COMMISSION'S ORDER

ON

SMALL HYDRO POWER PROJECTS

TARIFF AND OTHER ISSUES

December 18, 2007

HIMACHAL PRADESH ELECTRICITY REGULATORY COMMISSION

KEONTHAL COMMERCIAL COMPLEX,

KHALINI, SHIMLA-171002

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ORDER

A1: BACKGROUND

Promotion of Energy Generation from Renewables

1.1 Power is a critical infrastructure input for the development and growth of any country. Accelerating economic growth and achieving higher standards of living depend upon the availability of adequate and reliable power at an affordable price. Presently India has a total installed capacity of 134,716 MW and holds 5th position in world for electricity generated. However, annual per capita consumption in India is among the lowest in the world. Many households in a large number of villages have no access to electricity. The end users of electricity like households, farmers, commercial establishments, industries etc. are confronted with frequent power cuts, both scheduled and unscheduled. The government has envisaged an increase in per capita availability to 1000 kWh from existing 600 kWh by the end of 11th five year plan and provide "Electricity for all" by 2009, which will requires installation of additional capacity of more than 100,000 MW.

1.2 There are several constraints around generation from conventional sources of power:

(a) The availability of fuel (e.g. the inability of coal and gas supply to keep up with growing demand has resulted in the need to import these fuels).

(b) Price of fuels (e.g. gas prices have shown sharp volatility in recent years).

(c) Statutory clearances and environmental impact (e.g. large hydro projects have environmental and rehabilitation issues associated with them resulting in significant delays in project execution)

1.3 Ideal mix of thermal and hydro generation in India was supposed to be 60:40. However, over the years hydel capacity addition has not kept pace with the thermal capacity addition. Presently, in India coal based generation dominates the power scenario and will continue to do so in future also. Share of hydel energy in the total energy generation has gradually declined. Therefore, thermal generation, which should generally be used for base load operation, is also being used to meet peaking requirements. This leads to non-optimal utilisation of economic and perishable resources. The thermal generation causes generation of green house gases (GHG), namely, carbon dioxide, sulphur dioxide, nitrogen oxides and solid particulate matters, which beyond a specified limit are health hazards and have raised concern of global warming.

1.4 Given the nature of limitations, it is imperative that non-conventional energy source be encouraged to meet part of the increasing demand of energy in the country. Hydel energy potential in India still remain untapped and can be effectively utilised for augmenting power generation in India.

1.5 The Ministry of Non-Conventional Energy Sources (MNES) at the central level and various agencies at the state level promote the development of non-conventional energy sources in the Country. Small Hydro Projects upto 25 MW, Wind, Solar, Bio Mass, Urban Municipal/ Industrial Waste etc. are the Non-Conventional (Renewable) Energy Sources (NES), approved by MNES. Developing renewable energy sources, not only augments energy generation, but also contributes to improvement in environment, conservation of fast depleting fossil fuel and employment generation. In this backdrop, power from renewable energy assumes importance and therefore, NES need to be encouraged. The State Electricity Regulatory Commissions are also required to promote generation from renewable sources under the Electricity Act.

1.6 Keeping in view the importance of producing power from renewable sources and the statutory obligations in this regard, the Commission set about the task of framing regulations for promoting the sale of power from renewable sources and co-generation, fixation of tariff etc from renewable sources within the State of Himachal Pradesh.

Power Scenario and potential

1.7 Himachal Pradesh has no coal reserves in the state. The only significant source is hydel energy. Himachal Pradesh has vast hydel potential of approx. 21,000 MW (approx. 750 MW under Small Hydro Sector) in the five river basins. Of this potential, 6037 MW has been harnessed so far.

1.8 The large hydel projects have been associated with environmental degradation, population displacement and submergence of land, resulting in delays in implementation. Mini/micro/small hydro, projects are free from such problems associated with large hydro, hence generation from mini / micro / small hydro projects could therefore provide a feasible alternative to meet growing energy demand in as quick a manner as possible.

1.9 Presently, there are 20 SHP projects in Himachal Pradesh with an aggregate capacity of approximately 43 MW. Another 90 projects with an aggregate capacity of 299.40 MW are at the implementation stage. Also, 108 projects with an aggregate capacity of 227.45 MW are at MOU stage. Power Purchase Agreements for 38 projects have already been signed. Given the significant potential for development of Small Hydro Projects (SHP) in Himachal Pradesh, the Commission feels the need to facilitate rapid development of SHP in the state.

Legal Provisions for Promotion of Renewable Energy

Electricity Act 2003

1.10 Electricity Act, 2003 emphasizes the importance of non-conventional energy sources and clearly mandates for the promotion of electricity generation from non-conventional energy sources including co-generation.

1.11 Section 86(1) (e) of Electricity Act, 2003 empowers Commission to promote co-generation and generation from renewable sources of energy by providing suitable measures of connectivity with the grid and sale of electricity to any person, and also to specify percentage of renewable energy to be procured as renewable purchase obligation for distribution licensees.

1.12 Section 61(h) of Electricity Act, 2003 further stipulates that provides that the appropriate Regulatory Commissions 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 cogeneration and generation of electricity from renewable sources.

1.13 Section 3 of the Electricity Act, 2003 provides for formulation of National Electricity Policy and Plan for development of power system based on optimal utilization of resources including renewable sources of energy.

National Tariff Policy

1.14 The National Tariff Policy (2006) also reinstates the importance of the renewable energy generation and their subsequent benefits for the country. Some key extracts are presented below:

5.3 (i) " Tariff fixation for all electricity projects (generation, transmission, and distribution) that results in lower Green House Gas emissions than the relevant base line should take into account the benefits obtained from the Clean Development Mechanism into consideration, in a manner so as to provide adequate incentive to the project developers."

6.4 (1) "..... 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...."

National Electricity Policy

1.15 Section 61 of Electricity Act, 2003 also requires the Commission to be guided by the National Electricity Policy. Section 5.2.20 of the said policy mandates that "Feasible potential of non-conventional energy resources, mainly small hydro, wind and bio-mass would also need to be exploited fully to create additional power generation capacity. With a view to increase the overall share of non-conventional energy sources in the electricity mix, efforts will be made to encourage private sector participation through suitable promotional measures."

1.16 Several aspects in respect of promotion and harnessing of renewable energy sources have been highlighted in Section 5.12 of National Electricity Policy as stated under:

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

5.12.2- The Electricity Act 2003 provides that co-generation and generation of electricity from non-conventional sources would be promoted by the SERCs by providing suitable measures for connectivity with grid and sale of electricity to any person and also by specifying, for purchase of electricity from such sources, a percentage of the total consumption of electricity in the area of a distribution licensee.

Judicial precedents

1.17 The Appellate Tribunal for Electricity (APTEL) has also recognised the need for promoting renewable energy source. APTEL's order dated May 18, 2007 the tribunal notes that

"…The State and its Authorities including the Electricity Regulatory Commissions have a solemn responsibility to protect and improve the environment for present and future generations. Article 48A of the Constitution of India, as a directive principle of the State Policy, inter alia, provides that the State must endeavour to protect and improve the environment. Article 51-A (g) casts a duty on the citizens of India to protect and improve the natural environment. Article 21 of the Constitution, which in its bosom conceals different facets of the right to life, imposes a positive obligation on the State and the Authorities created by it, to take preventive measures, to protect the ecology

and environment and to conceive, anticipate and attack the causes of environmental degradation.

The preamble to the Electricity Act, 2003 recognizes the significance and importance of promotion of efficient and environmentally benign policies. In consonance with the preamble, Section 61 (h) of the Electricity Act, 2003, spirit of the Constitution and concern for the environment, it is the bounden duty of the Regulatory Commissions to frame Regulations with a view to give fillip to the production of power through renewable sources of energy. While framing the Regulations, the Regulatory Commissions must have regard to the thrust and spirit of the aforesaid provisions of the Constitution and Electricity Act, 2003, the National Electricity Policy and MNES guidelines. The Regulations should be fashioned in such a manner that it should be possible to built up sizable capacity through clean renewable sources of energy."

1.18 The Appellate tribunal further emphasized the mandate for regulatory commissions to incentivise renewable generation in it's order dated 28 Sept. 2006. The order notes that

"*...The preamble of the Act also recognizes the importance of promotion of efficient and environmentally benign policies. It is not in dispute that non-conventional sources of energy are environmentally benign and do not cause environmental degradation. Even the tariff regulations u/s 61 are to be framed in such a manner that generation of electricity from renewable sources of energy receives a boost. Para 5.12 of the National Electricity Policy pertaining to non-conventional sources of energy provides that adequate promotional measures will have to be taken for development of technologies and a sustained growth of the sources. Therefore, it is the bounden duty of the Commission to incentivise the generation of energy through renewable sources of energy. PPAs can be re-opened only for the purpose of giving thrust to non-conventional energy projects and not for curtailing the incentives.*

MNES/GoI Policy Guidelines

1.19 The Central Government is targeting that by the year 2012, 10% of generation capacity will be from renewable resources of energy. This includes small hydro power plants of capacity less than 25 MW. The MNES guidelines issued in 1993 assumes 1994-95 as the base year for tariff determination. For that year, the tariff was set at Rs.2.25 per kWh with annual escalation of 5% per annum for the first 10 years. From the 10th year and onwards, the price of power as per MNES guideline will be equal to the purchase price at the end of the 10th year, or the High Tension (HT) tariff, prevalent in the State at that time, whichever is higher. The MNES guidelines also require that the period of Power Purchase Agreement (PPA) must be a minimum of 20 years and can be extended by another 10 years, through mutual agreement

Government of Himachal Pradesh initiatives for SHPs

1.20 Himachal Pradesh Energy Development Agency (HIMURJA) has been designated as the nodal agency for the State of Himachal Pradesh to promote NES within the State. HIMURJA has since been instrumental on behalf of the State of Himachal Pradesh in formulating various policies, identifying potential sites, for the development of SHPs in private sector/joint sector.

1.21 In order to provide incentives for development of micro hydel projects in the State, Department of Science and Technology and Environment, GOHP issued its first notification in November, 1994 followed by notifications in August and September, 1999. Subsequently, GOHP through a notification dated May 6, 2000 revised the incentives for private/ joint sector participation in the micro hydel projects upto the capacity of 3 MW (revised to 5 MW in December, 2000). As per the policy, HPSEB was required to purchase power from IPPs/Joint sector companies @ Rs. 2.50 per unit.

1.22 With a view to further promote the generation of power from NES, Government of Himachal Pradesh formulated " Hydro Policy of Himachal Pradesh-2006".The Highlights of the policy have been as under:

(a) The tariff for purchase of power by HPSEB @ Rs. 2.50 per unit.

(b) Wheeling for captive use within the State allowed at a fee of 2% (including system losses). Wheeling charges @ 10% of the energy received (excluding royalty) for sale/captive use of power outside the State.

(c) Banking of energy allowed as per prevailing rules and regulations.

(d) Third party sale of power within the State was not allowed initially. However, in a subsequent amendment the third party sale within the state has been allowed for projects with tariff more than Rs. 2.50 per unit after due approval from the Commission.

(e) Royalty on water usage in shape of free power to the State from the small hydro projects having installed capacity up to 5 MW, is waived off for a period of 12 years reckoned after 30 months from the date of signing of IA of the Project (irrespective of extension in time period of IA granted to an IPP on any account). Beyond 12 years, the royalty @ of 12% is applicable for next 18 years and 18% for the remaining duration of PPA. The 12 years relaxation in royalty is not applicable to the Projects which make captive use of power outside the state or make third party sale outside the state. In that case, the royalty @ of 12% reckoned after 30 months from the date of signing of IA of the Project shall be applicable for the entire duration of PPA.

(f) The developer permitted to establish, own, operate and maintain the Project for a period of 40 years. Thereafter, the Project shall revert to the State Government free of cost and free from all encumbrances.

(g) Interfacing including transformers, panels, kiosks, protection, metering, HT Lines from the points of generation to the HPSEB's nearest feasible sub-station as well as maintenance shall be undertaken by the Developer as per the specifications and requirements of the HPSEB, for which the developer shall bear the entire cost.

(h) The Hydro Projects Developers shall be at liberty to erect common dedicated transmission lines for joint evacuation of Power from two or more Projects by way of suitable Consortium Agreements.

(i) Non-cash incentives shall be provided in terms of speedy clearances by the Screening Committee and timely payments by the Electricity Board to the entrepreneur.

   (i) Escort Service shall be provided by HPSEB or HIMURJA

   (ii) HPSEB shall clear all dues of a private party on account of purchase of power within thirty days from the receipt of the bill, failing which penalty @ 1.5% per month shall be payable by HPSEB. The HPSEB shall open a revolving Letter of Credit (LC) to ensure timely payment for which the charges shall be borne by the Company. The Letter of Credit provision shall be applicable only in case where the entire power is sold to HPSEB (excluding royalty).

   (iii) If the applicant does not take effective steps to undertake survey and investigation within a period of three months from the date of MOU or after finding the site feasible does not prepare DPR within the stipulated period as indicated in the MOU, the MOU shall be automatically terminated (except force majeure conditions) and the site shall be allotted to some other applicant. If, on the other hand, land is not leased to the entrepreneur and power purchase agreement is not signed by the HPSEB within six months from the date of signing of Implementation Agreement, the applicant will have the option to terminate the Implementation Agreement without any financial obligation on either side. The Implementation Agreement shall be signed within 30 months from the date of signing the Memorandum of Understanding (MOU).

(j) Provision for Deemed Generation:

(i) The deemed generation shall be payable in case of non-availability or partial availability of evacuation system beyond the interconnection point on various grounds of system parameters, and/ or backing down instructions from the state load dispatch centre.

(ii) Deemed generation shall be payable when water spillage exceeds 480 hours in a year, and in such cases only where evacuation system is connected to manned 22 KV Sub-stations declared as control sub-stations by the Board or 33 kV/EHV Sub-stations of HPSEB. However loss of generation due to the interruptions/ outages attributed to the aforesaid factor(s), lasting for a period of less than 20 minutes at a time or attributed to the Force Majeure event(s), shall not count toward deemed generation.The benefit on account of deemed generation shall not be allowed in case where captive use/third party sale is intended to be made outside the State

(iii) The HPSEB shall pay for the Saleable Deemed Generation on the basis of the deemed generation after deducting on deemed basis the corresponding quantum of Govt supply, auxiliary consumption transformation losses and transmission losses in deemed delivery of such power at the interconnection point.

(iv) For working out the benefit accruing on account of deemed generation, any loss in generation attributed to the factors governing the deemed generation during the first year of the operation of the plant shall be based on the hydrological data in the DPR relating to 75% dependable year. During the subsequent years, deemed generation shall be payable up to actual generation in previous years / 75% dependable year generation, whichever is lower.

HPERC's Responsibilities

1.23 On the basis of the legal & policy framework and judicial precedents described above, HPERC's primary responsibilities relating to Small Hydro Projects are:

(a) Specification of minimum purchase requirements from renewable sources.

(b) Fixation of tariff for purchase of power from small hydro projects by the distribution licensee in HP, when such purchase is not through the competitive bidding route as per the guidelines issued by the Ministry of Power u/s 63 of the Electricity Act, 2003.

(c) Fixation of terms & conditions for wheeling, banking and third-party sale.

(d) Provision for suitable measures of connectivity with the grid.

A2: Procedural History

Issue of Draft Regulations on Procurement of Renewable Energy

2.1 In compliance with the statutory provision in the Act and the policy guidelines given in the National Electricity Policy and National Tariff Policy, the Commission published draft regulations on "Power Procurement from Renewable Sources and Co-generation by Distribution Licensee" on 13th April 2007, vide notification No.HPERC/428, inviting suggestions/objections from all the stakeholders.. The salient features of these draft regulations were as follows:

(a) Grid Connectivity

(i) Mandatory open access for Non Conventional Energy (NCE) sources to any licensee's transmission system.

(ii) Generators to bear the expenditure incurred for connectivity up to inter-connection point and the transmission licensee or State Transmission Utility (STU) to bear the cost of augmentation of transmission system beyond the inter-connection point

(iii) Renewable Energy and Co-generation Producer(s) to provide interest free loan (shared amongst the IPPs based on the capital cost of the projects on pro rata basis) equivalent to 50% of the cost of augmentation works to be carried out for the evacuation of power beyond interconnection point. Transmission licensee or STU to repay the loan amount in 5 equal instalments, spread over a period of 5 years, commencing from one year after the date of commissioning of the project.

(iv) Priority to be given for connectivity/transmission/wheeling of energy from renewable sources and cogeneration through the grid. Banking of energy to be permitted by the distribution licensee.

(b) Quantum of purchase of electricity from renewable sources

(i) Distribution licensee to purchase a minimum of 20% of its total consumption during a year from renewable sources and cogeneration (available after the captive use and third party sale outside the state) subject to availability. This percentage to be reviewed once in every 3 years and the Commission could waive off the renewable purchase obligation of the distribution licensee in case of supply constraints or any other uncontrollable factors.

(c) Tariff

(i) The tariff for the procurement of energy from mini/micro/small hydro projects up to and including 25 MW by the distribution licensee to be as per the prevalent hydro policy notified by the GoHP.

(ii) Cost based benchmarks to be considered for the determination of the tariff determination.

(iii) The cost based benchmarks to be reviewed once in three years.

(iv) Allowance based on technology, market risk, environmental benefits and social contribution etc. of the mini/micro/small hydro project to be permitted in determination of tariff.

Public Participation

2.2 The Draft regulation was circulated to all concerned stakeholders wherein comments/ suggestions were invited from all the stakeholders so as to enable the Commission to take a view on various issues listed therein.

2.3 The Commission received comments/ suggestions on the various aspects of renewable energy projects and the respective provisions of the draft regulation from the following:

(i) The Chief Engineer (Comm), HPSEB.

(ii) Shri PN Bhardwaj, Consumer Representative.

(iii) The Secretary, Himachalis Hydro Power Developer Association.

(iv) Shri. A. K. Chopra, Secretary, M/s Himachal Small Hydro Power Association.

(v) M/s Himachal Hydel Project (P) Ltd.

(vi) Shri SN Kapur, Director (Technical),Astha Projects (India) Limited.

(vii) Shri Shyam Vaidya, Managing Director, Ascent Hydro Projects Ltd, Director, DLI Power (India) Private Ltd.

(viii) Shri AudityaYadlapati, Director, Aditya Cotton Mills Pvt. Ltd., Yadlapati Agro Products Pvt. Ltd., Managing Director, Upper Julakari.

(ix) Shri Dharampal Reddy, E D, Tejas Saranika Hydro Energies Pvt. Ltd.

(x) M/s Milestone Power Generation Limited.

(xi) M/s Chandigarh Distillers & Bottlers Ltd.

(xii) M/s Growel Energy Co. Ltd.

(xiii) M/s RPP Limited.

(xiv) Shri Maan Singh Thakur, Director, Swamini Hydro Powers Pvt. Ltd.

(xv) Shri PK Kohli, Director, M/s KKK Hydro Power Limited.

(xvi) Er. RL Justa, Member HP Govt. Grievances Committee (Shimla Distt.).

(xvii) M/s Punjab Hydro Power Pvt. Ltd.

(xviii) M/s Kapil Mohan & Associates Hydro Power (P) Ltd.

(xix) M/s Techman Infra Ltd.

(xx) M/s DSL Hydrowatt Limited.

2.4 Subsequently, a public hearing was held on 11 June, 2007. All concerned parties and stakeholders made their submissions/suggestions/presentations to the Commission which are summarized below.

Applicability and Project Classification based on size of Project

2.5 HPSEB submitted that the Regulations on Procurement of Renewable Energy (including tariff setting and connectivity to grid) should be applicable only for intra-state sale of power.

2.6 To enhance viability for projects of different sizes, IPPs and consumer representatives suggested that projects less than 5 MW should be classified into slabs for the purpose of tariff setting e.g. less than 50 kW, 51-100 kW, 101-1000 kW, 1-2 MW, and above 2MW, as smaller projects may not be comparable to bigger projects in terms of cost benchmarks and would typically require higher per unit capital and operating costs.

2.7 Further IPPs submitted that the hydro policy of Himachal Pradesh specifies the tariff for the projects up to 5 MW only and not for the projects between 5 MW and 25 MW capacities. They requested that HPERC address tariff determination issues for all small hydro projects upto 25 MW of capacity as per the guidelines of Ministry of Non-conventional Energy Sources (MNES), GoI.

Interconnection point and interconnection facilities

2.8 During the public hearing, various IPPs submitted that interconnection facilities between the developer and the STU be defined to avoid confusion e.g. it should address issues such as who shall bear the cost of land or building for substation. They also pleaded that the State Transmission Utility (STU) be made responsible for providing interconnection facilities in time bound manner and if the STU fails to provide appropriate interconnection facility within stipulated timeframe, the IPP should be entitled for the benefit of deemed generation charges.

2.9 HPSEB on the other hand submitted that the board would endeavour to provide inter-connection at the nearest HT/EHT sub-station. In case(s) where it is not feasible for the board to provide such inter-connection at the nearest sub-station for one or the other reason, the inter-connection may be given at an alternative sub-station. The HPSEB also submitted that where possible IPPs may enter into suitable arrangement for development of a joint evacuation system and inject power into the licensee's power system through the joint evacuation system in cases where there are right-of-way problems or there are space limitations at the sub-stations of the licensee. HPSEB also pleaded that the minimum voltage level for injections with respect to different plant capacities be specified.

Evacuation System beyond interconnection point

2.10 HPSEB stated that as per the hydro policy of Himachal Pradesh, augmentation cost (if any) has to be met by the IPPs. HPSEB suggested that it would be prudent to charge IPP on the basis of installed capacity of their projects instead of the capital cost of the augmentation as the determination of the capital cost may be a complex process. HPSEB also stated that the modalities for sharing recovery of the cost of augmentation/addition should also account for the apportionment of costs in cases where the system may have to be designed for a much higher capacity for additional future projects.

2.11 The IPPs contended that HPSEB alone should be mandated to meet the entire funding arrangement for augmentation of transmission system. However, if IPPs are to provide loan to STU for augmentation work, the quantum of loan be limited to 25% of augmentation cost to be repaid in 5 equal installments and there should be provision for charging of penal interest rate in case of default by STU. IPPs also suggested that repayment of such loan may be adjusted against the royalty payable to GoHP as free power. Himachal Power Hydro Association pointed out that as per the brochure and Hydro Policy before 2006, it was declared that augmentation cost beyond the interconnection point is to be borne by the Board. Consumer Representative highlighted that intra-state transmission, as per 39 (2) (c) of Electricity Act, 2003 is a clear responsibility of the STU.

Connectivity/Wheeling/ Transmission Charges

2.12 The Board stated that priority in connectivity/wheeling/transmission charges be given only for intra-state operations by the SHP developers.

2.13 It was submitted by the IPPs that 10% wheeling/transmission charges in case of export of power outside the state under open access have been prescribed by the GoHP and Regulatory Commission alone has the authority for fixation of wheeling/transmission charges and it should issue the necessary direction for charging of reasonable wheeling/transmission charges.

Banking of Energy

2.14 The Board argued that the Banking of Energy should not form part of these regulations, as it will come into picture only when the IPPs do not sell power to the Distribution Licensee. HPSEB also pointed out that owing to the variable cost of power for every block of 15 minutes, there could be commercial implications on the Board.

2.15 The IPPs stated that banking of energy may occur in a situation where IPP opts for captive use or 3rd party sale within or outside the state. The IPPs further suggested for incorporation of a provision in the PPA between developer and HPSEB allowing for the option of partial sale of energy to 3rd parties and balance to the Board, similar to the practice being followed in Madhya Pradesh.

Quantum of Purchase of Electricity from Renewable Sources

2.16 IPPs welcomed the provision for minimum procurement from non-conventional at 20% of total consumption; however IPPs submitted that sub-provision allowing for waiving off the target by the Commission (in case of supply constraints or any other uncontrollable factors) should be deleted, as this will defeat the very purpose of fixing the target quantum of purchase. Consumer representative, Mr. P.N. Bhardwaj submitted that 20% renewable power procurement fixed in these regulations could lead to a heavy pass through to the consumers and suggested that the additional per unit burden on account of this quantum needed to be worked out for various costs before deciding the energy purchase limit. The Board submitted that distribution licensee should have the first right to purchase power i.e. before captive use and third party sale instead of last right.

Determination of tariff

2.17 IPPs submitted that the hydro policy spells out the rate for the projects up to 5MW only and not the project more than 5 MW and up to 25MW capacities. It was also suggested that no other state commission has decided tariff determination for SHP up to 25 MW capacities for individual IPPs. Therefore, IPPs argued for withdrawal of the benchmarks, which logically should be prescribed for large projects only, as the SHP needs to be accorded a promotional treatment in the matter of tariff. The tariff for SHP should be revised upward from existing Rs. 2.50 per unit which was fixed by the hydro policy in 2000. The commission should also permit the allowance based on additional costs/levies such as increase in land cost, increase in royalty, Local Area Development charges etc. imposed by the state government for SHPs.

2.18 The Board suggested that flat rate of Rs.2.50 per unit for projects upto 5 MW should be followed as hitherto. If necessary, the Commission can review the rate on the basis of benchmark as may be considered reasonable by it from time to time, as a matter of general review for the future projects, after hearing all the stakeholders. For projects of more than 5 MW and upto 25 MW the tariff can be determined by HPERC on case to case basis on request from both the sides (seller & purchaser) rather than for individual projects.

2.19 Consumer Representative and some other stakeholders offered comments on the cost based benchmarks specified for determination of tariff for SHPs and the same have been discussed in chapter 4.

Issue of Final Regulations on Procurement of Renewable Energy

2.20 The Commission considered the comments, suggestions and presentations made during hearing and notified the final regulations on "Power Procurement from Renewable Sources and Co-generation by Distribution licensee" vide notification No.HPERC/428 on 18 June 2007. Subsequently an amendment to these regulations was notified on 16th November, 2007. Salient features of these regulations and their amendment are as under:

(a) Promotion of renewable sources of energy

(i) Open access for renewable generators to any licensee's transmission system and/or distribution system or grid, as the case may be under the HPERC (Terms and Conditions of Open Access) Regulations, 2005. Generator to bear the expenditure incurred for connectivity up to inter-connection point.

(ii) Interconnection of the project line(s) at its nearest control sub-station and if inter-connection at the nearest control sub-station is not feasible then transmission licensee or STU to propose to the generator other feasible interconnection sub-station(s) and the said proposal, along with the reasons for not allowing interconnection at the nearest sub-station, shall be submitted by the transmission licensee or STU for approval of the Commission.

(iii) The generator may, with the approval of the Commission, enter into a suitable arrangement for joint project lines for two or more projects and inject power into the grid through the joint evacuation system.

(iv) Evacuation of power from renewable sources and co-generation beyond the interconnection point, the transmission licensee or STU shall, in consultation with the HIMURJA or any other person whom it may deem fit to consult prepare for the eleventh five year plan a comprehensive plan for augmenting and establishing the transmission/sub-transmission system corresponding to the commissioning of the projects indicating therein, the year- wise time lines to match the commissioning of the project with the establishment of the related evacuation system. The plan for the projects expected to be commissioned during the subsequent five year plan period shall be prepared by the transmission licensee or STU at least one year in advance of the corresponding five year plan. Such plan shall be submitted by the transmission licensee or STU for the approval of the Commission and any expenditure on account of such plan shall be a pass through to the STU.

(v) Draft Regulation's provision that interest free loan equivalent to 50% of the capital cost to be provided by renewable energy producer to STU for augmentation of transmission system deleted.

(vi) Payment of penalty for both by the defaulting licensee or the generator, as the case may be, if time lines mentioned in plan are not followed.

(vii) Generators may, in consultation with the licensee and with the prior approval of the Commission, augment or establish, on behalf of the licensee, the transmission system beyond, interconnection point, on build and transfer basis, and the expenditure so incurred by the generators to be repaid by the licensee along with interest in five equal instalments, spread over a period of 5 years commencing from one year after the date of commissioning of the project and such expenditure to be allowed as a pass through to the licensee

(viii) Where the power purchase agreement, approved prior to the commencement of these regulations, is not subject to the provisions of the Commission's regulations on power procurement from renewable sources; or where, after the approval of the power purchase agreements, there is change in the statutory laws, or rules, or the State Govt. Policy; the Commission, may, after recording reasons, by an order, review or modify such a power purchase agreement or a class of such power purchase agreements

(b) Monitoring by Empowered Committee

An Empowered Committee constituted by the Commission, comprising of one representative each from the Commission, the transmission licensee or STU, the distribution licensee not below the rank of the Chief Engineer or its equivalent shall examine the change in the inter-connection sub-station before the Commission accords approval to it; shall examine the proposals for the joint evacuation system with respect to the overall transmission/ sub-transmission plan of the licensee before the Commission accords approval to it; shall monitor the adherence to the approved time lines, and submission of quarterly reports to the Commission and shall monitor the augmentation or establishment of the transmission/ sub-transmission system as per the best industry practices.

(c) Quantum of purchase of electricity from renewable sources

Distribution licensee to purchase a minimum of 20% of its total consumption during a year from renewable sources and cogeneration (available after the captive use and third party sale outside the state) subject to availability. This percentage to be reviewed once in every 3 years and the Commission could waive off the renewable purchase obligation of the distribution licensee in case of supply constraints or any other uncontrollable factors

(d) Tariff

(i) Tariff for purchase of energy from renewable sources and co-generation by the distribution licensee to be determined by the Commission by a general or special order.

(ii) Tariff for purchase of energy from SHPs up to 5MW capacity to be determined by the Commission by a general order and for SHPs of more than 5 MW and not exceeding 25 MW capacity by a special order on individual project basis.

(iii) The Commission shall adopt the tariff, if such tariff has been determined through transparent process of bidding in accordance with the guidelines issued by the Central Government.

(iv) The Commission shall determine the tariff separately for each category of renewable source e.g. mini/micro/small hydro power projects, wind, solar, biomass and urban/municipal waste power projects.

(v) While determining the tariff the Commission shall consider appropriate operational and financial parameters.

(vi) The tariff for SHPs (not exceeding 5 MW capacity) determined by the Commission shall be applicable for a period of 40 years. The tariff for SHPs is subject to review every 5 years and such revised tariff shall be applicable to power purchase agreements entered into after that date.

Purpose of this Order

2.21 From various comments and suggestions on draft regulations from multiple stakeholders, the Commission observed that issue of tariff determination and evacuation system for renewable energy source is very complex in nature The Commission is of the view that tariff determination and evacuation system issues should be addressed through a separate order, as it would elucidate the issues and concerns of the Commission, the reasons for the approach for tariff determination, formulation of tariff structure opinion on various benchmarks parameters and evacuation system costs etc. The Commission felt that an order on tariff and augmentation cost would capture the whole gamut of issues and give much greater transparency in the whole process.

2.22 Keeping in view the above, and also in pursuance to sub-regulation (1) of regulation 6 of HP Electricity Regulatory Commission (Power Procurement from Renewable Resources and Cogeneration by Distribution Licensee) Regulations, 2007, the Commission has, therefore, come up with this general order for determining tariff for purchase of energy from SHPs up to 5 MW capacity as specified in the final regulations.

A3: ISSUES AND CONCERNS

Power Scenario

3.1 Presently, India has an installed capacity of approximately 134,716 MW which comprise of 86,935 MW of thermal, 33,485 MW of hydel, 4120 MW of nuclear and remaining 10,175 MW of renewable power generation capacity.

3.2 Today, most regions in the country are plagued with power shortages leading to erratic and unreliable supply. The problem becomes acute during peak hours and thus necessitates planned load shedding by many utilities to maintain the grid in a healthy state. The peak shortage is approximately between 11% to 13% while the energy shortage is between 6% to 8.5%.

3.3 Electricity is a key driver for economic growth and social development. The Government has already envisaged a plan to provide "Electricity for all villages by 2007" and "Electricity for all by 2009", and the per capita consumption of electricity is targeted to exceed 1000 units by 2012. India has been experiencing economic growth (in the range of 6-8 per cent) over the last decade and is projected to grow at similar rates in the foreseeable future. In order to support the GDP growth rate of around 7 per cent per annum, the rate of growth of power supply needs to be over 10 per cent annually. Based on the projections of demand made in the 16th Electric Power Survey, additional generation capacity of over 100,000 MW needs to be added over 10th & 11th plan duration.

3.4 Given the huge shortage of power, any addition to the installed capacity is a welcome step towards sustained economic growth and social development of India. Further the environmental concerns associated with conventional power projects make it imperative to look at renewable energy sources to meet growing energy demand in the country.

3.5 Environmental concerns have raised the need for a fundamental change in approach towards development of energy sector in all countries. Adoption of clean technology, improving end use efficiency and diversifying energy bases and promotion of generation from renewable energy sources, such as wind, sun, hydro power and bio mass, which are abundant in nature, have been undertaken. The pace of their development has been accelerated through fiscal and tax incentives.

3.6 Himachal Pradesh, with no coal reserves has no other option but to tap the vast hydel energy potential in state. Promotion of SHPs is imperative, given their minimal environmental impact as compared to large hydro project.

3.7 In view of the increasing importance of renewable energy, most of developed countries have adopted proactive practices towards development of renewable energy sources. However, in India not much progress has been made on this front. India has lagged behind in development of non conventional energy sources. Renewable energy capacity remains at around 6-7% of the total installed capacity of the country. In India, potential from various renewable sources is estimate to be between 80,000 to 100,000MW. However, around 10,175 MW of renewable energy has been tapped so far which amply reflect the slow progress in the renewable sector. Out of the total installed renewable capacity about 7000 MW is wind energy, about 2000 MW is from small hydro and the balance is from co-generation.

Global warming and IPCC findings

3.8 Protection of environment is the crying need of the hour. The Fourth Assessment Report, 2007 rendered by the Inter-governmental Panel on Climate Change (IPCC), established by two United Nations Organizations, namely the World Meteorological Organization (WMO) and United Nations Environment Programme (UNEP) in the year 1988, is revealing. Due to the global warming contributed by use of fossil fuel, the glaciers and the snow cover have receded, level of oceans have risen and seawater has expanded. Though developed countries have been major contributories of green house gases in the past, fast economic growth and large populations of countries like India and China can exacerbate the existing situation. The danger needs to be averted by undertaking measures to curtail emission of green house gases by interested and enlightened agencies across all geographies.

3.9 The SERCs are required under the Electricity Act, 2003 to promote generation from renewable sources of energy. Small steps to reduce dependence on fossil fuel to the extent possible, which does not impact the progress of electricity sector, can ultimately lead to generation of momentum for a giant leap in the development of technology for production of clean energy. Therefore, it is imperative to promote and incentivise renewable energy generation.

Slow progress of SHP in Himachal Pradesh

3.10 Recognizing the importance and potential of small hydro power projects in Himachal Pradesh, GoHP announced incentives as early as in 1994. However even after more than a decade, progress in the development of renewable is far from satisfactory. So far only 20 number of project with aggregated capacity of around 43 MW has been harnessed out of total potential of 1625 MW from 323 identified sites.

3.11 The Commission has taken the note that despite policy initiative and other steps, there has not been any substantial growth in the installed capacity of small hydro power in Himachal Pradesh. Hitherto, only a minuscule fraction of small hydro power potential has been harnessed in the state. Desired urgency in terms of setting up projects is lacking inspite of a positive governmental policy frame-work and positivities in the sector in terms of large price increases at the trading edge. Therefore, one is forced to speculate as to what factors have come into play for this slow growth. Essentially, is it lack of incentives which have constrained the IPPs, is it the attitude and slow response on clearances of the bureaucracy and the Board, is that ROE at about 14% is inadequate, is it that other sub-sectors of the economy over the last one decade have leveraged far greater potential for revenue generation, or is it just the fact that the IPPs are looking for a tactical advantage enabling them to make a quick money by not producing power but waiting for opportunities to trade a project upfront enblock.

3.12 The view of the Commission is that it is a mix of these factors which have constrained the IPPs from moving forward effectively and efficiently towards actualisation of their projects It is, therefore, upto the Commission to not only provide for adequate tariffs, so as to provide for decent returns while ensuring balance for the consumer classes but also to address non-tariff issues like evacuation and clearances so as to ensure that the fruits of projectisation are available to the country as early as possible. At the end of the day, the most important factor is that any step which improves the nation's energy security needs to be effectively taken brushing aside minor state level or utility level distortions.

3.13 Ultimately the Commission would like to, while determining a tariff, also look at the strategic dimensions vide which neighbouring States are setting tariffs, so that SHPs are incentivised to sell to the State's utility and not incentivised to export power across the State threshold. Tariffs, therefore, have to be fixed in accordance with this strategic concern. Ultimately, however, the Commission will have to over the next few years also evaluate scenarios wherein, if the utility is making handsome profits from trade and export, a share in that profit is also available in terms of a constructive formulation, to the IPPs as well.

Strategic Concerns

(a) Neighbouring State Scenario

3.14 The Commission has noticed that the neighbouring states viz. Punjab and Haryana has recently come out with their respective tariff for small hydro projects. Both the states have determined higher tariff than hitherto applicable tariff for small hydro projects in Himachal Pradesh as per the Hydro Power Policy of government of Himachal Pradesh. A comparison of the tariffs with neighbouring states is summarised below:

State	Tariff (Rs./Unit)	Escalation in Tariff
Punjab	3.49	3% p.a. for 5yrs on base yr 2007-08
Haryana	3.67	1.5% p.a. for 5 yrs on base yr 2007-08
Himachal Pradesh	2.50	Nil

3.15 The important concern in this regard is to structure the tariff in such a manner so as not to hamper the investment in small hydro projects in the state of Himachal Pradesh. IPPs must have adequate incentive to invest in SHPs in Himachal Pradesh and the state should be able to optimize and make use of the benefits emanating from its own resources.

(b) Third Party Sale outside the State

3.16 Open Access provisions in Electricity Act 2003 enables end consumer to purchase power from a generator, trader or licensee of their choice.

3.17 However, the concern in case of interstate sale by renewable generator is that renewable generators are typically located in remote areas and require substantial investment for evacuation and transmission of power from such renewable generators to a point for export of power. The cost of such evacuation and transmission facilities is significant and the question of who pays for such facilities needs to be addressed. On one hand if the IPPs pay in full for interconnection including for augmentation/reinforcement of the grid, then some of the projects may become unviable. On the other hand, if the consumers of the state are burdened with the augmentation costs, it may not be fair as they would not get any benefits from such renewable capacity, as the energy from it is getting sold outside the state.

3.18 The Commission has compared the revenues generated for an SHP in both cases e.g. selling power within the state of Himachal Pradesh and selling power outside the state.

3.19 If an SHP opts for sale of power outside the state it will be required to give 12% power free of cost to GoHP in first 12 years of operation, which does not apply, if it sells power within the state.

3.20 For SHP intending to sell outside the state, loss levels on intervening transmission assets to the delivery point will be applicable. Transmission and wheeling charges to CTU and Transco of other state will also be applicable. Also, SHP may be required to pay higher transmission charges to Board/HP Transco on a deep/hybrid costing mechanism.

Description	Within State Sale	Outside State Sale
Royalty Power for first 12 Years	Nil	12% royalty power free of cost supplied to GoHP
Transmission Loss	Comparatively Low	High, as for outside state sale , energy at state boundary will be considered
Transmission Charges payable to	Not applicable if	As per Commission’s

HP Transco	purchased by distribution licensee	regulations
Wheeling charges	Not applicable if purchased by distribution licensee	Applicable as per Commission's regulations if distribution system is used
Augmentation Cost	Shallow approach	Deep /Hybrid approach
Transmission Charges payable to other state/central TransCo	Not Applicable	Applicable
Applicability of Inter-State ABT	Not currently in force	This will apply for inter-state sales. The SHP would need to bear cost of deviations from schedules.

3.21 Based on the above costs, the Commission is of the view that the incentivised tariff determined for SHP sale to HPSEB (while seemingly lower) negates the advantages of an apparently higher tariff for SHPs to sell power outside the state.

Hydro Power Policy of Himachal Pradesh

3.22 Department of Science and Technology and environment, GOHP issued its first notification in November, 1994 followed by notifications in August and September, 1999 to incentivise the development of micro hydel. Further, GoHP vide Notification No. MPP-F (2) –1/2000 dated May 6, 2000 announced a scheme of incentives for the Private/ Joint Sector participation in the Micro Hydel Power Projects of capacity up to 3 MW (revised to 5 MW in December, 2000). As per the said notification, HPSEB was required to purchase power from private parties/joint sector companies setting up Micro Hydel Stations @Rs. 2.50 per unit.

3.23 Subsequently, The State Government has reviewed earlier policy and formulated "Hydro Policy of Himachal Pradesh-2006", making it obligatory for the developers to cater to stipulations such as mandatory 15% water release, LADA, compensation to fisheries, Payments towards use of forest land etc. which were non existent when rate of purchase was announced in May, 2000. The new policy with retrospective effect, does not seem to have considered the impact of these changes as the energy tariff has been maintained at Rs. 2.50/unit.

3.24 The MNES guidelines issued in 1993 sets the tariff at Rs 2.25/kWh (for base year 1994-95) with annual escalation of 5% for first 10 years. However tariff fixed by GoHP in year 2000 remain fixed @Rs 2.50/kWh with no escalation.

3.25 **Inadequate Evacuation System**

3.25 Timely availability of appropriate evacuation system is of vital importance to the SHPs investors. The IPPs have voiced there concern on inadequacy of existing evacuation infrastructure and requested the Commission to direct the HPSEB, ensuring availability of requisite interconnection facilities for the new projects in a time bound manner. The Commission observes that strengthening of transmission/sub transmission system remained neglected, as initial thrust has been on the allotment of project and to attract private investment in the sector. The Commission is concerned that if suitable steps are not taken to augment transmission/sub transmission system, then there could be power evacuation problem for many of the projects under implementation.

3.26 SHPs possess specific attributes namely intermittence combined with higher-than-average distance from load centers that can increase the cost of transmission for these projects. High power evacuation cost may render potential SHP sites unviable from an economic point of view, even though social benefits from such projects might be significantly more. Simultaneous promotion of renewable energy with adequate investment in the transmission system and provision for justifiable returns to the transmission utility remains a major concern.

3.27 The Commission is concerned about the provision of evacuation facilities to small hydro projects in a time bound manner and towards ensuring that augmentation of evacuation/transmission system occurs in a planned manner to minimize over/under investment in the system and ensure optimal utilization of resources. Typically, SHPs capacity installations are staggered in nature whereas transmission investments are inherently lumpy in nature. The Commission would be inclined towards a synchronisation of generation and transmission investments to prevent assets from getting stranded.

HPERC Approach

3.28 It has been Commission's primary concern to adopt the best possible solution for all the stakeholders. The Commission seeks to follow the best practices in India and elsewhere in the world and thereby seeks to balance the interests of all concerned parties e.g. consumers, Board, IPPs and society at large and create a win-win situation for all.

Impact of SHPs

3.29 Presently, there are 20 SHP projects in Himachal Pradesh with an aggregate capacity of approximately 43 MW. Power available in FY 07-08 from private and State owned small hydro power plants is approximately 430 MUs (~8.6 % of power consumption for HPSEB).

3.30 In FY07, Himachal Pradesh had total energy sales of 4112 MU with in the state. With 18.56% T&D losses, total energy requirement for sale within Himachal Pradesh works out as 5049 MU. Energy sales in the state are expected to increase by 20% per annum in future years.

3.31 The commissioning schedule of small hydro power projects as given by the board up to year 2012 is as under

Year	2007-08	2008-09	2009-10	2010-11	2011-12
SHP commissioning Schedule (MW)	103.4	185	51	202	126
Cumulative SHP Capacity (MW) excluding Board's own projects.	125.75	310.75	361.75	563.75	689.75

3.32 To estimate the quantum of power purchase and the impact of the cost of procurement from SHP (excluding Board's own projects) on HPSEB, we have considered three cases - each assuming a certain percentage of capacity under planning gets commissioned and further assumed an average operating CUF of 45%

Case 1 - 50% of the planned capacity gets commissioned

Case 2 – 70% of the planned capacity gets commissioned

Case 3 – 100% of the planned capacity gets commissioned

Year	2007-08	2008-09	2009-10	2010-11	2011-12
Case 1	247.9	612.5	713.0	1111.2	1359.5
Case 2	347.0	857.5	998.2	1555.6	1903.3
Case 3	495.7	1225.0	1426.0	2222.3	2719.0

3.33 Total electricity demand in Himachal Pradesh is forecasted with the assumption of 20 % YoY growth.

Year	2007-08	2008-09	2009-10	2010-11	2011-12
Electricity Demand (MU)	6034	7241	8689	10427	12512

3.34 Assuming 4% annul escalation in the average power purchase cost of HPSEB (2.11 Rupee/Unit for FY 2007) the impact on the average power purchase cost of HPSEB for all three cases is summarised below.

Impact (in %) on Annual power purchase cost of HPSEB						
Year		2007-08	2008-09	2009-10	2010-11	2011-12
Tariff offered to SHP	Rupee 2.60/Unit					
Case 1		0.76%	1.18%	0.78%	0.57%	0.14%
Case 2		1.06%	1.65%	1.10%	0.80%	0.19%
Case 3		1.52%	2.36%	1.57%	1.14%	0.28%
Tariff offered to SHP	Rupee 2.80/Unit					
Case 1		1.13%	1.92%	1.47%	1.43%	0.99%
Case 2		1.59%	2.69%	2.06%	2.00%	1.38%
Case 3		2.27%	3.84%	2.95%	2.86%	1.97%
Tariff offered to SHP	Rupee 3.00 /Unit					
Case 1		1.51%	2.66%	2.17%	2.30%	1.83%
Case 2		2.11%	3.72%	3.03%	3.21%	2.56%
Case 3		3.02%	5.32%	4.33%	4.59%	3.66%
Tariff offered to SHP	Rupee 3.20/Unit					
Case 1		1.88%	3.40%	2.86%	3.16%	2.68%
Case 2		2.64%	4.76%	4.00%	4.42%	3.75%
Case 3		3.76%	6.80%	5.72%	6.32%	5.36%

3.35 Generally, power purchase costs accounts for approximately 60% of the ARR of board. Therefore, impact on aggregate revenue requirement of HPSEB due to purchase of renewable energy from SHP would be even less then the percentage impact on power purchase cost of HPSEB.

3.36 It is thus very obvious that the impact of ensuring greater tariffs to the SHPs as compared to the present tariff at Rs.2.50 per unit would have extremely marginal impact on the over all tariff structure of the utility and would have only negligible impact on the consumers within the State.

A4: TARIFF DESIGN FOR RENEWABLES

Objectives

4.1 The Tariff setting mechanism need to balance multiple objectives. It must be required to meet the following key objectives:

Efficient and economical development of RE

4.2 Efficient and economic development of renewable energy, in line with policy and regulatory requirements, is an important objective. The selection of optimum size of renewable energy plants, choice of plant location, use of cost effective equipment etc. should be encouraged through the tariff setting process. Tariff should be such that development of renewables gets expedited as this is not only in the interest of the State but also of the national interest.

Interests of consumers

4.3 The interest of consumers is of significant importance in tariff determination. The quantum of energy from renewable sources and the tariff determined for sale of such power should not have an unbearable impact on retail tariff. Also, there are other externalities such as consumer benefits arising from an adoption of energy generated from clean sources with a positive long term societal impact that need to be factored in.

Fairness to Investors

4.4 The tariff must ensure that the investor earns an adequate return on investment. This should be consistent with the risk and opportunity costs associated with the business. The tariff determination should also factor in changes in the risk and opportunity cost that investors face from time to time to provide adequate signals to potential investors to invest in green power.

Utility interests

4.5 The power purchase tariff must also be fair to the licensee(s) and should reflect the costs and benefits on account of the mandatory requirement to purchase power from renewable energy generators. Factors such as reliability and availability (e.g. infirm nature of renewable energy) could be of serious concern in case the quantum of renewable energy is large compared to the total purchase of the utility.

Operative and implementation simplicity

4.6 The tariff determination mechanism should be simple to understand and implement. Also, an effective design of the tariff mechanism could result in the development of a set of norms to establish the tariff for a wide range of plants as an effective alternative to the Commission having to examine and set individual tariffs for every single renewable generator.

Approaches for Tariff Determination

4.7 There are three dominant approaches available for tariff determination:

- Avoided cost based approach
- Marginal cost approach
- Cost plus approach
  - Benchmarking approach

Avoided Cost Approach

4.8 Avoided cost based approach for tariff determination is based on the unit cost of energy that is replaced at the margin in order to meet the renewable energy procurement requirement. This cost of energy is used to set tariff for the energy generated by the renewable energy plant. The avoided cost approach is based on the price of power from alternative conventional sources. Using the avoided cost approach results in no net impact on the utility's power purchase cost.

4.9 There are issues on the implementation of an avoided cost approach. Typically, SHP plants might be connected to the grid at lower voltage levels. The impact of the voltage and location of both the renewable energy generator and the avoided conventional generator could be factored. Also, the time period for computing the avoided cost is also important (this could occur on a 15 minute interval, hourly interval, daily, monthly or yearly interval) given the variations in power procurement profile of the utility. A trade off between accuracy and convenience usually occurs.

4.10 The key merit of the avoided cost method is that it is based on the most expensive power from conventional sources and this tariff in some sense acts towards encouraging development of renewable energy generation that can come on stream below this tariff level. However, avoided cost tariff computation will depend on the periodicity of calculations and will also vary on a year to year basis depending on the merit order and might thereby not provide adequate certainty on tariff to renewable developers.

Marginal Cost Based Approach

4.11 Marginal cost pricing is based on the expected future economic cost of power rather than current and historic financial costs. Long run Marginal Cost

(LRMC) is the future cost of power which takes account of the projected increase in demand and supply, the requirement for investment, availability from various fuel sources etc. The data requirements for the determination of the LRMC are the energy production and capital costs of future plants included in the long-term expansion plan. To determine the LRMC, the system expansion plan needs to be defined in terms of investment costs, variable costs and power and energy production. This is generally carried out with an investment horizon of 20 to 25 years.

4.12 The merit of adopting a marginal cost approach is that appropriate economic signals on the pricing of power would be provided to both the supplier and consumer. However, the calculation of Long Run Marginal Cost Pricing is not feasible in the current context as such a study has not been carried out for HP and in the absence of reliable data.

Cost Plus Approach

4.13 The cost plus approach is used to set tariff based on the cost build-up for a generation station. This relies on the availability of requisite station-wise generation, information on various cost elements of the generating station and thereafter builds up the tariffs from costs. This is typically the approach used for SHP tariff setting in India adjusted for performance standards set by regulators. Here the tariff setting is determined in a manner to ensure that the developer recovers cost components such as interest on debt, operation and maintenance (O&M) costs, depreciation etc. and also earns a regulated rate of return on equity.

4.14 This approach necessitates validating each element of the cost structure based on supporting information provided by the developer and monitored for efficiency by the regulator. (based on historical data/past trends and other supporting information) This approach is difficult to implement with inadequate supporting data.

Benchmarking Approach

4.15 The benchmarking approach is a variation of the cost plus approach and is preferred in instances when the Commission prefers to apply a normative tariff approach to set tariff for a large number of small plants. The approach identifies key determinants to define the variables in the framework and tariff is set for each combination of determinants. For example the Commission may decide to segment SHP generators based on the size of the plant and the river basin it is situated on. This approach is convenient to apply to set tariff on a normative basis for a large number of small and widely distributed projects. However, success of such an approach rests on the choice of appropriate determinants and classification of plants under each determinant (for example the size of plant determinant might have classification based on less than 100 kw, 100 kw - 1

MW, 1 MW – 5 MW etc.). The benchmark costs setting method is a convenient mechanism for tariff setting but is dependent on the availability of reliable data for setting tariff benchmarks.

Approach adopted by HPERC

4.16 Based on the above discussion on specific advantages and disadvantages related to different tariff methodologies, it emerges that both, the cost plus approach and the avoided cost based tariff setting methodologies have (a) specific advantages and (b) can be adopted/modified to address specific issue(s).

4.17 However, it is seen that in order to promote the development of renewable energy technologies, a cost plus approach with a return on equity, has been followed by the different state electricity regulatory commissions. This is primarily because the main advantage of a cost based tariff approach is that it has the ability of incorporating any incentive that is introduced for a particular technology and this gets reflected in the tariff that is calculated. Also the cost of renewable power generation sets are reducing rapidly and since it is difficult to predict this reduction, as the cost falls, the actual cost can be reflected through the cost plus tariff mechanism. Further, since the tariffs can be set for a longer period, the annual exercise of tariff setting can be avoided.

4.18 The Commission, therefore, has decided to determine tariff for small hydro energy projects based on the cost plus approach with certain performance benchmarks.

Single Part vs. Two Part Tariff

4.19 Two part tariff is applied in order to recover fixed and variable costs through the fixed and variable components of tariff. This is specifically useful in a scenario of merit order dispatch.

4.20 It has been felt that implementing a two-part tariff, which is implemented for large hydro power projects, will be difficult for SHP projects since the number of small hydro plants in the state is large. Also, since small hydro power projects are not amenable to merit order dispatch principles because of infirm nature and almost all the costs of SHP generators are fixed in nature, hence it is appropriate to have a Single Part tariff for SHP generators.

4.21 The Commission is of the view that a single part tariff would offer high level of investment certainty by guaranteeing a fixed price for every unit delivered.

4.22 Considering the practical difficulties in implementing a two-part tariff for a large number of SHP projects with low capacity, seasonal variation in water discharge and monitoring of large number of projects , the Commission deems it fit to determine and apply single part tariff for the small hydro projects.

Project Specific or Generalized Tariff

4.23 Strictly every project is unique in certain characteristics. However, it is difficult to set tariff for each renewable energy project as projects are small in nature and a large number of projects exist in the state. Tariff determination for each project will be cumbersome and put significant strain on Regulatory Commission.

4.24 A generalized tariff mechanism would provide an incentive to the investors for use of most efficient equipment to maximize returns and for selecting the most efficient site while an individual tariff determination (project specific tariff) would provide each investor, irrespective of the site selected, the stipulated return on equity, which, in effect, would shield the investor from the uncertainties involved.

4.25 Considering above arguments the Commission has decided to opt for generalized tariff rates for projects up to 5 MW and project specific tariff for projects with capacity more than 5 MW and up to 25 MW as specified in the regulations.

Average vs. Levelised Tariff

4.26 Average Tariff is method adopted with a view to avoid front loading of tariff particularly with decreasing trend. In this method the average of tariff for a certain number of years worked out on the basis of cost plus approach or return on capital employed is taken. This results in lower realization of tariff in initial years to be compensated during later year providing less comfort to lenders and investors.

4.27 Levelised tariff is a tool for taking investment decision as well as bid evaluation both for the investors and licensees. Levelised tariff which ensures realization of present day value of investment to investors is a better approach than average tariff approach for estimating tariff payments towards recouping of investments.

4.28 Considering both the approaches the Commission has decided to opt for levalised tariff as it ensure rather more accurate realization of present value of the investment to the investor. As per the CERC guidelines for determination of tariff by competitive bidding the discounting rate for computing levelised tariff shall be prevailing rate of 10 yrs GOI securities. Therefore, the Commission decides that discounting rate will be 11.10 % (as per CERC notice No. Eco 1/2007-CERC dated 1 April 2007).

Third Party Sale

4.29 Third party sales both within and outside the state shall be allowed and the same would be guided by the Open Access regulations framed by the Commission under Electricity Act 2003 namely HPERC (Terms and Conditions for Open Access) Regulations, 2005.

Tariff Structure

4.30 A single part tariff structure is applicable on the energy sold from the project to the purchaser. It is determined as Rate of Energy Charge = Annual fixed charge/Annual saleable energy. Annual Fixed Charge (AFC) for SHP includes all the cost components namely O&M cost, depreciation, interest, Return on equity, interest on working capital, taxes, levies and duties imposed by Government of India and Government of Himachal Pradesh.

4.31 As discussed above, the final tariff determined, in a cost-plus scenario, would depend significantly on the assumptions on investment costs, operating and financing costs and the CUF. The key drivers of cost are as mentioned below and the Commission's treatment of each is discussed in the subsequent sections:

(a) Capital Cost

(b) Capacity Utilization Factor

(c) Debt-Equity ratio

(d) Interest costs on debt

(e) Term of the Loan

(f) Return on Equity

(g) Depreciation rate applicable

(h) Advance Against Depreciation (AAD)

(i) Operation and Maintenance expenses

(j) Royalty Power / Free Power

(k) PPA Period

(l) Taxes/duties/levies imposed by all Governmental agencies

Capital Cost

4.32 Unlike thermal plants, a hydel power project does not incur variable costs (typically corresponding to usage of fuels – coal, gas, oil etc.). The fixed costs such as depreciation, RoE and interest are derivatives of the capital cost. Even

O&M costs can be determined as a percentage of the capital cost. Hence, accurate assumptions on capital costs are critical to ensure fair tariffs for hydel projects.

4.33 The following are the capital cost values allowed by some other Regulatory Commissions in determining tariffs for purchase of power from SHP's:

Cost/States	Andhra Pradesh	Karnataka	Uttar Pradesh	Uttarakhand	Maharashtra	Haryana
Project Cost (Cr/Mw)	4.5	3.9	4.5	5.5	4.4	10.25 (upto 2MW)
Notification Year	July 2004	Jan 2005	July 2005	Nov 2005	Nov 2005	Jan 2007
WPI	186.6	188.6	194.6	198.2	198.2	208.8
Equivalent Cost @ Nov 2007 prices WPI=215.4)	5.19	4.54	4.98	5.98	4.78	10.57

Stakeholders Comments

4.34 During the public hearing SHPs suggested that the benchmark specified in draft regulation of 6.5 Crore/MW is inadequate due to the steep rise in the various cost as well as the cost to interface with HPSEB grid and the additional costs on account of Local Area Development Charges, fisheries, forests increased cost of land and the 15% mandatory discharge requirement should also be taken into consideration. It was also suggested that for clarity purpose it would be better to list various salient components of cost included in benchmark capital cost such as cost of road construction to reach weir and power house sites, cost of evacuation system and up-gradation of facilities upto and at interconnection point etc. It was also suggested that cost benchmarks should be comparatively higher for smaller capacity projects. Consumer representative also suggested that the projects should be treated slab wise e.g. 1-50 KW, 51-100 KW, 101-1000 KW, 1-2 MW and above 2 MW. HPSEB made a submission that benchmark of Rs.6.5 Cr/MW needs to be reduced.

Commission Views

4.35 The cost of a small hydro project is mainly dependent on the site which is selected, and therefore, becomes very site specific, The Commission has decided to approve capital cost for tariff determination at Rs.6.5 crore/MW. The proposed bench mark may seem on higher side when compared to capital cost bench mark adopted by other states, however the Commission is of the view that higher capital cost is justified given the mountainous terrain and comparatively higher cost of transportation and long interconnecting transmission lines from project site to the interconnecting sub-station.

4.36 While deciding the project cost benchmark, the Commission has also considered additional expenditure incurred by the SHP developers on account of LADA charges, forest and fisheries levies. The Commission is also in favour of a single cost benchmark for all projects from 0-5 MW instead of slab-wise cost benchmarks suggested by many stakeholder primarily on account of the fact that economies of scale observed in larger projects are negated by the reduced MNES subsidy (per MW of installed capacity) for larger projects as indicated in the subsequent section.

4.37 The estimated capital cost benchmark includes the cost of interconnection facilities at the interconnection point. The cost of re-organization of bays at the Interconnecting Sub-station and associated civil works necessitated on this account has also been included in the capital cost.

MNES Subsidy

4.38 MNES, Govt. of India, provides capital subsidy for installation of Small Hydro Power projects which is paid directly to financial institutions for commissioning of the projects subject to prior sanction and policy in force.

4.39 Currently, MNES provides a capital subsidy limited to the amount indicated below:

Up to 100 KW	From 101 KW to 999 KW	From 1 MW up to 25 MW
45% of Project cost limited to Rs. 30,000/- per KW	45% of Project cost limited to Rs. 30.00 Lacs + Rs. 21,625/- per KW.	45% of Project cost limited to Rs. 2.25 Crores + Rs. 37.50 Lacs per MW.

Stakeholders Comments

4.40 HPSEB, in their comments on draft regulations submitted that capital subsidy available to the generators from MNES should also be accounted for.

Commission Views

4.41 The Commission is of the view that if the developer gets any subsidy / incentive from MNES / State Govt. or any other agency on the capital cost, then such subsidy / incentive shall not be adjusted against the capital cost of the project for the purpose of tariff determination. In order to fulfil the mandate of promoting renewable energy generation provided by Section 86 (1) (e) and Section 61(h) of the Electricity Act 2003, the Commission has decided that the entire benefit of subsidy be given to developer as incentive for the purpose of promotion of small hydro power in the state.

4.42 The above notation has validity for two more reasons. Firstly, there is doubt whether the Central Ministry will for purpose of subsidy switch over from continuing to give some subsidy to the projects which have been approved on the MOU route or would only seek to provision for only those IPPs who have migrated to the system via the competitive bidding route. Secondly, if we evaluate the over all likely explosion of renewable energy across the North-West and North-Eastern Himalayan region in the country over the next decade, the number of projects and the budgetary requirement for subsidy will become difficult to provision for by GOI. Similar constraints have been noted in many subsidy based programs, wherein recipients spend lot of time and effort on subsidy retrieval from the bureaucracy at the Central level. This will lead to policy makers at the Central Level to slow down or negate the subsidy transfers. It is thus imperative that like the CDM issue, MNES subsidy should not be accounted for within any tariff formulation but should be left as an incentive for the promoters, in line with the views enshrined in the National Tariff Policy.

Capacity Utilization Factor

4.43 In case of small hydro projects, CUF is an important parameter and is a measure of the estimated energy likely to be generated as a percentage of maximum energy that could have been generated with full capacity utilization of the installed capacity of the project.

4.44 The actual CUF for a hydel project would depend to a large extent on parameters such as location of the project, the river basin, rainfall, etc.

Stakeholders Comments

4.45 During the public hearing, HPSEB made a submission that the data in respect of 75% dependable year generation projects for about 140 projects chosen randomly for which DPRs are available, has been compiled, which has been summarised below:

River Basin	Satluj	Yamuna	Chamba	Beas (Palampur)	Beas (Kullu-Mandi)
No of Projects	34	17	30	28	33
Avg. CUF (%)	68	63	67	70	73

4.46 HPSEB has indicated that average CUF for such projects (upto 5 MW) is of the order of 68%. Hence tariff should be worked out on the basis of net generation corresponding to CUF of 65%. The Board also contended that if a lower CUF is considered then the benchmark generation for the purpose of deemed generation shall also have to be reduced accordingly. The consumer representative stated that if PLF at lower limit of 40% is fixed, the plants will hardly be attractive to an investor This means that the State Government will have to subsidise the project to make it financially attractive and therefore, the lower limit of project utilization factor should be 45%.

Commission Views

4.47 The Commission is of the view that for many of the SHP's, an accurate determination of the design energy and in turn saleable primary energy is difficult due to problems of reliability of available water discharge data. The DPRs of such projects do give estimated projections of the energy likely to be generated and the annual fixed cost (AFC) could indeed be distributed over the projected generation. However, there is an additional risk that if in a particular year water availability reduces, which is not unusual, the developer will not be able to fully recover the AFC as the comfort provided by capacity charge in the two part tariff structure applicable to Large Hydro Projects is not present in single part tariff structure contemplated for SHPs. At the same time, the single part tariff structure could result in an SHP developer earning much higher returns if actual generation is in excess (which should be deemed as an incentive for higher generation/productivity)

4.48 Normative values for CUF of SHP's adopted by different states are given below:

Andhra Pradesh	Uttaranchal	Maharashtra	Karnataka	Haryana	Uttar Pradesh
35%	45%	30%	30%	70%	35%

4.49 The higher CUF assumed in Uttaranchal is because the Himalayan Rivers are perennial.

4.50 The Commission also notes that HPSEB's own SHP projects are on average operating at a CUF less than 45% (except in a few cases) as shown below:

Name of Power Station (HPSEB)	Installed Capacity (MW)	CUF		
		2004-05	2005-06	2006-7
Thirot	4.50	17%	9%	21%
Gumma	3.00	25%	56%	30%
Holi	3.00	-	20%	36%

Nogli	2.50	47%	20%	40%
Rontong	2.00	10%	13%	10%
Sal-II	2.00	40%	46%	30%
Chaba	1.75	43%	57%	43%
Rukti	1.50	10%	9%	9%
Chamba	0.45	26%	55%	16%
Killar	0.30	48%	52%	41%

4.51 In comparison to HPSEB's own mini/micro projects, the plants run by private sector are far more efficient and consistently operate at a better CUF. However, there is considerable variation between the CUF achieved in two consecutive years.

Power Station	Installed Capacity MW	CUF(%)	
		2005-06	2006-07
Titang	0.9	28.0%	26.1%
Rasket	0.8	48.9%	45.2%
Maujhi	4.5	32.4%	30.8%
Dehar	5	57.6%	55.5%
Bara Gaon	3	64.8%	78.5%
Ching	1	34.1%	29.2%
Manal	3	13.6%	23.4%
Aleo	3	67.8%	116.1%
Manjhal	1	-	48.1%
Salag	0.15	-	75.3%

4.52 Moreover, the new State Hydro Policy makes it obligatory for the developers to maintain mandatory 15% water release. The impact of this on CUF would need to be factored in.

4.53 The Commission has also observed inconsistencies between the CUF projected in DPR and the actual CUF achieved in a few instances. The reasons behind this are not being considered here.

4.54 In the absence of adequate data for reliable determination of CUF as well as the fact that calculating and determining CUF on an individual basis for a large number of SHP would be a tedious and time consuming process, the Commission is inclined to use a normative value of CUF for the purpose of tariff determination.

4.55 Based on the normative CUF that has been adopted by different states, and the analysis of average CUF of projects across five river basins as reported in DPRs, low CUF of Board's own projects, vide variation in actual CUF of different projects in private sector and variation in CUF on year to year basis, the Commission determines that a normative value of 45% for CUF for the purpose of tariff determination for SHP plants. Uttaranchal, with a similar topography as the state of Himachal Pradesh has also adopted normative CUF as 45%. Benchmark CUF of 45% as decided also takes into consideration the factor of minimum 15% water discharge from diversion weir as mandated by GoHP policy directive

4.56 With a single part tariff for generation arrived at through a cost plus approach wherein the developer recover the annul fixed cost from the generation at normative CUF; a somewhat lower figure of normative CUF at 45% compared to projected average CUF in DPRs (between 63% to 73%) could considerably lower the risk of under recovery due to lower than projected generation.

Debit Equity Ratio

Stakeholders Comments

4.57 Some of the IPP suggested a debt equity ratio of 80:20 on account of difficulty faced by small entrepreneurs in arranging 30% equity. They also contended that some of the international banks are willing to finance the IPPs at a debt equity ratio of 80:20. The consumer representative suggested that the ratio should be 80:20 for all projects, to encourage the bonafide small investors belonging to the State of HP.

Commission Views

4.58 Debt Equity mix of the project is an important parameter influencing the return on a developer's investments. CERC norm for debt-equity ratio in case of conventional power plants is specified as 70:30. For a fixed PLF value and capital cost, a developer who is able to leverage his funds better and able to raise more debt than the 70% of the project cost, earns a higher return on his investment compared to another developer who invests more equity.

4.59 The main factor behind determination of debt-equity ratio is the comfort level of financial institutions. Most of the Financial Institutions insist on debt-equity ratio of 70:30.

4.60 In case of all SHP generating stations across different states, a debt-equity ratio of 70:30, as on the date of commercial operation has been considered for determination of tariff as shown below:

D/E Ratio/States	Andhra Pradesh	Karnataka	Uttar Pradesh	Uttarakhand	Maharashtra	Haryana
D/E Ratio	70:30	70:30	70:30	70:30	70:30	70:30

4.61 Taking into consideration all of the above the Commission determines that a debt-equity ratio of 70:30 shall be considered for the purpose of tariff calculation. The debt and equity amount arrived in this manner is to be used for calculating interest on loan and return on equity allowed to the investor.

Interest on Loan Capital

Stakeholder's comments

4.62 HPSEB submitted that interest rate is defined as "PLR of a Scheduled Bank plus a pre determined margin" in draft regulation. They sought clarity on the pre determined margin.

Commission Views

4.63 Interest on loan capital is computed loan-wise on the loans. The interest rate is based on the Regulatory Commission's assessment of the rates that are being offered by different financial institutions in their respective states. The table below gives the different interest rates that have been considered by Regulatory Commissions across their respective States.

Interest Rate/States	Andhra Pradesh	Karnataka	Uttar Pradesh	Maharashtra
Interest Rate (%)	10	11	10.25	9

4.64 The Commission has taken an interest rate of 11.5% for tariff determination which commission feels realistically reflects the cost of debt raised by the developers.

Term of Loan

Stakeholder's comments

4.65 Consumer Representative stated that the loan period should be 7 years with a moratorium of 18 months for mini/micro/small hydro projects.

Commission Views

4.66 Repayment of loan is considered as 12 years with two year's moratorium with effect from COD of plant which is in conformance with the prevalent practices adopted by the various financial institutions.

Return on Equity (ROE)

Stakeholder's comments

4.67 During the Public Hearing there were various suggestions made by some IPPs and Consumer Representative to set the RoE at a rate of 5% to 6% over and above that of PLR of scheduled banks, considering the nature of projects and risks associated with them.

Commission Views

4.68 The Return on Equity is to be computed on the equity base. The CERC (Terms and Conditions of Tariff) regulations, 2004, for large hydropower plants provides for a ROE of 14%. Further, UERC tariff regulations for small hydropower plants also provide for a ROE of 14% for such plants. However, for purposes of computing tariff for SHP projects, except for the state of Uttaranchal, all other states have used a rate of 16% per annum. This is based on an assessment of the financial risks and uncertainties faced by the small developers in the development and operation of an SHP plant (including aspects of CUF, release of water etc.) ROE as given in other States is given below:

ROE/States	Andhra Pradesh	Karnataka	Uttar Pradesh	Uttara khand	Maharashtra	Haryana	T.N
ROE (%)	16	16	16	14	16	16	16

4.69 The Commission feels that the investors perceive a high risk and a long pay back period in such projects and therefore, there should be an adequate return to the investor. At the same time, the Commission has set a procurement target for renewable sources to ensure promotion of renewable energy. Balancing interest of all stakeholders including consumers, the Commission fixes the RoE at 14%

post-tax which it is of the opinion effectively remunerates the developers for the risk assumed.

Depreciation

Stakeholder's comments

4.70 During the public hearing Aditya Cotton Mills Pvt.Ltd. suggested that depreciation should be raised to minimum 3% considering life of plant as 30 years. Techman Infra Ltd. suggested for adoption of depreciation rates applied by finance ministry for evaluation of profits

Commission Views

4.71 Depreciation is non-cash expenditure for the project holder, and facilitates the servicing of the principal repayment obligation under the loan agreement.

4.72 For the purpose of tariff computation, SERCs have estimated depreciation annually based on a straight-line method over the useful life of the asset and at the rates that are prescribed in their respective State regulations. The States like AP, UP and Karnatka allowed depreciation to cover fully the debt repayment obligation of the IPP. Andra Pradesh has allowed a rate of 7.84% per annum till 70% of the project cost and the balance depreciation of 20% has been spread over the balance period of the PPA. The depreciation rates that have been used by different SERCs are summarized in the table below:

Depreciation/States	Andhra Pradesh	Karnataka	Uttar Pradesh	Maharashtra
Depreciation (%)	7.84	7	7	2.57

4.73 In view of above considerations and relevant data, the Commission determines that the depreciation rate shall be taken as 2.25% over an operational life of plant as 40 years (corresponding to PPAs) and depreciation is to be allowed upto 90% of the cost of the project.

Advance Against Depreciation (AAD)

4.74 In addition to allowable depreciation, the Commission has allowed Advance Against Depreciation (AAD) to facilitate debt repayment and the same shall be calculated as under:

AAD = Loan (raised for capital expenditure) repayment amount based on loan repayment tenure, subject to a ceiling of 1/10th of loan amount minus depreciation as calculated on the basis of these regulations;

Provided that advance against depreciation shall be permitted only if the cumulative repayment up to a particular year exceeds the cumulative depreciation up to that year;

Provided further that advance against depreciation in a year shall be restricted to the extent of difference between cumulative repayment and cumulative depreciation up to that year.

Operation and Maintenance (O&M) Expenses

Stakeholder's comments

4.75 During the Public Hearing there were various suggestions made by the respondents stating that O&M cost at 1.5% of Capital cost is very low. IPPs suggested for O&M cost benchmark between 2.5 % to 3.5% of capital cost with annual escalation of 5% to 6%. The Consumer Representative argued that on account of special maintenance that run of rivers small hydro stations require to keep the unit operational, the O&M cost should be 3.5% with an escalation of 5%.

Commission Views

4.76 It is a known fact that the operation and maintenance expenses are higher in small hydro projects than in large hydro projects. Part of this is accounted for on account of economies of scale. O&M expenses typically cover the regular maintenance expenses, employees cost, repair and maintenance costs. Small hydro projects are also liable to be subject to harsh weather conditions. The electro mechanical equipment can suffer major faults due to flash floods, debris etc. The cost involved in repair and ensuring availability of the machine at all times for power generation results in extra expenditure. These are again pooled in the O&M expenditure of the plant. In the hilly areas, SHP schemes being the run off river, during months of rains the water contains silt/debris, which causes heavy abrasion to the turbine runner, casing and vanes etc. In storage scheme (normally for schemes having the dams) the impact of silt/debris is comparatively low and therefore, replacement of runner is not frequently required for dams. Referring to CERC guidelines for large hydropower generating stations, the operation and maintenance expenses is to be fixed at 1.5% of the capital cost and is to be escalated at the rate of 4% per annum from the subsequent year.

4.77 States such as Andhra Pradesh and Karnataka have followed the CERC norms of O&M costs as 1.5% of capital cost, even for SHP projects. However, this percentage of 1.5% of the capital cost may not actually cover some of the extra expenses incurred as discussed above. Therefore a relaxed normative ceiling of 2.5% - 3% of the capital cost for O&M expenditure has been considered by other states as tabulated below:

O&M Costs/States	Andhra Pradesh	Karnataka	Uttar Pradesh	Uttarakhand	Maharashtra
O&M cost % of capital cost	1.5	1.5	2.5	3.0	2.5
Annual Escalation	4	5	4	4	4

4.78 Keeping in view the factors stated above, the Commission has decided to relax the CERC norms for O&M costs and has fixed it at 2.25% of capital expenditure with 4% escalation every year.

Interest on Working Capital

Stakeholder's comments

4.79 In the public hearing, Aditya Cotton Mills Pvt.Ltd. submitted that maintenance of the spares should be provided @ 2% of the historical cost, escalated @ 5% from the date of commercial operation.

Commission Views

4.80 Composition of working capital for purposes of computing tariff for SHP projects that has been considered as per the CERC guidelines as summarized below:

(a) Operations and Maintenance expenses for one month;

(b) Maintenance spares equivalent to 50 % of R&M expenses for 1 month;

(c) Receivables equivalent to 2 months of fixed and variable charges for sale of electricity calculated on the normative Capacity Index.

4.81 Rate of interest on working capital is taken as 13.75%.which the Commission feels is representative of cost of short loans of the SHP developers.

Royalty Power / Free Power

4.82 The quantum of royalty power /free power to the state is a policy decision and may vary from year to year. Prior to 2006, Hydro Policy of Himachal Pradesh stipulated that no royalty for first 15 years of operation and 10% royalty was payable thereafter. The new hydro policy of Himachal Pradesh notified that there shall be no royalty for first 12 years, 12% after 12 years and till 30 years and 18% royalty payments thereafter.

4.83 Since royalty payment is a policy decision of government of Himachal Pradesh and not under the jurisdiction of the Commission, hence the Commission decides that any change is existing value of royalty payments by the state government, shall be treated as an uncontrollable element and treated as a pass through in tariff payable to IPPs. However royalty, as per GoHP Hydro Policy 2006 has been considered while determining the tariff.

PPA period

The PPA period has been considered for 40 years as per the GoHP Hydro policy 2006 wherein the projects are allotted on built, own, operate, maintain for 40 years before transferring to the State Government**.**

Taxes

4.84 Tax holiday benefit in the Income Tax in the form of exemption over a period of 10 years under Section 80IA of the Income Tax Act has been considered. However Minimum Alternate Tax (MAT) @ 11.22% (inclusive of surcharge and cess) under Section 115JB has been provided for in the tariff. Thereafter Income Tax at the rate of 33.66% (inclusive of surcharge and cess) has been considered.

4.85 Any change in the aforesaid taxes or any statutory taxes, duties, cess or other kind of imposition(s) including tax on generation of electricity whatsoever imposed/charged by State/Central Government and/or any other local bodies/authorities on generation of electricity, after the date of signing of the power purchase agreement, shall be a pass through and shall be reimbursed by the board to the generator on the quantum of net saleable energy.

Summary of the Tariff Structure

4.86 As discussed above, the Commission hereby notifies its approach for determining tariffs for hydro generating stations having capacities up to 5 MW

4.87 Generation tariff for SHP up to capacities of 5MW will be fixed on cost plus basis in accordance with Himachal Pradesh Electricity Regulatory Commission (Power Procurement from Renewable Sources and Co-generation by Distribution Licensee) Regulations, 2007 subject to following Cost benchmarks:

Project Life (Years)	40
Return on Equity (%)	14%
Debt Equity Ratio	70:30
Term of Debt (Years)	12
Moratorium (Years)	2
Interest Rate (%)	11.50%

Recovery of Depreciation (% of asset value)	90%
Rate of Depreciation (% p.a.)	2.25%
Availability (%)	95%
Auxiliary Consumption (%)	0.50%
Transformation Losses (%)	0.50%
Operation	
O&M Expenses (% of Project Cost)	2.25%
Annual Escalation Factor	4%
Working Capital Norms	
Receivables (no of months)	2
Spares (% of Project Cost)	1%
Escalation Factor for Spares (%)	6%
O&M Expenses (no of months)	1
Interest on Working Capital (%)	13.75%

To enable the debt repayment, any cash shortfall in debt repayment obligation was allowed as advance against depreciation (AAD)
11.22% Minimum Alternate Tax has been considered which also includes surcharge and cess
33.66% Income Tax has been considered which also includes surcharge and cess
Discount Rate of 11.1 % used for levelized tariff calculations
Levelized tariff calculations are taken for 40 years of plant operation

4.88 Considering all of the above parameter, the Commission has worked out the levelised tariff for the 40 years of commercial operation of SHPs at Rs 2.87/ Unit.

4.89 One notable aspect is that while the Commission has determined the tariff through cost plus approach, there would be a large number of other indicative factors which would move towards looking at this determination from different standpoints. The first, of course, would essentially be looking at cost parameters in the year 2000 when the tariff was fixed at Rs.2.50 per unit and working out the tariff in the current year based on yearly inflation. This would, therefore, increase tariff about 1/3rd of Rs. 2.50 per unit and a tariff between Rs.3.30/per unit and Rs.3.40 per unit would have adequate validity. Second methodology would be to look at the perspective of prevalent tariff in the adjoining States where it various from Rs.3.49/unit (Punjab) to Rs.3.67/unit (Haryana) on base year 2007-08 along with provision of escalation every year for next 5 years. From this perspective the average of the other States comes to Rs3.58/unit and, therefore, tariff in Himachal would be somewhere near this figure to discourage inter-state open access by the IPPs, thereby, providing advantage to entities within the State. Thirdly, today in terms of the latest competitive biddings undertaken by the Board, power being imported from Chhatisgarh at Rs.4.98 during the deficit months. If power from IPPs is to replace this power, obviously a tariff near Rs.4.98 from this standpoint have a certain degree of validity. Additionally IPPs have been insisting that the power be purchased from them at a tariff which while containing base tariff of Rs.2.50/unit with increased levies, duties and taxes and policy changes as compared to the year 2000 when this tariff at Rs.2.50 was specified originally. The tariff from this standpoint becomes project specific, but based on broad assumptions the tariff would approximately fall within the range of Rs.3.00/unit to Rs.3.30/unit.

4.90 Looking into all the various factors at play, the cost plus mechanism in spite of its ostensible upgrade gives us a tariff formulation which falls between the different standpoints, giving a major plus to the board. Thus the Commission views the new tariff as win-win for all parties- the utility, the consumers and the IPP(s). The utility today is able to sell power at Rs. 7.30 per unit. Buying power at Rs. 2.87/unit still leaves with it with a large spread during the surplus months and a plus during the hydrological deficient period in winter when inputs from these IPP's will bring added comfort to the Board during the period of power importation. The consumer gets more power with greater reliability, less outage and an upgraded wheeling network at a very marginal cost. Finally, the IPP's get a decent long term price, an evacuation structure at zero cost and CDM/ MNES benefits which strengthen their bottom line.

Excess Generation beyond Normative CUF

4.91 There are various approaches that have been followed in different states to address the issue of excess generation beyond normative CUF.

4.92 The approach which is adopted by APERC, UPERC is based on giving fixed incentive rate for every unit generated above generation at the normative CUF. APERC and UPERC has fixed an incentive rate of 21.5 paisa of every unit generated above the generation at normative 35% CUF. Uttranchal on the other hand, approved an incentive such that for actual PLF being higher than the normative CUF (which is 45%), an incentive, similar to that for achieving Capacity Index higher than normative is provided such that at 100% of normative CUF the incentive to such units would be 10% of the approved AFC. The rate of energy beyond the normative CUF is, therefore, given by UERC as

Rate of Energy = 0.1 x AFC/[365*24* Installed Capacity in KW* (1-CUF_n)]
Where, CUF_n – Normative Value of CUF.

4.93 The States like Maharashtra, Karnataka, Punjab and Haryana have adopted a different approach wherein tariff for excess energy is same as applicable to the generation within the normative CUF.

4.94 The Commission feels that incentive given by APERC, UPERC and UERC on the excess energy is not adequate for the IPP's as the returns are limited to 16% or 14% of the equity which may not be a good enough incentive for the IPP to invest in this relatively high risk sector in the state of HP. Also in context of Himachal the approach followed by UPERC, UERC and APERC would not be effective because of prevalent flat tariff rate of Rs 2.50/unit for entire generation.

4.95 The Commission in order to promote generation from SHP projects would like greater participation of private sector in the development of SHP projects thereby, creating more generation capacity, which is the need of hour. As already discussed earlier the Commission is also concerned about the very slow progress in small hydro sector.

4.96 Keeping in view the above, the Commission has decided to follow an approach adopted by Karnataka, Maharashtra, Punjab and Haryana and the tariff for excess energy shall be same as applicable to the generation within the normative CUF. The Commission strongly feels that it will result in a win-win situation in Himachal. On one hand the IPP's would be incentivised not only to invest in small hydro but also have adequate incentive to run their projects in most efficient way and generate maximum possible energy. The Board on the other hand would be assured of relatively cheaper power @ Rs. 2.87 per unit for a duration to 40 years. Commission has also analyzed the impact of generation of energy from SHPP on Board's ARR in next five years and the impact on the ARR of the Board is found to be minimal.

Other Issues

Clean Development Mechanism (CDM)

4.97 The projects which result in reduction of green house gases (GHG) are eligible to obtain credit for the emission reduction that is achieved through the Kyoto Protocol mechanism. For the developing countries like India, the CDM offers the opportunity to benefit from the projects resulting in GHG emission reduction that is paid for by Annexure 1 countries who are signatories to the Protocol.

4.98 There are some uncertainties on the quantification of CDM benefits to be taken into consideration while deciding the tariff (or using these for financing the renewable projects).

(a) The emissions reductions would result in additional revenue to the project. However, this revenue would not be easy to benchmark as CDM is a project-based activity, and the baseline and emission reductions vary from project to project.

(b) Further, all small hydro projects may not be eligible for earning CDM benefits as not all of them may fulfil the stringent criteria of CDM.

4.99 Thus, CDM projects offer an opportunity for additional revenue for the renewable projects and could result in lower consumer tariff if shared with the distribution licensee. However, the Commission is of the view that such additional revenues (CDM credits) be allowed to be retained by developer and not factored into tariff determination given the uncertainty involved in their award. This would also act as an incentive to attract more clean investment in renewable energy sector.

Banking

4.100 The existing banking provision in other states are summarised as under

(a)	Punjab, Maharastra, A.P.	12 Months
(b)	Kerala	9 Months (June-Feb)
(c)	Gujarat & West Bengal	6 Months
(d)	U.P.	24 Months
(e)	M.P.	Not allowed.
(f)	Karnataka	No time limit, UI linked to injection & drawl, banking charges being equal to rate difference.

4.101 Banking of energy has been a promotional tool. However, with the implementation of the ABT mechanism at the central level and the proposed implementation at the state level, there is a commercial impact on the HPSEB that would need to be factored in. Further, providing a banking facility to a set of generators that would constitute a significant proportion of generation capacity may not be advisable. Several states are in the process of reviewing their banking arrangements in light of the ABT implementation on account of developers pumping energy into the grid during higher frequency conditions (when system has surplus of energy and the utility receives a low tariff for the electricity pumped in) and drawing the banked energy during periods of low frequency (when system has deficit of energy & the utility is faced with a high tariff of electricity for such drawl).

4.102 Himachal Pradesh is energy surplus in summer months and energy deficit in winter months given the hydro based generation profile in the state. This pattern holds true even for generation from SHP. Given this energy profile, HPSEB typically sells surplus energy outside the state in summer months while in winter months HPSEB procures power from external sources at tariffs as high as Rs. 5 per unit. Providing a provision for banking would result in a situation where the SHP generators would be providing power to the grid in summer while withdrawing power in the energy deficit winter months with a resulting deleterious commercial impact on HPSEB. The Commission, therefore, is of the view that banking of energy would not be permitted for the time being.

A5: Transmission of Power & Grid Connectivity of Renewables

Statutory and general requirement

5.1 As per Section 172 of EA 2003, HPSEB, in their capacity as State Transmission Utility (STU) in accordance with the transitional provisions (or their successor entity, if and when notified as STU as per Section 39 of EA 2003 by GoHP) would be obliged to provide grid connectivity, evacuation facilities and transmission access to generation projects

5.2 Under Section 86(1)(e) of EA 2003 the Commission is empowered to promote co-generation and generation from renewable sources of energy by providing suitable measures of connectivity with the grid, and the Commission's jurisdiction covers the State of Himachal Pradesh.

5.3 With regard to connectivity with the grid, certain applicable legal provisions are given as under:

(a) The duties of the generating companies specified vide section 10 of the Act, among others, is to establish, operate and maintain tie lines or the dedicated transmission lines also.

(b) Section 30 of the Act provides that State Commission has to facilitate and promote transmission, wheeling and interconnection arrangements for the transmission and supply of electricity and its economical and efficient utilization.

(c) Section 38 (2) (d), 39 (2) (d) and 40 (c) of the Act provide for CTU/STU/transmission licensee to provide non-discriminatory open access to its transmission system to generating company/ licensee/consumer on payment of transmission charges.

(d) Section 39 2 (b) of the EA-2003 states that CTU/STU/transmission licensee "to discharge all functions of planning and co-ordination relating to intra-state transmission system with - (i) Central Transmission Utility; (ii) State Governments; (iii) Generating Companies; (iv) Regional Power Committees; (v) Authority; (vi) licensees; (vii) any other person notified by the State Government in this behalf "

(e) Section 39 (2)(c) of the Act provides for STU to ensure development of an efficient, coordinated and economic system of intra state transmission lines for smooth flow of electricity from a generating station to the load centers.

5.4 Usually renewable sites are remote in location and situated away from load centers. Thus the evacuation system to be developed would almost exclusively cater to SHPs. Also, while SHP capacity addition in a river basin may be in continuous fashion at different instances in time, the quantum and timing of the transmission capacity addition could be an issue especially in a situation with limited right transmission of way. Typically, the quantum of transmission capacity addition needed would need to be understood. The manner of determining how the costs for capacity addition would be borne also needs to be determined.

5.5 In view of above, grid connectivity for renewable power plants can be conceived as comprising of

(a) Connectivity with existing transmission and distribution system

(b) Augmentation of the existing transmission and distribution system to remove bottlenecks, if any, beyond the interconnection point

(c) Establishment of new network system beyond interconnection point.

5.6 It emerges that the STU would need to plan for grid connectivity required to meet location specific NCES power potential and ensure that addition to transmission capacity or augmentation of the system is synchronized with the creation of additional hydro power capacity. Therefore, the Commission in order to facilitate the evacuation of power from small hydro projects has provided for the following in its HPERC (Power Procurement from Renewable Sources) Regulations, 2007:-

(a) Provision of joint evacuation system after the prior approval of the Commission;

(b) Preparation of comprehensive five year plan for augmenting and establishing the transmission/ sub-transmission system corresponding to commissioning of the project alongwith time lines;

(c) Provision of penalty in case the time lines are not adhered to by the licensee or the generator;

(d) Provision for construction of transmission system by the generator beyond the interconnection point on Build and Transfer (BT) basis;

(e) Provision for constitution of Empowered Committee to:

i) To examine the proposals for joint evacuation system;

ii) To monitor adherence to approved time lines so as to avoid mis-match between creation of generator capacity and evacuation system;

ii) To monitor that the augmentation/ establishment of transmission system is as per best industry practices, if the same is being done on BT basis.

Stakeholder's Views on Interconnection Regime

5.7 A few respondents among IPPs submitted that interconnection facilities should be defined to avoid confusion and the substation nearest to the project powerhouse – preferably a manned 22 KV substation as control substation by HPSEB or a 33 KV/EHV sub-station of HPSEB – be stipulated as the interconnection point for the SHP projects.

5.8 IPPs further submitted that STU should provide interconnection facilities in time bound manner as requested by concerned IPP and in case STU fails to provide appropriate interconnection facility within stipulated timeframe, IPP should be entitled for the benefit of deemed generation charges. While IPP could bear the expenditure incurred for connectivity upto the interconnection point with cost of such evacuation line being loaded on tariff but the STU on its own should bear the cost of augmentation, if any, of transmission system beyond the interconnection point.

5.9 HPSEB contended that it shall provide inter-connection at the nearest HT/EHT sub-station on best effort basis, however, in cases where it is not feasible for the licensee to provide such inter-connection at the nearest sub-station for some reason, the inter-connection can be given at some other sub-station. Also the minimum voltage level at which injections are to be made for different capacities should be specified by the Commission. The cost of interconnection facilities is to be met by the generators as per the explicit provision in the PPAs.

5.10 In the matter of augmentation of transmission network beyond the interconnection point, the IPPs submitted that HPSEB alone should be mandated to meet the entire cost for augmentation of transmission system and any provision for IPPs bearing augmentation cost is inconsistent with both the "Model PPA for SHP's upto 5 MW" issued on 24th march, 2003 against petition no.1/2002 filled by HPSEB and with the MOU signed by IPPs with HP Govt.

5.11 Further, IPPs submitted that GoHP is promoting SHP development in the state as a vital environment friendly non conventional energy source. The quantum of capacity addition in the SHP development program is very minimal when compared to the proposed large capacity development. As such, it is to be recognized that the augmentation of transmission system beyond the interconnection point is not exclusively for evacuation of power from SHP, barring certain exceptional cases, which in any case cannot absorb the cost of augmenting the system. GoHP's hydro policy of year 2000 had duly taken in consideration these concerns of SHP developers. However the new power policy (2006) of GoHP loads the cost of augmentation on SHP developers. Any proposal of funding the augmentation by SHPs would be contrary to the very spirit of promoting non-conventional energy source.

5.12 HPSEB contended that the Hydro Policy of H.P. government clearly provides that the cost of augmentation of the system even beyond the interconnection point is to be met by the IPPs on proportionate basis, therefore, entire cost of augmentation and additional systems required for power evacuation must be borne by the IPPs alone.

5.13 HPSEB further suggested that it will be prudent to charge IPP on the basis of installed capacity of their projects instead of the capital cost of the augmentation as determination of the capital cost may involve complex process. HPSEB also stated that the modalities for sharing recovery of the cost of augmentation/addition should also account for the apportionment of costs in cases where the system is designed for a much higher capacity for the upcoming projects in the system and frequent changes in the number of projects with the passage of time.

Approaches for determination of interconnection Charges

5.14 There are two main approaches for determining transmission network connection charges: the deep cost approach and the shallow cost approach. In the deep cost approach the generator bears the burden of all the costs for connecting and improving the grid. The shallow cost approach allocates just the cost of connecting to the grid, whereas the other costs (improvement, upgrading) are socialized through the use of system charges.

Deep Cost Approach

Definition

5.15 In the deep cost approach, the generator pays the identified costs for both the connection to the grid as well as for additional investments. The connection of a generator to the network could involve a loss of system reliability and additional investments might be required to restore the system reliability to initial state. When applying a “deep connection approach” both grid connection and network reinforcement charges are entirely borne by the generator responsible for the loss of reliability. The connection charges do not imply only the cost of the lines but also the cost of all facilities necessary to the connection of the generator.

Properties of the Deep Cost approach

From the point of Generator/Investor

5.16 The adoption of a deep connection charge implies that the generator pays the complete cost associated with connection and upgradation. This high, upfront payment could have an impact on the financial viability of generation project.

5.17 In the deep connection policy, existing generators are not affected by the connection of a new one. Any new connection demand is treated in comparative isolation to the rest of the system. The deep cost approach is not particularly favourable for renewable energy plants that are located away from the load centre and could discourage the development of the project

From the point of Network Operator (NO)

5.18 The deep connection policy results in minimum outflow expenditure by the NO. The deep connection charge represents a low risk approach for the NO. All the cost are paid at the outset by the generator and the NO is not exposed to the risks associated with the possibility of transmission assets that may subsequently get stranded if the generator fails to develop on schedule.

Shallow Cost Approach

Definition

5.19 Under the shallow connection policy, the generator pays only for the cost of connecting to the grid while investments required for system augmentation are socialized and included in the use of system charges spread across a larger consumer base. The generator typically will not pay for use of system charge which would be borne by customers.

Properties of the shallow connection policy

From Generator point of view

5.20 From the generator point of view, this option is favourable since the reinforcement costs are shared by the load customers. Generation developers are not burdened by the reinforcement costs and such costs are passed onto end customers as part of a policy to support development of such renewable capacity. From an implementation viewpoint, this is simpler to undertake, as there is no computation or allocation of the individual impact of each generator on augmentation required in the system.

From Network Operator Point of View

5.21 By applying the shallow connection approach, the Network Operator would be responsible for bearing the costs associated with system augmentation. The network operator would typically be compensated for such investments through an annual use of system charges over the lifetime of the asset.

Hybrid Models

5.22 Some hybrid models emerge depending on local conditions or stakeholder requirements. For example, a shallow cost approach may be adapted to include a fee related to the location of the plant to be payable by the generator to provide incentives on the location of the plant. Another option would be to include a nominal norm based fee linked to the capacity of power to be transmitted.

5.23 Another option would be the introduction of "entry" charges to finance the cost of reinforcement in the grid. The entry charges could take the form of a single capacity payment or an annual charge. The network costs not covered by shallow connection charges and capacity-based entry charges can be socialised across all demand consumers through a separate network usage charge. These costs include payments for the difference between deep and shallow connection costs, the transport of electricity across the network, the operation and maintenance of the network and the provision of capacity to meet peak demand.

International Practices

5.24 Transmission Connection Charging Policy in various countries is summarized below.

New Zealand	Both generators and loads pay connection charges. There are no special provisions for renewable but distribution companies (discoms) are allowed to own distributed generation (DG) (up to 5% of the network's maximum demand or 5MW). There are no limits if the DG fuel is renewable. The government has proposed new regulations where there are no additional network charges or other connection costs for distributed generation less than or equal to 10kW capacity.
Northern Ireland	Demand customers above 1MW and generators pay deep connection charges. Charges are based on 100% of the cost of their connection but the charges for reinforcement charges are limited to the voltage level of connection and the voltage level immediately above the connection level.
Norway	Network Companies can charge new customers an investment contribution and/or a connection fee. Generators and loads pay shallow costs; there are no special provisions for renewables or cogenerators. There are refunds within a period of no later than ten years after the installation is finished. The network company can either prepay the investments costs or set the share of the investment contribution for each customer as they get connected to the network or customers get a refund as new customers are

	connected to the network.
Spain	Producers and demand users make up-front payments for the capital costs of connection, including the costs of the required network reinforcements). New users (generator or demand user) connecting to the same line extension within a period of 5 years will be responsible for a pro-rata payment of these costs, based on its relative use of the installed capacity. These payments will be used to reimburse the original contributor.
USA (California)	Generators pay deep connection charges, they get refunds if other generators use their assets. An FERC order sets standardised rules for large generator interconnections. According to the rules, generators have to pay for deep connection costs and can get refunds during the following 5 years of operation.
USA (PJM Interconnection- Independent System Operator)	Until now, generators and loads pay connection charges. They are allocated a share of the system upgrades cost There are no refunds, however if a new project impacts a facility already identified as requiring an upgrade, cost responsibility may be assigned to the later project. Small generators (<10 MW) can be connected through expedited procedures. FERC's standard interconnection rules apply
USA (New York Independent System Operator - NYISO)	Generators pay for deep connection charges. They are responsible for the cost of upgrading the transmission facilities that are not part of the Annual Transmission Baseline Assessment. FERC's new standard interconnection rules apply.
Alberta (Canada)	New generators bear full responsibility for their own interconnection costs while new loads share the cost responsibility for interconnection costs with existing customers through the investment policy of the transmission administrator. If a customer pays for a facility and Alberta Electric System Operator (AESO) uses those facilities to serve other Customers within 20 years, AESO will adjust the original contribution and assess each of the new customers' contribution. There are no special policies for renewables.
Ontario (Canada)	New generators and loads pay shallow connection charges. The Connection & Cost Recovery Agreement (CCRA) is negotiated. The transmission company, Hydro One Networks issues a refund or a rebate to the generator for subsequent generator connections. The refund to the initial generator is limited to a share of the amount recovered from the subsequent generator(s) connecting within five years.

5.25 As evident from the table above, different countries have followed different approaches namely deep, shallow or hybrid for levying interconnection charges of generating stations. Some of the countries have provided for special provisions for interconnection of non-conventional energy generators.

Interconnection approach followed by various SERC.

5.26 At present, different practices are being followed by the different state Regulatory Commissions on the issue of interconnection of renewables with the grid. For example, in case of Maharashtra, the MERC order says that the developer is required to initially contribute towards augmentation/transmission costs to partially meet the capital costs, with the same being refunded without interest in six annual installments.

5.27 The Madhya Pradesh Electricity Regulatory Commission's order says that the cost is to be borne by the developers initially and 50% would be paid back by the utility.

5.28 Chhattisgarh State Electricity Board mandates that the consumer has to bear the prescribed charge toward supply arrangement including the expenditure on grid interface / transmission line as per the tariff order for 2005-06, passed by CSERC on 15/06/05

5.29 In Rajasthan, the state regulatory commission has prescribed (based on State Government Policy) a uniform rate of Rs.15 lacs per MW towards augmentation charges of the transmission system for power evacuation and Rs.2 lacs per MW towards Grid Connectivity.

Approach followed by HPERC

5.30 The choice between deep or shallow cost is not easy to make. Adoption of a shallow cost approach would result in a part of the augmentation cost being borne by end consumers in Himachal Pradesh. Charging deep interconnection charges may render many small renewable energy projects unviable from a commercial point of view. Also, calculations of deep interconnection charges are very complex and would need to be undertaken on a case-to-case basis.

5.31 Therefore, the HPERC is of the view that a shallow connection policy be adopted to promote the development of non-conventional energy sources. For enunciation of a shallow connection policy for intra-state operations, the utility is being tasked with the creation of the necessary infrastructure for an evacuation system. This is essential, so as to bring about greater structural coherence at various stages of construction and in terms of the control mechanisms, since the wire business will have to be owned and operated upon by the Transmission or the Distribution Utility. The Price differentials between traded electricity today and the tariffs being fixed is nearly three times. Because of the cost parameters, and the control and structural parameters, a shallow connection policy will become essential and, therefore, the regulations for renewable sources have been so conceived. However, in case of third party sale within or outside the state through Open Access, the Commission shall adopt the approach as specified in HPERC (Terms and conditions for Open Access) Regulations, 2005.

Mechanism for Grid Connectivity

- IPPs shall bear the capital and operating costs of interconnection facilities up to the interconnection point which shall include, without limitation, switching equipment, control, protection and metering devices etc. for the incoming bay (s) for the project line(s), to be installed and maintained by the licensee at the Inter-Connection Point at the cost of the generator to enable evacuation of electrical output from the Project plus other expenditures like re-organisation of bays at the interconnecting sub-station and associated civil works along with the related operation and maintenance cost

- State Transmission Utility (STU) or Distribution licensee shall bear the cost for augmentation/establishment of network beyond the inter-connection point. The new or the augmented network shall form part of the assets of the transmission or the distribution licensee (as applicable) , the cost of such assets would be recovered from the transmission / distribution consumers (as applicable) through the transmission charge and/or wheeling charge over the life time of the asset.

- Implementation of grid connectivity to the small hydro projects and their monitoring through Empowered Committee shall be as per regulation 3 and regulation 4 of HPERC-(Power Procurement from Renewable Sources and Co-generation by Distribution Licensee) Regulations, 2007.

- The licensee and SHP developer shall adhere to the time lines as per transmission plan approved by the Commission. However, SHP developer shall give prior intimation of his intention to inject the power at least 6 months before the scheduled commissioning of the project to the licensee so that the licensee gears up administratively and otherwise into the state of readiness for the interconnection. By means of a separate order, the Commission shall set up a Security Mechanism to ensure the commitment of IPP's for timely usage of infrastructure built by the utility.

- Interconnection facility to be provided at the nearest substation of the HPSEB. In case an alternative arrangement of interconnection is desired by any of the parties than such alternative interconnection arrangement needs to be approved by the Commission after scrutiny by the Empowered Committee.

Wheeling and Transmission Charges

5.32 MNES Guideline stipulates that the SEB will undertake to transmit on its grid the power generated, and make it available to the producer for captive use or to a third party within the State at a uniform wheeling charge of 2 % of the energy fed into the grid, irrespective of the distance from the generating station. The third party must be a HT consumer of the Board, unless the Board relaxes this stipulation.

5.33 Wheeling charges for renewable energy generators in other states are summarised as below

(a)	Maharashtra, West Bengal	2%
(b)	Gujarat	4%
(c)	Andhra Pradesh .	50p/ unit (network charge) and 28.4% of energy (as losses)
(d)	M.P.	No wheeling charges
(e)	Rajasthan	10%

5.34 The Wheeling and transmission charges shall be governed by HPERC (Terms and Conditions for Determination of Wheeling Tariff and Retail Supply Tariff), and HPERC (Terms and Conditions for Determination of Transmission Tariff) Regulations, 2007 respectively.

Applicability of order

5.35 This order shall be applicable to all such Power Purchase Agreements (not exceeding 5 MW) which have already been approved by the Commission with a specific clause that "Tariff and other terms and conditions of the PPA shall be subject to the provisions of the Himachal Pradesh Electricity Regulatory Commission (Power Procurement from Renewable Sources and Co-generation by Distribution Licensee) Regulations, 2007" and also the Power Purchase Agreements to be approved by the Commission hereinafter.

5.36 This order shall not be applicable to Open Access Customers.

Sd/-

Shimla **(Yogesh Khanna)**

Dated:18.12.2007 **Chairman**