# “Policy & Regulatory Approaches for Promoting RE Power”

Prepared under the REEEP project

**`Capacity building for state regulators and policy makers in mainstreaming of RET’s in a reformed electricity sector’**

**The Energy and Resources Institute**
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# Contents

**Page No.**

# Chapter 1: Introduction

Renewable energy plays an important role in any government's strategy to reduce carbon-dioxide emissions, as well as for enhancing energy security. At present, different strategies are being used to promote renewable energy sources for power generation world over. 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 programmes that governments could devise vary according to market situations. There are three primary potential commercial markets for renewables:

*Utility power markets:* in such power markets, power production from wind, biomass, bagasse, and hydro resources is already, or nearly, commercially competitive with conventional sources for bulk power generation. Examples include the Non-Fossil-Fuel Obligation in the United Kingdom, the electricity feed laws in Germany and Spain, and renewable energy portfolio standards that are applied at the state level in the United States.

*Distributed markets:* such markets that relate to applications of renewables in utility distribution system are common in the developed countries, with generators that range from a few kilowatts to 30 MW. Policy experience in distributed markets is however, slowly emerging, primarily in regard to the promotion of early market-learning investments. Experience with "net metering", where a consumer can sell self-generated power back to a utility at the same cost as purchased electricity, is emerging in Japan and the United States. Another emerging policy innovation is the reshaping of traditional utility least-cost planning (which historically has focused on generation costs only), to require a broader optimisation of combined generation, transmission, and distribution costs. This type of utility planning could highlight commercial opportunities for distributed generation based on renewable energy sources.

This paper examines the policy and regulatory instruments that have been employed in the developed countries and are being followed in emerging economies to promote renewable energy based electricity generation. The paper also gives an overview of the Indian Experience in the light of the Electricity Act 2003 and the recently announced National Tariff Policy. Examining the regulatory environment in Andhra Pradesh for promotion of renewable energy, it deals with key issues affecting the renewable energy power sector in the state. The paper ends with a suggestive approach that attempts to address the regulatory issues overarching the renewable energy power sector.

# Chapter 2: International Policy and Regulatory regimes for promoting renewable energy based electricity generation

A Utility power market, distributed power market and rural off-grid market that have been described in the introduction pose a different competitive challenge for development of renewable energy technologies. However, based on various stages of their development, different countries have used different policy instruments to promote renewables. These have been described in the following sub-sections. An overview of the policy instruments in the EU Member States of Germany, Denmark, Netherlands and UK, along with a few other international policy initiatives that have been adopted in the countries of China, Sri Lanka, Thailand and Japan from the Asian region, to increase the contribution of electricity from renewable energy sources to the national energy mix. 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 in Germany and Denmark,
- Non-fossil-fuel-obligation and competitive bidding in UK
- Renewable Portfolio Standards (RPS) in Netherlands and Japan
- Green certificates in UK, Denmark and Japan
- Production and Investment Tax Credits in the US
- Net Metering and Power Purchase Tariff in Thailand
- Programmatic Approach of developing Renewable Energy Technologies (RETs) In Vietnam
- Avoided cost methodology of pricing RETs in Sri Lanka

A difference is made between investment subsidies, fiscal measures, feed-in tariffs, quota obligations/ green certificates, bidding systems, renewables portfolio standard and production/ investment tax credits.

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

**Table 1**: Policy Instruments used by different countries

| RE Technologies/ Countries | Feed-in tariffs | RPS | REO | Green Certificates | Production/ Investment Tax Credits | Subsidies/ rebates | Fiscal Measures |
|---|---|---|---|---|---|---|---|
| Germany | * | | | | | * | * |
| Denmark | * | | | | | | * |
| UK | | | * | * | | | * |
| US | | * | | * | * | | * |
| China | | | | | | * | * |
| Brazil | | * | | | | | * |
| Netherlands | | * | | | | | * |
| Japan | | * | | * | | | * |
| Sri Lanka | | | | | | | * |
| Thailand | | | | | | * | * |

The policy instruments that are in place in the different countries can 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

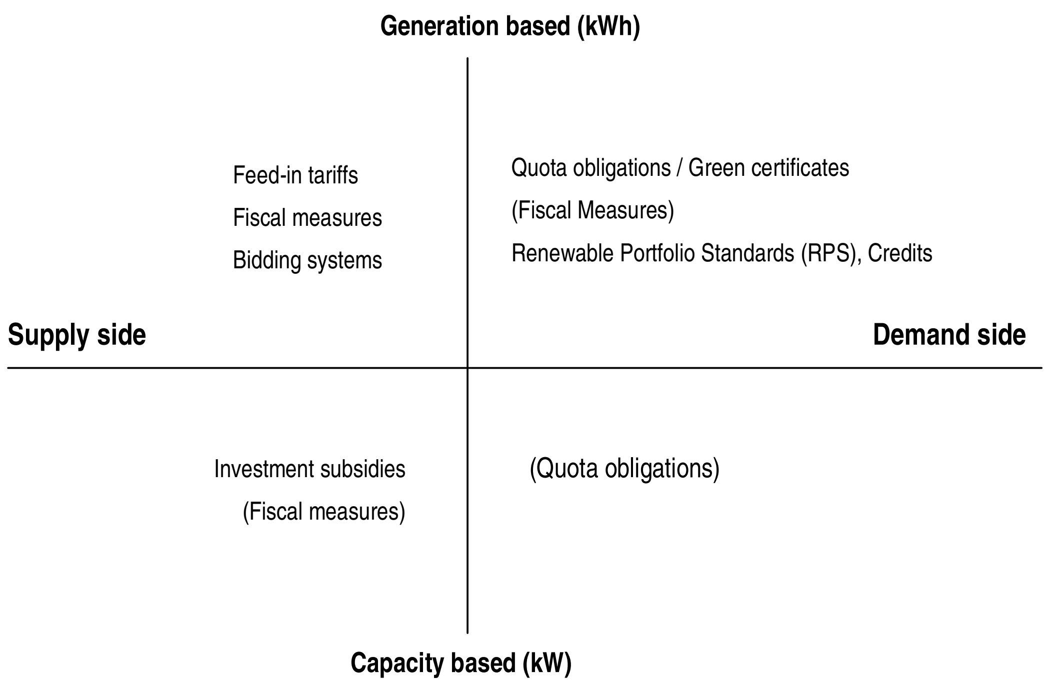


Figure 1: Categorization of policy instruments

either on electricity generation or on the installed capacity of renewable electricity plants:

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 examples that have been discussed with respect to each of the mentioned policy instruments are: **German** Feed-in tariffs and the Renewable Energy Sources Act (RES), 2000; the **UK** policy initiative in terms of NFFO and quota obligations/ green certificates and tendering schemes; quotas and Renewable Portfolio Standards (RPS), in the context of RET policies in **US, Netherlands and Japan**; 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 the net metering and power purchase tariff in case of **Thailand**; the programmatic approach of developing RETs in **Vietnam** and the avoided cost methodology of pricing RETs in **Sri Lanka**.

## Pricing Systems—Feed-In Law

Under the **pricing system** (or **feed-in law**) electric utilities are obligated to enable renewable energy plants to connect to the electric grid, and they must purchase any electricity generated with renewable sources at fixed, minimum prices. These prices are generally set higher than the regular market price, and payments are usually guaranteed over a specified period of time. The price may be based on cost, or may be chosen instead to spur investment in renewables.

### Early History — California PURPA Example

California enacted an early form of the pricing system, the U.S. Public Utilities Regulatory Act of 1978 (PURPA). 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 with fixed (and in some cases, increasing) payments for all or part of the contract term. 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. As a result, California became a world leader in renewable energy in the 1980s.

## Today—Germany Example

In Europe, meanwhile, the early pricing laws guaranteed producers a minimum share of the retail rate (at least 85% in Denmark and 90% in Germany). 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 was based on a percentage of the retail electric tariff.

### Electricity Feed-in Law

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

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.

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).

## Renewable Energy Sources Act

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) is summarized in the table below:

Table 2: 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<br>6.65∈cts. over 500kW | 9.67∈cts. up to 500kW<br>6.65∈cts. 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<br>6.65∈cts. over 500kW | 7.67∈cts. up to 500kW<br>6.65∈cts. over 500kw and up to 5 MW | Fees shall be reduced 1.5% annually. |
| Biogas | 10.23 ∈cts. up to 500kW<br>9.21 ∈cts. up to 5MW<br>8.70 ∈cts. Up to 20MW | 11.5∈cts. up to 150kW<br>9.9∈cts. up to 500kW<br>8.9∈cts. up to 5MW<br>8.4∈cts. up to 20MW | Fees shall be reduced 1.5% annually. |
| Geothermal | 8.95∈cts. up to 20MW<br>7.16∈cts. over 20MW | 15∈cts. up to 5MW<br>14∈cts. up to 10 MW<br>8.95∈cts. up to 20MW<br>7.16∈cts. over 20MW | Fees shall be reduced 1%annually. |
| Wind | 9.10 ∈cts. for the first 5 years<br>6.19 ∈cts. after reaching a certain reference revenue | 8.7∈cts. for the first 5 years<br>5.5∈cts. 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 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: 45.7∈cts.<br>For plants attached to or integrated on top of building:<br>57.4∈cts. up to 30kW<br>54.6∈cts. up to 100kW<br>54.0∈cts. over 100kW | Fees shall be reduced 5% annually. |

SOURCE: 2004 Renewable Energy Sources Act

- 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.1

- 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.

## 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. 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

[1] 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.

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.
As with the pricing 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.

## Early History— UK NFFO Example

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.

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.

## Today— Renewable Obligation, UK Example

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 3: 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;
- banking a maximum 25% of the needed certificates for a running obligation period, from the previous obligation period;
- “proving that another electricity supplier has done so, or that between them they have done so” (April 2002 Order on Renewable Obligation)
- 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[2]), 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.

[2] 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:

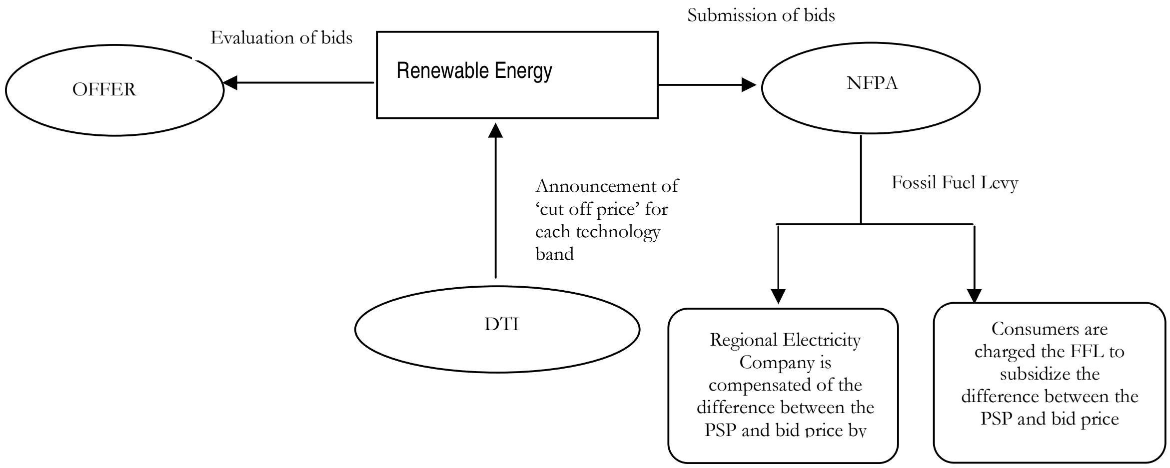


Figure 2: NFFO - the tendering process

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[3] 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)

[3] 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 4: NFFO 1-5

| | Projects | Contracted | | Projects | Generating | No progress | Projects | % |
|---|---|---|---|---|---|---|---|---|
| | Date | Number | MW (DNC)[4] | 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 5: 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

[4] 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 6: 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 2: 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**[5]**.** 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 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.

[5] 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.

## Quotas

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, distributors or consumers.

There are 2 main types of quota systems used today for electricity generation: obligation/certificate and tendering.

### Obligation/Certificate—*U.S. States Example*

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"—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.

Some of the efficiency advantages of the RPS approach are:

- Flexible procurement options based on market forces – The RPS works by requiring all electricity providers to include a minimum percent of renewable electricity in the electric power supply portfolio they offer to their customers. Electricity providers have great flexibility in meeting this requirement. They can generate the necessary amount of renewable electricity themselves; they can purchase it from someone else; buy credits from other providers who have exceeded the standard or from the spot market (as is the case in developed country). They choose the option that is cheapest for them. The RPS should ensure that the standard is met at the lowest possible cost.

- RPS will offer level playing field for renewable energy – The coal, oil, natural gas, and nuclear power industries are mature; yet continue to receive considerable government subsidies. Moreover, the market price of fossil and nuclear energy does not include the cost of the damage that they cause to the environment and human health. Conversely, the market does not give a value to the environmental and social benefits of renewable energy. Without the RPS or a similar mechanism, many RETs may not be able to compete in an increasingly competitive electricity market focused on producing power at the lowest direct cost. The RPS could be designed to deliver RE that is most ready for the market.
- RPS is good for consumers and the economy – A properly designed RPS has been successful in establishing a viable market for the long-term development of renewable energy industries in America; creating jobs at home and export opportunities abroad.
- Sunset date - The RPS should be "self-sun setting" -- meaning that the RPS policy sunsets when the price of Credits falls to zero, signifying that renewables are fully competitive and integrated into the market. A stable RPS will enable long-term contracts and lower-cost financing.

RPS policies are expanding at the state/ provincial level in the United States, Canada and India. 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 3 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.

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.

### Tendering—UK Example

Under tendering systems (as explained in greater detail in the sub-section on Tendering Schemes), 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. The UK's Non-Fossil Fuel Obligation (NFFO) was an early example of this type of policy. In contrast, under the RPS system, companies and project must constantly compete in the marketplace, with existing and new projects, unless they have signed long-term contracts.

As with the pricing 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.

## Financial Instruments

### 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.

### 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. Production tax credits have been supplied at the federal level in the US; they have tended to be most effective in States, which also provide some other form of support, most notably a quota mechanism.

The major US Federal legislation on financial incentives for renewable energy has been structured as tax credits and production incentive payments. For renewable energy, tax credits for purchases of renewable energy equipment were aimed at both residential and business sectors, while accelerated depreciation of renewable energy equipment and production incentives were aimed at investors. Two new types of financial incentives were introduced as part of the Energy Policy Act of

1992 (EPACT) – a production tax credit (PTC) and a renewable energy production incentive (REPI).

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[6] sources, and poultry waste. The credit provides a 1.5 cent per 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. Congress allowed this tax credit to expire on December 31, 2001. In March of 2002, due to the efforts of UCS (Union of Concerned Scientists)[7] and other organizations, the credit was extended until December 31, 2003. The legislation also restored the credit retroactively so that facilities which started up during the short period after December 2001 and before March 2002 could use the credit. Originally enacted as part of the Energy Policy Act of 1992, the credit was first scheduled to sunset on June 30, 1999. In December of 1999, again due to the efforts of UCS and other organizations, the credit was extended until December 31, 2001. One of the main advantages of the PTC initiative is that in the US, they have proven to stimulate capacity alongside quota mechanisms. They may be useful in bringing about stability to generators when used along side quota mechanisms, thereby reducing uncertainty and thus capital costs.

The Renewable Energy Production Incentive (REPI) is part of an integrated strategy in the Energy Policy Act of 1992 to promote increases in the generation and utilization of electricity from renewable energy sources and to further the advances of renewable energy technologies. This program, authorized under section 1212 of the Energy Policy Act of 1992, provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Eligible electric production facilities are those owned by State and local government entities (such as municipal utilities) and not-for-profit electric cooperatives that started operations between October 1, 1993 and September 30, 2003. Qualifying facilities are eligible for annual incentive payments of 1.5 cents per kilowatt-hour (1993 dollars and indexed for inflation) for the first ten-year period of their operation, subject to the availability of annual appropriations in each Federal fiscal year of operation. Qualifying facilities must use solar, wind, geothermal (with certain restrictions as contained in the rulemaking), or biomass

[6] 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.
[7] www.ucsusa.org – An independent non-profit alliance of more than 100,000 concerned US citizens and scientists

(except for municipal solid waste combustion) generation technologies.

In general production incentives are preferable to investment incentives because they promote the desired outcome—generation of electricity or other forms of energy. Although investment subsidies encourage installation at the optimal level for individuals or businesses, they do not necessarily result in installation at the optimal level for the society or community as a whole. Investment incentives encourage the purchase of renewable energy systems, but on their own they do not necessarily encourage investors to purchase the most reliable systems available, or to maintain them and produce as much energy as possible.

However, policies must be tailored to particular technologies and stages of maturation. Investment subsidies can be helpful when a technology is still maturing and relatively expensive. Further, investment support is often more appropriate for small-scale renewables such as heat pumps or small-scale PV because their administrative costs are lower—they require a one-time payment rather than annual payments based on metered data.

## 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). As with investment credits, rebates are most effective when linked to technology and performance standards.

### Vietnam Example

The government of Vietnam, for example, has an ambitious investment rebate program that offers a 100% tax exemption for equipment importation applying renewable energy technology. Such incentives will facilitate project investment, and thereby allow the country to increase renewable energy to about 2%, 3% and 6-7% of total commercial primary energy by 2010, 2020 and 2050 respectively.

## 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. Provided that such payments are high enough to cover the costs of renewable generation and are guaranteed over a long enough time period this policy integrates some key elements of a pricing law—similar in effect and perhaps more politically feasible in some countries.

## 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.

### Vietnam Example

In Vietnam, enterprises that invest in renewable energy projects or manufacture renewable energy or energy efficiency technology may receive medium or long-term low-interest loans from a government sponsored Development Support Fund. Loans for investment in rural electrification are especially important.

### China Example

Low interest loans have proved an effective central government tool for promoting renewable energy development in China. Since 1987 the Chinese government has enacted specific low-interest loans for rural energy development. Interest rates of these low-interest loans are only half that of a standard loan. The primary targets for these financial incentives are biogas projects, solar energy applications, small hydro projects, and wind technologies. The National Development and Reform Commission (NDRC) provides low-interest loans of up to 120 million RMB Yuan each year to support development of RE. The Ministry of Water Resources (MWR) provides low-interest loans of up to 300 million RMB Yuan for small-scale hydropower development. Projects installing over 3MW of grid-connected renewable energy receive further reductions in the interest rate. Furthermore, according to the latest renewable energy law in China, the State Development Bank is encouraged to give priority to Basic Construction Loans for renewables, particularly where these make use of domestically produced technologies, and to extend payback periods for such projects.

## Other renewable energy policy experience

### Power purchase tariffs and capacity cap in Thailand

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.

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 using such electricity generating processes.

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 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.

## Programmatic approach towards RE promotion in Vietnam

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.

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:

### 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.

### 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.

### 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 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) | |
| - Duy Son II Coop, small hydro (energy only) | 400 – 440 |
| | 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.

## Avoided cost methodology of pricing RETs in Sri Lanka

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 step-wise description of the present method of estimating avoided costs and determining tariffs is given 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 Rs. / kWh) for each plant. As an illustrative example, the data used by CEB in the calculation of 2005 small power tariffs, is given below[8]:

Table 8: 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 (Rs./ 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 (Rs./ 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 | | | | | |
| Rs./ kWh | 0.21 | 0.31 | 0.15 | | | | 1.53 | 0.92 | | | | | |
| Station Losses (%) | 3% | 3% | 3% | | | | 3% | 3% | | | | | |
| Rs./ 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% |
| Rs./ 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 (Rs./ 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 |

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.

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

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 below.

Table 9: 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 10: 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. 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 3: Estimation of fraction of time a power plant operates in the margin

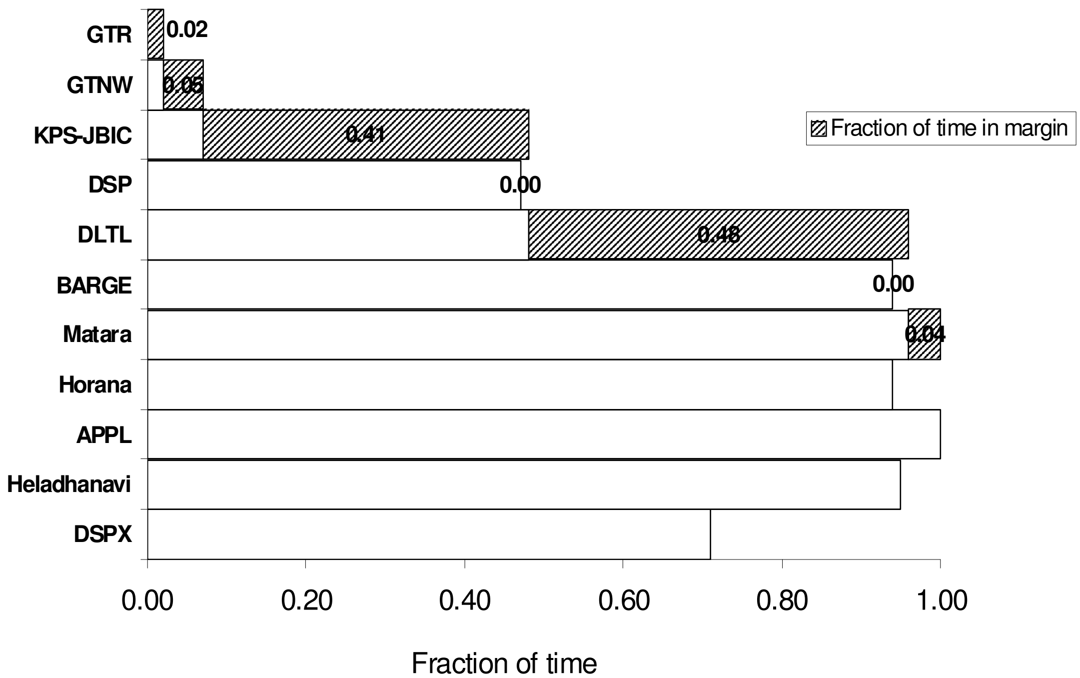


Table 11: Fraction of time in the margin

| Thermal Plants | Jan | Feb | March | April | May | June | July | Aug | Sep | Oct | Nov | Dec | Year | Capacity (MW) | Cost (Rs./kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. of days in the month | 31 | 28 | 31 | 30 | 31 | 30 | 31 | 31 | 30 | 31 | 30 | 31 | | | |
| 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 |
| GTNW | 0.05 | 0 | 0.05 | 0.01 | 0 | 0.01 | 0 | 0 | 0 | 0 | 0 | 0.01 | 0.01 | 115 | 11.22 |
| 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 |
| 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 |
| 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 |
| Embilipitiya | 0 | 0 | 0 | 0.07 | 0.18 | 0.3 | 0 | 0.06 | 0.1 | 0.2 | 0.2 | 0.08 | 0 | 100 | 5.94 |
| BARGE | 0 | 0.02 | 0.04 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.11 | 60 | 5.75 |
| 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 |
| Horana | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 20 | 5.67 |
| APPL | 0 | 0 | 0 | 0 | 0.08 | 0.22 | 0.18 | 0.14 | 0.13 | 0.1 | 0.02 | 0 | 0 | 45 | 5.66 |
| Heladhanavi | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 100 | 5.57 |
| 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).

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

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.

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 of 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).

# Chapter 3: Indian experience

## Background

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 provided.

Recognizing the high investment costs of renewable power projects, loan for renewable energy projects at lower interest rate were provided by Indian Renewable Energy Development Agency (IREDA), a financing institution established by MNES specifically for promotion of renewable energy. 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 that were proposed in the MNES guidelines.

The power sector reforms, which started in mid 90's, had its impact on the renewable power sector also. The Electricity Act 2003 that was notified in June 2003 recognized the role of renewable energy technologies for supplying power to the utility grid as well as in stand-alone systems. Some of the important provisions in the Act in this regard, 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.

***Section 86 (1) (e)***
*One of the functions of the state regulatory commission is 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.

In continuation to the Electricity Act 2003, the Ministry of Power, Government of India also notified the National Tariff Policy (NTP) on January 6, 2006. Some of the important provisions with regard to non-conventional energy generation are highlighted below –

***Section 6.4***

a) Pursuant to provisions of section 86(1)(e) of the Act, the Appropriate Commission shall fix a minimum percentage for purchase of energy from such 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.

b) 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.

c) 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 Electricity Act 2003 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.

## Status of regulatory practices across states

The present status of issuing tariff orders and specifying quotas for renewable energy procurement in some of the major Indian states, rich in renewable energy resources, is summarized below:

Table 12: Status of tariff orders and RPO regulation in Indian states at a glance

| States | Renewable Energy (RE) Procurent quotas | Tariff Orders for RE sources |
|---|---|---|
| Andhra Pradesh | Renewable Power Purchase Obligation (RPPO) Order: September 27, 2005 | Tariff Order for determination of tariff applicable to Non-conventional energy projects in AP: April 2004<br>(Wind, mini-hydel, biomass, bagasse, municipal waste, industrial waste) |
| Gujarat | GERC Power Procurement from Renewable Sources Regulation: October 2005 | |
| Karnataka | KERC Power Procurement from Renewable Sources by Distribution Licensee Regulation: September 2004 | Tariff Order for determination of tariff in respect of Renewable Sources of energy: January 18, 2005 (Mini-hydel, wind, cogeneration, biomass) |
| Kerala | Consultative paper on Purchase requirement of Non conventional energy and determination of tariff for small hydro generating stations and Wind Energy: January 18, 2006 | |
| Madhya Pradesh | MPERC Approach Paper on Tariff Setting and Support to Renewable Energy Sources: February 2004 | 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<br>MERC Order on 'Procurement of Wind Energy and Wheeling for third party sale and or self use': November 24, 2003<br>MERC Order on 'Tariff Determination for Small Hydro Projects in Maharashtra': November 9, 2005<br>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 |
| Orissa | OERC Petition of Power Procurement from Renewable Energy sources: April 2005 | |
| Rajasthan | RERC Consultation Paper on 'Power Purchase from Non Conventional Energy Sources', Rajasthan: November 2005 | |
| 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 up to 25 MW: November 10, 2005<br>UERC Order on Approach to Initial Tariff for Generating Stations with capacity up to 1 MW: November 10, 2005<br>UERC Approach for determination of Tariff for Micro Hydel Generating Stations with capacity up to 1 MW: September 2005 |
| Uttar Pradesh | UPERC Draft Regulations on Practice Direction for Generation from Captive Generating Plants, Co-generation, Renewable Sources of Energy and Other Non-Conventional Sources of Energy) Regulations, 2005 | 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<br>UPERC Approach Paper for Determination of Tariff for Captive Generation, Non-conventional and Renewable Energy Sources: July 2005 |

From the summary of state level renewable energy policies, it emerges that the SERCs of Andhra Pradesh, Karnataka, Gujarat, Madhya Pradesh, and Uttar Pradesh have issued final regulations specifying quotas (Renewables Procurement Obligations `RPO') for renewable energy based electricity generation as shown in Table 12. The salient features of these RPO regulations have been summarized in table 13. States like Tamil Nadu, Kerala, and Rajasthan have issued consultation papers for specifying the quantum of such quotas.

Table 13: Features of RPO in different states

| S.No | State | RPO | Time Period | Features |
|---|---|---|---|---|
| 1 | Andhra Pradesh | Minimum of 5% of consumption of energy | 2005-2006 and 2007-2008 | 0.5% for wind power, even if total NCE purchase exceeds RPO<br>Generating stations to be located within AP.<br>Every distribution licensee, captive power consumer, and open access consumer to be included.<br>Energy procured from outside AP but for use in AP, included while computing the RPO Quantum<br>No more biomass power, other than that already committed through PPAs.<br>Liable for Penalty in case of non-compliance. |
| 2 | Gujarat | Minimum Quantum:<br>2006-07: 1%<br>2007-08: 1%<br>2008-09: 2% | 2006-2009 | Discom to the extent possible, source NCE from RE sources within its Area of supply.<br>Not to be sourced from outside Gujarat.<br>To be reviewed every three years or as necessary<br>Purchase priority on the basis of the date of commercial operation of RE generating station. |
| 3 | Karnataka | Minimum quantum of 5% and a maximum quantum of 10% of total consumption in an year | _ | NCE to be sourced from within the state.<br>Purchase priority on the basis of the date of commercial operation of RE generating station.<br>To be reviewed every three years. |
| 4 | Madhya Pradesh | Minimum 0.5% of total consumption including third party sales, from wind energy. | 3 years | To be reviewed after 3 years.<br>Other RE technologies to be included as and when these are installed. |
| 5. | Uttar Pradesh | 5% of total power consumption | - | To be sourced from NCE located within UP<br>No penalty for the defaulters. |

Table 14 below gives a comparative picture of tariffs for different renewable energy technologies, in various states.

Table 14: Tariff for RETs in Indian states

| State/ | Biomass | Small hydro | Wind | Co-Gen | Wheeling & Banking | Other remarks |
|---|---|---|---|---|---|---|
| Andhra Pradesh | Rs 2.88/Unit for the first year, base year 04-05<br>Fixed cost without escalation: Rs 1.61/Unit Variable cost with escalation: Rs 1.27/unit with escalation of 5%, base year, 04-05 | Rs 2.60/Unit for the first year<br><br>Royalty charges will be paid by APTRANSCO and Discom's to GoAP.<br>Rs. 0.39 / unit up to 5 years.<br>Rs. 0.78 /unit beyond 5 years and up to 10 years.<br>Rs. 1.17 / Unit beyond 10 years. | Rs 3.37/Unit with 5% annual escalation, base year 2004 | Rs 2.74/Unit for the first year, base year 04-05<br>Fixed cost without escalation: Rs 1.72/Unit<br>Variable cost with escalation: Rs 1.02/unit with escalation of 5%, base year<br><br>Municipal waste to Energy: Rs 3.37/Unit with 5% annual escalation, base year 2004. | Wheeling charges – 2% of energy. There is ambiguity about status of banking. | An incentive of 25 paisa/Unit for electricity generated above the min PLF.<br><br>Third party sale not allowed |
| Madhya Pradesh | | | Rs 3.97/Unit for new projects in the first year and Rs 3.30/Unit after five years till twenty years. | | No wheeling Charges.<br>Banking is not allowed. | Third party sale is allowed. |
| Karnataka | Rs2.85 /Unit for the first year with 2% annual escalation on base tariff | Rs. 2.80/ unit for the first year with no escalation<br><br>No Royalty charges. | Rs 3.40 /Unit for the first year with no escalation | Rs 2.80 /unit for the first year with 2% annual escalation on base tariff | Banking is allowed | Third party sale is allowed |
| Uttar Pradesh | Rs 2.50/Unit for the year 05-06 with 4% annual escalation | Rs 3.39/Unit<br><br>Royalty Charges will be paid by distribution licensees to GoUP | Rs 2.50/Unit for the year 05-06 with 4% annual escalation | Rs 2.86/Unit for the first year<br>Non escalating Fixed cost:<br>Rs 1.39/Unit<br>Escalating fixed cost:<br>Rs 0.189/Unit<br>Variable cost: Rs 1.28/Unit with 6% annual escalation | Banking Charges are 12.5% of energy for 24 months | Third party sales allowed |

| State/ | Biomass | Small hydro | Wind | Co-Gen | Wheeling & Banking | Other remarks |
|---|---|---|---|---|---|---|
| Uttaranchal | | For projects less than 1 MW and for less than 25 MW it will do according to regulation and on case to case basis.<br>For 1 MW the guiding will be "tariff will be will be determined as the weighted average of power allocated to the state from central government stations. All other related provision remains unchanged as per the regulation of 2004. If any generating company wants to get the tariff determined in accordance to the regulation of 2004 then he could approach the commission. | | | Wheeling and banking allowed | An incentive of 0.26/Unit will be given for electricity generated Above the stipulated PLF.<br><br>Third party sales is allowed |
| Maharashtra | Rs 3.04/Unit for the first year. | Rs 2.84/Unit in the first year, which increases by Rs.0.03/unit every year till the debt repayment, is over i.e. in the10th year. The tariff shall remain constant at Rs 3.11/unit between the 10th year and the 15th year after which it again increases annually at a constant rate of Re 0.03/unit.<br><br>Royalty charges are passed through. | Rs 3.50/Unit for the first year with increment of 15 paisa every year for thirteen years | Qualifying projects – Rs 3.05/Unit in the first year with 2% annual escalation on compounded basis.<br>Non qualifying – Rs 1.94/Unit in the first year with 2% annual escalation on compounded basis. | Wheeling charges at 2% energy.<br>Banking allowed for one year | Third part sales is allowed |
| Rajasthan | | | To be revised to Rs 3.31/Unit in the first year fro Rs 2.90/Unit. | | | |

# Chapter 4: Andhra Pradesh scenario

## Power Scenario in Andhra Pradesh

As per the CEA study, the growth rate of electricity demand may be considered to follow its GDP growth rates, ranging between 6 to 9 %. Thus, the study recommends that additional power projects totalling to a capacity of about 1300 MW need to be identified in 10th Five-year Plan period itself. The power plants under construction in Andhra Pradesh would add total 1400 MW capacity by end of 2006[1]. As per Southern Regional Load Despatch Centre's Monthly Report[2]; during February 2006, as against an unrestricted peak demand of 7969 MW, 7868 MW peak demand was met, thereby leaving a peak deficit of 101 MW. Similarly, against unrestricted energy requirement of 4718 MU, unmet energy was to the tune of 33 MU. Also, to enhance rapid economic and industrial growth, addition of power generation capacity is imperative.

## Renewable energy based power in Andhra Pradesh

The renewable energy programme was looked after by Agro Pump-sets and Implements Ltd. initially. Later on, to develop these resources in an accelerated fashion, the Non-Conventional Energy Development Corporation of Andhra Pradesh Ltd. (NEDCAP) was established. NEDCAP started many programmes relevant to Andhra Pradesh. Realising the need for augmenting power generation capacity in the state, NEDCAP put a lot of emphasis on renewable energy resources based power generation, to be fed to the grid. One of the prime considerations pertained to the tail-end voltage strengthening of the transmission system. The following are the resources that are available abundantly in the state:

- Biomass
- Bagasse based Co-generation
- Wind
- Small Hydro
- Municipal solid waste
- Industrial waste

[1] Monthly report of broad status of thermal power projects in the country (Feb 2006), Central Electricity Authority, http://cea.nic.in/thermal/project_monitoring/index_Thermal_Project_Monitoring.htm

[2] http://www.srldc.org/repmonthly.php accessed on April 3, 2006

Looking at the vast potential of biomass resources in the state, Andhra Pradesh went all out in exploiting the same for the power generation (while the potential of biomass power was estimated to be around 448.5 MW by the Expert Committee formed by the Government of Andhra Pradesh; as per NEDCAP estimates it is 627 MW. The Administrative Staff College of India, in turn, has estimated biomass power potential to be around 220 MW). The result of combined policy push of MNES and NEDCAP in this field was establishment of a sizable capacity of biomass power plants. The programme became so successful that the biomass demand started outstripping supply, thereby resulting in rise in biomass prices. The rising fuel prices coupled with the reduced electricity tariff created a situation wherein no fresh investments in this field are forthcoming in the state. Moreover, as against Expert Committee's estimated potential of 448 MW, NEDCAP has already sanctioned biomass projects totalling 276.25 MW. APERC, therefore, has ordered that no more biomass power projects would be licensed in the state. Instead, the state would encourage resources like wind and municipal wastes. The following table 15 gives a comparative picture of resource potential and already installed capacity in the state of Andhra Pradesh:

Table 15: Status of Renewable Energy Power Projects (as on March 31, 2006)

| Resource | Potential* (MW) | Projects sanctioned (MW) | Capacity commissioned (MW) |
|---|---|---|---|
| Biomass | 627 | 276.25 | 207.75 |
| Bagasse Co-generation | 350 | 323.75 | 181.25 |
| Municipal Solid Waste | 40 | 30.35 | 12.75 |
| Industrial waste | 135 | 55.35 | 13.50 |
| Small Hydro | 500 | 114.25 | 92.35 |
| Wind | 745 (1920[3]) | 330.12 | 124.97 |
| Total | 2397 | 1130.07 | 632.57 |

* As per NEDCAP Survey

The contribution of renewable generation in Andhra Pradesh during the year 2005-06 was about 2.7%[4].

## Regulatory practices in AP

The Andhra Pradesh Electricity Regulatory Commission has specified buyback tariffs for power from renewable energy sources i.e. wind, small and mini hydro, biomass, and bagasse co-generation.

[3] As per MNES
[4] As per the Global Energy Accounting, APTRANSCO http://aptranscorp.com/global-acc.html

The renewable power policies and hence their impact can be divided in two phases:
1. Initial stage of promotional policy which included investment subsidy and also guideline from central government and
2. Post-reforms and Electricity Act 2003.

The first phase has its impact by initiating developments in this sector, establishing manufacturing, knowledge and human resource base. During this phase stakeholders like the power producers and utilities gained experience and understanding of this sector. This phase also made the renewable power sector ready for the next phase.

The second phase of post reforms and Electricity Act 2003, with more transparent process of tariff setting, is ongoing and expected to make renewable power competitive.

As per APERC's Renewable Power Purchase Obligation Order no. 9 of 2005; a RPO of minimum 5% of the consumption has been prescribed for the years 2006-07 and 2007-08. Moreover, within this RPO, 0.5% has been kept reserved for wind power even if because of it, the overall renewable power procurement exceeds the RPO. The main features of APERC order are as follows:

- Reservation of RE quota of0.5% for wind power, even if total NCE purchase exceeds RPO
- Generating stations to be located within AP
- Every distribution licensee, captive power consumer, and open access consumer to be included
- Energy procured from outside AP but for use in AP, included while computing the RPO Quantum
- No more biomass power, other than that already committed through PPAs
- Liable for Penalty in case of non-compliance

Insofar as tariffs are concerned, the same are as follows:

1. Bagasse based power generation: Rs 2.74/Unit for the first year, base year 04-05
   - Fixed cost without escalation: Rs 1.72/Unit
   - Variable cost: Rs 1.02/unit (with escalation of 5%, base year being 2004-05)
2. Biomass based power generation: Rs 2.88/Unit for the first year, base year 04-05
   - Fixed cost without escalation: Rs 1.61/Unit
   - Variable cost: Rs 1.27/unit (with escalation of 5%, base year being 2004-05)
3. Mini Hydro based power generation: Rs 2.60/unit for the first year
4. Municipal waste to energy: Rs 3.37/Unit with 5% annual escalation, base year 2004.

5. Wind energy based power generation: Rs 3.37/Unit with 5% annual escalation, base year 2004

## Key issues in Andhra Pradesh

In order to ascertain the main issues affecting renewable energy power sector in Andhra Pradesh, consultations were held with different stakeholders in Andhra Pradesh, including APERC, NEDCAP, and developers. While few issues concern specific resource/technology, others are overarching. These are discussed below:

### Tariff/pricing of RE based power

Pricing of power from RE power projects is an inherently complex task. The *cost plus approach* relies on the availability of requisite station-wise information for the generating stations, and thereafter builds up the tariffs from the costs. However, since in case of RE power, there are a number of small power stations; APERC, like other SERCs, has adopted price benchmarks based on standard cost parameters, and not station specific pricing.

Benchmark pricing typically adopts a representative power plant 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.

In the context of complexities involved in fixing tariff for RE power, the following critical issues need closer examination so as to ensure that RE power producers get a remunerative price for the electricity generated by them:

- Since the cost-plus approach is adopted for fixing the tariff for RE power, determination of various factors become very crucial. Thus, There is a need to establish standard values of the following
    - Capital cost
    - O&M cost
    - Depreciation
    - Return on equity
    - Interest rates
    - Threshold capacity utilization/plant load factor

Additionally, for the biomass/cogeneration projects, following aspects need to be benchmarked:

- Specific Fuel Consumption
- Fuel cost
- Auxiliary consumption
- Heat rate of the coal, used during rainy season
- The tariff beyond threshold limit should be limited to the variable cost and incentives only and not the full tariff.

It may be noted that factors like O&M costs that are being used presently have been benchmarked for the large thermal power plants and not for small-sized, RE power plants.

- There is no mechanism by which the environmental benefits that accrue by producing power using RE sources can be quantified and factored in the tariff.
- The possibility of cost sharing, if tariffs set using the cost-plus principles exceed the average cost of generation from RE sources, needs to be explored.
- Moreover, there is also an issue as to who would bear the burden of the additional cost of generation. Should it be the state government which subsidizes the entire cost differential or whether this amount is be cross-subsidized through consumer tariffs.
- Should there be tariff escalation for all RETs, including for those that do not incur any fuel cost? If so, should it be uniform?

The NTP has recognised these issues and preferential tariffs have been recommended till the different RE technologies become commercial. The NTP also goes one step further in bringing competition “within the RE technologies” in future.

Some of the other issues that warrant particular consideration particularly in the context of Andhra Pradesh are:

- Power Purchase Agreement (PPA): to procure power from RE sources, it is essential for distribution utilities to sign PPAs with such developers and procure power from them at the mutually agreed rate. If a PPA does not exist, then at what rate will the utility purchase power from the RE developers?
- Minimum power procurement from wind based power plants: as per the APERC Order on Renewable Power Purchase (2005), all distribution utilities in Andhra Pradesh are obligated to procure 0.5% of power from wind energy. In case a distribution utility does not comply with this mandate and purchases below this level, what is the compliance mechanism to ensure that this obligation is met?

## Grid connectivity issues

### Infirm power

Electricity generating stations face the problem of deciding how to schedule generation to minimize the total fuel cost or to maximize the total profit over a period (which can vary from a few hours to a day or even a month) subject to a set of constraints. The two short-term operational issues that need to be managed by a load despatch center are: (a) Unit Commitment, which is the process of deciding when and which generating units at each power station has to start-up and shut-down and (b) Scheduling of power outputs of the individual generating stations for each scheduling interval in advance and monitoring the same in real time.

The main problem with some of the renewable based power plants based on wind and small hydro is that these plants are non-despatchable and the nature of demand that these plants cater to (whether peak demand or a base-load demand) and the time during which these plants supply power to the grid is not known. Any such small power station is subject to fluctuations in output and where 'day–ahead' advance scheduling is not possible; the utility cannot take the capacity availability from such plants into consideration and plan their operations accordingly.

Some of the issues that could arise in the context of despatchability and scheduling of small RE based power plants are summarized below:

- How to integrate small RE power plants into the system despatch schedule.
- How to take into account such power plants (e.g. wind based power plants that rely on highly intermittent resource) in the generation planning exercise.

These issues become more critical in low demand situations.

### Wheeling charges

The Electricity Act 2003 allows non-discriminatory use of a licensee's network on payment of wheeling charges either in the event of a third-party sale or with the licensee buying only part of the electricity generated by the RE plants. Some of the issues related to this are:

- Some of the RE plants may be very close to the consumption points while others may be away. How should the wheeling charges and T&D losses be computed in these cases?
- Is it possible to award a rebate for wheeling of RE based power, on account of it being green power?

## Carbon credits and Renewable Energy Certificates

The projects which result in reduction of green house gases (GHG) can get credit for the emission reduction through the flexibility mechanisms as per the Kyoto Protocol. For the developing countries like India, the CDM offers the opportunity to benefit from the projects resulting in GHG emission reduction.

In order to bring down the tariff, possibility of incorporating (a) Renewable Energy Certificates (RECs) and (b) carbon credits arising out of CDM in the tariff may be explored.

## Other Issues

1. There is an issue regarding royalty. The reason cited for imposing a royalty on water is that since small hydro plants use natural resources (which essentially are State resources); they should pay some royalty on them.
2. For greater absorption of RE power, it is imperative that its cost comes down so that there is no unnecessary burden on the utilities and consumers. Therefore, MNES should support R & D for making these technologies more cost-effective.
3. For encouraging wind power in the state, APERC has taken concrete steps comprising (a) attractive tariff and (b) specific quota for wind power. However, even now, the Distribution Companies are reluctant to sign PPAs even with the commissioned projects.
4. There is no mention about banking facility in the Open Access Regulations passed by APERC. Hence DISCOMs and APTransco are not obligated to provide this facility to wind projects.

# Suggested approach

The following approach is suggested to address the aforementioned issues. This approach is based on wide discussions that a number of regulators and developers had during National Conference on “Renewables and regulatory issues” on February 21-22, 2006 in New Delhi. In this approach, there is a specific role for all the major players viz. CERC, APERC, MNES, NEDCAP, Forum of Regulators, and project developers.

1. The CERC and FoR (Forum of Regulators) may come out with a paper detailing standards that should be adopted by the regulators for estimating costs instead of estimating costs plant-wise and using the norms developed by CEA for large thermal plants. For the

benchmarking of cost and performance parameters, specialized agencies may be engaged.

2. Considering that renewables, such as wind and hydro do not have any fuel costs, for them annual escalation of tariffs may not be necessary.
3. The incentives to RE power generation may be linked to performance for which performance benchmarks need to be established for Andhra Pradesh.
4. It may be desirable to quantify the impact of the preferential tariff given to RE power on overall electricity consumption. If effect of these preferential tariffs on consumer tariff is within a nominal limit (say 5 paise/kWh) then it may be borne by the electricity consumer or the rate payers. Beyond that, the incremental quantum may be shared by the state government and/or central government.
5. To ensure that distribution utilities comply with the mandate of RPO as outlined by the APERC, the Commission may put a rigorous penalty/compliance mechanism in place.
6. As and when APERC decides to introduce RECs (renewable energy certificates), it may take up a pilot project taking in to account, learnings from experiences such as that of US on tracking and compliance mechanisms.
7. A mechanism of operating the RECs could be as follows.
    - Step I – Distribution company buys the RE-generated power at pool price
    - Step II – State regulator may mandate that a certain amount of REC has to be bought by the distribution company through a competitive bidding route
8. Insofar as issue of infirm power is concerned in case of wind power, the wind power generators may be asked to employ latest forecasting models on a pilot scale that predicts wind power generation within 10% accuracy, 24-hours in advance.
9. The facility of banking may be allowed by APERC for all RE power projects with reasonable level of banking charges. The issue of allocating a specific time frame for reuse of the banked power may also be studied in detail.
10. The CDM modalities and procedures are still evolving and there would be some time before the benefits of CDM are actually realised. Secondly, while the emissions reductions would give additional revenue to the project, this revenue would not be uniform across all the projects, as CDM is a project-based activity and the baseline and emission reductions vary from project to project. Moreover, considering the criteria of 'additionality', all RE power projects may not qualify as

CDM projects. In such a scenario, it may not be justified to build in carbon credits in the tariff.

Similarly, it may be too premature to dwell on sharing of the CDM proceeds with the utilities at present.

11. Regarding grid connectivity, renewable electricity generators may be allowed open access irrespective of phasing on contracted capacity and voltage of supply at consumer point. Moreover, renewable electricity generators may be exempted from surcharge on open access.
    The connection costs may be borne by the project developers, which is included in the project costs facilitating APERC to take it in to consideration while computing the tariff.
12. Competition among renewable generators is an issue that may have to wait till adequate quantities become available from such sources.
13. Rather than prohibiting biomass power generation on account of biomass availability, Government of AP/NEDCAP may like to encourage `closed loop' biomass power plants that have their own dedicated energy plantation.
14. Though water and wind can be termed as State resources, levying a royalty on them would be a deterrent to promotion of RE power, especially since these resources are not being consumed (or depleted). Therefore, such a royalty may not be imposed.
15. There may be a separate cell within APERC that deals with renewable producers' issues with the state utilities, in a time-bound manner.
16. MNES may like to assume a more proactive role with regard to greater interaction with the CERC while preparing guidelines for tariff fixation for RE sources and preparing guidelines for RE certificate trading and quotas.

# References

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# Annexure 1: Comparison of cost components in different Indian States

**Table A. Biomass based power generation**

| Components/States | Andhra Pradesh | Karnataka | Maharashtra |
|---|---|---|---|
| Project Cost/MW (Cr/MW) | 4 | 4 | 4 |
| PLF (%) | 80 | 75 | 70 |
| Cost of fuel(Rs/MT) | 1000 | 1000 | Rs 690-Rs1200 |
| Specific consumption of the fuel(kg/Unit) | 1.16 | 1.16 | 1.02-1.25 |
| Auxiliary Consumption (%) | 9 | 9 | 10 |
| O&M (%) | 4 | 4 | 4 |
| O&M escalation (%) | 5 | 5 | |
| Debt Equity ratio | 70:30 | 70:30 | 70:30 |
| ROE (%) | 16 | 16 | 16 |
| Interest on term Loan (%) | 10 | 11 | 9 |
| Interest on working Capital (%) | 12 | 12.5 | |
| Depreciation (%) | 7.84 | 7 | 5.28 |

**Table B. Co-Gen based power generation**

| Components/States | Andhra Pradesh | Karnataka | Uttar Pradesh |
|---|---|---|---|
| Project Cost/MW (Cr/MW) | 3.25 | 3 | 3.5 |
| PLF (%) | 55 | 60 | 60 |
| Cost of fuel(Rs/MT) | 575 | 800 | 740 |
| Specific consumption of the fuel(kg/Unit) | 1.6 | 1.6 | 1.5 |
| Auxiliary Consumption (%) | 9 | 8 | 8.5 |
| O&M (%) | 3 | 3 | 2.5 |
| O&M escalation (%) | 4 | 5 | 4 |
| Debt Equity ratio | 70:30 | 70:30 | 70:30 |
| ROE (%) | 16 | 16 | 16 |
| Interest on term Loan (%) | 10 | 11 | 10.25 |
| Interest on working Capital (%) | 12 | 12.5 | 10.25 |
| Depreciation (%) | 7.84 | 7 | 7 |

**Table C. Small Hydro based power generation**

| Components/States | Andhra Pradesh | Karnataka | Uttar Pradesh | Uttaranchal | Maharashtra |
|---|---|---|---|---|---|
| Project Cost/MW (Cr/MW) | 3.625 | 3.9 | 4.5 | 5.5 | 4.4 |
| PLF (%) | 80 | 30 | 35 | 45 | 30 |
| Auxiliary Consumption (%) | 1 | 0.5 | 1 | 0.2-0.7 | 0.5 |
| O&M (%) | 1.5 | 1.5 | 2.5 | 3 | 2.5 |
| O&M escalation (%) | 4 | 5 | 4 | 4 | 4 |
| Debt Equity ratio | 70:30 | 70:30 | 70:30 | 70:30 | 70:30 |
| ROE (%) | 16 | 16 | 16 | 14 | 16 |
| Interest on term Loan (%) | 10 | 11 | 10.25 | | 9 |
| Interest on working Capital (%) | 12 | 12.5 | 10.25 | | |
| Depreciation (%) | 7.84 | 7 | 7 | | 2.57 |

**Table D. Wind based power generation**

| Components/States | Madhya Pradesh | Karnataka | Maharashtra |
|---|---|---|---|
| Project Cost/MW (Cr/MW) | 4.5 | 4.25 | 4 |
| PLF (%)/CUF (%) | 22.5 | 26.5 | 20 |
| Auxiliary Consumption (%) | | 0.5 | |
| O&M (%) | 1 | 1.25 | 5 |
| O&M escalation (%) | | 5 | |
| Debt Equity ratio | 70:30 | 70:30 | 70:30 |
| ROE (%) | 16 | 16 | 16 |
| Interest on term Loan (%) | 10.5 | 11 | 12.5 |
| Interest on working Capital (%) | | 12.5 | |
| Depreciation (%) | 4.5 | 7 | 5 |