects would be extremely difficult. Further, the average rate as shown in the analysis of northern grid, may not be economical for some of the renewable energy technologies. In addition, with better grid discipline the UI rate and hence the revenues for the power plant, would further reduce.

2. *Impact on grid*

As it has been mentioned earlier, the ABT and UI mechanism was implemented in order to bring in grid discipline. The backing down or increase in generation of higher capacity plants in response to the frequency linked UI rates would have positive impact on grid frequency. However the same impact cannot be expected to occur with small sized non- conventional energy based power plants.

C. Renewable energy certificates (REC)

RECs are a market-based instrument to promote renewable energy and facilitate renewable energy portfolio obligations. Some of the other common names that represent RECs are, 'Green Tags', 'Tradable Renewable Certificates', 'Tradable Renewable Energy Credits' (mainly in USA), 'Renewable Obligation Certificate' (in UK), 'Tradable Green Certificates', 'Green Electricity Certificates' and 'Green Credits' (mainly in Europe).

A REC is the aggregation of non-energy and societal beneficial attributes (e.g. environmental and socio-economical benefits) of a quantifiable unit of renewable energy power production – usually a MWh, represented as a tradable product. Tradable RECs are used to represent the renewable energy element of electricity generation. By separating the environmental attributes of renewable energy generation from the physical unit of electricity, RECs allow the green power attributes to be sold or traded separately from the physical unit of energy.

Essentially, a renewable energy generator produces two products: a MWh of electricity for sale and a renewable energy certificate demonstrating that a MWh of renewable energy power has been produced and delivered into the grid. REC is basically a document through which it is claimed that a unit of electricity has been produced from a renewable energy source. Generators receive a certificate for each predefined unit of electricity produced from their renewable energy scheme. If RECs are allowed to meet Renewable Purchase Obligation (RPO), renewable energy generators will be able to earn revenue not only from selling the power but also from selling the additional certificates.

Through such a system, a utility needing to demonstrate compliance with an RPO needs to own a certain number of certificates. For example, if the RPO sets the utility's renewable energy obligation at 1,000 MWhs it would need to own 1,000 one-MWh certificates. The trades can either be bi-lateral (between the buyer and seller) or they can be facilitated through a central trading market.

Property rights

The ownership of tradable renewable energy credits belongs to the qualified generator of the underlying kWh until the credits are transferred to another party. The certificates are awarded by an independent, administrative entity/agency which also tracks the credit certificates from the generator to the distributor. However, in some countries, the Government is also responsible for certifying credits, monitoring compliance and imposing penalties if necessary.

Price of tradable credits

Under the REC mechanism, the renewable energy generator can sell the electricity at a predetermined pool price (or average cost of power purchase for the utility). In addition to the purchase of electricity, the utility would also have to buy the certified renewable energy credits in order to meet their RPO.

Possible Indian Scenario

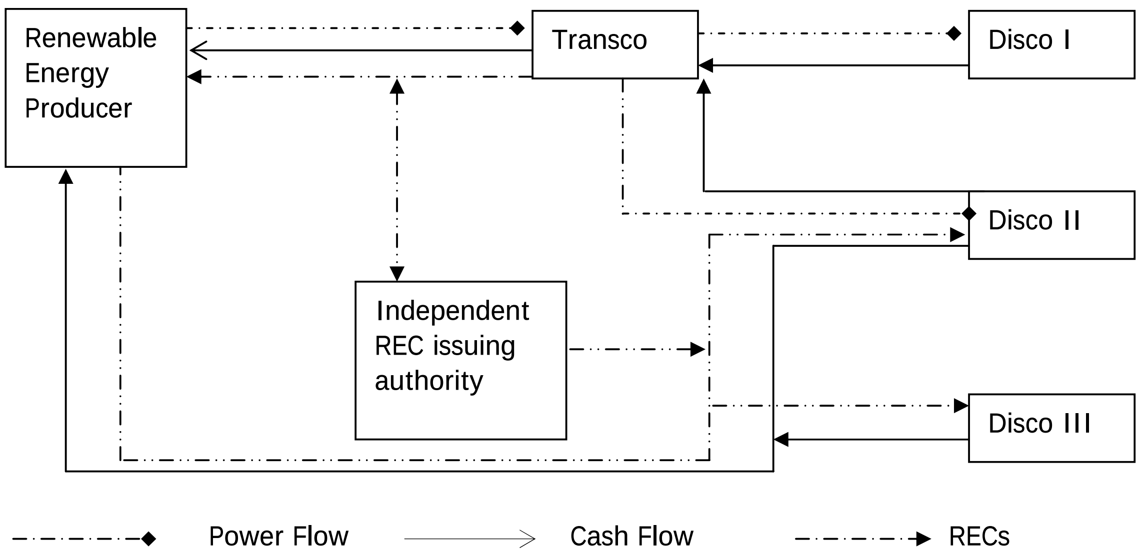

Fig. 1. Transaction of energy and green power attributes

In figure 1, the renewable energy producer can sell the energy and REC to different suppliers. The producer of renewable energy sells energy and REC to Discoms separately depending upon the arrangement between the Discom and the renewable energy producer. The renewable energy producer gets paid for the energy, at mutually agreed rate e.g. average of variable cost of all sources, from the Discom to which it is selling energy. While as the RECs can be sold to another Discom. The rate at which RECs are traded would be decided by the market forces. This arrangement would offer the distribution licensee the option to buy energy from any supplier and still meet its RPO by purchasing RECs. This might happen when a distribution licensee may have to meet its RPO but the state does not have any renewable energy plant. The trading of RECs will allow those states that do not have renewable energy generators to buy certificates from a renewable generator outside its state to meet its respective RPO.

Salient features of the REC trading system

A REC trading system has several characteristics:

1. It provides additional financing for renewable energy generators because they can earn money by selling RECs in addition to energy.

2. It facilitates the development of a regional renewable energy market to meet RPO requirements.
3. It reduces the cost of the RPO by providing easy access to a geographically diverse array of generating resources.
4. It makes it possible for states in which there are no renewable energy producers to nonetheless have an RPO in place that utilities can meet by acquiring RECs from outside the state.
5. The REC tracking system provides assurance and verification that a REC actually represents real renewable generation; it prevents fraud and promotes confidence in the renewable energy market.
6. Certain specific features/requirements for implementing RECs in the Indian scenario are-
    a. The legislation/quota obligation is already in place, which is a basic requirement for implementing RECs
    b. There is need to put in place a body for registration and tracking of RECs
    c. Need to examine the requirement of a uniformly high quota across all states
    d. Need to gradually replace the present tariff system

Tradable RECs have been used extensively as a successful market based policy instrument to promote renewables in Australia, Japan, US (Texas, Arizona, Winsconsin, Nevada), Netherlands, Denmark and UK.

Summary

From the analysis above it is clear that the two major pricing approaches are marginal cost and cost based approach. The applicability of avoided cost or the marginal cost methodology is based on the assumption that the demand supply gap is very small and expected to remain low and thus any new power coming in 'replaces' power generation from existing sources in short term and alters capacity addition plans in long term. The marginal cost methodology then gives the appropriate economic signals and allocates resources in an efficient manner. In case of India, currently, all states are facing demand supply gap, with energy and power shortages. It was projected that a new capacity addition of about 100000MW would be needed till 2012 (6). As per CEA projections using the energy demand forecasts of 16th EPS shows that there would be peak deficit of about 16% and energy deficit of about 13%, this deficit is with an assumption that about 32000 MW capacity added as per the 10th plan. The revised 10th plan target is capacity addition of 36955 MW however the actual capacity additions are about 15000 MW (thermal and hydro) till March 2006 (7). These deficit projections are uniform across almost all the states except very few states like Goa, Himachal Pradesh, Uttaranchal, etc. Thus the applicability of the marginal cost approach is questionable. Further, the marginal cost analysis would need frequent estimation of tariffs depending upon the new capacity additions, changes in demand and generation from other plants. In case of relating the cost of renewable power with highest total power procurement cost, the costs would change from state to state depending upon the demand and supply scenario.

The overall approach in India through the EA 03 and the National Tariff Policy indicates the competitiveness through the quota and competitive bidding. The use of marginal cost methodology would make the renewable technologies compete with the conventional power technologies. The EA 03 by specifically making a provision of quota from renewable energy technology (Section 86 (1) (e)) acknowledges the emerging nature of renewable energy technologies and the need to develop them before competing with other conventional power technologies. The national tariff policy also clearly recognizes this fact and recommends a ‘preferential tariff’ for renewable energy technologies.

The cost based approach can be used in short term irrespective of the non-firm nature of power generated from renewable sources. Further, the Commission may allow developers to avail of tariffs based on the UI mechanism (as discussed earlier), as an alternative option to cost-based tariffs. However, even within short term, efforts must be made to reflect the true costs and technology trends, as adoption of cost based approach would not directly result in cost reductions. In long term, however the approach would be to increase competitiveness and reduce costs. The section on strategy for pricing of power from non-conventional energy sources provides the suggestions for cost based approach in short term and the long term strategy to make the power generation from renewable sources competitive.

SECTION 6

Strategy for pricing of power from non-conventional energy sources

A review of the provisions and guidance regarding treatment of power from non-conventional energy sources in the EA 03, the National Electricity Policy and the National Tariff Policy provides the long-term strategy in addition to the measures that are to be undertaken in the short term to promote power generation of non-conventional energy sources. In short term, as per the national electricity policy, there is need to promote generation of electricity from non-conventional energy sources. The national tariff policy also recognizes the present high costs and need for 'preferential tariffs'. Further the tariff policy also provides a long-term vision of reaching a stage where the non-conventional technologies compete with other sources of power generation. Thus the strategy that emerges is promotional measures in short term with cost reduction through competition within same technology. The possible medium term measures involve technology specific quotas without predetermined preferential tariffs to achieve the long term goal of renewables competing with other sources of power generation. This strategy with short term and medium terms measures that need to be undertaken is discussed in this section with an analysis of technology specific issues and its treatment in short term.

Short term

The analysis in the earlier sections regarding pricing options for power from non conventional energy sources shows that in the present scenario, the cost based 'preferential tariff' methodology may be adopted. Thus in short term the power generation through non conventional energy sources is to be promoted with 'preferential tariffs' and quota for purchase of power from RETs.

Cost based tariffs

As the number of renewable resource-based projects is higher with small individual plant capacity, estimation of cost based tariffs for each project is practically difficult. Thus, a benchmarked parameter of cost and performance is to be used for arriving at a technology specific tariff, which would be applicable to all projects using some renewable energy resources. As a result, in case of cost based tariffs for renewable energy technologies, a proper benchmarking exercise becomes very critical. The possible approaches for benchmarking the cost and performance parameters are discussed below.

Financial parameters

Capital cost

The capital cost is the most important parameter in case of cost based tariffs, especially for technologies with low capacity utilization factors like wind. In case of wind and small hydro the capital cost is also dependent on the site conditions and vary in a large range. The international costs would also be of limited help since most of technologies are now indigenous, especially the biomass, bagasse and small hydro, with very limited component of imports. In case of technologies like biomass, cogeneration, the data supplied by the manufacturers and other stakeholders can be used for tariff determination, in short term.

The objective of providing the cost based tariff is cost reduction in long term. Thus the subsequent revisions of tariff orders for the same technology should consider the cost reductions in real term compared with the capital costs considered in the earlier tariff estimations for the same technology in the same state.

Other Financial parameters

Return on Equity

The RoE can be considered as per the standard norm of CERC -14% pre tax. However the states may consider providing a higher RoE in order to promote the power generation from renewable energy sources, especially in states where the penetration of renewable power is low and/or having high potential for power generation from renewable energy sources. It may also be noted that most of the states have considered 16% RoE while tariff setting for renewable energy based power generation.

Depreciation

For the purpose of tariff, depreciation will be computed in the following manner, namely:

(i) The value base for the purpose of depreciation shall be the historical cost of the asset;

(ii) Depreciation will be calculated annually, based on straight line method over the useful life of the asset and at the rates prescribed by the appropriate Commission.

The residual life of the asset will be considered as 10% and depreciation shall be allowed up to maximum of 90% of the historical capital cost of the asset. Land is not a depreciable asset and its cost will be excluded from the capital cost while computing 90% of the historical cost of the asset. The historical capital cost of the asset will include additional capitalisation on account of Foreign Exchange Rate Variation up to 31.3.2004 already allowed by the Central Government /Commission.

(iii) On repayment of entire loan, the remaining depreciable value will be spread over the balance useful life of the asset.

(iv) Depreciation will be chargeable from the first year of operation. In case of operation of the asset for part of the year, depreciation shall be charged on pro rata basis.

(v) For estimation of depreciation, life of the plant can be assumed as 20 years

Accelerated Depreciation: The fiscal incentive of accelerated depreciation is available for wind power projects and certain equipments in case of biomass/bagasse projects. Though the duration over which the accelerated depreciation benefits are availed varies from project to project, this need to be considered for tariff estimation. The tariff estimation can include the tax saving component as a result of accelerated depreciation as an inflow to the project distributed over 2-5 years.

Technology specific issues for short term cost based tariffs

Wind power

The analysis of pricing options of non firm power indicates that, in the short term the wind power generation will receive the full tariff irrespective of its non-firm nature. The wind power producer will dispatch all the power that is generated at any time.

Capital cost

The capital cost is the most critical cost parameter in case of wind power. The authentic and accurate data about details / breakup of the capital costs in India are not available to arrive at a benchmark even at a state level. In case of wind power the Indian capital costs considered by various commissions are lower than the international costs. The international costs would also be of limited help since most of components are now manufactured in India with very limited component of imports. A World Bank study that was conducted in November 2005 (8), shows capital costs of wind power in the range of 1200 $/kW to 1400 $/kW which is equivalent to Rs. 5.4 to 6.3 Cr/MW. Though these costs are in 2004 US$ terms, still the Indian costs used by various commissions are lower than this. The capital costs considered by various state regulatory commissions are in the range of Rs. 4- 5Cr/MW.These costs were based on submission of various stakeholders like the manufacturer's association, Indian Renewable Energy Development Agency (IREDA) etc. For instance in case of Karnataka, based on the costs that were suggested by Karnataka Power Transmission Corporation Limited (KPTCL), Karnataka Renewable Energy Development Agency Limited (KREDL), Indian Wind Energy Association (InWEA) and Indian Wind Power Association (IWPA), the Commission took a view that it is reasonable to adopt a project cost of Rs.4.25 Cr/MW for wind power projects. In case of Maharashtra, the MERC expressed the lack of availability of accurate and authentic cost data and indicated in the tariff order that *'… However, no detailed project report as required by the Commission and other stakeholders were provided. Thus the commission was constrained to proceed without adequate data and financial information'*.

The investment size in case of wind power is increasing and the investments are being made on the basis of competitive bidding. For instance, HPCL has invited bids for installation of 25MW wind power project in Maharashtra / Karnataka. The regulators / utilities can request the investors to furnish the capital cost data. The cost data collected then can be used to decide the cost benchmarks that will be used in the subsequent tariff determination exercise. Now with more than 5000MW capacity installed of wind power, out of which about 1900 MW being added in 2005-06 the latest cost data must be used for cost benchmarking.

Thus the capital cost for wind power project, being site specific, varies in a broad range, as seen in the costs considered by different state commissions. Thus for estimation of tariffs a broad range may considered from Rs 4.00 Cr/MW to 5.00 Cr/MW. Though these costs are no way indicators of the actual cost of wind projects but are based on the information supplied by the manufacturers to various state regulatory commissions during the detailed tariff determination exercises in various states as indicated in table 4 in section 4.

Operation and maintenance costs

The O&M of wind power plants is being undertaken by the turbine manufacturers on Annual Maintenance contract (AMC) basis. These costs can be used for estimation of O&M costs. *In addition with concept of large size "wind farms", where centralized monitoring, control and maintenance is undertaken for the large size wind farm, the operation and maintenance costs are reduced*. The O&M costs, and the justification for the same in the tariff setting process in different states, and the present cost of AMCs indicates that O&M costs can be assumed to be 2% of the capital cost.

Capacity utilization factor

The capacity utilization factor (CUF) to be considered for the tariff estimation is dependent on location i.e. the wind resource and the wind turbine characteristics. The CUF of existing wind power plants have been used to arrive at the benchmark CUF by the various state electricity regulatory commissions to determine tariff for wind power projects.

Another option to arrive at the benchmark CUF, which includes the latest technological trends, is to use the wind resource data along with the power curve of wind turbines offered by different manufacturers. The wind resource data is published by the Centre for Wind Energy Technology (C-WET) for various potential sites in different states. The wind data and the turbine power curve can be used to arrive at CUF that can be achieved at potential sites in the state. Average CUF of all the sites in the state can be used for tariff estimation rather than using the CUF of existing wind plants, which does not capture latest technological trends.

Since the CUF of a wind power project depends completely on the site specific wind resource, it would be impossible to provide a single benchmark CUF for all the states. As the wind resource availability across different states is different, the average CUFs vary in the range of 20% to 30% across states. However, a minimum CUF can be established in order to tap only the economically viable wind sites. Based on the CUFs considered by various state commissions, a lower limit of 20% is suggested, i.e. the CUF considered in any state should not be lower than 20%.

Another alternative for fixing tariff based on benchmarked CUF is to provide only an incentive for generation over and above the benchmarked CUF. Presently, all the generation from a wind power plant receives the full tariff. In order to reduce burden on the utilities, an option of providing only an incentive for power generation over and above the benchmarked CUF can be considered. In such a scenario, the full tariff would be applicable till the generation reaches the benchmarked CUF. The additional generation, over and above the benchmarked CUF will receive an incentive instead of the full tariff.

The incentive can be decided depending upon the power situation in the state. One option is to provide an incentive equivalent to the lowest variable cost from conventional power option available in the state.

Small hydro

Capital cost

The capital costs of small hydro projects vary from project to project and region to region. The Alternative Hydro Energy Centre (AHEC), Roorkee, has carried out a sample survey of small hydro projects from different parts of the country (9). Based on the study, it was noticed that the capital cost of the small hydro projects differ from hilly to non hilly regions. Twelve states were covered under the study, out of which, Andhra Pradesh, Karnataka, Orissa, Punjab, Kerala, Madhya Pradesh, Maharashtra were considered as non hilly regions and Jammu and Kashmir, Uttaranchal, Himachal Pradesh, Arunachal Pradesh and Sikkim were considered as hilly regions. An analysis of the data taking into consideration, only the small hydro sites which were commissioned after the year 2000, shows that the capital costs for small hydro projects in “hilly areas”, fall in the range between Rs 5Cr/MW - Rs 6 Cr/MW whereas for “non-hilly regions”, the costs fell in the range between Rs 4Cr/MW - Rs 5 Cr/MW.

O&M costs

It is a known fact that the operation and maintenance expenses are higher in small hydro projects than in large hydro. This details out to the regular maintenance expenses, employees cost, repair and maintenance costs, interest on working capital and taxes. All these are high in case of small hydro projects. Small hydro projects need more number of manual labor and also it is subjected to harsh weather conditions. The electro mechanical equipment suffer major faults due to flash floods, debris etc. Referring to CERC guidelines for large hydropower generating stations, the operation and maintenance expenses is to be fixed at 1.5% of the capital cost and is to be escalated at the rate of 4% per annum from the subsequent year. Therefore, 2.5% of capital cost as O&M cost may be considered for SHP projects.

CUF

The small hydro plants are either run of the river or canal based. In case of run of the river small hydro projects, the CUF is dependent on location as well as hydrology. The CUF can be assumed based on the past performance of the run of the river small hydro plants. In case of canal based plants the CUF can be higher.

One option is to use two different CUFs for run of the river and canal based small hydro plants. Another less complicated, option is to use single benchmarked CUF, equivalent to average CUF of existing run of the river plants, for tariff estimation for both run of the river and canal based small hydro plants. With more experience of developing small hydro projects, a long term data for CUF should be used to arrive at benchmarked CUF as there are annual variations in the CUF.

Though, it is not possible to suggest a single CUF for small hydro projects in different states, a minimum CUF, different for hilly and non-hilly states, can be established. Based on the CUF considered by various states, the suggested minimum CUF in case of “non-hilly” states is 30%, while in case of “hilly” state, 35% CUF is suggested. Thus, in tariff estimation in non-hilly areas the CUF should be more than 30%, and in case of hilly area, it should be more than 35%.

Incentives

In case of using single CUF for both types of small hydro plants, only an incentive for power generation over and above the benchmarked CUF needs to be provided. In this a scenario, the full tariff would be applicable for power generation till the benchmarked CUF. The additional generation, over and above the benchmarked CUF will receive an incentive instead of the full tariff.

The incentive can be decided depending upon the power situation in the state. As mentioned above, providing an incentive equivalent to the lowest variable cost from conventional power in the state can be considered.

Non firm power issue

The power from small hydro plants is non firm in nature. The variations in generation are seasonal in nature in case of small hydro plants. This fact along with the analysis of non firm power pricing options indicate that the pricing of small hydro power be as per the cost based approach with the power producer eligible to dispatch all the power generated.

Biomass

Capital cost

The analysis of the tariff estimation by different states for biomass power along with the analysis of the submissions by the various stakeholders, about the capital cost of a biomass power plant, indicates a uniform cost, Rs 4.00 Cr/MW, across different states. Thus the capital cost of the biomass power plant can be considered as Rs 4.00 Cr/MW.

O&M costs

The O&M cost of biomass power plants is on the higher side compared with the thermal power plants because of small size of the plants as well as fuel handling related issues. The biomass power producers have reported, through the submissions to the regulatory commissions for tariff determination, the O&M costs in the range of 3-5% as shown in table 7 in section 4. Based on the analysis of the O&M costs considered by the state regulatory commissions, the O&M cost can be taken as 4% of the capital cost of the biomass power plant.

CUF

The biomass power plants can operate at higher CUF in the range 75%-85%, like any other thermal power plant. Further, like the conventional power plants the tariff can be a two part tariff – fixed cost and variable cost. The Fixed part can be estimated with higher CUF as mentioned above.

Incentives

In order to provide incentive for optimum utilization of the capacity, the energy generation over and above the benchmarked CUF can be provided an incentive in addition to the variable cost.

The incentive can be decided depending upon the power situation in the state. The incentive can be equivalent to the lowest variable cost from conventional power option available in the state.

Fuel cost

The fuel i.e. biomass is normally purchased from the open market with varying costs. One option for deciding the fuel cost is to link it to market price of biomass and revise the variable cost component of the tariff more frequently, i.e. within three years, to incorporate the fuel cost variations. Another approach is to link the fuel cost with the equivalent coal costs.

The approach of linking the fuel cost with equivalent coal cost can be followed in states where there is limited experience of biomass power generation and hence the fuel costs can be benchmarked. In states where the biomass power plants are operating for some time the actual fuel costs with periodic revisions of the variable cost is an advisable approach.

Station heat rate / specific fuel consumption

The station heat rate is an indicator for plant efficiency while as the specific fuel consumption is dependent on the calorific value of fuel i.e. dependent on the type of fuel. Thus it is suggested that the station heat rates should be used in tariff estimations along with the calorific value of main fuel or mix of fuels.

The CEA has used 3650 kCal/kWh as the station heat rate for small capacity thermal power plants of the capacity size 30MW with solid fuels like coal in the planning studies (8). Various state regulatory commissions have used the station heat rates in this range. Till heat rate for biomass power plants are established, the above station heat rate can be used.

Scheduling and dispatchability

The biomass power plants can supply firm power and can be scheduled. However, the installed capacities of individual biomass power plants are considerably lower than the conventional power plants and it may not be practical to bring these plans under scheduling. However, if a state decides to bring the biomass plants under scheduling, then these power plants become eligible for ‘deemed generation’ benefit.

Bagasse

Capital cost

The capital cost of bagasse cogeneration project depends on parameters like project type i.e. expansion in existing plant or new plant, type of technology etc. The analysis of the costs considered by different regulatory commissions for specific cogeneration projects indicate that the costs vary in a broad range depending upon the parameters mentioned above. Based on the costs in the DPRs and capital cost considered by different regulatory commissions a broad range of capital cost from Rs3.00 Cr/MW to 3.75 Cr/MW can be established.

O&M costs

The O&M cost of bagasse power plants is on the higher side compared with the thermal power plants because of small size of the plants. Analysis of the O&M costs and related discussions in the tariff setting exercises undertaken by different stases in establishing the tariff for bagasse power plants shows that the O&M cost are in the range of 3 – 4.5%. Thus O&M cost can be taken as 3% of capital cost of the bagasse power plant.

CUF

The tariff for bagasse plants can be two part tariff, as in the case of any thermal power plant. An estimation of CUF is required to arrive at the fixed cost component of the tariff. The CUF in case of bagasse cogeneration can be estimated depending on the duration of crushing season of the sugar factories in the state and additional off season operation with stored/purchased bagasse.

A conservative estimate of off season operation can be made to arrive at the benchmarked CUF to be used in tariff estimation. The fixed part of the tariff can be estimated with higher CUF as mentioned above. The tariff for generation after the benchmarked CUF would be variable cost plus an incentive. This condition makes the assumption of benchmarked CUF less critical and a conservative estimate would safeguard the project returns.

Fuel cost

The bagasse is a by product in sugar industry. It also has alternate uses which are basically non fuel applications like in paper industry. The price that bagasse would otherwise get for other applications, can be considered as cost of bagasse in short term. Alternative approach is to link the fuel cost with the equivalent coal costs.

The approach of linking the fuel cost with equivalent coal cost can be followed in states where there is limited number of bagasse power plants. In states where number of bagasse power plants is operational for some time, the alternative cost that the bagasse would have otherwise obtained, can be used as fuel cost.

Loading of variable cost on power and steam generation

In case of cogeneration the fuel is used to generate steam and power. The steam is used in the industry for thermal applications while as surplus power is exported. The fuel cost thus needs to be loaded accordingly for estimation of tariffs

Scheduling and dispatchability

The bagasse power plants can supply firm power and can be scheduled. However, during the crushing season the power generation is dictated by the process requirements. Taking this into consideration, along with the fact that installed capacities of individual bagasse power plants are considerably lower than the conventional power plants indicates that it may not be practical to bring these plants under scheduling.

Municipal Solid Waste (MSW)

In case of MSW projects, there is very limited operational experience on commercial scale in India. There are only two MSW plants operational in India with total installed capacity of 12.6MW.

Though these MSW plants have very high potential and also have the additional benefit of treating the waste, these plants need to be promoted with attractive tariffs. However due to lack of operation data, the cost benchmarks can not be worked out and needs to be determined on a project to project basis till sufficient amount of data is generated.

Determination of Quota

The Electricity Act 2003 had mandated the SERCs to determine quota for purchase of power from renewables. The determination quota has been recommended in order to promote the power generation from renewable sources.

The state level quota should be based on

a) potential of different renewable energy sources;

b) the impact on consumers as result of higher tariff and quota;

c) already installed capacity based on different renewable energy sources in the state. The quota recommended should be higher than the present contribution from already operational projects in the state.

Another related issue is - should the quota be overall renewable energy quota as in RPO mechanism or technology specific as in case of RPS. In case of overall renewable energy quota, different renewable energy sources would compete with each other and only the most economical sources will get developed. In case of technology specific quota all the eligible technologies will get support. With the overall objective of energy security and diversity in supply, the development of all major renewable energy technologies is essential. The tariff policy also indicates competition within same technologies. Thus in the short term the quota can be technology specific to develop all the renewable energy technologies.

The distribution of renewable energy resources is uneven and hence some states, with very limited resource availability would face problem is determining the quota. The quota will be very less in such states or the distribution licensees in that state will have to purchase the power from renewable energy sources from other states. Such transactions would increase the cost of power as a result of transmission charges. The RECs if introduced can overcome this difficulty as a licensee can just buy the certificates to meet its obligation.

Annex 6 provides the details of the regulations on quota for power purchase from non conventional sources of energy by different states.

Long term strategy

The above analysis and suggestions are for the short term strategy of determining the cost based tariffs for different renewable energy technologies and the determination of technology specific quota. The subsequent revisions in the technology specific tariff orders must improve on the cost and performance benchmarks to the extent possible with latest available technologies.

In medium term, there should be technology specific renewable energy quota and the same technologies will compete with each other. The national tariff policy also recommends competitive bidding as far as possible within same technologies as a means to achieve the cost reductions. There will not be any predetermined tariffs, except in exceptional cases of new technologies, and the quota would create a market force which will determine the price of power from a particular technology. To facilitate this, a mechanism will have to be put in place for trading of power or RECs. The trading of RECs mechanism offers advantages such as overcoming the non firm power issue. Further, it offers a possibility of deciding meeting renewable energy quota obligation in states which do not have substantial renewable energy potential. It also helps to harness the cheapest renewable energy in different locations by separating the actual power generation and the trade of RECs. However, it may also be noted that for the REC mechanism or even the bidding route to succeed in promoting RETs while achieving the cost reductions, the quota determination is very critical. The quota has to be substantially higher than the energy generation from the present installed capacity, for this mechanism to succeed in absence of preferential tariffs. It is also desirable to have progressively increasing quota for renewables with a long term goal of reaching a certain amount of power generation from renewable energy technologies.

Box 3 discusses the procurement of renewable energy power by distribution licensees through competitive bidding in the future.

Box 3: Procurement of renewable energy power by distribution licensees through competitive bidding

Promotion of competition in the electricity industry in India is one of the key objectives of the Electricity Act 2003 (the Act), the National Electricity Policy and the Tariff Policy. Competitive procurement of electricity by the distribution licensees is expected to reduce the overall cost of procurement of power and facilitate development of power markets. Internationally, competition in wholesale markets has led to reduction in prices of electricity and in significant benefits for consumers.

Section 61 and 62 of the Act provide for tariff regulation and determination of tariff of generation, transmission, wheeling and retail sale of electricity by the Appropriate Commission. Section 63 of the Act states that –

"Notwithstanding anything contained in section 62, the Appropriate Commission shall adopt the tariff if such tariff has been determined through transparent process of bidding in accordance with the guidelines issued by the Central Government."

Subsequently, Section 6.4 (2) of the Tariff Policy states that -

"Such procurement by Distribution Licensees for future requirement shall be done, as far as possible, through competitive bidding process under Section 63 of the Act within suppliers offering energy from same type of non-conventional sources. In the long-term, these technologies would need to compete with other sources in terms of full costs."

Based on Section 63 of the Act and Section 6.4 (2) of the Tariff Policy it emerges that in the long-term, the procurement of non-conventional power by distribution licensees would have to be based on competitive bidding, the guidelines for which would be developed by the Central Government over time. The specific objectives of these guidelines would be, (a) Promote competitive procurement of electricity by distribution licensees; (b) Facilitate transparency and fairness in procurement processes; (c) Facilitate reduction of information asymmetries for various bidders; (d) Protect consumer interests by facilitating competitive conditions in procurement of electricity; (e) Enhance standardization and reduce ambiguity and hence time for materialization of projects.

There is subsidy being provided by the government for power generation from non conventional sources of energy. Thus the bidding can be on the basis of tariffs offered by a) different producers of same renewable energy technology in the medium term and b) producers of power based on different renewable energy technologies. However, in order to promote and sustain the growth of renewable energy technologies, it would essential that the quota for non conventional energy sources be sufficiently higher and increasing annually.

Except the NFFO, implemented in the UK, there not much experience internationally about competitive bidding for power generation from non conventional energy sources. In case of NFFO, the bidding was based on the subsidy requested from government by different producers of power from non conventional energy sources.

The competitive bidding guidelines would have to be developed by the Central Government.

Though it is possible to put time frames for this strategy of shifting from preferential tariff and quota to technology specific quota only and subsequently to the stage of only overall renewable energy quota, the technological development and commercial maturity may not be uniform across different renewable energy technologies. Hence, the transition from the above mentioned three stages can be technology specific, i.e. based on the level of development of a particular technology, the appropriate transition strategy can be designed. For instance, one way of deciding the transition could be determination of the contribution of a particular renewable energy source in the state grid. Alternatively, the short term measures like cost based tariff as well as quota would be provided till 2012 only and after that there would be transition to technology specific quota only and no predetermined cost based tariffs.

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Annexes

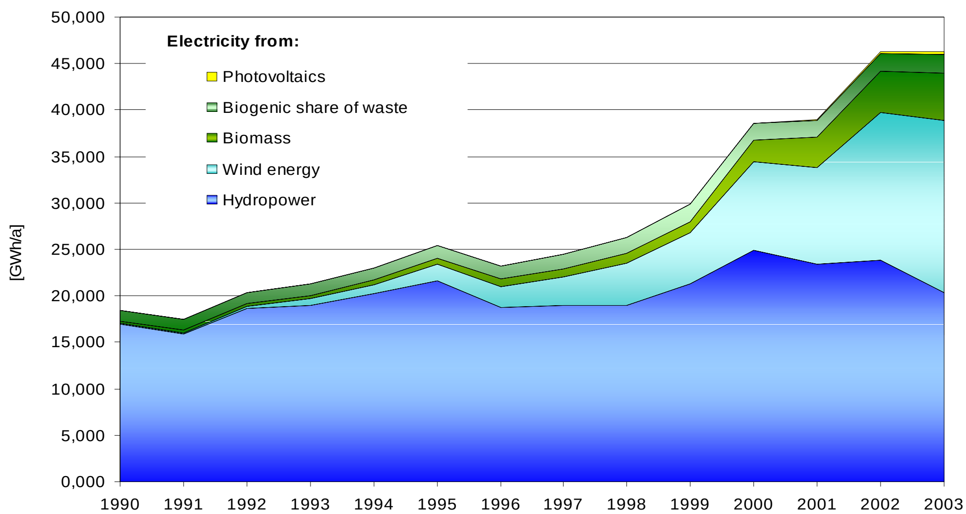
Annex 1: Country Specific Experience

Germany

Background

The installed wind power capacity was 48 MW in 1990. It increased to 12 GW in 2002, the largest amount of installed capacity in the world. According to industry associations, installed capacity increased to 16.6 GW in 2004[3]. Electricity production from wind turbines was 18.5 TWh in 2003, more than 3% of Germany's electricity production, and 22.6 TWh in 2004. The electricity generation mix in Germany during 2004, is illustrated in the diagram below –

Figure 1: Temporal development of energy supply from renewable energy; Electricity - Total



Source: Renewable Energy Sources – Figures; Federal Ministry of Economics and Technology

Germany's long-term target aims to produce 25% of the country's electricity from wind power by 2025.

Dominant Renewable Energy Policy Instrument: Feed-in tariffs

Electricity Feed-in Law, 1991

The most significant policy instrument that was adopted in Germany for promoting wind energy based electricity generation was the Stromeinspeosungsgesetz or Electricity Feed-In

[3] Global Wind Energy Council, press release, March 2005

Law (EFL) that was introduced on 1st January 1991. Some of the key features of the EFL are summarized below:

- The Law obligated German distribution network operators (DNOs) to purchase all electricity offered to them from a range of renewable sources, with wind generated electricity to be paid a price equal to 90% of the average price charged to end-users over the year,
- The price was paid by the local company and was passed on to local consumers,

- Under EFL, each DNO had an effective catchment area within which it was obligated to pay tariff to the generators of electricity from any qualifying projects within that area,
- The law mandated that the actual connection of the generator to the grid would have to be paid by the project developer, while the utility would have to be responsible for utilizing the electricity delivered to its grid network

It is important to note that the EFL was a system based on the 'market price' topped-up by a premium payment. The legislation was supported by a 100 MW subsidy programme, which was then extended to a 250 MW programme (because of the favourable response). The programme provided an additional operating subsidy of 6pfg/ kWh on top of the EFF mandated price (equal to 16.52pfg/ kWh, in 1991).

Box 1: Subsidy incentives for promoting wind based technologies

250 MW wind programme (initially 100 MW wind programme, since 1995 the 250 MW wind programme)
Applied from - until:
1989-2006
Targeted technology:
Wind
Objective:
To stimulate the installation of wind as well as to acquire statistical data on the operation of wind turbines
Operational period:
1989-2006
Specification of the measure:
The programme provided grants for the installation and operation of wind turbines at suitable sites. The subsidies (grants) go up to 25% of the investment with a maximum of 46.000 €. Additionally the programme provides operation subsidies of up to 4-ct/kWh fed into the public grid with a maximum of 25% of the total investment costs. The last grants were approved in 1996 for turbines that had to be connected to the grid by mid 1998. All turbines that receive financial support will be analysed for 10 years.

Renewable Energy Sources Act, 2000

In 2000 Germany revised the feed-in laws to create a more complex, but still attractive pricing formula. Germany's Renewable Energy Sources Act (Erneuerbare-Energien-

Gesetz, EEG) makes it compulsory for operators of power grids to give priority to plants generating electricity from renewable energy sources, and to pay fixed prices for renewable electricity. These prices vary by technology type, plant size, and occasionally by location (e.g. wind energy), and are based on the costs of generation. Some of the salient features of the EEG are summarized below:

- The EEG no longer required the utilities to pay the feed-in tariffs, but the grid operators. The utilities still have the legal obligation to take off the electricity produced from RES.
- The grid operator whose grid is closest to the location of the RES installation has the obligation to pay the tariffs.
- The tariffs are only paid to generators within the territorial scope of the Act, or within Germany's exclusive economic zone.
- The EEG states that the electricity from renewable energy must be transported and charged to the final customer.
- The prices paid under the EEG are based on a fixed price scheme combined with a nominal digressive price element, in order to allow for technological progress and the expected reduction of costs. From 2002 on, new installations of biomass (minus 1.5%), wind (minus 2%) and PV (minus 5%) receive lower tariffs. From 2003 on, new installations of these types receive tariffs lowered by a further, 1.5, 2 and 5%, and so on for the next following years. For every installation, the expiry date is in 20 years time from the installation. A summary of the feed-in tariff rates as per the EEG (along with revised announced rates of 2004) has been summarized in Chapter 2 of the Paper.

The EEG law obligates the nearest grid system operator (that is most closely located to the plant site) to connect a new renewable energy generator to their grid. While the generator owner is liable for the costs of connection to the grid, the grid owner is liable for any costs relating to the upgrading of the grid to facilitate the new generator.

The costs of the feed-in mechanism are met by all end customers. While under the EFL, each DNO had to bear the total costs of renewables in their area individually, the EEG has established a mechanism whereby the costs are spread countrywide, through the 'Nation-wide Equalization scheme'. Under this scheme, the grid operator has the obligation to buy the output from renewables, but also has the right to sell it on to the transmission network operator (TNO) it is connected to. The TNOs spread it equally amongst themselves, depending on the share of electricity sold in their grid area.[4]

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[4] By 30 September of each year, the TNOs have to determine the quantity of energy purchased and paid for in the previous calendar year and provisionally equalize such differences amongst themselves along with the percentage share of this quantity in relation to the total quantity of energy delivered to final consumers by the utility companies in the area served by the individual transmission system operator in the previous calendar year. If the transmission system operators have purchased quantities of energy that are greater than this average share, they shall be entitled to sell energy to and receive fees from the other transmission system operators, until the other grid system operators have purchased a quantity of energy equal to the average share.

The TNO shall pay for the quantity of energy that the grid system operator has purchased and paid for. The Utility companies which deliver electricity to final consumers shall purchase and pay for that share of the electricity, which their regular TNO purchased from the grid system operator. The share of the electricity to be purchased by a utility company is based on the quantity of electricity delivered by the utility company concerned. The mandatory quantity to be purchased (share) is calculated as the ratio of the total quantity of electricity paid for to the total quantity of electricity sold to final consumers.

The fees that the utility company pays to the TNO is calculated as the expected average fees per kilowatt-hour paid by all grid operators, less any avoided charges for use of the grid system.

The TNOs assert claims held against the utility companies that arise from equalization by 31st October of the year following the feeding-in of electricity. Equalization for the actual energy quantities purchased and the fees paid, take place in monthly installments before 30 September of the following year.

The costs of higher payments to renewables may be covered by an additional per-kilowatt hour (kWh) charge on all consumers according to their level of use, a charge on those customers of utilities required to purchase green electricity, by taxpayers, or by a combination of these charges. Today pricing laws exist in Germany, Spain, France, Austria, Portugal and Greece, in addition to South Korea.

The diagram below shows the growth of renewables stimulated by the first mechanism from 1991 until 1998 and the even stronger increase after the introduction of the new EEG mechanism in 1998. The EEG does not stipulate any upper capacity limit and the growth of renewable generation is likely to continue.

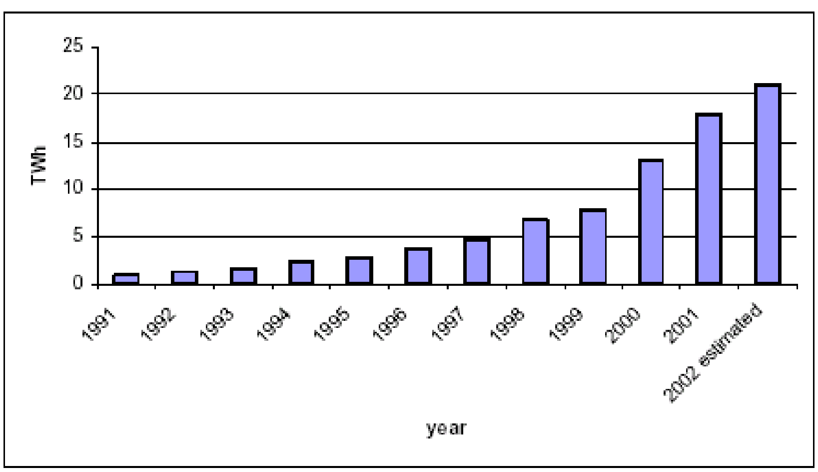


Figure 2: Annual electricity generation benefiting from the feed-in mechanism

Source: Effectiveness through risk reduction; C. Mitchell, D. Bauknecht, P.M Connor

General Pricing Experience

As explained in the earlier sub-section, the EEG requires network operators to, (a) connect renewables to their grid; (b) accept the entire electrical output from these plants; (c) remunerate generators at a pre-determined rate for every kWh produced. The remuneration decreases over time, but generators are guaranteed to receive remuneration for 20 years.

The EEG supports a wide range of renewable technologies and places a lot of emphasis on differentiated remuneration:

- First, the remuneration depends on the technology, with only 7ct2/kWh being paid for large geothermal plants and up to 51.62ct/kWh for solar plants.
- Second, the commissioning date is also relevant. For wind plants, for example, the remuneration decreases by 1.5% every year for new plants.
- Third, the remuneration is site specific. Wind plants currently receive 9.1ct/kWh for 5 years after commissioning (plants coming on-line next year will receive 1.5% less, see above) After that period the remuneration depends on the income of a plant compared to reference plants. Plants that have done well, for example due to relatively good wind conditions, and have received a remuneration that exceeds 150% of the reference plant income will receive less money after year five. Lower-quality sites, on the other hand, will continue to receive the full remuneration for longer, depending on the extent to which they are below the 150% threshold.

Moreover, there is a review carried out by the government every other year, looking at technological and market developments. The review is required to make a recommendation to the parliament, which can then decide to change both the tariffs and the reduction rates. They will only be changed ex-ante, i.e. only for plants that have not been commissioned yet.

The costs of the feed-in mechanism are met by all end customers. Whilst under the old Stromeinspeisegesetz, each DNO had to bear the total costs of renewables in their area individually, the EEG has established a mechanism whereby the costs are spread country-wide. The distribution network operator (DNO) has the obligation to buy the output from renewables, but has the right to sell it on to the transmission network operator (TNO) it is connected to. The TNOs spread it equally amongst themselves, depending on the share of electricity sold in their grid area. They then pass it on to the suppliers in their region. The costs of developing renewable energy in Germany is now socialised across all electricity customers rather than impacting more heavily on customers in areas where more renewable energy resources are being exploited.

According to the German government (BMWi 2002), the feed-in mechanism has increased the cost of electricity to end-users by 0.18-0.26ct/kWh, depending on the market price for electricity.

Further, some of the key features of the Pricing Scheme that has been adopted in Germany are highlighted in the box below.

Box 2: Features of the German Pricing Scheme

- The German energy policy is carried out both at the Federal and at the state level. In particular, with regard to the policy on renewable energy development, a high degree of autonomy exists for the states.
- At the federal level, a framework regulation has been established for connection and sales of electricity to the electricity grid. The regulation is based on political determination to promote renewable energy rather than on a recovery of avoided system costs.
- No avoided costs of transmission and distribution are compensated.
- No system reinforcement costs are incurred and no avoided future reinforcement costs are recompensed.
- Connection costs are charged for the connection to the 22 kV grid. In some states, the utility company may require that the generator be connected to the 60 kV grid. For distribution of connection costs between several connectees in the same area, different rules apply for each state. Some utilities have used so called development plans as a basis for charging for future system reinforcement needs. These development plans include information on projected renewable generators in the relevant areas, together with expected overall reinforcement costs for the area. These costs are then shared between the individual projects.
- No use-of-system charges are being charged.

Grid Integration issues

Wind turbines are largely connected to the grid at low and medium voltages. With the advent of the feed-in tariffs in 1991 and the spurt of wind developments that followed, the transmission system operators had concerns about grid integration reliability and cost issues. They looked to the government for a solution. The Renewable Energy Sources (RES) Act 2000 consequently provided for a burden sharing between all network operators and allocation to their customers. This solution is estimated to currently add about €12 per year to the average household electricity bill. The significant growth of onshore wind power led to collaboration between the transmission system operators and German research institutions to develop advanced forecasting and modelling tools for wind power. Subsequently, the expected extension offshore led to a more fundamental review of grid extension and upgrade needs, which culminated in a joint research effort between German research institutions, grid operators and the electricity supply industry.

The RES Act (Act on granting priority to renewable energy sources) was further amended in July 2004. Among the grid integration enabling provisions of the Act, some of the sections that are worth a mention at this stage are – grid system operators are obligated to connect plants generating electricity from renewable energy sources or from mine gas to their systems, on a priority basis, and guarantee priority purchase and transmission of all electricity from renewable energy sources or from mine gas supplied by such plants. A grid is required to be deemed as technically suitable even if feeding in the electricity requires the grid system operator to upgrade its grid at a reasonable economic expense; in such a case, the grid system operator has to upgrade its grid without undue delay, if so requested by a party interested in feeding in electricity. Further, the obligation for priority connection to the grid system is applicable even if the capacity of the grid system or the area serviced by the grid system operator is temporarily entirely taken up by the electricity produced from renewable energy sources or mine gas, unless the plant does not have a technical facility for reducing the feed-in in the event of grid overload. The Important provisions of this Act with regard to grid interconnection clauses are detailed in Note 1.

The German Government has a target of 20% share of renewable energy in electricity generation between 2015 and 2020. Most of this is expected to come from wind power. Concerns about network integration and infrastructure capacity to accommodate some 37 GW of wind power by 2015 were the impetus for a federal government and industry joint-financed report released in February 2005, “Energy Planning for the Integration of Wind Energy in Germany on Land and Offshore into the Electricity Grid”. The key outcomes of this study are given in Note 2. Among its key findings, it has been indicated that reinforcement and extension of the grid and technical solutions for reliability are preconditions for achieving the envisaged wind power development and avoiding 20 to 40 million tons of CO_2 emissions in 2015. It would entail about 850 kilometres of new high-voltage lines and 400 km of grid upgrades at an estimated cost of €1.1 billion. The study cautions that implementation could be stymied by the planning and legal authorization process for transmission lines. The study suggests that the additional cost for the expansion of wind power will be 0.39 – 0.49 € cents per kWh in 2015 for a residential consumer.

United Kingdom (UK)

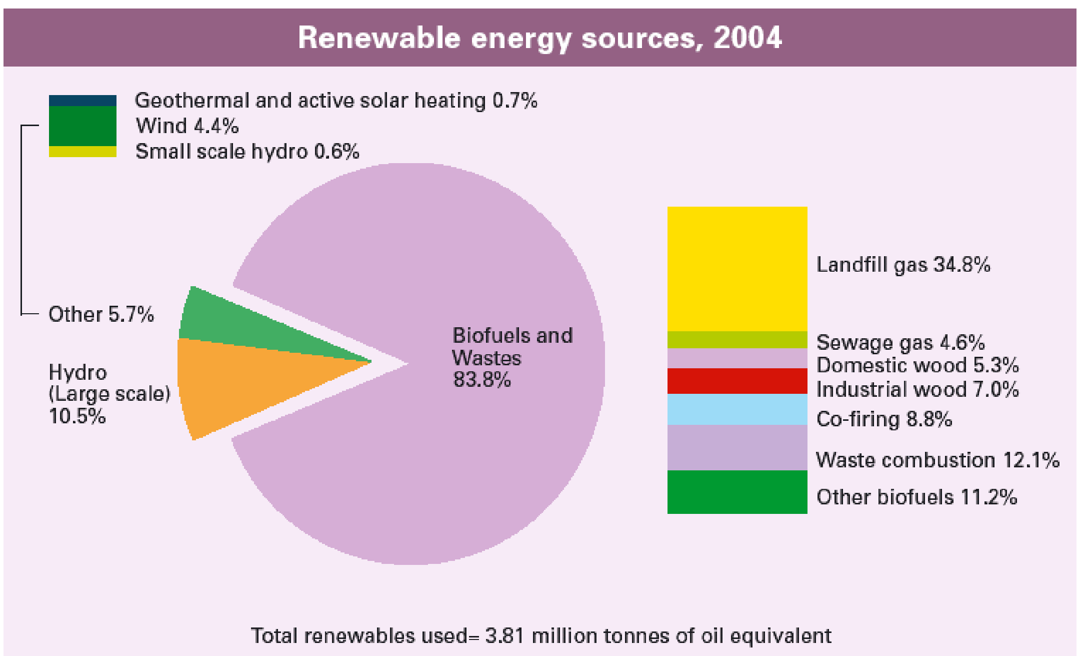
Background

The emergence of the renewable energy policy in the UK is closely linked to the restructuring if the electricity industry. UK was the first European country to privatize the electricity sector and attempt opening it up for competition. Through the 1989 Electricity Act, the entire sector of England and Wales was vertically de-integrated and competition was introduced at the generation level through an energy pooling system. In 1990, the British government asked the European Commission for the ability to charge a Non-Fossil Fuel Levy on consumers' bills and this marked the beginning of governmental support for market diffusion of renewables in the UK.

In UK, the electricity production mix mainly consists of nuclear energy, gas and coal. Renewable electricity production is only about 2% of total production, but the installed capacity of wind and biogas are increasing steadily, off late.

The renewable energy mix in the country in 2004 is illustrated in the diagram below –

Figure 3: Renewable Energy Mix in UK



Source: DTI, UK, Energy in Brief, July 2005

The UK government has been supporting renewable energy and other novel energy systems since the mid-1970s, first under the aegis of the Department of Energy and recently under the Department of Trade and Industry. Over this period, renewable energy technologies have evolved and matured, and the more advanced ones have made contribution to energy supply in the UK, accounting for 2.8% of the nation's electricity in 1998.

The UK has a 10-point strategy for renewable energy, which is intended to deliver 5% of the nation's electricity from renewables by 2003 and 10% by 2010. A number of interlinked initiatives are intended to deliver this increased contribution. These include research, development, demonstration and dissemination programmes that are linked to a market stimulation initiative, which will build on the successes of the NFFO (non-fossil-fuel-obligation).

UK Renewable Energy Policy – Targets and Objectives

The UK government has held programmes in support of renewables, which have aimed at evaluating, developing and encouraging commercialization in the field of renewable energy for over 20 years. Initially, the programme conducted by the Department of Energy concentrated on assessing the feasibility of renewables, the potential contribution to the UK energy supplies and the costs and timings of such contributions. In 1990, as part of the changes in legislation associated with privatization of the UK electricity industry, renewables were included in the NFFO. This provided an incentive and route for the commercialization and deployment of better-developed electricity-producing technologies. Since the introduction of NFFO, there have been regular views to assess progress and set priorities for future activities.

In 1990, when the first NFFO tender round was called, the only type of renewable resource used in UK was hydropower. Coal was the dominant fuel for electricity production with a 67% share, followed by nuclear energy with, 19%. In 2000, after 10 years of private initiative, natural gas became the fuel with the largest market share of 39%. The share of primary resources for electricity production in 1990 and 2000 is given in the table below. In 2000, the contribution of RES toward electricity production accounted for 2.8%. Hydropower plants of various sizes generated almost 50% of this, while around 40% was coming from landfill gas and waste incineration plants.

Table 1.1: Percentage of electricity production provided by each types of fuel in 1990 and in 2000 – UK (DTI 1999)

Year	Coal	Natural Gas	Nuclear	Oil	Hydropower	Other fuels including RES	Imports
1990	67%	0.5%	19%	7%	2.5%		4%
2000	31%	39%	21%	1.5%	1%	2.5%	4%

Source: Danyel Reiche (ed.), Handbook of Renewable Energies in the European Union

Dominant Renewable Energy Policy Instrument: Tendering Scheme and Quota Obligation

A special support mechanism for renewable energy sources (RES) was introduced in England and Wales in 1990 under the name Non-Fossil Fuel Obligation (NFFO). It was based on a tendering process, whereby generators using eligible types of RES competed for limited capacity within specified technological bands. The elected projects were offered two crucial government guarantees: a purchase contract with regional electricity companies for a certain minimum period of time, and an index-linked price per kWh. Five tender rounds were organized during the 1990’s, the last being called in 1998. For the first two rounds, the purchase contracts with Regional Electricity Companies were guaranteed for eight years. For the last three rounds the contract guarantee extended to fifteen years. The guaranteed contract price emerged as a result of the tendering process and was made up of two components – the pool price and a technology-specific premium, which came from the Non-Fossil Fuel Levy Fund.

After 2000, a new system was shaped to support commercial viability of RES, consisting of three elements. The first and central element of the new support system is a quota Renewable Obligation (RO) on electricity supply companies with a 25-year horizon. The second element is the exemption from the Climate Change Levy (CCL) for renewable electricity consumed by industrial and business consumers. The third is a governmental subsidy program to support the more expensive technologies and those that still need technical improvements.

The purpose of the Renewable Obligation imposed on suppliers of energy is to reach 10% renewable electricity share by 2010. This policy is envisaged to be in place until March 2027.

Table 1.2: Obligation deadline

Obligation deadline	Percentage of supplies from RES
31 March 2003	3%
31 March 2004	4.3%
31 March 2005	4.9%
31 March 2006	5.5%
31 March 2007	6.7%
31 March 2008	7.9%
31 March 2009	9.1%
31 March 2010	9.7%
31 March 2011	10.4%
Each following year, until March 2027	10.4%

Under the Renewable Obligation, suppliers can meet their obligation by means of: -

- generating renewable electricity, buying physical streams of renewable electricity, buying green certificates;

- o banking a maximum 25% of the needed certificates for a running obligation period, from the previous obligation period;
- o “proving that another electricity supplier has done so, or that between them they have done so” (April 2002 Order on Renewable Obligation)
- o or ‘buying out’ their obligation

Mechanism of operation of the NFFO

The NFFO legislation obliges the public electricity suppliers in England and Wales to buy all NFFO generation offered to them. The awarding of the NFFO contracts and the price paid for the renewable generation is decided as a result of competitive bidding within a technology band on a pre-decided date. The coming together of the competitive bids takes place in a tranche, and the successful projects are awarded contracts that are announced as an Order by the Secretary of State. This also means that wind projects compete against other wind projects, but wind does not compete against, for example biomass projects. Each application undergoes a technical and commercial scrutiny by the Office of Electricity Regulation (OFFER). Once passed by the regulator, the cheapest bids per kWh within each technology band are awarded a contract.

The Regional Electricity Companies pay the contracted NFFO premium price for the NFFO generation to the NFFO generator, for instance 4p/ kWh. However, the Regional Electricity Companies has to buy the renewable generation at the market price (which is the average monthly pool selling price, PSP[3]), for example 2.8p/ kWh. The premium price paid for the renewable generation may be very close to the PSP or it may be much higher depending on the technology. The Non-Fossil Purchasing Agency (NFPA) reimburses the difference between the premium price and the PSP to the Regional Electricity Companies, which in this case would be 1.2p/ kWh. This difference is the subsidy and is paid for by a Fossil Fuel Levy (FFL) on all electricity bills, paid for by electricity consumers. The NFPA is an agency that is wholly owned by the Regional Electricity Companies, which act as an accounting body for the FFL.

The Department of Trade and Industry (DTI), the Ministry responsible for energy supply, decides the final capacity and technology mix of the awarded contracts. The applications for an NFFO contract in an Order are divided into technology bands. The key aspect of each application is the bid-price per kWh (for e.g. 3p/ kWh from an on-shore wind farm). The bids per kWh are then arranged or stacked for each technology band with the lowest bid/ kWh at the bottom rising to the highest bids at the top. The lowest bid-price projects are awarded the contracts.

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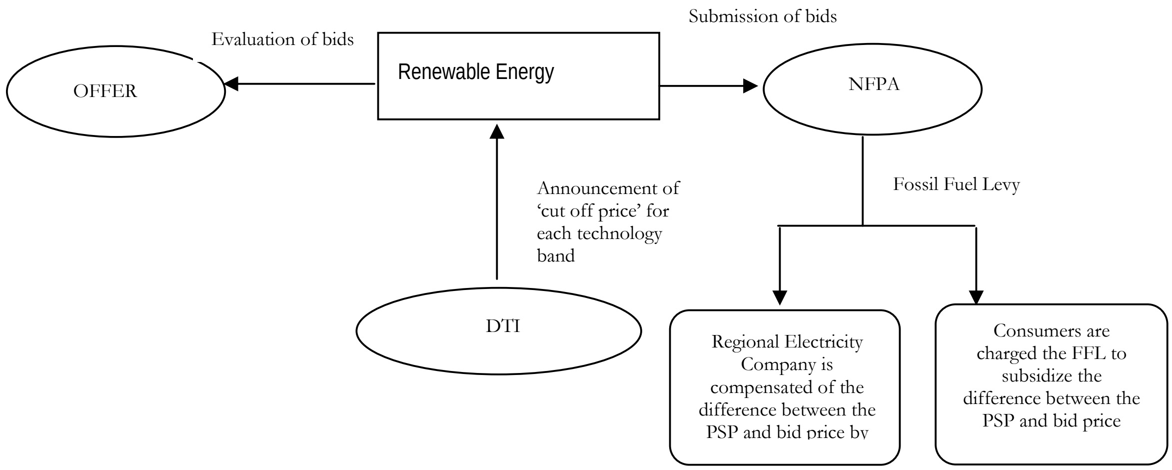
[3] Pool Selling Price is the price that the Pool agrees to sell electricity at, to suppliers, should they need it. In UK, for licensed generators the open market for power is the electricity Pool. The generator sells to the Pool on a half hourly basis, bidding for the price of their electricity and receiving the PPP should their power be required to meet demand.

The institutional set up that is involved in a typical NFFO process is illustrated below:

Figure 4: NFFO - the tendering process



To subsidize the difference between the PSP and the bid price, the NFPA charges a Fossil Fuel Levy on the end consumers, i.e.

FFL p/kWh = PSP – bid price

Where,

PSP p/kWh = PPP p/kWh + Uplift

Where,

Uplift: - charged by the National Grid Company/ Power Pool to cover costs and profits incurred in providing secure transmission

PPP: - Pool Purchase Price[4] is the price that the Pool agrees to pay generators for their capacity, and is a function of the System Marginal Price (SMP)
(The explanation of the UK electricity market and the concept of electricity pool are summarized at the end of this sub section)

[4] Licensed generators (Declared Net Capacity greater than 50 MW) are obliged to become members of the Electricity Pool, and they can sell all, or part of their generated power into the Pool.
Large centrally-dispatched generators (exporting over 100 M) wishing to sell to the Pool submit bid prices on a half hourly basis and receive the Pool Purchase Price (PPP) for their power. At present, the PPP is capped and is subject to control by the regulator; PPP p/ kWh = SMP + capacity, where capacity is a function of loss of load probability (LOLP) and value of loss of load probability (VOLL) and SMP is the price bid by a generator, when that generator is the last whose output is required to meet demand from the pool.

A summary of the number of projects contracted and the capacities under NFFO Orders 1-5 is given in the table below:

Table 1.3: NFFO 1-5

	Projects	Contracted		Projects	Generating	No progress	Projects	%
	Date	Number	MW (DNC)[5]	Number	MW (DNC)	Number	MW (DNC)	
NFFO1	1990	75	152.12	61	144.53	14	7.58	93
NFFO2	1991	122	472.23	82	173.73	40	298.49	37
NFFO3	1994	141	626.91	75	254.47	38	234.4	40.6
NFFO4	1997	195	842.72	56	132.62	90	494.66	15.74
NFFO5	1998	261	1177	17	24.31	159	960.43	2.07
Total		794	3270.98	291	729.66	341	1995.3	

Source: Catherine Mitchell; England and Wales NFFO: History and Lessons

Renewables Obligation, Post 2000

The Renewables Obligation is an obligation on licensed electricity suppliers to source a specified percentage of electricity they supply from renewable sources. Suppliers can meet their obligation through producing Renewables Obligation Certificates (ROCs) and/ or by paying buy-out. The Office of Gas and Electricity Markets (OFGEM) is responsible for issuing ROCs to accredited generating stations. The percentage target is set to increase each year from its current level of 4.9 per cent in 2004/ 05 to reach 10.4 per cent by 2010/ 11. In December 2003, the Government announced its intention for the Obligation percentage to continue to rise beyond 2010/ 11 to reach 15.4 per cent by 2015/16. A summary of the Obligation is given below:

Table 1.4: Obligation level

Period	Estimated sales by licensed suppliers in UK	Actual sales by licensed suppliers in UK	Total Obligation (UK) is based on (a)	Total Obligation as a percentage of sales (UK) is based on (a)
	(a)	(b)	(c)	(d)
	TWh	TWh	TWh	%
2001/02	310.9	318.35		
2002/03	313.6	319.42	9.4	3.0
2003/04	316.2	328.36	13.5	4.3
2004/05	318.7	330.13	15.6	4.9
2005/06	320.6		17.7	5.5
2006/07	321.4		21.5	6.7
2007/08	322.2		25.4	7.9
2008/09	323.0		29.4	9.1
2009/10	323.8		31.5	9.7
2010/11	324.3		33.6	10.4

SOURCE: http://www.dti.gov.uk/renewables/renew_2.2.1.htm

[5] DNC – Declared Net Capacity, the equivalent capacity of base load plant that would produce the same average annual energy output

The eligible renewable sources as per the obligation, is summarized in the table below:

Table 1.5: Eligible Renewable Sources

Source	Eligibility
Landfill gas	Yes
Sewage gas	Yes
Hydro exceeding 20 megawatts declared net capacity (DNC)	Only stations commissioned after 1 April 2002
Hydro 20 MW or less DNC	Yes
Onshore wind	Yes
Offshore wind	Yes
Co-firing of biomass	Any biomass can be co-fired until 31 March 2009 with no minimum percentage of energy crops
	25 per cent of co-fired biomass must be energy crops from 1 April 2009 until 31 March 2010
	50 per cent of co-fired biomass must be energy crops from 1 April 2010 until 31 March 2011
	75 per cent of co-fired biomass must be energy crops from 1 April 2011 until 31 March 2016
	Co-firing ceases to be eligible for Renewable Obligation Certificates (ROCs) after 31 March 2016.
Other biomass	Yes
Geothermal power	Yes
Tidal and tidal stream power	Yes
Wave power	Yes
Photovoltaics	Yes
Energy crops	Yes

SOURCE: http://www.dti.gov.uk/renewables/renew_2.2.1.htm

The NFFO of 1990 has now been completely replaced by the Renewables Obligation of 2000 which is a part of the new support system for promoting renewables along with an exemption from the CCL for renewable electricity consumed by industrial and business consumers and the governmental subsidy program to support the more expensive technologies.

Box 3: Detailed Explanation of the Operation of the Electricity Pool in UK

The Electricity Pool
Within England and Wales, legislation has created a unique market for electricity, which is designed to enable electricity trade. It is called the Electricity **Pool**[6]**.** Licensed generators **(Declared Net Capacity (DNC)** greater than 50 MW) are obliged to become members of the Electricity Pool, and they can sell all, or part, of their generated power into the Pool. These large generators are usually connected directly to the national Grid, which operates at 275 and 400 kV.

Large centrally-dispatched generators (export over 100MW) wishing to sell to the Pool submit bid prices on a half hourly basis and receive the Pool Purchase Price (PPP) (units p/kWh) for their power. At present this price is capped, and is subject to control by the industry regulator, OFFER. There are additional payments

[6] A market structure that was established in UK after the privatization of the electricity industry in 1989. It is administered by the National Grid Company, with representatives from all Pool members. Pool members include licensed generators, licensed suppliers, and transmission and distribution agents.

made in cases where standby and reserve generation capacity is required. Smaller generators who are part of the Pool (50-100MW), but are not centrally dispatched, can operate at any time and receive **PPP** for their generated output. They cannot receive additional payments above the PPP, unlike centrally-dispatched generators.

All generators who are Pool members bid a price for their electricity at half hourly intervals each day. This bid price (units p/kWh) will include the costs of generation and profit. The Pool managers rank the bids in order of price, with the cheapest first, and buy electricity from the lower priced generators which are required to meet demand. The price bid by the final (and most expensive) generator which is needed to meet demand is the **System Marginal Price (SMP)** (units p/kWh). PPP is a function of SMP.

PPP = SMP + Capacity

There is also an allowance for reserve and standby power, whereby capacity scheduled as reserve receives the PPP if required, and the PPP minus its bid if not used.

Capacity (units p/kWh) is a factor which takes into account the possibility of any load loss. Loss of load probability (LOLP) (no units) and Value of lost load (VOLL) (units p/kWh) incorporate this possible cost within the Capacity and hence within PPP.

Capacity = LOLP x VOLL

Licensed suppliers who wish to purchase electricity from the Pool, in order to sell on to customers, do so at the nearest GSP. This is the transformer station at which the Grid and the Regional Electricity Companies 3-phase distribution network meet. The GSP is also the point at which the net demand of the supplier is metered, to determine their electricity demand from the Grid. Net demand from the Grid (for a supplier) equals the algebraic sum of all customer demand and embedded generation below the suppliers GSPs. Customers purchasing from their supplier are also metered at their premises.

$$\text{Supplier electricity demand from Grid} = \sum \text{customer demand} - \sum \text{embedded generation}$$

Suppliers buying from the Pool pay the Pool Selling Price (PSP). This comprises PPP plus Uplift.

PSP = PPP + Uplift
Uplift is charged by the NGC to cover costs and profits incurred in providing secure transmission. The great majority of suppliers are the Regional Electricity Companies. However, there are other private suppliers. Regional Electricity Companies are licensed suppliers who are legally required to supply electricity to any customer within their geographical area of operation, given certain technical considerations.

General Pricing Experience

The UK pricing system is not based on price regulation but rather on regulated competition, by which renewables are provided special competitive conditions.

Renewable power generators have the following options for selling electricity:

- Through the pool: Selling through the pool requires membership. Payment will be based on Power Purchase Price plus capacity payments plus avoided transmission and distribution costs
- To a regional distribution company: Generally, the local distributor would offer a price slightly under the Power Purchase Price plus capacity and avoided transmission and distribution costs plus 3.7%
- To an independent electricity distributor: if the independent distributor can provide competitive conditions
- Directly to consumers: All producers less than 50 kW may sell directly to individual consumers whereby transmission costs are avoided. Larger producers may also sell directly provided they are member of the pool and obtain a supply license
- Through the Non Fossil Fuel Obligation, a particular bidding for renewables where prices are not connected to the pool prices

Most renewable energy in UK had been traded through NFFO contracts till 2000.The general terms of bidding included the condition that the local distributor was obliged to purchase power from the renewable energy generator at a determined price for the complete contract period. During the tendering process, generators using eligible types of RES competed for limited capacity within specified technology bands. The elected projects were offered two governmental guarantees: a purchase contract with regional electricity companies for a certain minimum period of time, and an index-linked price per kWh. Five tender rounds were organized during the 1990s, the last being called in 1998. For the first two rounds, the purchase contracts with Regional Electricity Companies were guaranteed for eight years. For the last three rounds, the contract guarantee extended to fifteen years. The guaranteed contractual price emerged as a result of the tendering process and was made up of two components: the pool price and a technology-specific premium, which came from the Non-Fossil Fuel Levy fund.

The NFFO scheme has proven effective in promoting renewable energy, although not all scheduled projects have been implemented due to administrative problems. From the state regulatory point of view, the NFFO concept holds a few advantages. First of all, it is a strong tool in implementing a government set target for use of renewable energy. Further, there is little risk of over-or-under compensation of the renewable energy generators, which could arise in the case of subsidy based promotion schemes.

Some of the problems that have been identified in the NFFO mechanism are:

- Such a mechanism sometimes favours less efficient systems. For example waste incineration plants using co-generation of power and heat have been less competitive under this system, although co-generation is more fuel-efficient.
- The short duration of the first rounds of bidding resulted in quite high electricity costs
- Developers have found considerable difficulties in obtaining all the necessary clearances required from the relevant authorities

After 2000, a new system was introduced to support the commercial viability of RES, consisting of three elements. The first and central element of the new support system is a quota Renewable Obligation on electricity supply companies with a 25 year horizon. The obligation is on licensed suppliers to supply a specified proportion of their electricity supplies to their customers from renewable sources of energy. Any additional sot of supplying electricity from renewables will be met by suppliers and may be passed onto their customers. There will be no new levy for these arrangements. However, a price cap will limit the cost to consumers. This will be implemented by there being a fixed price at which suppliers can buy out their Obligation as an alternative to supplying renewable electricity.

Grid Integration Issues

Although there exists no clarity with regard to ho the upstream reinforcement costs will be determined since there is no legal practice. One of the options would be to use the regulation for power consumers installing new power capacity, whereby only when the power consumption assumes more than 25% of the local sub-station, a system reinforcement cost will be incurred.

With regard to connections, some of the major principles that are followed in UK are –

- All immediate costs related to the connection are paid by the connectee
- All costs related to system reinforcement are paid by the connectee
- Future maintenance and replacement costs of equipment installed for the connection are being capitalized and paid for by the connectee
- Possible postponement of future investment in transmission and distribution systems are not being recompensed
- Costs incurred to recompensate for increased fault levels are paid by the connectee

United States (US)

Background

As explained in the section on overview of international pricing experience of renewable energy based electricity generation, the foundation of pricing principles for renewables has been found in the Public Utility Regulatory Policy Act (PURPA) that was passed in California, in 1978, to reduce dependence on foreign oil, to promote alternative energy sources and energy efficiency, and to diversify the electric industry. Before, PURPA, only utilities could own and operate electric generating plants. PURPA required utilities to buy power from independent companies that could produce power for less than what it would have cost for the utility to generate the power, called the 'avoided cost'.

PURPA has been the most effective single measure in promoting renewable energy. Some credit the law with bringing on line over 12,000 megawatts of non-hydro renewable generation capacity. The biggest beneficiary of PURPA, though, has been natural gas-fired "cogeneration" plants where steam is produced along with electricity.

However, there have been considerable changes since PURPA was implemented. The price of oil had declined, post 1985 and supplies of natural gas had increased, driving down the cost of electricity. Many independent power producers had signed contracts in the 1980s with prices that were higher than current spot market prices. All these contracts were based on the avoided cost of electricity at the time. The salient features of the PURPA regulation are explained in the subsequent section on general pricing experience.

During the late 1990s there was a second period of growth of renewable energy in the United States that was spurred by a combination of federal tax incentives and policies adopted in several states such as the Renewable Portfolio Standard (RPS). As of mid-2005, 19 states plus the District of Columbia have adopted an RPS policy[7]. In Texas, around 1000 MW of wind power capacity was installed in 2001, in part to meet the state's renewable energy portfolio standard. The details of the RPS programme in Texas is explained in the subsequent sub-section. Apart from this, voluntary green power marketing programmes have also encouraged wind power developments, which represent a significant share of the green power sold in the United States. One of the federal incentives, the production tax credit (PTC) dating back to 1992 has also resulted in the boom for new wind power installed capacity. A key aspect of US federal policy with regard to PTC is that it is specifically targeted to support electricity generated from wind, closed-loop biomass[8] sources, and poultry waste. The credit provides a 1.5 cent per

[7] Source: State Renewable Portfolio Standards – A Review and Analysis; National Conference of State Legislatures
[8] Closed-loop biomass: Plant matter that is grown for the sole purpose of being used to generate electricity. Due to the cost of developing a closed-loop facility to generate electricity, this tax credit has not been used to date.

kilowatt-hour payment, payable for 10 years to private investors as well as to investor-owned electric utilities for electricity from wind and closed-loop biomass facilities.

Dominant Renewable Energy Policy Instrument: Renewable Portfolio Standard

The RPS, widely used in U.S. states, is based on the obligation/certificate system. Under an RPS, a political target is established for the minimum amount of capacity or generation that must come from renewables, with the amount generally increasing over time. Investors and generators then determine how they will comply, the type of technology used, the developers to do business with, the price and contract terms. At the end of the target period, electricity generators must demonstrate, through the ownership of credits that they are in compliance in order to avoid paying a penalty. Producers give credits—in the form of ‘Green Certificates’, ‘Green Labels’ or ‘Renewable Energy Credits’ — for the renewable electricity they generate. Such credits can be tradable or sellable, to serve as proof of meeting the legal obligation and to earn additional income. Those with too many certificates can trade or sell them; those with two few can build their own renewable capacity, buy electricity from other renewable plants, or buy credits from others. Once the system has been established, government involvement includes the certifying of credits, and compliance monitoring and enforcement.

Texas RPS Policy (The RPS in Texas: An Early Assessment; Ryan Wiser; Ernest Orlando Lawrence Berkeley National Laboratory)

The Texas RPS required the installation of 2000 MW of new renewable capacity by the year
2009, in addition to preserving the 880 MW of renewable energy already on line. This translated to about 3% of present electricity consumption.[9]

Intermediate new renewable capacity goals in Texas are 400 MW by 2003, 850 MW by 2005, 1400 MW by 2007, and finally 2000 MW by 2009 and through 2019. These capacity goals are translated into megawatt hour based energy requirements by using an average capacity factor of all eligible renewable plants; its value is initially set at 35% and will be adjusted over time based on actual plant performance. Electricity retailers that serve markets open to competition are obliged to fulfill their portion (based on yearly retail electricity sales) of the renewable energy requirement by presenting renewable energy credits (RECs) to the regulating authority on an annual basis. The obligation begins in 2002 and ends in 2019. The tradable RECs are issued for each MWh of eligible renewable generation located within or delivered to the Texas grid. With the exception of renewable power plants with a capacity smaller than 2 MW, the REC trading program is

[9] Based on an assumed average capacity factor of 35%. Assuming an average annual growth in demand of 3% this translates to a renewable energy share of 2.2% by 2009.

restricted to facilities erected after September 1, 1999. A wide variety of renewable technologies are eligible. The table below summarizes the design features of the RPS policy.

Table 1.6: The Texas RPS: Design Details

Design Element	Design Details
Renewable energy purchase obligations	Capacity targets of 400 MW of eligible new renewables by 2003, 850 MW by 2005, 1400 MW by 2007, and 2000 MW by 2009 and through 2019 Annual energy based purchase obligations beginning in 2002 and ending in 2019 derived based on capacity targets and average capacity factor of renewable generation (initially set at 35%)
Obligated parties	all electricity retailers in competitive markets (80% of total Texas load) share the obligation based on their proportionate yearly electricity sales; publicly owned utilities must only meet the RPS if they opt-in to competition
Eligible renewable energy sources	new renewable power plants commissioned after September 1, 1999 and all renewable plants less than 2 MW capacity, regardless of date of installation power production from solar, wind, geothermal, hydro, wave, tidal, biomass, biomass-based waste products, and landfill gas are eligible purchases of renewable energy from plants larger than 2 MW and built before September 1999 may count towards a supplier's REC obligation, but are not tradable power must be located within or delivered to the Texas grid renewable energy sources that offset (but do not produce) electricity (e.g., solar hot water, geothermal heat pumps), and off-grid and customer-sited projects (e.g., solar) are also eligible
Tracking and accounting method	tradable RECs with yearly compliance period 3 month grace period after compliance period allowed for fulfillment
Certificates	issued on production, unit 1 MWh, 2 years of banking allowed after year of issuance, borrowing of up to 5% of the obligation in first 2 compliance periods allowed, development of web-based certificates tracking system
Regulatory bodies	Texas Public Utilities Commission establishes RPS rules and enforces compliance; ERCOT Independent System Operator serves as REC trading administrator
Enforcement penalties	the lesser of 5(US)¢ or 200% of mean REC trade value in compliance period for each missing KWh

The RPS policies that have been adopted in several of the US states do not contain the same strong provisions as those established in Texas, and may do little to instill confidence in the renewable energy industry. The most important problems experienced in U.S. RPS design include:

- Inadequate attention to the relationship between the renewable energy purchase requirement and eligible renewable energy sources. For example, Maine established a 30% RPS. Though this represents the highest RPS in the world, eligible resources include the vast majority of renewable energy and high-efficiency natural gas cogeneration in the New England region. Existing supply therefore far exceeds the standard itself. As a result, the RPS will do nothing to support new renewable energy development, and is unlikely to do much to support existing supply either.
- Selective application of the purchase requirement. Several U.S. states only apply the RPS to a small segment of the state's market, muting the potential impacts of the policy. For example, in Connecticut the utilities that deliver energy to customers that do not switch to a new electricity supplier are exempt from the purchase requirement. Not only does this approach violate the principle of competitive parity, it also ensures that the RPS will have only a marginal impact, as the vast majority of customers have shown no interest in switching suppliers.
- Uncertain purchase obligation or end-date. Another common concern is the uncertainty in the size of the purchase standard and its end-date in some U.S. states. In Maine, for example, the RPS is to be reviewed every five years. In Connecticut, when and how the RPS will end is simply unclear. Such uncertainty limits the ability of renewable generators to obtain reasonably priced long-term financing.
- Insufficient enforcement of the purchase requirement. Without adequate enforcement, retail electricity suppliers will surely fail to comply with the RPS. In this environment, renewable energy developers will have little incentive to build renewable energy plants. At best, the enforcement rules of a number of U.S. RPS policies are vague in their application: these include those policies in Connecticut, Maine, and Massachusetts.

Though of substantially lesser importance, still other states have failed to implement a renewable energy certificate system for easily tracking and monitoring compliance with the RPS. States in this category include Maine, Connecticut, New Mexico, Pennsylvania.

General Pricing Experience

The PURPA act imposed an obligation on power utilities to connect and buy power from distributed generators without limitation. The Act established a general framework for determining the pricing of connection and trade of power, while the exact determination of pricing and other conditions was supposed to be determined at state level. The basic principle was that the distributed generator should have recovered no less than the avoided costs incurred on the power utility while the costs to be paid for interconnection should not exceed costs of the power utility not being recovered through the electricity rates.

The distributed generator is allowed to choose between a contract with no obligation on provided capacity (non-firm) or a type of contract by which a certain amount of energy or capacity would be guaranteed (firm). The Act provided the right of the distributed generator to simultaneously sell and purchase power if commissioned after the Act. This would imply that the distributed generator might sell all its power generated to the utility and purchase the power that it consumes from the utility.

The Act provided the right of the distributed generator to enter into an agreement on a fixed energy cost based on avoided energy costs at the time of signing the contract. Through this, the risk linked to possible future oil price reduction of the distributed generator gets reduced to some extent. Upon renewal of the contract, the rates get adjusted according to changes in avoided costs.

Further, according to the Act, line losses would be accounted for if any benefits could be proven and the power utility could refuse to buy power at times when the distributed generator power would force the utility to stop low cost base load units and operate on higher cost units with short start up times.

Grid Interconnection Issues

To date, intermittency, per se, has not been an obstacle to wind projects in the United States (*International Energy Technology Collaboration and Climate Change Mitigation; Wind Power Integration into Electricity Systems*). Wind power development has largely been in remote areas and connected to high voltage transmission networks. However, access to transmission networks and pricing for intermittent resources has been a hurdle. In 2004, the Federal Energy Regulatory Commission proposed modifications in the wholesale electricity market structure that would eliminate penalties associated with wind's variable output when it does not result in increased costs to the system. This proposal is currently under consideration.

Thailand

Background

A gradual evolution has been taking place within the energy sector of Thailand that has as its foundation, enhanced private sector participation through the opening of the market. This has occurred mainly in the form of a comprehensive Independent Power Producer (IPP) programme and the facilitation of privately owned distributed generation facilities under the Small Power Producer (SPP) programme and the Net Metering legislation that was introduced in May 2002.

The National Energy Policy Council of Thailand has concluded that electricity generation from non-conventional energy, waste or residual fuels and cogeneration increases efficiency in the use of primary energy and by-product energy sources, and helps to reduce the financial burden of the public sector with respect to investment in electricity generation and distribution. The Council has therefore approved a Policy that allows SPPs to generate and supply electricity and has drawn up regulations (January 1998, revised on August 2001) for the purchase of electricity from SPPs[10] using such electricity generating processes. The details with regard to pricing and grid-interconnection clauses are described in the subsequent sub-sections.

Further, in May 2002, the legislation passed by the National Energy Policy Council, Thailand entitled "Regulations for the Purchase of Power from Very Small Renewable Energy Power Producers", consists of two sections: commercial and technical. The commercial regulations discuss permitted renewable energy fuels, application and connection procedures, costs incurred by each party, tariffs, and billing arrangements. The technical regulations specify the requirements for a small renewable energy generator to connect to the grid. These include the discussion of responsibilities for each party (utility or customer generator); criteria for synchronization (acceptable voltage levels, frequency, power factor, harmonics); required protection relays, and provisions for emergency disconnect.

Some of the features of the regulations are worthy of note. First, they allow renewable energy generators to export up to 1 MW of electricity. The focus on electricity export allows systems larger than 1 MW to connect as long as the customer consumes sufficient electricity on-site. Second, the regulations provide for aggregate net metering. Aggregate net metering allows an entire renewable energy generating community to connect as a single customer and manage their own distribution. Aggregation, however, is allowed only for new customers, i.e., the arrangement must not "steal" existing customers from the utility. Third, net metering regulations combined with time-of-use (TOU) metering allow the possibility of increasing revenues by generating electricity during peak tariff

[10] The total capacity supplied by any SPP to the Power Utility system is not supposed to exceed 60 MW at the connection point.

hours (9am to 9pm) and consuming less expensive electricity during off-peak hours. This arrangement is expected to be of particular benefit to solar electric systems (which inherently produce during day-time peak hours) and renewable energy technologies such as biogas and biomass, which can store fuel. The details of this regulation are explained in the subsequent sections.

Dominant Renewable Energy Policy Instrument: Net Metering System

Thailand has recently introduced net metering legislation that provides streamlined procedures for small renewable energy generators to connect to the grid, and guarantees both a market and good prices. The new laws create income opportunities for rural communities based on locally produced, clean, renewable energy supplies and offer significant potential to reduce Thailand's dependence on imported oil and coal.

In May of 2002, Thailand's Cabinet passed landmark renewable energy legislation requiring the country's electric utilities to allow solar, wind, micro-hydroelectricity, biomass or biogas generators up to 1 MW per installation to connect to the grid. The regulations provide for net metering, which means renewable energy producers can literally "spin the meter backwards". Under this arrangement, generators that produce less than they consume in a monthly period receive the retail tariff rate for electricity fed onto the grid. For net excess production, producers are compensated at the "bulk supply tariff" - which is the average cost of generation and transmission in Thailand and is about 80% of the retail rate.

As per the Regulations of the Purchase of Power from Very Small Renewable Energy Power Producers (VSREPP), a VSREPP can be a generator of the private sector, state agencies, state-owned enterprises or general public, with his own generating unit and who sells no more than 1 MW of electrical power to a Distribution Utility. The Distribution Utilities are the sole purchasers of power from the VSREPP. The amount of net power each VSREPP dispatches into the distribution system at the connection point will not exceed 1 MW. The Distribution Utility is required to consider capability and security of the distribution system in determining the level of net power acceptable on a case-to-case basis, in accordance with the Technical Regulations. The Distribution Utilities are required to purchase power from a VSREPP at the point at which the meter that measures the amount of power sold by a VSREPP to a Distribution Utility is located (Purchasing Point).

As of September 2003, twenty-three applications had been submitted to connect net-metered systems. Most of these are small rooftop solar electric systems under 5 kW peak, but there are four significantly larger plants including a 400 kW woodchip-fired generator, a 950 kW municipal waste biogas digestor and a 1 MW rice-husk fired plant.

Under the new regulations, one net-metered generator has already come on-line, a 3.1 kW solar electric installation.

Applicants in the near future are expected to include significant numbers of small rooftop solar electric systems, biogas digestors at pig farms, community micro-hydroelectric generators, biomass-fired generation in rice and palm mills, and possibly wind turbines. Photovoltaics are poised for growth in Thailand. There are already 64 grid-interconnected solar electric systems in the country, although they predate the new regulations and are not yet under the net metering program. Since the technology to interconnect solar electricity is well established, these systems offer easy first steps for Thai utility personnel.

General Pricing Principle

The 2 regulations that have been issued by the National Energy Policy Council, namely, the 'Regulations for the Purchase of Power from Small Power Producers (SPPs)' issued initially in January 1998 and later revised in August 2001, and 'Regulations for the Purchase of Power from Very Small Renewable Energy Power Producers', issued in May 2002 have some distinct pricing features that are highlighted below.

'Regulations for the Purchase of Power from Small Power Producers (SPPs)'

1. Capacity Payment (Section J, Clause 1-2)

- The capacity payment is determined from the Electricity Generating Authority of Thailand's (EGAT) long-run avoided capacity cost in purchasing electricing from SPPs. The capacity payment is then determined from the contracted term that the SPP will generate and supply electricity to the power utility as follows –

	Length of contract	Capacity Payment
o	Not exceeding 5 years	No Capacity Payment
o	Exceeding 5 years to 25 years	Equivalent to the long-run avoided capacity cost during the contracted term that the SPP generated and supplies electricity

2. Energy Payment

- For any SPP that is eligible for capacity payment, the energy payment is determined from EGAT's long-run avoided energy cost resulting from purchasing electricity from the SPP
- For any SPP that is not eligible for capacity payment, the energy payment is determined from EGAT's short-run avoided energy cost resulting from purchasing electricity from the SPP
- The energy payment is based on the 'time of day' as follows:

- *Energy Payment during the Peak Load*: is equivalent to the fuel cost and the operating and maintenance costs of the power plant which will be avoided or which will reduce electricity generation during peak load
- *Energy Payment during the Partial Peak Load*: is equivalent to the fuel cost and operating and maintenance costs of the power plant which will be avoided or which will reduce electricity generation during partial peak load
- *Energy Payment during the Off Peak Load*: is equivalent to the fuel cost and the operating and maintenance costs of the power plant which will be avoided or which will reduce electricity generation during off peak load

- If the SPP's meters are unable to measure the energy supplied during the above times of day, the energy payment is equal to the average rates of the three periods

'Regulations for the Purchase of Power from Very Small Renewable Energy Power Producers (VSREPPs)'

The criteria in determining the tariff rates for selling and purchasing of power to/from VSREPPs are developed based on the following principles: (Section H)

1. For a (monthly) billing period in which a VSREPP consumes more electricity than it generates (net energy consumption), the Distribution Utility will charge the VSREPP only for the net amount of electricity consumed at the retail base tariff rate that is applicable to the VSREPP's customer category plus the retail fuel (automatic adjustment) charge for that month.
2. For a billing period in which a VSREPP consumes less electricity than it generates (net energy generation), the Distribution Utility will buy the net amount of electricity generated by the VSREPP at the average bulk supply tariff rate that the Electricity Generating Authority of Thailand sells to the two Distribution Utilities plus the average wholesale fuel charge for that month.
3. For VSREPPs that have a TOU meter(s) and wish to sell electricity using the TOU tariff rate, the Distribution Utilities will purchase the electricity at the bulk supply tariff rate (which depends on the time of use) plus the average wholesale fuel charge for that month. The VSREPPs shall still pay for other non-energy components of the total electricity tariffs in accordance with the VSREPPs' respective customer categories.

Grid Interconnection conditions

Both the regulations that have been issued by the National Energy Policy Council, very clearly indicate the requirements and expenses that have to be incurred by the Obligatory Party for grid interconnection. The responsibility of the SPPs and VSREPPs are outlined below. Further, the criteria for synchronization of the VSREPP to the Distribution Utility System is also explained in substantial detail in the Technical Regulations for VSREPPs.

'Regulations for the Purchase of Power from Small Power Producers (SPPs)'
Expenses of the SPPs (Section G)

1. Cost of System Interconnection: which includes the costs of the transmission and distribution system of the SPPs and the power utility, the meters, the protective devices and other expenses arising from undertaking purchasing electricity from SPPs
2. Cost of Equipment Inspection: which refers to cost of inspection of the SPP's equipment and devices that are connected to the power utility system and the expenses to be incurred from corrective actions that may arise that are in addition to the normal practices of the power utility.

'Regulations for the Purchase of Power from Very Small Renewable Energy Power Producers (VSREPPs)'
Costs to be Incurred for VSREPPs (Section G)
A VSREPP is responsible for the following costs:

1. Costs of system interconnection comprising the costs of upgrading the distribution system from the connection point to the VSREPP's generation system, costs of a meter, costs of protective equipment (unless the generation system already has embedded protective features) and costs of testing equipment. VSREPPs connected to the low-voltage distribution system are exempted from paying the costs of interconnection study by the Distribution Utilities. A VSREPP shall pay for the entire costs of connection before the Distribution Utility starts the connection process.
2. Costs of equipment checking comprising the costs of checking a VSREPP's generation and interconnection equipment (regardless of whether the checking is done in accordance with the Distribution Utility's regulations or at the request of the VSREPP), and the incurred operating costs that are additional to the utility's normal operating costs. A VSREPP is required to be responsible for the costs of equipment checking only in the case where the utility finds, after checking, that there is a problem attributable to the VSREPP.

A VSREPP shall pay the costs of equipment checking to the Distribution Utility within 30 days from the date it receives a bill from the utility.

China

Background

The Government strategy also emphasizes the importance of development of renewable energy to reduce the power sector's heavy reliance on coal, in order to reduce GHG, TSP, NO, and SO2 emissions. Energy is the largest source of GHG emissions worldwide, and China accounts for 10 percent of GHG emissions from energy use, behind the United States (21 percent), the former Soviet Union (18 percent), and Europe (21 percent). China's share is expected to grow because of its low energy consumption per capita, the size of its population and its rapid economic growth. However, macroeconomic and energy modeling work show that an aggressive program to promote energy conservation and renewable energy could limit the increase in GHG emissions between 1990 and 2020, under a high economic growth scenario, from a threefold increase to less than twofold.2 Reducing local environmental damage from coal use is also essential, as annual health and agricultural losses associated with coal-related air pollution in China are estimated to be as high as 6 percent of gross domestic product (GDP). China's long-term energy strategy for rural development has relied and will continue to rely heavily on renewable energy. China has strongly supported small hydropower (less than 25 MW), biogas, and small wind turbines over the past 35 years, to provide energy and electricity to isolated rural populations. In 1995, the Government of China (GOC) renewed its commitment to renewable energy, in the New and Renewable Energy Development Program, 1996-2010, jointly developed by the State Development Planning Commission (SDPC, formerly the State Planning Commission), the Ministry of Science and Technology (MST, formerly the State Science and Technology Commission-SSTC) and SETC. This program aims at improving the efficiency of renewable energy technologies, lowering production costs and increasing its contribution to energy supply. The 1995 Electricity Law also extends support to solar, wind, geothennal and biomass energy for power generation.

Renewable Energy Policy Experience

The Chinese government has taken a conscious effort to develop renewable energy resources. Starting with the Eighth Five-Year Plan, renewable energy development and utilization have been an important part of the national development strategy. The Chinese government enacted the Electric Power Act in 1995 that explicitly encouraged the power grid to employ renewable energy resources for electricity generation. The Government issued the "Parallel Operation Regulations for Wind Power Generation" in 1996 that required power grid to purchase energy from wind farms and established a pricing principle. These two initiatives have had considerable impact on the renewable energy development in China. However, the Government mandate in China differs considerably from those of the developed countries. The Chinese laws enacted to support renewable energy policies usually contain a general framework. They describe the intent of the law and cover basic principles, but they lack detailed implementation rules and regulations and specific implementation targets. Although they afford government agencies maximum flexibility in executing, the drawbacks of nonuniform interpretation of the laws and lack of specific policy goals often hinder the actual implementation. Similarly, on account of economic incentive options for publicly leveraged market driven deployment of RETs, while developed countries' financial subsidies are geared more towards actual production of electricity from renewables (such as the PTC in US), the Chinese government subsidies are more focussed on the capital investment of RETs. Finally, there also exists a market difference in the pricing policies for renewables in China and the some of the developed countries such as the US. For instance, In the United States, 1978 PURPA specified utility's avoided cost as purchasing price for renewable energy generated electricity. Chinese government issued a pricing principle in 1994 requiring power grid to include production cost, debt service, taxes, and reasonable profits in determining purchasing price of wind energy. The difference is PURPA price applies to all renewables and is enacted by the Congress, but the Chinese pricing principle is only for wind power and is issued by the Government as an executive order. In the United States, the costs of price policies are borne by individual electric utility customers. In China it is borne by the customers of the entire power grid.

Recently China came out with `Renewable Energy Law'. The salient features of this law, which will become effective on January 1, 2006, with regard to the pricing and grid interconnection issues, are given in the subsequent sections.

Box4: Chinese Renewable Energy Law, January 1, 2006 – Salient Features

Article 5
The Energy authorities of the State Council would be responsible for the development and utilization of renewable energy at the national level.

Article 13
The process of bidding would be adopted if there is more than one applicant for project license for the renewable power generation projects.

Article 14
Grid enterprises shall enter into grid connection agreement with renewable power generation enterprises (that have legally obtained administrative license or have applied for the same) and buy the power produced within their coverage area. The grid enterprises would provide grid access to renewable power generation companies.

Article 15
The Government supports the construction of independent renewable power systems in areas not covered by the power grid to provide power service for local production and living.

Article 18
The Government encourages and supports the development and utilization of renewable energy in rural areas. The government would provide financial support for the renewable energy utilization projects in the rural areas.

Article 19
The Price Authorities of the State Council would determine the tariff for renewable energy power generation projects. The guiding principle is that the tariff would (a) encourage development and utilization of renewable energy and (b) be economic and reasonable. It is proposed that timely adjustment would be made on the basis of the development of technology. For those projects where bidding has been carried out, the tariff would not exceed the aforementioned tariff.

Article 20
The difference between the price of RE power and the average price of the conventional power would be shared in the selling price.

Article 21
Grid connection expenses paid by grid enterprises for the purchase of renewable power and other reasonable expenses may be included into the power transmission cost and recovered from the selling price.

Article 29
If the power grid enterprise fails to purchase renewable power fully, resulting in economic loss to the renewable power generation enterprises; the power grid enterprises shall be liable for compensation for this loss. Moreover, the power grid enterprise would be required to take remedial measures within a stipulated period of time; failing which it would be penalised.

Pricing Principles

The Price Authorities of the State Council determine the tariff for renewable energy power generation projects. The guiding principle is that the tariff would –

(a) encourage development and utilization of renewable energy and
(b) be economic and reasonable. It is proposed that timely adjustment would be made on the basis of the development of technology. For those projects where bidding has been carried out, the tariff would not exceed the aforementioned tariff.

The difference between the price of renewable energy power and the average price of the conventional power is to be shared in the selling price.

For the selling price of power generated from independent renewable energy power system invested or subsidized by the Government, classified selling price of the same area is to be adopted, and the excess between its reasonable operation, management expenses and the selling price shall be shared in the selling price.

Further, the Act states that if the power grid enterprise fails to purchase renewable power fully, resulting in economic loss to the renewable power generation enterprises; the power grid enterprises shall be liable for compensation for this loss. Moreover, the power grid enterprise would be required to take remedial measures within a stipulated period of time; failing which it would be penalised.

Grid Interconnection Experience

Grid enterprises are required to enter into grid connection agreement with renewable power generating enterprises that have legally obtained an administrative license, and buy the grid-connected power produced with renewable energy within the coverage of their power grid, and provide grid-connection service for the generation of power with renewable energy.

Grid connection expenses that are paid by grid enterprises for the purchase of renewable power and other reasonable expenses are to be included into the power transmission cost and recovered from the selling price.

Vietnam

Background

Vietnam has introduced institutional reforms in the mid-1990s and established state energy enterprises as state corporations under the legal purview of the Law of State Enterprises and Law of Government Corporation. The Electricity of Vietnam (EVN) was established in 1995 as a state corporation under the policy and oversight of the Ministry of Industry (MOI), the body mainly responsible for energy policy and planning.

Despite EVN's progress on its rural electrification program and the government's target of 90% rural household electrification rate in 2010, there remains around 1000 communes representing about 500,000 households and more than 2 million people outside of the EVN grid expansion program. Furthermore, there exists households in electrified communes that cannot be economically connected to the grid.

Private investments for renewable energy however remain relatively low despite the existence of renewable energy supportive policies. This is because there are several barriers to renewable energy development in the country, which include, lack of policy mechanisms, awareness, commercial capability, financing mechanisms, high quality technology and resource data information.

Renewable Energy Policy Experience

To address these barriers, the MOI and EVN have launched the Renewable Energy Action Plan (REAP). REAP is a 10-year programme divided into 2 phases: institutional and capacity building in phase 1, and project implementation in phase 2. REAP aims "to support an acceleration of renewable electricity production to meet the needs of isolated households and communities that cannot receive electricity services from the national grid, and to supplement grid supply cost effectively in remote areas."

Project components

REAP identifies 5 programme components, 3 of which are areas where renewable energy could be developed for electricity generation. These are:

A) Individual renewable energy systems

Individual renewable energy systems are aimed for households and institutions that are geographically dispersed and have relatively small loads, where the extension of the national grid or development of isolated grids is not economically feasible. REAP identified pico-hydro and solar PV systems as candidate technologies.

Policy Intervention

Under this project component, preliminary market assessments in Vietnam indicate that out of the 750,000 households that will not be connected to the grid in the next 10 years, about 200,000 households could best be served by isolated systems. For the first five years, the programme intends to support the installation of 25-50 thousand units, and in the subsequent five years, this would increase to 60-100 units.

REAP plans to mobilize commercial companies as the main providers of the stand-alone systems. It also proposes to provide ‘smart’ subsidies for marketing outreach and development of after-sales service networks, and access to working capital. The subsidies will then be gradually removed with economies of scale, reductions in technology supply costs and rising consumer incomes.

B) Community isolated hydro grids

REAP proposes the development of community isolated hydro grids in Northern and Central communities of Vietnam. Preliminary studies show that 700 communes, which will not be electrified before 2005, have small hydro resources potential suitable for commune based hydropower system.

Policy Intervention

The first phase of the programme aims to provide electricity services to around 10-40 thousand households in 20-80 sites. The aggregate capacity of the systems is around 2-6MW. However, electricity generation from the operation of small hydro-grids would be unaffordable without a capacity cost subsidy provided to the commune level cooperative system. Some of the potential sources of capital cost subsidies include current programmes such as the Government of Vietnam - supported Project 165 Poverty Alleviation Programme, JBIC – supported Rural Infrastructure Development and Living Standard Improvement Project and the World Bank – supported community-based Rural Infrastructure Project.

C) Grid-connected renewable energy

The 2 main components of grid-based renewable energy systems under REAP are: non-utility investment and rehabilitation of EVN-owned mini-hydro projects. The government encourages renewable energy electricity investments for grid supply by non-utility public and private enterprises, cooperatives and other non-governmental organizations. The investments will be for small power plants using hydropower, biomass, wind and geothermal resources.

Policy Intervention

Under this programme component, some of the issues that are being reviewed by EVN to encourage non-utility investments are:

- Notification issue to purchase power from Small Power Purchase Agreement (SPPA);
- Establishment of a transparent and streamlined approval and contractual processes;
- Financing facilitation;
- Development of a fair purchase contract and price under the SPPA.

The existing power purchase tariffs based on negotiated agreements along with the proposed SPPA for Vietnam are highlighted in the table below.

Table 1.7: Economic avoided costs and power purchase tariffs

	Average tariff (VND per kWh, equivalent)
Economic avoided costs	
Energy only	427
Energy + Capacity	750
Proposed small power purchase tariff	
Energy only	420
Energy + Capacity	602
Existing negotiated agreements	
Vietnam Bourbon Sugar Mill (max 12 MW; Energy + Capacity)	609
Other sugar mills (energy only)	400 – 440
Duy Son II Coop, small hydro (energy only)	351

SOURCE: ESMAP, 2002
Exchange Rate: 1US$ = 14.522 VND (2002)

This clearly shows that the proposed SPP tariff is relatively lower than the estimated economic avoided costs.

Sri Lanka

Background

Sri Lanka's population was around 19,905,165 in 2003, with population growth rate of 0.81%. At the beginning of year 2002, only 65% of the population had access to electricity from the national electricity grid. When the planned electrification schemes are implemented, it is expected that 77% of the population will have access to electricity by year 2006. Present installed capacity of the system is 1758.5 MW, which needs to rise to about 4524 MW by 2017. At the instance of Energy Supply Committee (ESC), in 2002, total of 270 MW of emergency plants were connected to the system by private parties. The existing generating system in the country is still predominantly owned by the Ceylon Electricity Board, which is about 76% of the total existing capacity. Balance is owned by IPPs. While presently, Sri Lanka depends heavily on its hydro resources for electricity generation, in the drought year's government had to cope up with conflicting demands for hydro-power, irrigation and drinking water. As per CEB's long term generation expansion plan, present share of the thermal capacity at 37% will be increased to 54% by the year 2010 and to 67% by the year 2017. All fossil fuel-based thermal generation in Sri Lanka would continue to depend on imports.

In Sri Lanka, the installed capacity of the power system comprises 1828 MW of Ceylon Electricity Board (CEB) owned plants, 455 MW of independent power producers (IPPs) excluding 76 MW as on April 2005 of grid connected renewable energy based embedded generation (from Small power Plants, <10 MW). The contribution of IPPs in annual generation during 2004 was 3252 GWh (approx. 42.7% of total power generation) while the contribution of SPPs was approximately 2.4% of total generation. Further, over 50,000 homes in Sri Lanka have been electrified through solar home systems by Sept 2004, and the number is growing at about 1,400 per month. Thus, over 1% of the total number of households in Sri Lanka use renewable energy technologies. The national target is to have 10% of electricity capacity from renewable energy technologies. Ministry of Power and Energy is the National Agency responsible for renewable energy development.

The dominant renewable energy technologies for electricity generation in Sri Lanka, presently comprise of small and mini hydropower plants, biomass based plants and wind power plants.

Pricing Principle

The present method of pricing RETs in Sri Lanka estimates the avoided marginal cost as a result of small power projects added in the national grid. In this method, the variable costs of operation of Ceylon Electricity Board's (CEB) thermal plants and Independent Power Producers (IPPs) are calculated (after adjusting for losses at the 33 kV level).

Thereafter, on the basis of projected load duration curve, the (monthly) fraction of time that a particular thermal plant operates in the margin is estimated. The fraction of time for which the particular power plant operates in the margin is then used as weighting factor to the respective variable costs of operation of each thermal plant in order to obtain the monthly weighted marginal energy cost, also called as the monthly avoided energy cost.

The avoided cost is then computed separately for the dry season (February to April) and the wet season (May to December and January). The seasonal tariff that is announced by CEB every year is a 3-year moving average of the last 3 years avoided energy costs. If the announced tariff for a particular year falls below 90% of the tariff during the year in which the SPPA was signed for a given SPP, the tariff applicable will be the tariff of the previous year.

A committee, comprising CEB officials undertake the exercise of avoided cost estimation every year. This includes projection of demand, simulations for estimation of plant factors and estimation of fraction of time that a particular power plant would operate in the margin along with the estimation of variable costs of the thermal power plants. The tariff is then published along with all the assumptions and data.

The present method does not calculate separate capacity credits. Further the variable cost of the thermal plants is estimated on the basis of the fuel (diesel) prices (CIF basis) applicable at the time of calculation (typically the month of November for the tariff calculations of the subsequent year). However, this method is likely to undergo a change, shortly.

The box below summarizes the existing small hydropower tariff setting process in Sri Lanka.

Box 5: Small hydropower tariff setting methodology in Sri Lanka

The variable cost of each thermal plant is estimated based on the average fuel cost of each thermal plant (given the fuel prices, heat content and heat rate data). The fuel costs are then adjusted for station losses and transmission losses (all thermal plants connected at 132 kV and above). This gives the variable costs at 33 kV level (in LKR/ kWh) for each plant.

The expected energy to be delivered from each power plant during each month of a particular year is estimated by the utility, Ceylon Electricity Board (CEB), using a short-term demand-forecasting model.

Using monthly (plant-wise) energy delivered, plant capacity, the plant factor (or capacity factor) is calculated for each month.

The time for which a particular plant operates at margin is estimated by stacking the power plants with increasing order of variable costs. The thermal plants are stacked in an increasing order of variable costs such that those plants which are most expensive, are run for the shortest margin of time followed by the next most costly plant and so on.

The avoided cost is the weighted average of avoided variable costs of the thermal power plants (the weighting factors being the fraction of time that each plant would operate in the margin).

$$\text{Monthly avoided cost} = \sum_{i=1}^{i=n} \text{monthly fraction of time}_i \times \text{variable cost}_i$$

Where,

n – Thermal Plants

The Avoided Costs are averaged separately for the Wet Season (May – January) and the Dry Season (February – April).

The Published Small Power Purchase Tariff for a particular year that is announced on 1st December of the previous year is a 3-year moving average of the last three years avoided cost.

Note 1: Key provisions of Renewable Energy Sources Act, 2004

Article 4
Obligation to purchase and transmit electricity

1. Grid system operators shall immediately and as a priority connect plants generating electricity from renewable energy sources or from mine gas to their systems and guarantee priority purchase and transmission of all electricity from renewable energy sources or from mine gas supplied by such plants. After establishment of a register of installations pursuant to Article 15(3), such obligation for the purchase pursuant to the first sentence above shall apply only if the plant operator has submitted an application for entry into the register.

   Notwithstanding Article 12(1), plant operators and grid system operators may agree by contract to digress from the priority of purchase, if the plant can thus be better integrated into the grid system. When determining the charges for use of the grid, grid system operators may add any costs incurred in accordance with a contractual agreement pursuant to the third sentence above, provided that such costs are substantiated.

2. The obligation under paragraph (1) first sentence above shall apply to the grid system operator that is most closely located to the plant site and is in possession of a grid technically suitable to receive electricity if there is no other grid with a technically and economically more suitable grid connection point. A grid shall be deemed to be technically suitable even if – notwithstanding the priority established under paragraph (1) first sentence above – feeding in the electricity requires the grid system operator to upgrade its grid at a reasonable economic expense; in this case, the grid system operator shall upgrade its grid without undue delay, if so requested by a party interested in feeding in electricity. If the plant must be licensed in accordance with any other legal provisions, the obligation to upgrade the grid in accordance with the second sentence above shall only apply if the plant operator submits either a license, a partial license or a preliminary decision. The obligation to upgrade the grid shall apply to all technical facilities required for operating the grid and to all connecting installations which are owned by or passed into the ownership of the grid system operator.

3. The obligation for priority connection to the grid system pursuant to paragraph (1) first sentence above shall apply even if the capacity of the grid system or the area serviced by the grid system operator is temporarily entirely taken up by electricity produced from renewable energy sources or mine gas, unless the plant does not have a technical facility for reducing the feed-in in the event of grid overload. The obligation pursuant to paragraph (1) first sentence above for priority purchase of the electricity produced in these plants shall apply only if the capacity of the grid system or the area serviced by the grid system operator is not already used up by electricity produced in other plants generating electricity from renewable energy sources or mine gas which were connected prior to these plants; the obligation to upgrade the grid system without undue delay pursuant to paragraph (2) second sentence above shall remain unaffected. In the event of non-purchase of such electricity, the grid system operator shall, if so requested by the plant operator, provide proof of fulfilment of the conditions set out in the second sentence above in writing within four weeks and produce verifiable calculations.

4. The relevant data on the grid system and on the electricity generation plants, which are required to test and verify the grid compatibility, shall be presented upon request within eight weeks where this is necessary for the grid system operator or the party interested in feeding in electricity to do their planning and to determine the technical suitability of the grid.

5. The obligation for priority purchase and transmission of electricity in accordance with paragraph (1) first sentence above shall also be applied, if the plant is connected to the grid of a plant operator or a third party who is not a grid system operator within the meaning of Article 3(7) and if the electricity is offered to a grid system in accordance with Article 3(6) via a merely budgeted transit through this grid system.

6. The upstream transmission system operator shall guarantee priority purchase and transmission of the quantity of energy purchased by the grid system operator in accordance with paragraph (1) or (5) above. If there is no domestic transmission system in the area serviced by the grid system operator entitled to sell electricity, the most closely located domestic transmission system operator shall purchase and transmit electricity in accordance with the first sentence above. The first sentence above shall apply mutatis mutandis to other grid system operators.

Article 5
Obligation to pay fees

1. Pursuant to Articles 6 to 12, the grid system operators shall pay fees for electricity generated in plants exclusively using renewable energy sources or mine gas and purchased in accordance with Article 4(1) or (5). The obligation in accordance with the first sentence above shall only apply to plants with a capacity of over 500 kilowatts where the capacity is measured and recorded.
2. Pursuant to Articles 6 to 12, the upstream transmission system operator shall pay for the quantity of energy which the grid system operator has purchased in accordance with Article 4(6) and paid for in accordance with paragraph (1) above. Any avoided charges for use of the grid system, calculated in accordance with good professional practice, shall be deducted from the fees. Article 4(6) second sentence shall apply mutatis mutandis.

Article 13
Grid costs

1. The costs associated with connecting plants generating electricity from renewable energy sources or from mine gas to the technically and economically most suitable grid connection point and with installing the necessary measuring devices for recording the quantity of electrical energy transmitted and received shall be borne by the plant operator. In the case of one or several plants with a total capacity of up to 30 kilowatts located on a plot of land which already has a connection to the grid, this plot’s grid connection point shall be deemed to be its most suitable connection point; if the grid system operator establishes a new connection point for the plants, he shall bear the resulting incremental cost. Implementation of this connection and the other installations required for the safety of the grid shall meet the plant operator’s technical requirements in a given case as well as the provisions of Article 16 of the Energy Industry Act. The plant operator may have the connection and the installation and operation of measuring devices implemented either by the grid system operator or by a qualified third party.

2. The costs associated with upgrading the grid in accordance with Article 4(2) that solely result from the need to accommodate new, reactivated, extended or otherwise modernized plants generating electricity from renewable energy sources or from mine gas for the purchase and transmission of electricity produced from renewable energy sources shall be borne by the grid system operator whose grid needs to be upgraded. He shall specify the required investment costs in detail. The grid system operator may add these costs when determining the charges for use of the grid.

Article 14
Nation-wide equalisation scheme

1. The transmission system operators shall record the different volumes of and periods of generation of energy paid for in accordance with Article 5(2) as well as the fees paid, and provisionally equalise such differences amongst themselves without undue delay and settle the accounts with regard to the quantities of energy and the fees paid pursuant to paragraph (2) below.
2. By 30 September of each year, the transmission system operators shall determine the quantity of energy purchased and paid for in the previous calendar year in accordance with Article 5 and provisionally equalised in accordance with paragraph (1) above, and the percentage share of this quantity in relation to the total quantity of energy delivered to final consumers by the utility companies in the area served by the individual transmission system operator in the previous calendar year. If transmission system operators have purchased quantities of energy that are greater than this average share, they shall be entitled to sell energy to and receive fees from the other transmission system operators in accordance with Articles 6 to 12, until the other grid system operators have purchased a quantity of energy equal to the average share.
3. Utility companies which deliver electricity to final consumers shall purchase and pay for that share of the electricity which their regular transmission system operator purchased pursuant to the provisions of paragraphs (1) and (2) above in accordance with a profile made available in due time and approximated to the actually purchased quantity of electricity pursuant to Article 4 in conjunction with Article 5. The first sentence above shall not apply to utility companies which, of the total quantity of electricity supplied by them, supply at least 50 per cent in accordance with the provisions of Articles 6 to 11. The share of the electricity to be purchased by a utility company in accordance with the first sentence above shall be placed in relation to the quantity of electricity delivered by the utility company concerned and shall be determined in such a way that each utility company will receive a relatively equal share. The compulsory quantity to be purchased (share) shall be calculated as the ratio of the total quantity of electricity paid for in accordance with Article 5(2) to the total quantity of electricity sold to final consumers. The fees as specified in the first sentence above shall be calculated as the expected average fees per kilowatt-hour paid by all grid system operators combined two quarters earlier in accordance with Article 5, less the charges for use of the grid avoided pursuant to Article 5(2) second sentence. The transmission system operators shall assert claims held against the utility companies in accordance with the first sentence above that arise from equalisation in accordance with paragraph (2) above by 31 October of the year following the feeding-in of electricity. Equalisation for the actual energy quantities purchased and the fees paid shall take place in monthly instalments before 30 September of the following year. Electricity purchased in accordance with the first sentence above may not be sold below the fees paid in accordance

with the fifth sentence above if it is marketed as electricity produced from renewable energy sources or as comparable electricity.

4. If a valid court decision in the principal case issued after a billing statement pursuant to paragraph (2) first sentence or paragraph (3) above leads to any changes regarding the quantities of energy to be billed or the payments of fees due, such changes shall be taken into account in the next billing statement.

5. Monthly instalments shall be paid on the expected equalisation payments.
6. Grid system operators that are not transmission system operators and utility companies shall without undue delay make available the data required to perform the calculations referred to in paragraphs (1) to (5) above and present their final accounts for the previous year by 30 April. Grid system operators and utility companies may request that final accounts pursuant to the first sentence above be certified by 30 June and final accounts pursuant to paragraph (2) above by 31 October by a chartered or certified accountant. Plant operators shall make the data required for the final accounts of the previous year available by 28 February of the following year.
7. Final consumers who purchase electricity not from a utility company but from a third party are placed on an equal footing with utility companies as defined in paragraphs (2) and (3) above.
8. The Federal Ministry for the Environment, Nature Conservation and Nuclear Safety is authorised, in agreement with the Federal Ministry of Economics and Labour, to issue an ordinance setting out the provisions on
   1. the organisational and temporal framework for equalisation pursuant to paragraph (1) above, in particular with a view to determining the responsible party and ensuring optimum and equal forecasting options with regard to the quantities of energy to be equalised and burden trends;
   2. determining or identifying a uniform profile in accordance with paragraph (3) above, on the question of when, including the run-up period, and how such a profile and the underlying data are made available and on
   3. the specification of the data required in accordance with paragraph (6) above and how such data are to be made available.

Note 2: Planning of the grid integration of wind energy in Germany onshore and offshore up to the year 2020 – Summary of findings

Scenarios of wind energy development

Assumptions:

The capacity that can be installed on the area assigned to wind energy use is determined on the basis of an average area required of 7 ha/ MW (1 ha = 2471 acres). Taking into account the wind turbines already installed by the end of 2003, it was possible to determine the potential still remaining in suitable areas.

Out of the wind turbines installed after 1998, one-third will be replaced after 12, one-third after 15 and one-third after 20 years, with a factor of 1.4 for the growth in capacity due to repowering.

Summary of forecasted installed capacity of wind energy development for years 2007, 2010, 2015 and 2020 (cumulated, figures in MW)

Year	Onshore	Repowering (growth)	Offshore	Total
2007	21,620	768	476	22,864
2010	24,540	1503	4382	30,426
2015	26,544	3601	9793	39,938
2020	26,544	7056	20,358	53,958

Effects on the grid

Necessary system extension over the time horizons 2007, 2010 and 2015

Up to the time horizon 2015, it has been indicated that there will be a need for approximately 850 km of 380-kV transmission routes to transport the wind power to the load centres. In addition, it has been highlighted that numerous 380 kV installations will need to be fitted with new components for an active power flow control and reactive power generation. On the basis of the assessed regional distribution, the integration of a total of 36 GW of wind power capacity into the German transmission system will be possible. This wind power is in line with the target of a 20% share of all renewable energy in the German electricity supply that the Federal Government wants to achieve by the year 2020 at the latest.

Table: Overview of major system extensions (cumulative figures)

	By 2007	By 2010	By 2015	By 2020[a]
Construction of new 380 kV routes	5 km	460 km	850 km	1900 km
System reinforcement of existing routes	270 km	370 km	400 km	850 km
Quadrature regulators	3	3	3	4
Reactive power compensation	3600 Mvar	6600 Mvar	7350 Mvar	10,850 Mvar

a – Provisional results

The study indicates that the total costs for the transmission system extension necessary up to the time horizon 2015 are approximately 1.1 billion euros. The investigated solutions for the time horizon 2020 are restricted to stationary observations for determining the necessary transmission line cross sections. The estimated cost of extending the transmission system up to the year 2020 amount to approximately 3 billion euros in total.

The specific installation costs (excluding system connection costs) for installed wind power of between 20 and 40 GW are approximately 50 euros per kW. This does not include the land and marine cable connections to the offshore WEP. The costs of these connections for connecting approximately 10 GW in the North Sea and the Baltic Sea up to the time horizon 2015 are estimated at approximately 5 billion euros in total. These are classed as system connection costs to be added and included under construction costs for the wind power plant and hence, funded by the European Commission (EC) infeed payments.

Impact on supply reliability

The grid related problems arise particularly because wind energy is available to the extent required neither in the right location nor at the right time.
Existing wind power plants connected to high and medium voltage grids are immediately disconnected from the grid in the event of grid-faults to prevent damage to the wind power plant and to observe the safely criteria in the distribution systems. However, conventional generation units are obligated to maintain their supply and to support the system stability in line with the system connection conditions even in problem situations.
For wind power plants, this problem can be solved for new plants with the aid of advanced technology and more complex integration into the grids. The improved system support from the new plants and replacement of the old plants by repowering will therefore result in a continuous reduction in the wind power outage capacity in the event of grid problems for the time horizons 2007 and 2010.

Effects on demands placed on conventional power plant system

Due to the dependence of the electricity supply from wind power plants on a very changeable wind availability, only a small proportion of the installed wind power capacity can contribute to the reliable capacity among a conventional and regenerative power plant mix. Depending on the time of year, the gain in guaranteed capacity from wind based plants as a proportion of the total installed wind power capacity is between 6% and 8% in the case of an installed wind power plant capacity of around 14.5 GW (in 2003) and between 5% and 6% in the case of an installed wind power capacity of around 36 GW (in 2015).

In the year 2007, mostly electricity generation from natural gas and hard coal power plants, which have higher generation costs with lignite and nuclear power plants, will be displaced. In the years 2010 and 2015, the electricity generation that has been displaced by additional wind based power generation will depend significantly on the (expected) fuel-price development. As a result of the volatile wind power generation and associated reduction in the average capacity utilization of conventional power plants, the new construction of capital-intensive power plant technologies to cover base and lower medium load will be less cost-effective. Flexible peak load power plants such as gas turbines, of which an increasing number will be built due to expansion of wind energy, mainly serve to cover the additional short and long-term regulating and reserve requirement and hardly change electricity generation based on fossil fuels.

Effects of the additional wind power based infeed on electricity generation costs

The increased electricity feed-in from renewable energies avoids the need for electricity generation in conventional power plants and, thereby also avoids fuel costs related to generation. It also results in a change to the power plant mix, thereby also altering the fixed maintenance costs and capital costs. The sum of the cost changes arising from these effects can be regarded as cost reductions in the conventional power plant system.

The absolute net costs will continue to expand between the year 2007 and 2015, as wind power-based electricity generation will increase significantly. While in the year 2007 about 830 and just under 860 million euros (2003) will be incurred in net costs for the expansion of wind energy, the additional net costs will rise in the year 2015 – depending on the assumed fuel-price development – to 1.6–2.3 billion euros (2003).

Increases of electricity prices for end user consumption through the support of renewable energies

The costs of the promotion of electricity generation based on renewable energies according to the RES act are allocated to the end-users of electricity. There will be an average purchasing costs increase of electricity for end-users through the expansion of wind power electricity generation of approximately 1.3 euros (2003) per MWh in the year 2007 that will rise to between 3.3 and 4.2 euros (2003) per MWh by the year 2015 – depending on the assumed fuel-price development.

Annex 2: Summary of Renewable Energy Tariff Orders passed by different SERCs

Table 2.1: Renewable Energy Tariff Orders issued by different SERCs

States	Tariff Orders for RE sources
Andhra Pradesh	- Tariff Order for determination of tariff applicable to Non-conventional energy projects in AP: April 2004 (Wind, mini-hydel, biomass, bagasse, municipal waste, industrial waste) - Review petition on 'tariff for biomass-based power generation': July 2004 - Review petition on 'tariff for small-hydro power generation': July 2004
Karnataka	- Tariff Order for determination of tariff in respect of Renewable Sources of energy: January 18, 2005 (Mini-hydel, wind, cogeneration, biomass) - Review petition on tariff determination in respect of Renewable Sources of energy: July 20, 2005
Madhya Pradesh	- MPERC Order on Power Procurement and Tariff Determination of wind energy based power: June 2004
Maharashtra	- MERC Order on 'Tariff and related dispensation for procurement of power from Biomass based generation projects': August 2005 - MERC Order on 'Procurement of Wind Energy and Wheeling for third party sale and or self use': November 24, 2003 - MERC Order on 'Tariff Determination for Small Hydro Projects in Maharashtra': November 9, 2005 - MERC Order on Tariff and dispensation for purchase of power from Bagasse and other non-fossil fuel based non-qualifying cogeneration projects': May 25, 2005 - MERC Order on 'Procurement of Wind Energy and wheeling for third party sale or self-use': September 18, 2003
Tamil Nadu	- TNERC Draft Discussion Paper on 'Tariff Related Issues' for Non Conventional Energy sources: December 2005
Uttaranchal	- UERC Tariff Order for determination of tariff for new hydro generating stations with capacities greater than 1 MW and upto 25 MW: November 10, 2005 - UERC Order on Approach to Initial Tariff for Generating Stations with capacity upto 1 MW: November 10, 2005 - UERC Approach for determination of Tariff for Micro Hydel Generating Stations with capacity upto 1 MW: September 2005
Uttar Pradesh	- Order on suo moto proceedings in the matter of Terms and Conditions of Supply and Tariff for Captive Generating Plants and Renewable and NCE source based plants: July 18, 2005 - UPERC Approach Paper for Determination of Tariff for Captive Generation, Non-conventional and Renewable Energy Sources: July 2005
Gujarat	- Order on Determination of price for procurement of power by the Distribution Licensees in Gujarat from Wind Energy Projects: 11^{th} August 2006
West Bengal	- West Bengal Electricity Regulatory Commission (Cogeneration & generation of electricity from Renewable Sources of energy) Regulations, 2006.

Annex 3: Avoided cost estimation methodology presently used by CEB

The avoided cost methodology which is presently being used by the Ceylon Electricity Board (CEB) is based on estimation of *marginal energy cost* due to power generation by small power producers. The method followed for estimation of avoided cost is as explained below.

Step 1 –

The average fuel cost of each thermal plant (CEB owned and IPPs) is calculated based on the fuel prices, heat content and heat rate data. The fuel prices are projections for the next year, for the 2005 estimations the crude costs were provided by the Ceylon Petroleum Corporation (CPC) on *CIF* basis. These fuel costs are then adjusted for station losses and transmission losses (all thermal plants connected at 132 kV and above). This gives the variable costs at 33 kV level (in LKR/ kWh) for each plant. As an illustrative example, the data used by CEB in the calculation of 2005 small power tariffs, is given below[11]:

Table 3.1: Average Fuel Cost by Plant Type

Thermal Plants	GTR	GTNW	KPS-JBIC	DLTL	APPL	BARGE	DSP	DSPX	Matara	Horana	Heladhanavi	AES CCP	Embilipitiya
Fuel Used	Auto Diesel	Auto Diesel	Naphtha				Residual Oil	Residual Oil					
Fuel Price (LKR/ Litre)	39.32	39.32	31.98				19.13	19.13					
Heat Content (kCal./ Litre)	8,862	8,862	7,657				9,682	9,682					
Heat Rate (kCal./ kWh)	3,911	2,868	1,793				2,246	2,068					
Fuel Usage (Litres/ kWh)	0.44	0.32	0.23				0.23	0.21					
Fuel Cost (LKR/ kWh)	17.35	12.73	7.49		4.94	4.79	4.44	4.09			5.4	5.21	5.76
Variable O&M Cost													
US Cents/ kWh	0.198	0.291	0.143				1.43	0.8603					
LKR/ kWh	0.21	0.31	0.15				1.53	0.92					
Station Losses (%)	3%	3%	3%				3%	3%					
LKR/ kWh	0.53	0.32	0.21				0.18	0.15					
Transmission Losses (%)	3.20%	3.20%	3.20%		3.20 %	3.20%	3.20%	3.20%			3.20%	3.20%	3.20%
LKR/ kWh	0.58	0.35	0.23		0.18	0.18	0.2	0.17			0.17	0.17	0.18
Avoided Cost at 33kV level (LKR/ kWh)	18.67	11.22	7.47	6.12	5.66	5.75	6.32	5.40	5.73	5.67	5.57	5.38	5.94

[11] GTR, GTNW, KPS-JBIC, DSP, DSPX and AES-CCP are CEB owned Thermal plants while, DLTL, APPL, Barge, Matara, Horana are IPP Thermal Plants

Step 2 –

The Systems Control Dispatch Centre of CEB uses the short term planning model (takes into account a 3-year planning horizon), called the METRO model, which provides estimates of energy expected to be delivered from each power plant during each month of the particular year.

While estimating the energy expected to be delivered by a particular plant, the model optimizes various power plants based on the generation cost along with other constraints and inputs in the model.

As per the avoided cost estimation by CEB for 2005, the estimated energy delivery by different thermal power plants for the year 2005 is as shown in table 2 below.

Table 3.2: System Control Dispatch Schedule (GWh), 2005

Thermal Plants	Jan	Feb	March	April	May	June	July	Aug	Sep	Oct	Nov	Dec	Total
GTR	2	1	1	0	0	0	0	0	0	0	0	0	4
GTNW	6	1	5	1	0	1	0	0	0	0	0	1	15
KPS-JBIC	59	62	44	11	6	3	1	1	6	1	5	42	241
DSP	25	23	25	24	25	24	37	37	36	37	34	37	364
DLTL	16	14	15	14	11	7	5	8	8	6	11	14	129
Embilipitiya	0	0	0	67	62	55	51	56	57	66	63	68	545
BARGE	42	38	42	39	35	26	17	31	30	37	36	29	402
Matara	17	15	17	15	13	8	6	10	9	10	14	15	149
Horana	14	13	14	13	11	8	5	9	9	9	12	12	129
APPL	35	31	35	33	32	32	29	30	30	33	32	35	387
Heladhanavi	71	64	71	68	69	67	63	66	65	70	65	71	810
DSPX	42	38	42	40	42	41	42	42	41	42	39	42	493
AES CCP	99	88	80	58	28	19	9	17	27	8	28	84	545
Total Thermal	428	388	391	383	334	291	265	307	318	319	339	450	

Step 3 –

Using monthly (plant-wise) energy delivered, plant capacity, the plant factor (or capacity factor) is calculated for each month. The table below gives the calculated plant factors for the year 2005.

Table 3.3: Calculated Plant Factors

Plant Factors	Jan	Feb	March	April	May	June	July	Aug	Sep	Oct	Nov	Dec	Total	Capacity
No. of days in the month	31	28	31	30	31	30	31	31	30	31	30	31		(MW)
GTR	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	120
GTNW	0.07	0.01	0.06	0.01	0	0.01	0	0	0	0	0	0.01	0.01	115
KPS-JBIC	0.48	0.56	0.36	0.09	0.05	0.03	0.01	0.01	0.05	0.01	0.04	0.34	0.17	165
DSP	0.47	0.48	0.47	0.46	0.47	0.46	0.69	0.69	0.69	0.69	0.66	0.69	0.58	72
DLTL	0.96	0.93	0.9	0.86	0.66	0.43	0.3	0.48	0.49	0.36	0.68	0.84	0.65	22.5
Embilipitiya	0	0	0	0.93	0.83	0.76	0.69	0.75	0.79	0.89	0.88	0.91	0.62	100
BARGE	0.94	0.94	0.94	0.9	0.78	0.6	0.38	0.69	0.69	0.83	0.83	0.65	0.76	60
Matara	1	1	1	1	0.87	0.56	0.4	0.67	0.63	0.67	0.97	1	0.85	20
Horana	0.94	0.97	0.94	0.9	0.74	0.56	0.34	0.6	0.63	0.6	0.83	0.81	0.74	20
APPL	1	1	1	1	0.96	0.99	0.87	0.9	0.93	0.99	0.99	1	0.98	45
Heladhanavi	0.95	0.95	0.95	0.94	0.93	0.93	0.85	0.89	0.9	0.94	0.9	0.95	0.92	100
DSPX	0.71	0.71	0.71	0.69	0.71	0.71	0.71	0.71	0.71	0.71	0.68	0.71	0.7	80

Step 4 –

The time for which a particular plant operates at margin is estimated by stacking the power plants with increasing order of variable costs, as shown below in figure 1. The plant facts are taken from the published small power purchase tariff for 2005, published by CEB. The plant factors for the month of January are used in the figure to explain the methodology. The power plant GTNW would operate for 0.07 fraction of time out of which it would operate in the margin for 0.05 fraction of total time.

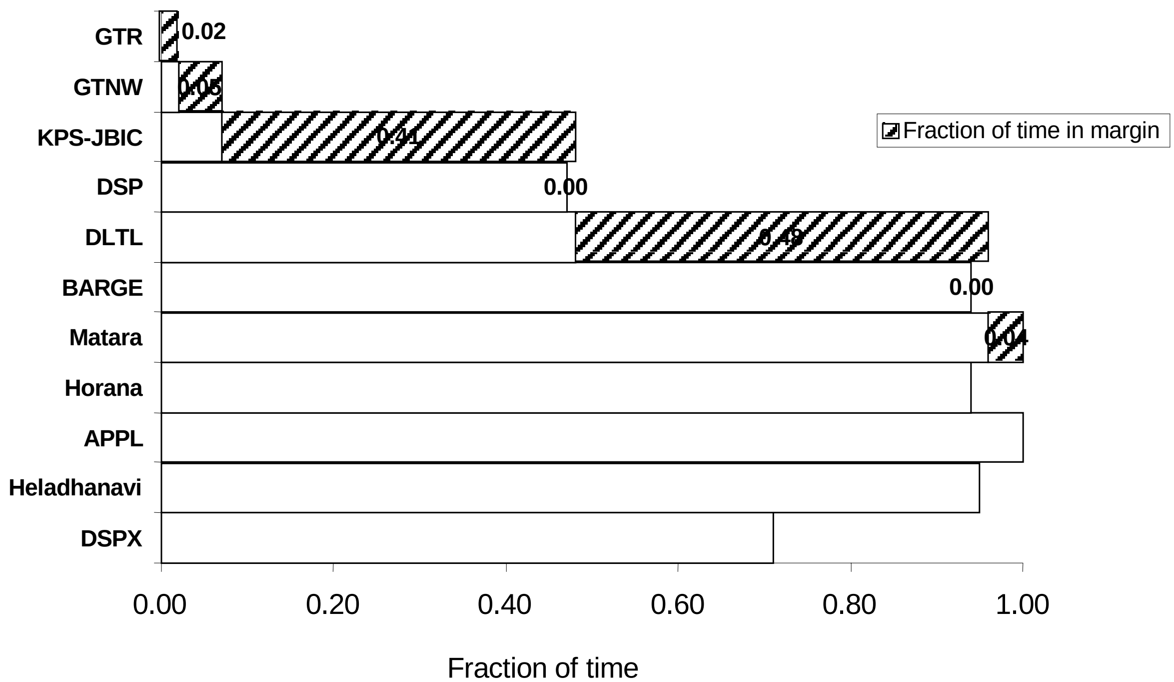


Figure 5: Estimation of fraction of time a power plant operates in the margin (based on plant factors in January 2005, as given in table 1.3)

This figure is an illustrative description of the way in which thermal plants are operated in the margin and the mechanism by which fraction of time that these plants operate in the margin is determined. This has been verified by the CEB. The thermal plants are stacked in an increasing order of variable costs such that those plants which are most expensive, are run for the shortest margin of time followed by the next most costly plant and so on. However, it should be noted that only those plants that are technologically suited to be dispatched at the margin (i.e. having low ramp-up and ramp-down times and costs) are stacked in the manner that has been depicted. This would mean that if the variable cost of Plant A is lower than that of Plant B, but it is technologically suited to run Plant B at the margin rather than Plant A, then, Plant B will be run for a specific margin of time, even though it might be more expensive than Plant A.

Table 3.4: Fraction of time in the margin

S. No.	Thermal Plants	Jan	Feb	March	April	May	June	July	Aug	Sep	Oct	Nov	Dec	Year	Capacity (MW)	Cost (LKR/ kWh)
1	GTR	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	120	18.67
2	GTNW	0.05	0	0.05	0.01	0	0.01	0	0	0	0	0	0.01	0.01	115	11.22
3	KPS-JBIC	0.41	0.55	0.3	0.08	0.05	0.02	0.01	0.01	0.05	0.01	0.04	0.33	0.15	165	7.47
4	DSP	0	0	0.11	0	0.42	0.43	0.68	0.68	0.64	0.68	0.62	0.35	0.41	72	6.32
5	DLTL	0.48	0.37	0.43	0.77	0.19	0	0	0	0	0	0.02	0.15	0.08	22.5	6.12
6	Embilipitiy a	0	0	0	0.07	0.18	0.3	0	0.06	0.1	0.2	0.2	0.08	0	100	5.94
7	BARGE	0	0.02	0.04	0	0	0	0	0	0	0	0	0	0.11	60	5.75
8	Matara	0.04	0.06	0.06	0.07	0.04	0	0	0	0	0	0.1	0.09	0.09	20	5.73
9	Horana	0	0	0	0	0	0	0	0	0	0	0	0	0	20	5.67
10	APPL	0	0	0	0	0.08	0.22	0.18	0.14	0.13	0.1	0.02	0	0	45	5.66
11	Heladhana vi	0	0	0	0	0	0	0	0	0	0	0	0	0	100	5.57
12	DSPX	0	0	0	0	0	0	0	0	0	0	0	0	0	80	5.4

Step 5 –

The avoided cost is the weighted average of avoided variable costs of the thermal power plants (the weighting factors being the fraction of time that each plant would operate in the margin).

$$\text{Monthly avoided cost} = \sum_{i=1}^{i=n} \text{monthly fraction of time}_i \times \text{variable cost}_i$$

Where,

n – Thermal Plants (GTR, GTNW, DSP, etc)

Step 6 –

The Avoided Costs are averaged separately for the Wet Season (May – January) and the Dry Season (February – April).

Step 7 –

The Published Small Power Purchase Tariff for a particular year that is announced on 1st December of the previous year is a 3-year moving average of the last three years avoided cost.

Annex 4: Avoided energy cost estimation in the state of Andhra Pradesh

The avoided energy cost estimation can be undertaken based on existing data of variable costs of thermal generating stations in a particular state. In this sub-section, an analysis of variable costs of existing thermal power stations in the state of Andhra Pradesh based on secondary data has been undertaken. It needs to be noted that the figures that have been arrived in this exercise are indicative and have been derived for explaining the methodology.

The step-wise approach that has been used for the estimation of avoided costs in the state of Andhra Pradesh is described below[12]

Presently, there are sixteen thermal power plants operational in Andhra Pradesh. The break-up of these plants based on ownership is given below –

1. APGENCO Power Plants: 6 (RTS 'B', KTPS V, VTPS, KTPS A B C, RTPP and APGPCL)
2. Central Generating Stations: 6 (NTPC Ramagundam, RSTPS – 7, Neyvelli Lignite Corporation Limited, NPS MAPS, NTPC Talcher and NTPC Simahdri)
3. IPPs (GVK, Spectrum, Lanco Kondapaali and BSES)

The variable costs of these thermal power plants is given in the table below:

Table 4.1: Variable costs of Thermal Power Plants in Andhra Pradesh

S.No	APGENCO	Installed Capacity (MW)	Variable Cost (Rs./ kWh)
1	RTS 'B'	62.5	1.06
2	KTPS V	500	0.91
3	VTPS	1260	1.20
4	KTPS A B C	720	1.07
5	RTPP	420	1.45
6	APGPCL	272	2.65
	Central Generating Stations		
7	NTPC Ramagundam	667.25	0.95
8	RSTPS - 7	160.7	1.21
9	Neyvelli Lignite Corporaton Limited	297.23	1.82
10	NPS MAPS (Madras Atomic Power Plant)	31.76	2.10
11	NTPC Talcher	450	0.67

[12] The similar mechanism of estimating short-term marginal costs or avoided energy costs has been followed in Sri Lanka and is explained in greater at Annex 2

S.No	APGENCO	Installed Capacity (MW)	Variable Cost (Rs./ kWh)
12	NTPC Simhadri	1000	1.06
	IPPs		
13	GVK	216	1.05
14	Spectrum	208.31	1.05
15	Lanco Kondapalli	351.49	1.25
16	BSES	220	1.08

The annual generation from each of the thermal plants for the FY 2005-06 has been obtained from APTRANSCO. Based on the annual generation (in MU) and the installed capacity of each of the thermal power plants, the annual plant load factor of each thermal power plant is estimated. This has been tabulated below:

Table 4.2: Annual Plant Load Factor of each Thermal Power Plant in Andhra Pradesh

S.No	APGENCO	Installed Capacity (MW)	Generation FY 2005-06 (MU)	CUF (%)
1	RTS 'B'	62.5	397.1	0.725
2	KTPS V	500	3482.1	0.795
3	VTPS	1260	9755	0.884
4	KTPS A B C	720	4732.3	0.772
5	RTPP	420	2371	0.644
6	APGPCL	272	1841.3	0.773
	Central Generating Stations			
7	NTPC Ramagundam	667.25	4422.2	0.757
8	RSTPS - 7	160.7	1003.6	0.713
9	Neyvelli Lignite Corporaton Limited	297.23	1550.1	0.595
10	NPS MAPS (Madras Atomic Power Plant)	31.76	130.3	0.468
11	NTPC Talcher	450	2505.0	0.635
12	NTPC Simhadri	1000	7635.0	0.872
	IPPs			
13	GVK	216	1297.9	0.686
14	Spectrum	208.31	1308.4	0.717
15	Lanco Kondapalli	351.49	2111.0	0.686
16	BSES	220	842.1	0.437

The time for which a particular plant operates at margin is estimated by stacking the power plants with increasing order of variable costs, as shown in the table below.

The thermal plants are stacked in an increasing order of variable costs such that those plants which are most expensive, are run for the shortest margin of time followed by the next most costly plant and so on. However, it should be noted that only those plants that are technologically suited to be dispatched at the margin (i.e. having low ramp-up and ramp-down times and costs) are stacked in the manner that has been depicted in the table.

Table 4.3: Fraction of time that a power plant operates in the margin

S. No.	Plants	Variable Cost (Rs./ kWh)	CUF (%)	Weights (%)	Avoided Energy Cost (Rs./ kWh)
1	APGPCL	2.86	0.77	0.7730	2.2123
2	NPS MAPS (Madras Atomic Power Plant)	2.27	0.47	0.00	0.00
3	Neyvelli Lignite Corporaton Limited	1.96	0.60	0.00	0.00
4	RTPP	1.57	0.64	0.00	0.00
5	Lanco Kondapalli	1.35	0.69	0.00	0.00
6	RSTPS - 7	1.31	0.71	0.00	0.00
7	VTPS	1.30	0.88	0.0011	0.00144
8	BSES	1.17	0.44	0.00	0.00
9	KTPS A B C	1.15	0.77	0.00	0.00
10	RTS 'B'	1.15	0.73	0.00	0.00
11	NTPC Simhadri	1.14	0.87	0.00	0.00
12	GVK	1.13	0.69	0.00	0.00
13	Spectrum	1.13	0.72	0.00	0.00
14	NTPC Ramagundam	1.03	0.76	0.00	0.00
15	KTPS V	0.98	0.80	0.00	0.00
16	NTPC Talcher	0.72	0.64	0.00	0.00
	Total			0.7741	**2.21**

The avoided cost is the weighted average of avoided variable costs of the thermal power plants (the weighting factors being the fraction of time that each plant would operate in the margin).

$$\text{Annual avoided cost} = \sum_{i=1}^{i=n} \text{fraction of time}_i \times \text{variable cost}_i$$

Where,

n – Thermal Plants (APGPCL, NPS MAPS, RTPP, etc)

From the above analysis, the indicative avoided cost that has been estimated for FY 2005-06 for Andhra Pradesh is Rs. 2.21/ kWh.

Annex 5: Total Power Procurement costs of generating stations in the state of Andhra Pradesh

Table 5.1: Thermal Power Generating Stations in AP and their Total Power Procurement Costs, FY 2006-07

S.No	APGENCO	Installed Capacity (MW)	Generation FY 2006-07 (MU)	Fixed Cost (Rs. Crores)	Fixed Cost (Rs./ kWh)	Variable Cost (Rs./ kWh)	Total Power Procurement Cost (Rs./ kWh)
1	RTS 'B'	62.5	394.24		0.77	1.06	1.83
2	KTPS V	500	3610.95		0.77	0.91	1.68
3	VTPS	1260	8781.52		0.77	1.20	1.98
4	KTPS A B C	720	5161.26		0.77	1.07	1.84
5	RTPP	420	3033.22		0.77	1.45	2.22
6	**APGPCL**	**272**	**382.73**		**0.67**	**2.65**	**3.32**
S.No	**Central Generating Stations**						
7	NTPC Ramagundam	667.25	4631.8	145.80	0.315	0.95	1.27
8	RSTPS - 7	160.7	1114.9	75.60	0.678	1.21	1.89
9	Neyvelli Lignite Corporaton Limited	297.23	1687.3	68.87	0.408	1.82	2.23
10	NPS MAPS (Madras Atomic Power Plant)	31.76			0.000	2.10	2.10
11	NTPC Talcher	450	2936.0	221.91	0.756	0.67	1.42
12	NTPC Simhadri	1000	7400.0	452.00	0.611	1.06	1.67
S.No	**IPPs**						
13	GVK	216	1364.5	160.34	1.175	1.05	2.22
14	Spectrum	208.31	1346.3	158.09	1.174	1.05	2.22
15	Lanco Kondapalli	351.49	2302.9	310.88	1.350	1.25	2.60
16	BSES	220	937.5	158.41	1.690	1.08	2.77
17	GVK Extension	220	394.86	37.3	0.945	0.92	1.86
18	Vemagiri	370	588.71	57.4	0.975	0.92	1.90
19	Gouthami	464	420.69	41.0	0.975	0.92	1.90
20	Konaseema	445	343.42	33.5	0.975	0.96	1.93

Annex 6: Quota/Renewable Purchase Obligation status across states

Table 6.1: Status of renewable energy quota across states

S. No.	State	Quota/ Renewable Purchase Obligation	Time Period
1	Andhra Pradesh	Minimum of 5% of consumption of energy	2005-2006 and 2007-2008
2	Gujarat	Minimum Quantum: 2006-07: 1% 2007-08: 1% 2008-09: 2%	2006-2009
3	Karnataka	Minimum quantum of 5% and a maximum quantum of 10% of total consumption in a year	2004-05
4	Madhya Pradesh	Minimum 0.5% of total consumption including third party sales, from wind energy.	2004-2007
5.	Uttar Pradesh	5% of total power consumption	-
6	Maharashtra	2006- 07 : 3% 2007- 08 : 4% 2008 -09 : 5% 2009 -10 : 6%	
7	Tamil Nadu	10%	2006 -2009
8	Rajasthan	Wind– 2%, 2006-07 (7.5%, 2011-12); Biomass– 0.5%, 06-07 (2%,2011-12)	
9	West Bengal	2006-07: 1.9%(WBSEB), 1.02% (CESC); 2007-08: 3.8% (WBSEB), 2.03%	
10	Kerala	5% (2% for Wind)	3 years from 2006
11	Orissa	3% (for Wind and Small Hydro)	