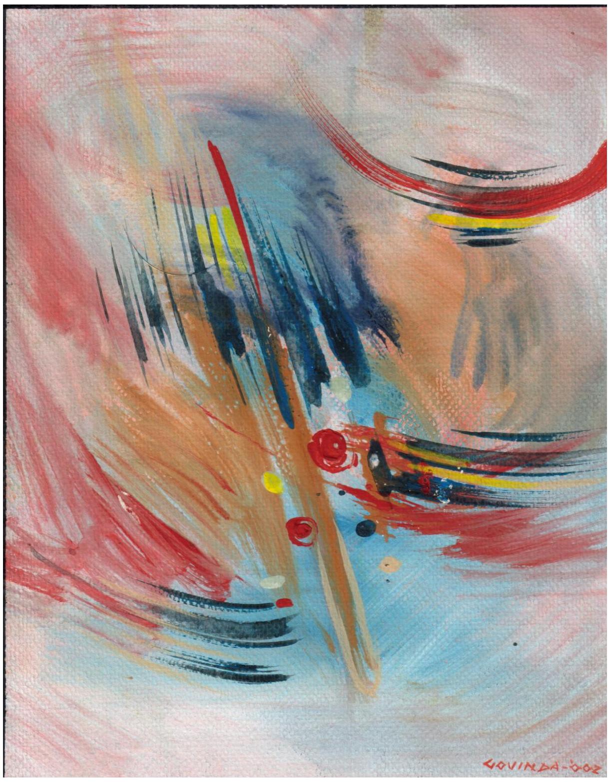
HYDROPOWER PRICING IN NEPAL

DEVELOPING A PERSPECTIVE



Edited by

Upendra Gautam

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JALSROT VIKAS SANSTHA (JVS), NEPAL

Kathmandu

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Foreword

After the establishment of Global Water Partnership in August 1996, the critical first steps taken, in the process of implementing its mandate, were the creation of GWPs Regional Technical Advisory Committees (RTACs) to generate interests among the stakeholders and, based on the interest, encourage setting up of regional and national water partnerships as a forum for exchange of information and experience between and among all users of water.

South Asia Technical Advisory Committee (SASTAC) was set up in 1998. SASTAC, though by its very nomenclature, was regional technical arm of GWP for South Asia, functioned both as technical and administrative regional arm of GWP till GWP South Asia - Regional Water Partnership was brought into being in 2002.

SASTAC in early 2001 identified "Hydropower Development" as one of the priority areas for immediate action in South Asia. In the area of "Hydropower Development", "Hydropower Pricing" was and still is regarded as one of the critical gaps in prevailing arrangements in South Asia. To bridge this gap and as an attempt to devise possible solutions confronting hydropower pricing issue, SASTAC decided to take up hydropower pricing and Nepal Water Partnership (NWP) was assigned to play the lead role for this exercise. The initial plan towards completion of the exercise included:

- *to make country water partnership undertake national study on hydropower pricing;*
- *to make prepared national study available to NWP, by each country water partnership; and*
- *NWP, after the receipt of all national papers and based upon national studies, to at least develop guidelines on hydropower pricing for South Asian countries.*

SASTAC on the basis of financial disbursement formula devised by itself, disbursed financial grant to each of the country water partnership, within its jurisdiction, to prepare country paper on hydropower pricing.

During First South Asia Water Forum (SAWAF-I) held in Kathmandu, Nepal, from 26 to 28 February 2002, eight papers were presented by the participants from Bangladesh, India, Nepal, Pakistan and Sri Lanka on hydropower pricing. But NWP did not receive national paper as such on hydropower pricing from any of the country water partnerships.

Jalsrot Vikas Sanstha (Water Resources Development Association - in short JVS), the host institution of NWP, took the issues of hydropower pricing very seriously and went into all possible length and breath of this issue in Nepal, through its activities such as:

- *brain storming sessions among the technical experts on the subject; and*
- *technical consultations at different stages during the course of the preparation of this study along with technical inputs of each consultation.*

The Editors note contains the detailed accounts on the efforts made through technical exercises and on the contributors who played their respective roles in the preparation of this study in hydropower pricing. I do not need to repeat those already stated and explained in the Editors note.

It goes without saying that the subject on fixing parameters for hydropower pricing is still a matter for debate and discussion and no single formula can be advanced on the subject at this stage. However, I feel that though efforts have been made to develop a perspective in the context of Nepal, the methodology used in the exercise may be applicable for other countries, and I trust that this publication would work as useful reference guide to other South Asian Countries on the issue of hydropower pricing.

I offer my sincere thanks to all the technical experts, JVS executives and JVS administrative support staffs who have contributed in one way or the other, in bringing out this study - Hydro Power Pricing in Nepal, Developing a Perspective.

Finally, I owe my deep gratitude and sincere thanks to Dr. Upendra Gautam and Mr. Ajoy Karki for their excellence in editing this study.

Bhubaneshwor P. Daibagya
Secretary General
Jalsrot Vikas Sanstha (JVS), Nepal

The Editors' Note

Developing a Perspective: the Process and the Message

The genesis of this book dates back to 2001 when the South Asia Technical Advisory Committee (SASTAC) of South Asia Water Partnership, a regional network of Global Water Partnership (GWP), Stockholm, initiated the discussions on hydropower pricing as distinct from hydropower development. Dr. M.S. Reddy, former water resources secretary in the Government of India, played a steering role in the discussion. As a result of the discussion, SASTAC made a decision whereby each of the Country Water Partnerships (CWPs) in South Asia was to develop a country paper following the steps in sequence: keynote paper-country workshop-country paper. This was to be followed by a regional workshop to be held in Kathmandu, back to back with the first South Asia Water Forum (SAWAF I). Furthermore, it was decided that "water for energy" would have a special focus in SAWAF I. The decision was no doubt consistent with the host country's water resources characteristics.

Jalsrot Vikas Sanstha (JVS), Nepal, the host institution of Nepal Water Partnership (NWP), complying with the SASTAC decision, appointed Dr. Janak Lal Karmacharya to help plan, organize and coordinate the hydropower pricing study as well as SAWAF I. Dr. Karmachara, a civil engineer by training, specializes in hydropower and hydrology. He has more than 35 years of experience in planning, construction and management of hydropower projects. He joined the Department of Electricity (DoE), Ministry of Water Resources, His Majesty's Government of Nepal (HMGN) in 1968. In 1985 he was transferred from the Department of Electricity to Nepal Electricity Authority (NEA). From 1995-1997, he worked as a World Bank Consultant. He was associated with International Hydropower Association to prepare a response to World Commission on Dam (WCD) report on "Dam and Development". In 2000, he was with WCD as a Forum member and contributed to its policy approach and cross-check survey. In 1999, he became the Deputy Managing Director, Planning, and General Management of NEA. As the Deputy Managing Director, he supervised the functions of Corporate and System Planning Departments as well as Assets and Material Management, Human Resources Development, Administration, Finance and Accounts Departments. He was also a member of Nepal's new Hydropower Policy Drafting Committee. Since the past three years Dr. Karmacharya has been serving as the Managing Director of NEA, the topmost executive position in this organization.

JVS, with inputs from Dr. Karmacharya, planned and contracted out the hydropower pricing study to the three-member team led by Mr. Vijaya Shanker Shrestha on 1st August 2001.

Mr. Vijaya Shanker Shrestha is a civil engineer by training. He holds substantial experience in the hydropower sector. His experience ranges from hydropower policy development and planning to project management, system planning and construction. He joined DoE, HMGN in 1967. He served as a senior engineer for the Kulekhani Hydro-electric Project from 1976 to 1981. In 1982, he returned to DoE as the Chief of its Planning Division. He was made Director of System Planning Division, NEA in 1985. He was shifted to Electricity Division, Ministry of Water Resources in 1989 in the capacity of Joint Secretary. From 1993 to 1998, he served as the Director General of Electricity Development Center (currently the Department of Electricity Development, DoED), Ministry of Water Resources. He retired from the 30 years of the government service in 1998. From then on, he has been active as a freelance senior consulting engineer in the hydropower sector.

Dr. Durga Lal Shrestha, the consulting economist in the team, was a visiting Senior Research Fellow at the Department of Economics, University of Bergen, Bergen, Norway in 2001. At the University of Bergen, he was involved in research work in the power sector. He served as an advisor to the National Planning Commission (NPC) to prepare policy framework to identify and determine the strategy for private sector involvement in water resources development. He also served as an Economist for Nepal Water Resources Strategy Formulation Study Phase-I and Phase II, HMGN/World Bank (1996, 1997 and 1999). He was involved in determination of sectoral investment based on macro-modelling in view of cost recovery policy along with identification of the issues in different uses of water and its economic value. In 1994, he worked as a Senior Economist for Perspective Energy Plan preparation, NPC.

Another member in the team was Mr. Sanjib Man Rajbhandari, a water resources engineer by profession. He is associated with NEA as an Assistant Manager. He was engaged in optimization of water conveyance system for several hydropower projects. Detailed studies of financial analysis and power purchase agreement with the private developers are other areas of Mr. Rajbhandari's expertise. He has conducted financial analysis of different hydroelectric projects and compared energy cost of these projects to support policy and planning decisions. There are several papers to his credit. They include "Appropriate Generation Mix for Integrated Nepal Power System", and "Generation Pattern of Different Type of Hydropower Plants in the Nepalese Context."

The team of experts led by Mr. Vijaya Shanker Shrestha submitted the draft report on 19th October. The study report was presented in the review workshop held at Shangri-la Hotel, Kathmandu on 11 November 2001. A three-member peer review committee consisting of Mr. Shanker Krishna Malla, former Managing Director of NEA, Dr. Bishwamber Pyakuryal, Professor of Economics, Tribhuvan University, and Mr. Jyoti Prasad Lohani, Director, Center for Policy Research and Analysis presented the results of their review of the study report. The peer review was followed by extensive discussion. Dr. Binayak Bhadra, Chairman, JVS, chaired the review workshop.

After incorporating the relevant comments of the review workshop, Mr. Vijaya Shanker Shrestha (VSS) submitted the final version of study report as per the contractual provisions on 10th January 2002. He in collaboration with Dr. Shrestha and Mr. Rajbhandari presented the major features of the study report in the SAWAF I in the last week of February 2002. Meanwhile, JVS continued to internally review the strengths and weaknesses inherent in the VSS study report. While conducting such an exercise at variable intervals, the JVS reviewers were apparently baffled by high project costs (and consequent high average per unit cost) of hydropower. Though they fully understood the limitations inherent in the cost plus approach and methodology of hydropower pricing that was adopted in the study report[1], they did not

[1] One of the editors has the experience of a sort of anti-climax when a US firm refused to fund the 30 Megawatt Chamelia Hydropower Project in Darchula district of West Nepal. In February 1997, a US energy investment service was willing to fund and undertake the project as it met one of their key criteria of project selection. The key criterion was the real potential of the project to benefit the poor people in the remote areas. As the project met their key criteria, the US energy service asked for the project details including its both preliminary and updated detailed feasibility studies. Consolidated Management Services (CMS) Pvt. Ltd., the partner entity of the US energy service and its allied firm, in close

seem to be able to accept that the per unit average cost of Karnali Chisapani Hydropower Project, the largest hydropower project so far studied in Nepal, would be 10.88 US cent/Kwh. They also did not seem to digest very easily the per unit cost projection for the Upper Karnali Hydropower Project, that is, 6.31 US cent/Kwh for the basic reason that this project has since long been considered as one of the most feasible projects so far studied in Nepal[2]. *If one further transparently analyzes the strategic implications of the "high cost" of hydropower pricing in Nepal, no developer other than India would have an interest in harnessing Nepal's water for energy as it is only India which can reap all other geo-political and economic benefits (flood and drought mitigations, maintenance of ecological balance, industrial development, and redistribution of benefits in the poverty-centered and politically - sensitive heart-land of densely-populated northern states of India, namely, the Uttar Pradesh, Bihar and West Bengal) out of the "high cost" hydropower development*[3]

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collaboration with NEA and Nepal Industrial Development Corporation (NIDC), which, at that time, had the license to develop the project, collected volumes of the documents on the project and sent them to the US energy service. The result: The US energy service refused to fund and undertake the project because the internal rate of return (IRR) calculated on the project was just 10 percent. The documents which were mostly prepared by and/for NEA or bodies similar to NEA considered 10 percent IRR as something adequate. The grave lesson learned by this editor and CMS from the case of "the refused Chamelia" was: The organizational cultural milieu under which an investment project is studied holds critical importance to competitively appeal independent developers.

[2] Here it is worth noting that the unit costs of the 20 MW Chilime Hydropower Plant designed and implemented by the Nepal Electricity Authority and the 3 MW Piluwa Hydropower Plant by the Nepalese private sector are US$1547/kW and US$ 1451/kW respectively (base year 2002). The unit costs of Upper Karnali and Karnali Chisapani hydropower projects have been estimated at US$ 2761/kW and US$1501/kW respectively. Although, Upper Karnali is of large scale storage type (300 MW) where one expects economy of scale to apply, its unit cost is significantly higher than those of the smaller power plants (i.e., Chilime and Piluwa) built indigenously. On the other hand, although the unit cost of Karnali Chisapani (even larger storage type plant with 10,800 MW capacity) is comparable to Chilime and Piluwa, the average tariff has been estimated at 10.88 US cents per kWh whereas Chilime and Piluwa have signed Power Purchase Agreement with Nepal Electricity Authority at 6.9 US cents per kWh and 5.9 US Cents per kWh respectively.

[3] One of the editors, who had participated in a hydropower development discussion on 28 October 1999 at the Chinese Ministry of Water Resources during a study visit of China organized by China Study Center, Nepal, the Chinese side had posed a pragmatic counter question: "As the foreign investors will be motivated by their interest in hydropower, why should they take interest in developing water resources in a holistic way to serve the key national strategic development objectives including protection of life and property of the citizens?"

Mr. Som Nath Paudel, a veteran career water resources engineer, former Executive Secretary, Water and Energy Commission Secretariat (WECS), and an Executive Member of JVS, in close consultation with Dr. Binayak Bhadra, former Water Resources Member of NPC, and an inter-disciplinary specialist who envisions economics, water, energy and public policy in a unified spectrum of national capability building without claiming to be as such, prepared an internal JVS note on the VSS study report. The Note, among others, stated:

> The concept of hydropower pricing as proposed in the study report seems to be reasonable. However, the result of the calculation shows some anomalies in average energy prices as well as the capacity and energy prices of the two projects (that is, Karnali Chisapani Project and the Upper Karnali Project). Therefore the calculation and input data of these projects have to be reviewed and formula for those calculations is also to be scrutinized by the experts.

The Note further suggested:

> It will be better, if the generation cost (energy) of each project be calculated with transmission and without transmission cost, so that there will be fair comparison between the projects.

In keeping with the spirit of the internal Note, JVS, on 16th October, 2003, decided to award a contract to Dr. Saurav Dev Bhatta to review and update the economic analysis aspect of the study report, also taking into account the linkages and conditions brought forth by the Kyoto Protocol-induced Clean Development Mechanism (CDM), Nepal's accession to World Trade Organization (WTO), redistribution of benefit, and industrial development. Dr. Bhatta was selected for the work for his knowledge, experience and skills in evaluation methods (including advanced statistical approaches) for cost-benefit analysis, environmental policy analysis, analysis of inequality and poverty, and strategies/policies for dealing with these phenomena. He holds more than 10 years experience in private banking and asset management, university teaching and research, and consulting in Switzerland, USA and Nepal. He has authored/co-authored several publications. Some of them include "Are Inequality and Poverty Harmful for Economic Growth: Evidence from US Metropolitan Statistical Areas," Journal of Urban Affairs, 23(3-4), 335-359, 2001, "An Examination of Spatial

Income Inequality and Poverty Across the Metropolitan Areas of the United States, 1969-1996," Working Papers in Planning, No. 184, May. Ithaca: Department of City and Regional Planning, Cornell University, 1999, "Reviewing the Evidence on Endogenous Growth," Working Papers in Planning, No. 178, November. Ithaca: Department of City and Regional Planning, Cornell University, 1998 and "Are Electric Vehicles Viable in Kathmandu? A Cost-Benefit Perspective", a study undertaken for Winrock International Nepal and published by the Kathmandu Electric Vehicle Alliance (KEVA) in July 2004. His latest consulting experience included preparation of the baseline report for the national Poverty Reduction Strategy Paper for NPC (2003), guidance on environmental economics to the Institute of Environmental Management, Kathmandu (2003) and Asian Development Bank (ADB) funded project which deals with the construction of a Social Protection Index for Nepal.

The objective of the Bhatta-exercise was to understand and operationally provide a fairer treatment to the linkage that exists between the hydropower pricing issues in the public policy domain with broader socio-economic development, not hydropower development *per se*. Dr. Bhatta submitted the updated study report on 3rd February 2004. Mr. Iswer Onta, Vice-chairman of JVS, presented the updated version of the study report in SAWAF III held in Dhaka, Bangladesh in July 2004.

The process did not end here. JVS wished to disseminate the hydropower pricing study report to a larger audience-domestic as well as foreign. So it intended to publish the study report in a book form. JVS, on 4th April 2004 signed a contract with Mr. Ajoy Karki, consulting senior hydropower and water resources engineer and Editor, Biogas and Natural Resources Management (BNRM) Newsletter, to prepare the study report as a final pre-publication copy. Mr. Karki has for the last 15 years been continuously involved in projects that have been planned, designed, developed and managed by private and community entities-both domestic and foreign. He was assisted by Mr. Prawodhit Gautam, an information and marketing professional with B.P. Koirala Cancer Hospital, Chitwan, in organizing the chapters, preparation of references, and subject index of the book.

As it should have been very clear by now, this book would not have been possible without the hard work and ingenuity of the participating senior civil servants, private consultants, academic and corporate faculties, professionals working with the civil society, and the contribution of researchers from social, economic and environmental fields of study. It might be satisfying to all who have been involved in the study report, and in the evolution of the study report that took place on its own, that their contribution not only enhanced the original integrity of the study report, but also helped to much clearly understand the inherent character of cost plus approach in hydropower pricing, thereby enabling the readers to ask the right empirical questions. On behalf of JVS, we would like to express our deep sense of gratitude to Dr. Janak Lal Karmacharya, Mr. Vijaya Shanker Shrestha, Dr. Durga Lal Shrestha, Mr. Sanjiv Man Rajbhandari, Dr. Binayak Bhadra, Mr. Som Nath Paudel and Dr. Saurav Dev Bhatta for their contribution in the process of the study. Indeed, this study would not have reached this final publication stage without the wonderful contributions from the professionals mentioned above who provided valuable knowledge, skills and insights in the making of this book. We are indebt to Mr. Prawodhit Gautam and Mr. Pradeep Mathema for their professional and administrative support to the study. It must be quite gratifying to JVS, the host institution of NWP, to declare that this publication on hydropower pricing is the first of its kind in South Asia planned and completed under the partnership and inter-governmental network of GWP. This could just happen because the other country water partnerships in the region simply did not initiate the study work on hydropower pricing, apparently mostly on the ground that they did not receive enough fund in time from GWP.

The book, as its title suggests, attempts at developing a perspective on hydropower pricing. The key message out from this perspective building exercise at the hindsight, as the editors have understood it, is *Nepal can produce and market hydropower at a reasonably affordable price if hydropower generation and utilization is linked to distributive justice, industrial development, and as a common means of modernizing way of life of the Nepali people*. The key message of the book, as a matter of fact, is the conclusion at which one arrives after one encounters the costs (which includes currently "accepted" rate or percentage such as of inflation of currencies-foreign and local, escalation of tariff, gross return on equity, debt service ratio etc.). The book, thus, raises a fundamental issue, which is more intricately related with making, applying and enforcing of public policies in the benefit of the people than simply pricing hydropower in a sectoral and organizationally ingrained manner. However, situation like the ones prevailing in Nepal and a number of other conclusions and recommendations that are drawn from the study and presented in this book may be applicable in the context of Nepal only, but most of the issues and concepts raised are universally applicable in hydropower pricing as well as in testing the mechanism. Be that as it may, the editors are thankful to JVS for entrusting them with the editorial responsibility. No individual contributor and JVS should be held responsible for the final structure of the book. This responsibility solely rests with the editors.

Upendra Gautam
Ajoy Karki

ABBREVIATIONS

AEP	Average Energy Price
BNRM	Biogas and Natural Resources Management Newsletter
C	Marginal Cost of Extraction
CC	Capacity Cost
CDM	Clean Development Mechanism
CO_2	Carbon Dioxide
CP	Capacity Price in kW
CR	Capacity Royalty
CT	Corporate Tax
CWP	Country Water Partnership
D	Debt Repayment
DDC	District Development Committee
DoE	Department of Electricity
DoED	Department of Electricity Development
DT	Dividend Tax
EC	Energy Cost
EHV	Extra High Voltage
EP	Energy Price
EP	Energy Price per Unit
ER	Energy Royalty
ERI	Expected Return on Investment
GWh	Giga Watt hour
GWP	Global Water Partnership
HEP	Hydropower Export Premium
HMGN	His Majesty's Government of Nepal
IF	Insurance Fee
IP	Interest Payment
JVS	Jalsrot Vikas Sanstha, Nepal
KEVA	Kathmandu Electric Vehicle Alliance
kW	kilo Watt
kWh	kilo Watt hour
LIBOR	London Inter-Bank Offered Rate
MIGA	Multi-lateral Investment Guarantee Agency
MW	Mega Watt
MWR	Ministry of Water Resources
NEA	Nepal Electricity Authority
NPC	National Planning Commission

NWP	Nepal Water Partnership
OC	Operating Expenses
OU	Units of Energy Production at off-Peak Time (kWh)
P	Price
PDF	Power Development Fund
PEP	Peak Energy Price
PPA	Power Purchase Agreement
PU	Units of Energy Production at Peak Time
Q	Installed Capacity of Hydropower Plant in kW
R	Marginal User Cost
RLDC	Regional Load Dispatch Centre
RNPB	Revenue from Non-Power Benefits
SASTAC	South Asia Technical Advisory Committee
SAWAF	South Asia Water Forum
SO_2	Sulfur Dioxide
t	Time
U	Units of energy production
UNFCCC	United Nations Framework Convention on Climate Change
US	United States
VAT	Value Added Tax
VDC	Village Development Committees
VSL	Value of Statistical Life
WCD	World Commission on Dam
WTA	Willingness to Accept
WTO	World Trade Organization
α	Premium of Peak Energy Price over off-Peak Energy Price

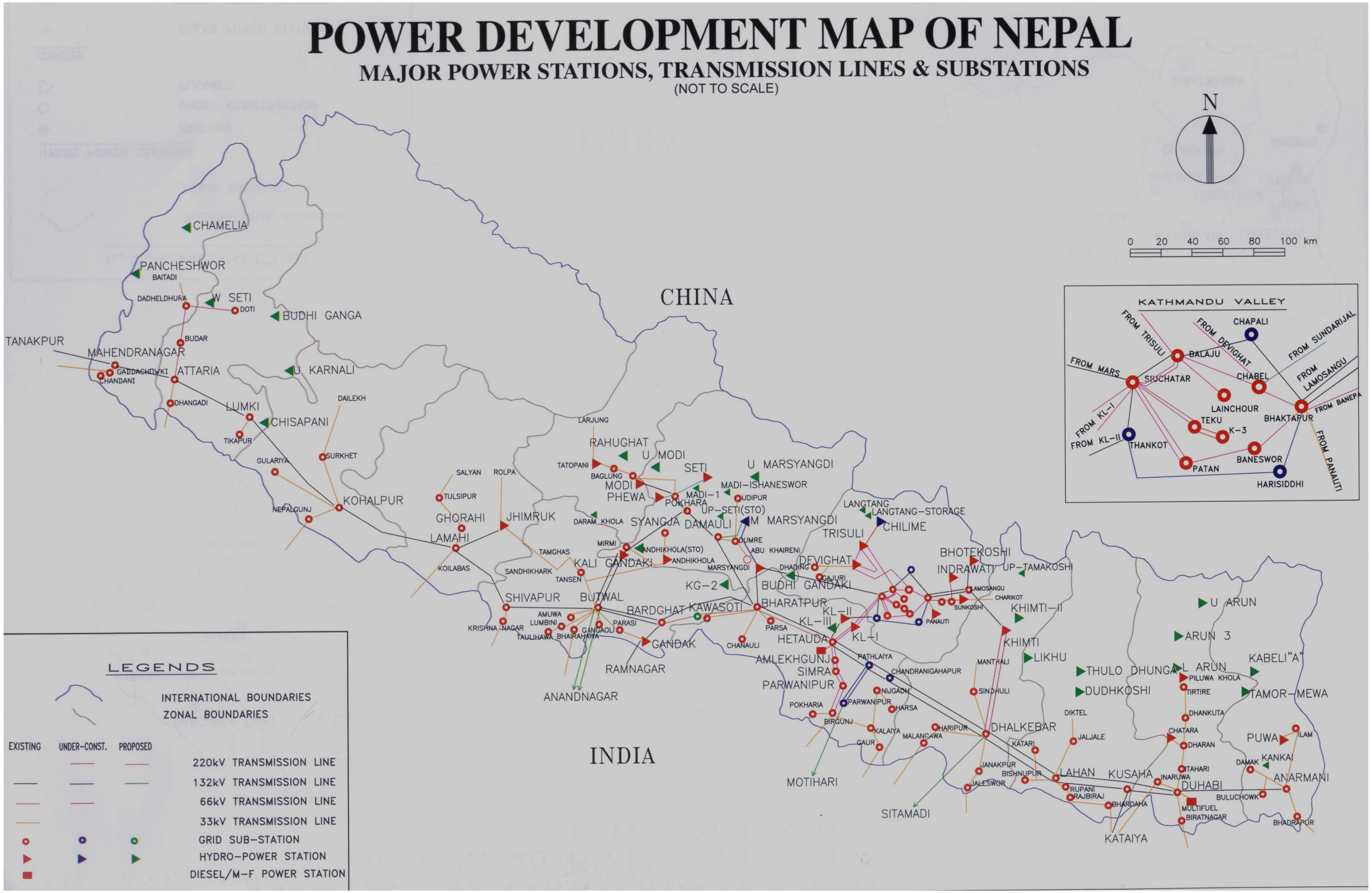

Figure 1. **Power Development Map of Nepal** *Source: Nepal Electricity Authority (NEA)*

1. Introduction

1.1 Nepal's Hydropower Potential

Nepal with its high specific runoff and steep terrain has a large potential for hydropower generation.[4] According to a study the theoretical hydropower potential of the country in terms of electrical energy is 727,000 GWh per year based on average flow, and 145,900 GWh per year based on 95% exceedance flow. The theoretical hydropower potential of the country in terms of installed capacity is estimated at 83,000 MW[5,6]. Approximately half of this potential is considered to be technically and economically viable in the present context, i.e., given the available infrastructures such as roads and electricity grid and the price of fossil fuel. Many of these hydropower projects will be storage types. Such projects will also produce substantial non-power benefits such as irrigation, flood control etc. in downstream reaches due to inherent flow regulation. Such non-power benefits will reach even beyond the borders of Nepal into neighboring riparian countries, namely; India and Bangladesh.

As of August 2003, the installed capacity within the Nepal Electricity Authority's (NEA) grid system is 606 MW of which hydropower accounts for about 550 MW (91% of installed capacity). Apart from Kulekhani I (60 MW) and Kulekhani II (32 MW), which are storage plants, the rest of the hydropower plants in the country are basically of run-of-river types. The only significant hydropower plant currently under construction is the 70 MW Middle Marsyangdi which is expected to come into operation by the end of 2006. These figures indicate that Nepal has developed just a minuscule portion of its realizable hydropower potential and thus, has a significant development opportunity in this sector.

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[4] Nepal's specific runoff is 0.0446$m^3/s/km^2$, out of which 77% is contributed from the territory within Nepal and rest 23% from outside Nepal, mostly from Tibet region of China. - Water Resources Development – Nepalese Perspectives, 1995.

[5] The widely quoted theoretical hydropower potential in Nepal of 83,000 MW is based on Dr. Hari Man Shrestha's Ph. D. Thesis (1966) from Moscow Power Institute, USSR on "Cadastre of potential water power resources of less studied high mountainous regions, with special reference to Nepal". Dr. Shrestha is known as the pioneer Hydropower Engineer of Nepal.

6 Water Power Potentiality of Nepal in the Proceedings of the Seventh World Energy Conference, 1968 – Hari Man Shrestha, Ph.D.

1.2 Domestic Market

Nepal's electricity needs are mostly met by hydropower generation. In 2002-03, Nepal's peak power demand was 470 MW and, the energy available for use within the NEA system totaled 2,261 GWh, out of which 2107 GWh was met by hydropower generation (93%). Moreover, of the total energy available 1,478 GWh was obtained from NEA's hydro generation, 4.4 GWh from NEA's thermal generation, 150 GWh was imported from India (in accordance with Power Exchange Agreements) and 629 GWh purchased from private generators.

By 2010, Nepal's peak power demand is expected to reach 864 MW with the corresponding annual energy requirements of 3,936 GWh and by 2020, they are expected to be 1,742 MW and 7,933 GWh respectively.[7] In this period, Nepal's electricity demand is forecasted to grow at around 8% per annum. Even at a high growth scenario of about 12% per annum, peak power demand will reach only 3,400 MW and energy requirement 16,000 GWh in 2020. Thus, even in the foreseeable future Nepal's electricity needs will still be a small percentage of its realizable hydropower potential. Thus, in order for Nepal to exploit its hydropower potential in a substantive way it has to look for an export market where there is a demand for such power.[8]

1.3 Export Market

Nepal's immediate neighbor India can be a potential export market for its hydropower generation. India has been divided into five regional electricity grids for over-all control and supply of power. The Indian northern region comprises of northern states including Uttaranchal and Uttar Pradesh, which adjoin Nepal's western and southern borders. Eastern Indian region comprises of some eastern states including Bihar and West Bengal, which adjoin Nepal's southern and eastern borders. In 1998-99, the Northern region suffered a deficit of 2,096 MW (10.4%) in peak power demand and 6,240 GWh (4.8%) in energy requirement while

[7] Nepal Electricity Authority's (NEA) Publication 'FY 2002-03 A Year in Review', August 2003.

[8] Nepal's Electricity Act, 1992 provides for export of electricity generated by a developer to foreign country by entering into an agreement with the government. The developer will have to pay export duty as determined in such agreement.

the Eastern region suffered a deficit of 475 MW (6.4%) in peak power demand whereas energy availability was sufficient to meet energy requirement. All India figures of deficits for that year were 9,460 MW (13.9%) and 26,349 GWh (5.9%) respectively.[9] Against a target of adding 6,500 MW per year set by the Central Electricity Authority of India only about half is being achieved in the recent years. Therefore, in India power and electrical energy shortage has been worsening annually. The situation is worse in the Northern region because recent augmentation in power supply has been mostly in the Western and Southern regions. Even the Eastern region has currently become energy deficit. By 2011-12, peak power demand and energy requirement of the Northern region will be 60,077 MW and 350,185 GWh while that of the Eastern region will be 23,228 MW and 135,049 GWh respectively. The corresponding power and energy requirement figures for all India are 176,647 MW and 1,058,440 GWh respectively.[10]

In addition, generation in power front in India is highly skewed towards thermal. Hydro-thermal (including nuclear and wind) mix in the installed generation capacity is 24:76 while in energy generation, it is 19:81. According to Indian government hydropower policy, ideal hydro-thermal mix is 40:60. Because of an imbalance in hydro-thermal mix, many thermal power stations are required to back down during off-peak hours. Though India also has a large hydropower potential, it is experiencing many constraints to develop its potential. These facts show the high possibility of exporting hydropower to India from Nepal. Recognizing this possibility, in 1997 Nepal and India signed a Power Trade Agreement to facilitate the exchange of power/electrical energy between the two countries.[11] This Agreement is yet to be ratified by the governments of the two countries.

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[9] Central Electricity Authority, India

[10] Fifteenth Electric Power Survey of India, July 1995.

[11] This Agreement allows any party in Nepal or India to enter into an agreement for power trade between the two countries irrespective of them being government, semi-government or private enterprise. The parties can themselves determine the terms and conditions of such an agreement including the quantum of supply and its price. The parties will be afforded all the assistance and granted all the incentives and concessions in accordance with the relevant laws of the respective countries for generation and transmission of power. The parties will have to fulfill all necessary requirements stipulated in the relevant laws of the respective countries as well as comply with necessary technical requirements of each country.

1.4 Regional Power Pool

Recently India has embarked on interconnecting the regional grids by Extra High Voltage (EHV) transmission lines. In the beginning these interconnections along with Regional Load Dispatch Centers (RLDC) will help India in reducing the power deficit in a particular region by transferring surplus power from another region. Subsequently, it will evolve into a power trading enterprise where utilities and generators buy and sell power in a competitive market through a power pool, which would work as follows:

- Each participating generator will indicate daily to RLDC, their capacity and energy availability for the following day. On the basis of such declarations, RLDC will advise each participating utility (i.e., electricity distribution entity) the capacity and energy availability of the system.
- Each participating utility will indicate daily, to RLDC, for the following day, their power and energy requirement from the regional grid.
- RLDC will schedule the participating generation for the following day and indicate the scheduled generations to the generators and scheduled withdrawals to the utilities.
- Any utility withdrawing power would be charged as per the applicable Power Purchase Agreement (PPA) and similarly any generator supplying power would be paid as per the applicable PPA according to the amount of scheduled withdrawals and generation respectively.

In the beginning, such declarations of availability and requirement can be in a weekly basis and later it can progress to daily or even into an hourly basis. Power pool can also evolve into a competitive market where generators will indicate their selling prices along with their availability (such prices may or may not reflect the cost of generation at any time) and utilities will indicate their buying prices along with their requirements. Thus, power purchase agreement will be done on the basis of competitive market price (i.e., market equilibrium price) at the particular time. The Success of such a power trading system through power pool is heavily dependent on efficient working by the dispatchers and prompt payment mechanism.

India still has a long way to go prior to the establishment of such a power pool. Power sector reform has to take root firmly, particularly the tariff and institutional reforms in order to move towards such power pool. Nevertheless, Nepal can benefit from such power pool whenever it is established once necessary interconnections between Nepalese and Indian grids are in place.[12] Then Nepal will have an opportunity to offer its power to more solvent utilities than depending on the neighboring insolvent ones. When necessary interconnections are in place between Indian grid and other national grids of India's neighboring countries, then such a power pool can be expanded to a regional power pool and Nepal's opportunity for export of power will further increase.[13]

1.5 Electricity Tariff

Prior to undertaking a detailed discussion on the economics of the hydropower sector, the terms, "cost", "price" and "tariff" should be clearly explained. Costing involves determining the value of resources consumed in the production of goods or the provision of a service[14]. Costing's role in pricing is to act as a benchmark against which pricing and production decisions can be made. Thus, cost of electricity refers to the cost of generating and delivering one unit (kWh) of electricity form a hydropower plant to an agreed delivery point. Pricing refers to the process of determining a figure at which products or services will be exchanged in the marketplace. The focus of pricing is on the income received from the exchange of the good. In the context of this report, hydropower price refers to *wholesale price* (stated clearly in section

[12] At present, Nepal and India have an agreement for exchange of power of up to 50 MW along the border on both sides, which is transmitted by two 132 kV and fourteen 33 kV interconnections. Recently, this quantum has been increased to 150 MW but existing interconnections are not capable of transmitting such power and they need to be strengthened considerably. There is another 132 kV interconnection in the Far West but that is dedicated to import of free power from India by Nepal under the Mahakali Treaty. Actions are being taken on both the sides to have 3 more 132 kV interconnection links between the power systems of the two countries.

[13] There are examples of such regional power pools operating successfully in the world. Nord Pool in northern Europe encompassing Norway, Sweden, Finland and Denmark is the first such regional power pool. Southern African Power Pool in southern Africa is another example, which encompasses South Africa, Lesotho, Mozambique, Namibia, Malawi, Zimbabwe and Zambia. Brazil, Argentina, Paraguay and Uruguay in South America trade electricity. Central America has an interconnected grid. New England states in USA import electricity from Canada. In northern Africa the countries of the Nile River Basin are exploring ways to establish electricity trade.

[14] It might also involve determining the cost or value of negative impacts of the project.

6.3), which is the price at which the electricity producer sells electricity to the utility company or a distributor. Tariff, on the other hand, is basically the retail price or the price charged by the utility to the final consumer.

Energy generated from hydropower has to be ultimately sold to the consumers (after deducting the system losses). If the power market cannot afford the electrical energy, no hydropower generation can take place. Therefore, knowing the present electricity tariff structures of Nepal and India will be beneficial in understanding the electricity market situation. Nepal's electricity tariffs for the year 2000-01 are presented in Table 1.1 whereas those of India along with the neighboring states of Uttar Pradesh and Bihar for year 1999-00 are given in Table 1.2. Nepal's tariffs have been increased by about 10% effective from September 2001. The tables show that Nepal's average tariff to the consumers is almost double of India's. The main reason being Nepal's tariffs are not subsidized while those of India are heavily subsidized. As a result, Nepal's electricity utility is a profit-making organization generating even some internal funds for investment in power system expansion while almost all of India's electricity utilities are running at loss. Agriculture tariff in India is abysmally low while its share is about 30% of the total electricity consumption. The largest consumer is the industrial sector, which consumes about 34% of the total electricity supplied. This sector is heavily charged. This again highlights the urgent need for tariff structure reform in India. Unless this reform takes place no substantial investment will come forward in the power sector and hence, no dent will be made in acute power shortage in India. In this backdrop, it should be noted that India has recently started restructuring its electricity sector by reforming its policies and involving the private sector.

As can be seen from Tables 1.1 and 1.2 the cost of supply of electricity in the two states (Bihar and Uttar Pradesh) of India is about 26% lower than that of Nepal. This is mainly due to the fact that India is able to produce construction materials such as steel and cement in sufficient quantities and also manufactures electrical and mechanical equipment such as generators and turbines. Nepal has to import such construction materials (mainly steel) and the equipment required. Furthermore, local contractors contribute a significant work volume in the construction of hydropower plants in India. In Nepal hydropower plants (especially the larger ones by Nepalese standard) are implemented under bilateral or multilateral donor aid with the precondition (tied aid) that the main contractors be from the donor countries. Furthermore, unlike India, which is able to mobilize significant local finances and less hard currency loans, Nepal relies heavily on external loan finances in hard currencies.

Table 1.1 Electricity Tariffs in Nepal (2000-01)[15]

Category	Tariff, NRs /kWh
Household	6.30
Industrial	5.80
Commercial	8.36
Non-Commercial	8.54
Water Supply & Irrigation	4.57
Transport	4.70
Others	4.75
Export	3.50
Average	6.03

Cost of Supply	6.00

Table 1.2 Electricity Tariffs in India (1999-00)[16]

	All India	Uttar Pradesh	Bihar
Category	Tariff, IRs/kWh (NRs/KWh)	Tariff, IRs/kWh (NRs/KWh)	Tariff, IRs/kWh (NRs/KWh)
Household	1.49 (2.38)	1.05 (1.68)	1.09 (1.74)
Industrial	3.50 (5.60)	4.18 (6.69)	2.75 (4.40)
Commercial	3.54 (5.66)	3.04 (4.86)	2.23 (3.57)
Agriculture	0.25 (0.40)	0.49 (0.78)	0.12 (0.19)
Railway	4.11 (6.58)	4.50 (7.20)	3.30 (5.28)
Export	1.21 (1.94)	0.16 (0.26)	1.91 (3.06)
Average	2.08 (3.33)	1.86 (2.98)	2.00 (3.20)

Cost of Supply		2.78(4.45)	2.78(4.45)

Note: IRs 1.00 = NRs 1.60.

[15] Nepal Electricity Authority's (NEA) Publication 'FY 2000-01 A Year in Review', August 2001.
[16] Planning Commission of India.

1.6 Need for Hydropower Pricing

Water resource is the only natural resource Nepal has in abundance. Converting this renewable natural resource to its beneficial uses has become imperative for Nepal to take a quantum jump in the race for economic development. Hydropower is one such beneficial use. Widespread electrification in the country based on hydropower will not only provide the base for industrialization of the country but also become one of the tools for social equity and justice (especially in the improvements of health and education through quality supply of electricity and support to the rural economy). Excess hydropower can be shared with other countries of the region and thus, can become another link in the integration of the economies of the countries of the region. For these to happen proper hydropower pricing is necessary so that it is both affordable and competitive in the domestic as well as export markets. Use of a renewable, natural resource has some value that can be termed "opportunity cost". Therefore, hydropower price must also reflect the full cost associated with its development including the renewable, natural resource use cost. Furthermore, export of hydropower creates substantial secondary benefits in the importing country in addition to the direct benefits of the power. There is a need to assess such secondary benefits by the exporting country and reflect them in the pricing mechanism. These considerations have led to the need for a study in hydropower pricing from Nepal's perspective.

1.7 Objective of the Study

The objective of this study is to,

1. propose a mechanism for pricing the hydropower with in-depth analysis of the elements of the mechanism, and
2. test the proposed mechanism to one run-of-river and one storage hydropower projects.

1.8 Limitations of the Study

The mechanism that is proposed for hydropower pricing in this study is in fact, universal. It would be applicable for other hydropower projects at other locations. 'Nepal's Perspective' in the title of the study has been included only to highlight the unique position Nepal occupies in the renewable, natural resource position in this region including the country's capacity to meet the energy needs of the region. It should also be noted that case studies presented in the study are from Nepal and thus some of the topics that are discussed may be relevant to Nepal only. These projects are tested in the prevailing economic, financial and legal framework of the country. Thus, some of the conclusions and recommendations that are drawn in the study may be applicable in the present Nepalese context only. Furthermore, "benefits" in this report are taken into account only to evaluate the project, i.e., to determine whether and how much the benefits outweigh the costs. Benefits are not used in the pricing process. The pricing approach discussed here only looks at the production or cost side and does not take consumer benefits into account; benefits are only used to evaluate the project within a benefit-cost framework.

1.9 Organization of the Report

Background information such as Nepal's hydropower potential and generation, current power market, tariff and the objectives of this study have been presented in Chapter 1. Chapter 2 covers the assessment of costs of hydropower projects. Different types of costs associated with the implementation of hydropower projects are discussed in this chapter. The natural resources uses costs in hydropower projects are comprehensive and thus dealt separately in Chapter 3. Similarly, Assessment of various tangible and intangible benefits from hydropower projects is presented in Chapter 4. Chapter 5 discusses the allocation of costs in multipurpose projects. Key issues in hydropower pricing are discussed in Chapter 6. Hydropower pricing mechanism is covered in Chapter 7. Two specific case studies, namely Upper Karnali Hydropower Project (300 MW) and Karnali-Chisapani Multipurpose Project (10,800 MW) are presented in Chapter 8. Detailed analysis of costs and benefits from the development of these two projects are presented in this chapter. Finally, the conclusions drawn from this study and the recommendations that follow are presented in Chapter 9. Chapter 10 includes the list of references used in the course of this study, which is followed by a glossary of technical terms used in this document. The details of the economic analyses for the case studies are presented in the Annexes.

2. Assessment of Costs of Hydropower Projects

2.1 Cost components of Hydropower Projects

Hydropower pricing is basically a function of the costs of the hydropower project. Costs of a hydropower project consist of four parts – *associated costs*, *induced costs*, *external costs* and *the opportunity cost of water*. Associated costs are costs that are associated with the need to produce hydropower, such as costs of engineering structures and equipment as well as their operation and maintenance costs. Induced costs are costs that are needed to mitigate the adverse impact produced by the project on nature, people or existing ground conditions, such as costs of environmental mitigation measures. Furthermore, there are external costs also that may be needed for the smooth construction and operation of the project though they may also serve other purposes, such as new infrastructure development required for accessibility to the project site. In addition, the opportunity cost of using the natural resource – water - in a hydropower project should be added to the total cost to reach the full cost.

Costs of a hydropower project occur during two distinct time frames – one, during the construction phase of the project and two, during the operation phase. Most of the costs are borne during the construction phase, some in the operation phase and some of the costs in both the phases. For example, costs for engineering structures and equipment are borne during the construction phase while their operation and maintenance costs are borne during the operation phase. Costs for environmental mitigation measures may continue in both the phases.

Unlike a thermal or nuclear power plant, a hydropower project is very site specific. A particular site for a hydropower project will produce a specific amount of power and energy that no other site can duplicate. That means the design and consequently, the associated costs of a hydropower project are very much dependant on the site. Induced costs and external costs also are dependent on the particular site selected. Remoter site may mean higher infrastructure cost, storage site may mean higher resettlement cost, pristine site may mean higher environmental mitigation cost, etc.

The cost of a hydropower project is dependent on its function as well. A hydropower project can be of five types depending on its function: *simple run-of-river* where power is produced daily according to the flow of the river; *peaking run-of-river* where water is stored in a pond daily during off-peak hours and released during peak hours to produce peaking power; *seasonal storage* where water is stored in a reservoir behind a dam during lean demand period of a year and released during peak demand period to meet the peaking demand; *cyclic storage* where enough water can be stored in a reservoir to meet the peak demand of more than one year; *pumped storage* where water is pumped from a lower pond or reservoir to an upper pond or reservoir during off-peak hours of the day and released during peak hours to produce peaking power. Usually for a comparable size of the project, a storage project is costlier than a run-of-river project. A storage project can serve other purposes also such as irrigation, water supply and flood control besides generating hydropower. Such a project is called a multipurpose project though hydropower generation remains a major component of the project.

The costs of a hydropower project that are mentioned above occur during the construction and operation phase of the project only. There are two other types of the costs that are usually overlooked but are essential from the viewpoint of hydropower development. The first such cost is the *conception cost*, that is, the cost from the very beginning of the identifying the site of a hydropower project to bringing it to the construction phase through field reconnaissance, field investigation, pre-feasibility study, feasibility study and detailed engineering design. Seldom are costs involved in these activities included in the particular project cost and these costs are treated as a part of the overhead cost or sunk cost of the concerned organization.

The second cost is the *decommissioning cost*. When the economic or commercial life of a project is over it needs to be decommissioned so as to bring the ground situation back to its previous condition. But in a hydropower project with large civil works construction that totally changes the landscape, that is not a practical solution. However, generating equipment can be decommissioned after its life is over. Decommissioning cost becomes more important in thermal plants compared to hydropower plants because their lives are shorter than hydropower plants. This implies that in an economic analysis the inclusion of such cost will benefit hydropower plant when compared to a thermal plant. As in the conception cost, seldom is the decommissioning cost included in the particular project cost. Therefore, no further discussion is taken up on these two costs though it should be kept in mind that these two costs are also parts of the total project cost.

2.2 Associated Costs

Associated costs of a hydropower project during the construction phase are the costs for the following:

- Compensation and right-of-way for land and built-in property,
- Preparatory works such as camps, construction power supply and access roads within the site area,
- Dam or headworks, waterways, powerhouse and switchyard,
- Electrical and mechanical equipment,
- Reregulating structure in case of storage project,
- Transmission line and substation, if they are integral part of the project, and
- Engineering, management and administration.

Associated costs during the operation phase are simply the costs for operation and maintenance, replacement and administration of the project.

Sometimes, associated costs include some part of induced and external costs when project design itself takes these aspects as an integral part. Fish ladder provided for migration of fish, gate provided for release of minimum flow downstream of intake, equipment provided in power-station/switchyard for local electricity supply are some of such examples.

2.3 Induced Costs

Induced costs of a hydropower project during the construction phase may consist of the following:

- Resettlement and rehabilitation,
- Environmental impact mitigation measures and
- Relocation of existing infrastructure such as transportation and communication lines, water supply structures, public buildings, etc.

Usually there are no induced costs involved during the operation phase unless some of them such as environmental mitigation measures spill over in the operation phase[17].

Land acquisition, compensation, resettlement and rehabilitation play a vital role in the development of a hydropower project. Satisfactory conclusion of it goes a long way in not only successful and timely completion of the project but in its hassle-free operation also. Government support is crucial in each step for its satisfactory conclusion. Concerned government agencies may also need to be involved in such steps in order to expedite the process. A generally accepted approach to compensation is that it is based at market price and is distributed well before the start of the project. A better and more standard approach is to come up with a compensation package based on the willingness to accept (WTA) principle. In other words, the displaced should be paid the amount at which they would be willing to relocate elsewhere. Given that the real estate market and market for land are not very efficient in areas where hydropower projects might be built, it would be difficult to come up with market prices in most cases. The underlying objective in both principles, i.e., "WTA" and "compensation at market price" is that people displaced by a hydropower project must be resettled and rehabilitated in a better manner than their previous living condition and environment. Such resettlement and rehabilitation must be completed well before the completion of the project. Employment generation schemes must be a part of the rehabilitation process for those who are bereft of their livelihood due to the project. These are necessary in order to gain the acceptance and goodwill of the people towards the project. A hydropower project is usually situated in a remote and underdeveloped area inhabited by economically weaker and underprivileged part of the society. In such a situation, it becomes more imperative that these activities should be done in a satisfactory manner for the sake of social justice as well as for smooth construction and operation of the project.

Consideration of environmental issues has come to the fore not only in development of a hydropower project but in any development activity since the last two decades. The basic premise behind the consideration

[17] Induced costs, although always relevant from society's perspective, are not relevant from the project's perspective if there are no legal requirements on the project to bear these costs.

of environmental issues is that the earth is not the inheritance from past generation to present; rather it is the trust of the future generation with the present one. Hence, no activity of present generation should adversely impact the environment of the earth. If such adverse impact takes place due to any activity, then adequate mitigation measures must be undertaken as a part of that activity. This concept is now universally accepted but it must be clearly understood particularly in the context of developing countries like Nepal that poverty is the biggest enemy of nature. It prompts mankind to assail nature to alleviate sufferings. In the name of safeguarding the environment it is not possible to stop development activities. Any development activity will more or less adversely impact the environment. It is the question of balancing such adverse impact with the gains or benefits from such activity. In other words, how much should the present generation suffer and sacrifice for the sake of the future generation? The answer to this question must be left to the individual nation to decide for itself. In the case of an individual development project, complete mitigation of all adverse impact on environment may not be possible or even practicable; it is a question of including such mitigation measures in the project as are practicable and still keep be able to the project viable.

2.4 External Costs

External costs of a hydropower project during the construction phase may consist of the following:

- Infrastructure costs such as upgrading of existing and construction of new transportation and communication lines to provide accessibility to the project site,
- Local development and rural electrification and
- Watershed management.

Similar to the induced costs, no external costs are involved in the operation phase unless some of them such as watershed management spill over in the operation phase.

There is no question that all associated and induced costs borne by a hydropower project during both the construction and operation phases should be considered while calculating the hydropower price. But some questions might arise in case of the inclusion of the external costs in such pricing. Hydropower projects are usually located in remote and underdeveloped areas necessitating access roads. If the cost of the access road is small compared to the total cost of the project and the road serves no other purpose, this cost may be treated as a part of the induced costs and included in the hydropower pricing. But in the case of a hydropower project requiring a long access road whose cost is appreciable compared to the total cost of the project a different approach may be needed. This road may as well be used as access to other economic development activities in the area simultaneously with the hydropower development. In fact, this road may become a catalyst for over-all economic development of the area. Will it then be equitable in such a situation to load the full cost of the access road to the hydropower project cost and thus, increase the hydropower price? But the other side of the argument is also strong. There may not be any road built in the area if hydropower development is not taken up there. The location of the hydropower project at the particular site and access required may justify the road.[18]

[18] An example is the 120-km long access road required for the 402 MW Arun-3 Hydropower Project in Eastern Nepal. The cost of the road is 16 % of the total project cost.

In such a situation one should look from a wider perspective. On one hand, it is not equitable to ask the consumers alone to pay a higher tariff for the power if the cost of the access road is included in the project cost. On the other hand, it is not fair to ask the developer of such a project to bear the cost of the road without any return on it if the cost of the access road is not included in the project cost. From a national perspective, all taxpayers should pay for building of such a road. To realize this objective, one solution is to postpone the development of the hydropower project until the government builds the road with its own resources. Considering the priorities and the resource crunch of the government, it may take a while for the road to be built. Meantime, the hydropower project may loose its attractiveness due to delay in its implementation. If the government thinks that a particular hydroelectric project is a priority and hence, builds access road to it on a priority basis then the cost of such road obviously will not be a part of the project cost but it will be fair to charge the developer some rent for its heavy use during the construction period to meet the maintenance costs. The other solution is to ask the developer to build the hydropower project along with the road but not to include the cost of the road in the project cost. The developer should be compensated separately for the cost of the road by the government in a mutually agreed manner within a certain time frame after the completion of the road. The developer should be allowed a fair return on his investment along with the debt service burden, if any, incurred for the road. This method can be termed as Built and Transfer method for infrastructure development.

If the second solution is taken up for consideration, it is advisable to entrust the maintenance of the road to the developer itself during the construction phase of the project and he be allowed to include the maintenance cost of the road for that period in the project cost. Then the road is handed over to the government immediately after the commissioning of the hydropower project in fair condition. Same principle may be applied for the communication line that is initially required for the construction of the project but later on can be used for the benefit of the local area.

When any economic development activity comes to a remote and underdeveloped area, it raises the hopes and expectations of the people of that area. A hydropower project is not an exception. People's demands and expectations are not much. They want local development to take place. They want schools and health centers built and run properly. They want roads and bridges constructed. They want drinking water and rural electrification schemes implemented. It will be a social injustice if a hydropower project is built in an area but underprivileged people of that area do not avail of benefits of electricity while the privileged people of far off area fully enjoy such benefits. In the context of Nepal it is an important issue because only about 23%[19] of the population have access to grid electricity supply. These local development activities do not cost much. Implementation of these along with the project's implementation will not be a burden to the developer. However, it is essential to define the limit of such activities that the developer should be responsible for.

As the time goes by people's demands and expectations also rise. But the developer is not in a situation to satisfy all these demands, particularly during the operation phase. And one should not expect him to be able and be responsible to do so for all the time. In fact, it is the government's or local authority's job and responsibility to do so. Nonetheless, considering that taking up such activities during the construction phase of the project will create goodwill among the people towards the project, it might be advisable to ask the developer to take up such activities on a limit basis. That limit should be a small percentage of the project cost so that it is not a burden to either the developer to arrange fund or the consumer in the ultimate power tariff. List of such activities in the vicinity of the project area should be decided in close consultation with the local people subject to the limitation of the fund beforehand and they should also be closely involved in its implementation. It is not going to be an easy task but some compromise will have to be reached by both the sides considering the constraints of the developer and the aspirations of the local people. During the operation phase of the project other mechanisms should also be looked at to generate fund for local development and rural electrification.

[19] According to the 2001 National Census, access to electricity is estimated to have reached almost 40% of the population. In urban areas sub-meters are installed in apartments that are rented out, which are not accounted for by NEA - the national electricity utility. Similarly, in rural areas a household may subscribe electricity services from NEA and have a meter installed and then supply electricity to the neighbours separately on a cost sharing basis which too would not be accounted for in the NEA records. Although, these practices would increase the access to electricity by a few percent, it is difficult to justify a 10% discrepancy.

Sharing of some of the revenue from the project between the government and the local authorities can be one way.[20]

Watershed management can be looked from two angles. Watershed management in the catchment area of a hydropower project effectively helps the project during its operation phase by reducing the sediment load. In the storage project the life of the project is increased by increasing the period required to fill up the dead storage while in the run-of-river project the maintenance cost is decreased due to the longer period required for runner replacement. This argument points towards the necessity for the developer to contribute in the watershed management costs. On the other hand, watershed management helps in limiting the overall degradation of the catchment area by reducing deforestation and water-induced damages. Even if there is no hydropower project, such watershed management activity has to be taken up by the government and local authorities on their own. Furthermore, other development activities are also helped by watershed management and perhaps more, for example, in road building. In such a situation, it may not be fair to load the hydropower project alone in contributing towards the watershed management cost, particularly during the construction phase. In the operation phase, it may be fair for a hydropower project to contribute towards the watershed management cost, as there is direct benefit to the project. The same method as adopted in local development cost sharing may be adopted by sharing some part of the royalty to the government from the project with the agencies responsible for watershed management. As argued in the next chapter (3) that royalty is in lieu of the cost of the natural resource used, i.e., water and sharing some part of that royalty with watershed management agencies for sustaining this natural resource is justified.

[20] At present by law, 10% of the royalty earned from a hydropower project in Nepal is forwarded directly to the concerned districts where the project is located, for such development activities. The rest of the royalty goes to the government treasury. Similarly, 1% of the royalty from a hydropower project is proposed to be forwarded directly to the concerned villages directly affected by the structures of the project for rural electrification purpose only of those villages.

3. Natural Resource Use Costs in Hydropower Projects

3.1 Need for Natural Resource Use Cost

Water in the rivers, which is the source of generating hydropower, is a renewable natural resource.[21] Water and other natural resources are economic goods rather than free goods since they are relatively scarce and they cost money for their uses. Broadly speaking, a natural resource has intrinsic value as well as economic value[22]. In addition, it is owned by the State.[23]

Since natural resource has both economic and intrinsic values to the users and society, it has its own demand price. The demand price of a natural resource for different users may be different. It is based on the users' willingness to pay, which, in turn, is determined by the purposes and types of uses, expected profitability in its uses and location of the natural resource. The price of natural resource is usually determined by the demand price because it is a free gift of the nature to the nation. The use of the natural resource costs some money, which is called the extraction cost. The difference between the price and marginal extraction cost is the marginal net benefit or marginal user cost, which is also termed natural resource use cost or royalty. In practice, some policy or act of the government usually fixes the royalty or natural resource use cost.

In the case of a hydropower project, the developer uses the natural resources such as water, river-belt, catchment area, location or site

[21] Natural resource refers to the freely given material phenomena of nature on the earth. It is even extended to above and below the earth's surface e.g., land, oil, coal, mineral deposits, natural forests, rivers, lakes, wind, rainfall, etc. Some of natural resources are renewable and rests of them are exhaustible.

[22] If an environmental good, service or function contributes to human welfare and if people are willing to pay for it, then it is understood to have an economic value. A market does not have to exist for a good to have an economical value. Pearce, D. W. (1988). *Economics And Environment: Essays On Ecological Economics And Sustainable Development.* Northampton: Edward Elgar.

[23] All natural resources, situated within the boundaries of a nation (extending to above and below the earth's surface of within the boundaries of the nation), are owned by the State. Ownership creates the rental value of the natural resources if these resources are used by someone else, i.e., other than the owner.

specific facilities, etc. to generate hydropower.[24] Thus, the user has to pay some fee to the government for the use of the above mentioned natural resources and their facilities as these resources have both intrinsic and economic values and are owned by the State. Such payment is the royalty or natural resource use cost, which is the price of using natural resource for the owner and the cost for the users. Since, the royalty is one of the non-tax revenues of the government; it is the cost component for the users. Therefore, the royalty can be considered as a cost component in fixing the electricity pricing. The government can use such royalty payment for the people's welfare through investment in local as well as national development activities.

3.2 Assessment of Natural Resource Use Cost or Royalty

In simple terms, royalty is the payment made to the owner (the State) of natural resources (water, river-belt, catchment area, site specific facilities and other surrounding natural facilities) by the user (hydropower developer) of the resources in return for the right to use the resources. Royalty is used as a device to extract economic rents from the exploitation of a natural resource. There is no universally accepted method for fixing the royalty. It varies from case to case. It is sometimes, a contractual amount fixed by an agreement between the owner and the user of the resources with reference to the quantity produced or sold. Royalty is usually fixed as a certain percentage of sales of the product. The percentage of sales as the royalty is usually fixed either by an agreement between the developer and the State or by a relevant development policy or act of the government.

According to the Hotelling rule, the royalty is the surplus or the difference between the price (P) and the marginal cost of extraction(C). The surplus or rent is the marginal user cost (R) i.e., $P - C = R$[25]. The marginal user cost is also called royalty, especially when someone owns a resource and wants to sell the rights of using the resource; the owner

[24] Location or site specific facility means the hydraulic head available at a particular location or site to generate hydropower.

[25] The optimal price of natural resource is equal to the sum of marginal extraction cost and marginal user cost (royalty), i.e., $P_t = C_t + R_t$, where P is the optimal price, C is the marginal extraction cost, R is the royalty or marginal user cost and t is the time.

collects royalty from the user for the use of resource[26]. That is, $R_t = P_t - C_t$.[27] In other words, it is the rental value, which can be computed on the basis of net benefits of its use in a particular project (including its opportunity cost of foregoing the net benefits from the next best alternative use).

The determination of royalty as the net benefit has some practical problem. It is very difficult to calculate the net benefits of using the natural resources. Thus, this approach recommends an unequal royalty for run-of-river and storage projects having equal installation capacity. The royalty for storage project will be lesser than that for run-of-river project because the net benefit of the storage project is smaller than that of the run-of-river project if non-monetary benefits and costs of using the resources cannot be properly valued. The reasons are: (1) the cost of the storage project is higher than that of the run-of-river project and (2) the sales revenues of both the projects may be the same due to a single price if the non-power benefits are not taken as saleable products. In the contrary, the storage project uses relatively more natural resources compared to the run-of-river project. So, the developer of a storage project needs to pay higher royalty. But, the larger natural resource user paying smaller royalty to the State is practically inconsistent. However, it is difficult to generalize for all storage projects because hydropower project is site specific. As the definition of the royalty indicates, it is the payment made to the owner by the user for the use of natural resources for a certain purpose. The user of the larger quantity of natural resources, in principle, requires paying higher royalty. Therefore, it is better to use the royalty as a certain percentage of gross benefits for simplicity.

Since the level of gross benefits, total production or total sales are positively related with the volume of natural resources used, for economic analysis natural resource use cost can be estimated as a certain

[26] In order to estimate the lump sum royalty at the initial period of the project, the method of discounting should be applied. The royalty or marginal user cost in initial period is equal to the price of the backstop technology minus the cost of extracting the resource, which is discounted to the present.

[27] In order to estimate the lump sum royalty at the initial period of the project, the method of discounting is required to be used. The royalty or marginal user cost in initial period is equal to the price of the backstop technology minus the cost of extracting the resource, which is discounted to the present.

percentage of gross benefits obtained by the user using the natural resource whereas it can be obtained as a percentage of total production or total sales to the user for financial analysis. The natural resource use cost as a percentage of gross benefits or total sales is usually fixed considering following factors:

- net economic benefits obtained by the user,
- opportunity cost of using the natural resource in the project and
- cost of mitigating probable negative socio-economic and environmental externalities in the project localities as well as to the national economy.

However, the royalty or natural resource use cost should not be more than the net benefits obtained by the developer; otherwise, the developer may be discouraged from investing in hydropower project, which is against the national objective.

At the initial stage of the use of natural resources, the actual royalty may be very low due to the small volume of production. During this stage the owner may charge a fixed minimum rent, irrespective of the level of sales revenue, based on its opportunity cost of using the resources in the particular project in order to escape from the owner's loss. At this stage, minimum rent is higher than the actual royalty. The difference between them is the loss of the user. No doubt, it can be recouped in future to restore the user's loss at the initial period. In principle, the owner is always entitled to get either the minimum rent or the actual royalty whichever is more. But the use of royalty system as a fixed minimum rent may have discouraging effect on the users at least during the initial stage of using the natural resource. Thus, it should not be the preferred option at least for hydroelectricity projects.

Since hydropower projects are site specific, the use of natural resources may not be identical between individual projects. Then, it will be an injustice to fix the same royalty for all types of hydropower projects. [28]

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[28] The Electricity Act, 1992 fixes the same royalty for all types of hydropower projects. According to the Act, any developer generating more than 1,000 kW has to pay royalty to the government. For 15 years from the date of generation of electricity, the capacity royalty will be Rs. 100 per installed kW of electricity per year and the energy royalty will be 2% of the average tariff per kWh. After 15 years, the capacity royalty will be Rs. 1,000 per installed kW of electricity per year and the energy royalty will be 10% of the average

For example, a storage project may use relatively more natural resources compared to a run-of-river project with similar installation capacity. Then the storage project naturally has to pay more royalty to the State and electricity tariff of the storage project may be relatively higher. In this situation, the storage project may be discouraged due to higher royalty. The storage project has extra benefits: non-power benefits in addition to power benefits. The project cost needs to be separated between the power and non-power users in relation with the power and non-power benefits. The adjustment of separated cost of producing the non-power benefits in total cost may reduce the hydropower price and the royalty may not increase the power tariff to that extent that may discourage the installation of storage project in the country. The royalty rate should be higher for a storage project than that for a run-of-river project if the project cost cannot be separated on the basis of the power and non-power benefits.

Two-part electricity tariffs (capacity and energy tariffs), depending on two-part costing for electricity supply, are mostly used as the power utility provides each of its consumers with two services: readiness to supply power (in kW) whenever required and the actual energy consumed (in kWh). For example the NEA consumers tariff system is based on the capacity allotted (i.e., the higher the rated ampere of the meter the higher the minimum monthly tariff) and the energy consumed. Similarly, two-part royalty: capacity royalty and energy royalty are used for social justice and for coverage of both costs: fixed and variable cost components. Since the quantity of natural resources held and subsequently used in hydropower generation in a storage project is higher than in a run-of-river project, it is reasonable that the capacity royalty be higher for a storage project. For example, in a run-of river plant any excess flow in the river (beyond the design discharge) is conveyed past the intake and is not utilized for power generation.

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tariff per kWh. Capacity royalty is not escalated. That means value of capacity royalty is going down every year in real term. Energy royalty is calculated as a product of energy generated net of station use, average tariff per kWh and energy royalty rate (percentage). That means energy royalty is charged on system loss also. Conversion of these rates in actual practice shows that the capacity royalty is nominal compared to the energy royalty. For example, in case studies of the projects taken in this paper, the capacity royalty varies from 2% to 8% of the energy royalty. However, it should be noted that The Electricity Act 1992 will have to be amended in the near future in line with the new Hydropower Development Policy 2001 (the first Hydropower Development Policy was promulgated in 1992).

However, in case of a storage project, depending on its storage capacity excess flows during the high flow seasons can be stored and utilized during the dry season. On the other hand, the energy royalty could be the same for both the storage and the run-of-river projects as energy royalty is based on energy sales.

The government has recently adopted the new Hydropower Development Policy, 2001 where major changes are incorporated in the electricity royalty.[29] These changes need to be harmonized with the

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[29] In the Hydropower Development Policy, 2001, energy royalty is fixed as a percentage of sales revenue of net energy generated. Capacity royalty is based on the installed capacity with an annual growth rate of 5% irrespective of size and purpose of the project.
Energy royalty = (Generated Energy – Self-consumption) x Average Selling Price x Energy Royalty Rate.
Capacity Royalty = Capacity Royalty Rate x $(1 + 5/100)^{(\text{Year} - 2001)}$ x Installed Capacity (kW).
Royalties are fixed for internal consumption and export-oriented projects as follows:

		Up to 15 years		After 15 years #	
Purpose of the Projects	Size of the Projects	Annual Capacity Royalty Rate per kW (Rs.)	Energy Royalty Rate per kWh (%)	Annual Capacity Royalty Rate per kW (Rs.)	Energy Royalty Rate per kWh (%)
Internal Consumption					
	Up to 1 MW	-	-	-	-
	1 to 10 MW	100	1.75	1,000	10
	10 to 100 MW	150	1.85	1,200	10
	Above 100 MW	200	2.00	1,500	10
	Captive Use Projects	1,500	-	3,000	-
Export-oriented up to 1,000 MW					
	Run-of-River Projects	400	7.5	1,800	12
	Storage Projects	500	10	2,000	15

After 15 years of commercial operation of the project.
For export-oriented projects of above 1,000 MW, royalties will be fixed on the basis of negotiation keeping in view the rates mentioned above.

existing Electricity Act, 1992 to give them a legal effect. The capacity royalty is now escalated with 2001 as the base year. The royalty rates are based on the size and purpose of the projects. The reason behind charging higher royalty for larger size of the project appears to be based on the assumption that both the marginal and average cost of the larger projects may be relatively low due to economies of scale in power generation and thus higher profits to the developer. However, this reasoning is yet to be verified as large scale projects to date are only built by NEA and these too under bilateral or multilateral donor aids. In such projects, the costs are also governed by the conditions of the aids which may negate the advantages gained from the economy of scale.

Similarly, the government has tried to tap the multiplier value of added benefits obtained by the importing countries by charging remarkably high royalties, both capacity and energy, for export-oriented projects. Though the government has fixed higher royalties for storage projects vis-à-vis run-of-river projects in the case of export-oriented ones, this differentiation is not yet recognized for internal consumption projects. Some anomalies and questions still remain on the subject of royalty that are discussed in the following paragraphs.

Fixing of royalties in reality is not an easy task. It must be admitted that royalties fixed, as per the Electricity Act, 1992 and the Hydropower Development Policy, 2001 have no rationale behind them. What should be the total royalty figure? It is a value judgement of the government considering the factors that are mentioned in section3.2 and it should not be more than the marginal net benefit to the developer.

Since the natural resources are used from the very beginning of the commercial operation till the end of the project life, the royalty in principle should be charged from the first year of operation till the end. It is not that lower amount of natural resources are used in the initial years and higher amount in later years for power production, i.e., generally equal volume of flows are used annually in hydropower plants. Even if there are fluctuations in the use of natural resources from year to year, it is automatically reflected in the energy produced, which is the basis for calculation of energy royalty. Hence, in principle the same rate

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Royalties from export-oriented projects will have to be paid in the currency of export sales.

of royalty should be charged from the beginning of the commercial operation till the end of the plant life. The only rationale for lower royalties during the first 15 years of operation and higher royalties thereafter, seems to be to attract developers to invest in the hydropower sector.

In Nepal, royalty is paid to the government in the form of cash while in India it is given in the form of free electricity. Both methods are good enough if one understands the benefits and shortcomings of each method. However, there should not be any rigidity in selecting the form of royalty payment. Selection of the form of royalty payment should be dictated by the needs and responsibilities of the government. Payment of royalty in the form of cash helps the government to utilize the fund so collected in the manner the government thinks best for the country. This fund can be used in any sector including the electricity sector. In Nepal, diversion of 10% of royalty payment in cash directly to the affected districts and proposed 1% of royalty payment in cash directly to the affected Village Development Committees (VDC) where power projects are located, for local development and rural electrification respectively, is an example of utilization of such fund. Similarly, as mentioned in the new Hydropower Development Policy, 2001, a 'Rural Electrification Fund' will be established by apportioning a part of the royalty payment for micro hydropower development and rural electrification. This method of payment of royalty is suitable where electricity price is not subsidized. Payment of royalty in the form of free electricity may be suited where the government feels it is its responsibility to expand the power system and to provide electricity at subsidized price. One has to realize that to bring and manage even free electricity to the doors of consumers costs money.

What should be the ratio of capacity royalty and energy royalty in the total royalty figure? In a sense, capacity (kW) and energy (kWh) of a hydropower project can be related to the head and the river-flow. And in calculation of both capacity and energy, both head and river-flow give equal inputs.[30] In other words, capacity and energy royalties should also take into account the "head" of a hydropower plant since as the head is

[30] $P = 9.8QH\eta$ and $E = Pt$ where P is the capacity or power in kW, E is the energy in kWh, Q is the discharge or river flow in m^3/s, H is the net head in m, η is the overall efficiency of the generating system and t is the time of power production in hours.

increased less flow is required to generate the same installed capacity (kW) and energy (kWh).

In a supply-surplus situation, is there a need to charge capacity royalty when it is known that a particular hydropower plant may not be operated at all? One may say that the consumers are being charged for the idle plant, as it has been build as a reserve in the power system, hence, capacity royalty should be charged. Other may say that without operating the plant no natural resource is being used at all, hence, no capacity royalty should be charged as no energy royalty can be charged in such a case. But the natural resource is booked for the purpose to be used at any time in future, hence, capacity royalty need to be paid even for an idle plant. It is like a utility collecting demand charge from the consumers in a two-part tariff system even though the consumers may not be consuming any energy.

In a hydropower project, separate emission benefit payment may materialise in the future provided that the Kyoto Protocol is ratified resulting in the implementation of the Clean Development Mechanism (CDM). In addition, in a multipurpose project, separate non-power benefit payment may also materialise. In such cases, the above benefits could be used in reducing the tariff. The question that then arises is - should energy royalty be reduced in proportion to the reduction in the energy tariff or should it be charged to the emission benefit and non-power benefit payments also in the same ratio as in the case of energy tariff? From the point of view of use of natural resources, it should be charged to both emission benefit and non-power benefit payments also, as they are other products besides power, arising from the use of natural resources. But the rates of royalty are related to the installed capacity and energy generation of the project and therefore, those making such payments may object to pay such royalty. In order to cover such eventuality, the royalty should be redefined when the Electricity Act (1992) is amended by relating it to the gross revenue of the project where such revenue may be earned from any source.

When a hydropower project generates and sells energy from the powerhouse end, then the calculation of energy royalty can be done as envisaged by the law, i.e., a product of energy generated net of station use, average tariff per kWh and energy royalty rate. But mostly, hydropower projects being located far from the load centers, will have their own transmission lines also as an integral part of the projects and the energy will be sold at the end of such dedicated transmission lines. And these lines will have inherent technical losses. In such cases, fixing royalty on the basis of tariff at the transmission line end and energy generation at the powerhouse end is not fair to the developer and ultimately, to the consumers. Energy available at such transmission line end should be taken for the calculation of energy royalty. That means system loss, i.e., transmission loss is not charged as part of the royalty. Hence, energy royalty should be calculated on the basis of the tariff and availability of energy at the same point of energy supply line.

This logic suits well in the case of powerhouse end or transmission line end, but in the case of distribution end; a problem arises due to the nature of the distribution losses. Transmission loss is purely an unavoidable technical loss but distribution loss is both the technical loss in the distribution system and non-technical loss due to unauthorized use of electricity. Had there been only unavoidable technical loss in the distribution system, then the calculation of energy royalty would have been easy. Taking end tariff to the consumers and energy available to the consumers would have given the energy royalty amount. But when non-technical loss is also present, then what should be the energy availability figure in the calculation of energy royalty? If it were the energy available to the consumers, then this figure combined with the tariff to the consumers would give an energy royalty amount less than what the government should have received. If it is energy available at the transmission line end, then this figure combined with the tariff to the consumers would give an energy royalty amount that is high and thus, the consumers will suffer. In such a case, the utility that distributes electricity and the government should reach an understanding on what percentage of the total distribution loss (which can be calculated) is technical and what percentage is non-technical. Energy royalty calculation should be done on the basis of considering the technical part of the distribution loss, i.e., energy availability will be net of technical part of the distribution loss. While non-technical part of the distribution loss would be charged as royalty, i.e., non-technical part of the distribution loss would not be deducted from the energy availability. This way it will be fair to both the consumers and the government.

The basic premise for above consideration is that unless the consumers can get the benefit from the use of natural resource, i.e., hydropower, no royalty should be charged to them. In the power system, technical losses are inherent during power production, transmission and distribution. It can be reduced to a minimum, but it cannot be totally eliminated. Therefore, the consumers will not be getting the benefit of hydropower to the extent that is equivalent to the technical losses in the system. Hence, the consumers should not be charged energy royalty on the technical losses. Non-technical losses are due to the inefficiency of the utility and with proper actions, these losses can be eliminated completely. Hence, energy royalty should be charged on non-technical losses.

4. Assessment of Benefits from Hydropower Projects

4.1 Benefit Types in Hydropower Projects

Benefits from hydropower can be classified as primary benefits, secondary benefits, employment benefits and public benefits. Primary benefits again can be further classified as direct benefits and indirect benefits. Hydropower projects may produce negative benefits as well which may be called disbenefits but such disbenefits are usually nominal compared to the positive benefits. It may not be possible to give monetary values to some of these disbenefits and hence, they cannot enter into the benefit-cost analysis. It should be noted that since disbenefits are basically the costs of negative impacts of the project, there is a danger that they may be included both as part of induced costs and as negative benefits. Hence, to avoid double counting, induced costs and disbenefits should be clearly defined for a particular hydropower project. For example, loss of agricultural land due to inundation may be classified as disbenefit, whereas cost of constructing a new town for rehabilitation of population in the inundation area can be termed as "induce cost". Similarly, it may not be possible to evaluate some of the benefits due to paucity of data. But it should be realized that they also need to be considered when taking a decision on a hydropower project. It should also be noted that some of the benefits may not follow just by building a hydropower project unless investments in non-power infrastructure are also made. In case of a storage project, for example, irrigation benefits cannot be realized unless a canal system is also developed. It should be noted that as discussed in Chapter 1, "benefits" in this report are taken into account only to evaluate the project, i.e., to determine whether and how much the benefits outweigh the costs. Benefits are not used in the pricing process. The pricing approach discussed here only looks at the production or cost side and does not take into account the consumption or benefit side.

One can also argue that there is a unique benefit of hydropower project in that it utilizes renewable natural resource – water as its fuel. This "renewability" helps limit the use of non-renewable resources such as fossil fuels in alternate thermal plants to produce electricity. Such fuels thus, can be conserved or diverted to other uses in the national economy. Assessment of such benefit will need an in-depth analysis in economic terms of all aspects of the national economy where such fuels are used.

Proper assessment of benefits becomes even more important when major project output is utilized in other country. When project output is utilized domestically it may be argued that the pricing need not consider some of the benefits such as secondary benefits, employment benefits, etc. as such benefits are to the nation and they help in achieving the desired social goals. As an opposite corollary to this argument it follows that such benefits must be considered in output pricing in the case of output being utilized by other country so that the nation constructing such hydropower project can be compensated for benefiting the other country.

Benefits in general follow in the operation phase of the hydropower project after completion of the construction phase. However, some benefits also occur during the construction phase. For example, 'induced-by' secondary benefit will occur during the construction phase due to backward production linkages. Employment benefits and public benefits will occur both during the construction phase and the operation phase.

4.2 Direct Benefits

Direct benefit from a hydropower project is the power produced. If it is a multipurpose storage project then other direct benefits also occur. These are irrigation, water supply, flood control, navigation, recreation, etc. Power benefit can be further differentiated into capacity benefit and energy benefit. Capacity benefit is the capacity (kW) of the hydropower project that can be produced at any time on demand. Energy benefit is the energy (kWh) generated by the hydropower project at a given period of time. Thus, capacity benefits are derived from the readiness of power supply while energy benefits are derived from the actual consumption of electrical energy. Direct benefits can be estimated either through the market value of the output produced or through the cost of producing the same output in some alternative manner. It should be noted that the market value estimate will underestimate the direct benefits obtained by the users even in a perfectly competitive market since many users are generally willing to pay more than the market price for the product. Prevailing market conditions may rob market price of its normative significance through external effects, natural monopoly, outside intervention (price regulation, for example), export-import restrictions etc. as is the case in hydropower pricing. In such cases, benefits are often taken as the cost of the second least costly alternative project. The reasoning is that if a demand for an output is sufficiently strong, it would be satisfied in the second least costly manner even if the least costly alternative were not built. The gross benefit equals the value of the stream of resources released by not constructing the second-best alternative.

In case of the hydropower project the alternative project will be an appropriate thermal plant producing same net output (capacity and energy) as the hydropower plant. Depending upon the size and type of the hydropower project the alternative may be an appropriate mix of thermal plants running on different fuels. Capacity benefit will be the cost required for the installation of the thermal plant while energy benefit will be the cost required for operation and maintenance of the thermal plant including fuel cost. In addition, in case of the storage project irrigation benefit will be the value of increased crop production in the existing irrigation system as well as in new irrigation system due to augmented flow in dry season. Water supply benefit will be the value of the water supplied in municipal and urban areas and rural settlements. Flood control benefit will be the value of the damages to land and structures saved due to non-occurrence of floods. Flood control could also save the lives of the people but it is difficult to attach a monetary value to it. Lives saved are usually quantified in monetary terms by using information on tradeoffs people make between fatality risk and monetary return (for example, in the labor market) to derive a value of statistical life (VSL). Since such value of life studies have not been done for Nepal, estimates of VSL must be imputed from results obtained in other parts of the world. Navigation benefit will be the value of the transportation of people and merchandise in the lake behind the dam. Navigation benefit will also occur in the downstream reaches of the river below the storage project if the river is made navigable by regulated flow from the project. Recreation benefit will be the expenditures incurred by people to enjoy outdoor recreation in and around the lake.

4.3 Indirect Benefits

Indirect benefits from a hydropower project mainly include environmental and health benefits from the reduction of emissions that would otherwise result from an alternate thermal plant producing the same net output as the hydropower project. These benefits derive from two sources—a) reduction of primary pollutants that affect the local environment (including health and property of the population), and b) reduction of greenhouse gases such as CO_2 and SO_2 that affect the global environment. The possibility of capturing the global benefits from the reduction of greenhouse gases through global trading of emissions credits will be discussed briefly in the later section. Indirect benefit may also result from the economic consequences of the project output or its use. For example, flood control from a storage project may benefit the users of transportation and communication systems by reducing interruptions and reduce the wages lost by workers when flooding closes industrial plants. Irrigation may reduce dust storms particularly in the arid region.

4.4 Land-Enhancement Benefits

Another indirect benefit that may result form a hydropower project (especially multipurpose projects) is land-enhancement benefits. Such benefits result when a more productive land use is made possible by the hydropower project. For example, flood control from a storage project may enable a switch from a lower-value crop to a higher-value crop in the flood plains. Agricultural land may be converted to urban development and land productivity may increase due to flood protection. Value of land in urban areas surrounded by newly irrigated land may be enhanced. Enhancement of land values along the lake behind the dam may also be considered as land-enhancement benefit though some analysts may consider it as recreation benefit.

4.5 Secondary Benefits

Secondary benefits from a hydropower project result from its backward and forward production linkages with the different sectors of the economy. Within any economy, each industrial sector both sells its output to other sectors (forward linkage) and buys inputs from them for its own production (backward linkage). Thus, each sector is directly or indirectly linked with all the other sectors through these purchase-sales or input-output relationships. The actual computation of secondary benefits is a rather complicated process that requires detailed disaggregated data on the input-output relationships among the various sectors of the economy.

Backward linkages produce benefits to the sectors that provide goods and services to the industry in question both directly and indirectly. For example, when there is an increase in the demand for a sector's product, the sector initially produces output equal to the demand change. This increase in output is known as the direct impact of the demand change. But since the sector requires inputs from other sectors to produce this output, and the other sectors subsequently require inputs themselves, there will be multiple rounds of interaction among the sectors resulting in additional output from each sector of the economy. These additional impacts are known as indirect impacts. When wages and salaries paid to households and the expenditure of households on different goods and services are also incorporated in these multiple rounds of interaction, there are still further impacts on sectoral outputs. Such impacts are termed induced effects. The sum of the direct, indirect, and induced impacts of the change in the demand for an industry's output constitute the total benefit from backward linkages. The net benefit from backward linkages is the total benefit minus the loss of output of those industries that can no longer provide inputs to investments displaced in the process. Similarly, forward linkages produce benefits to the sectors that directly or indirectly use the output of the industry for their own production. The net benefit from forward linkages is the direct, indirect, and induced multiplier effects of these sales relationships minus the total output loss experienced by sectors that process output displaced directly or indirectly by the industry. The net benefit from these backward and forward linkages in the economy can also be expressed in terms of employment and income to individuals and households since output, employment and income are closely related concepts. In this report, the employment benefits are discussed separately because of the special importance of jobs from a socio-economic perspective.

Backward linkage benefits from a hydropower project arise primarily during the project's construction phase. Since only limited industrial inputs are required to run a hydropower plant after starting operation, backward linkages during the project's operation phase are quite limited. In the context of Nepal, the scale of the project plays a particularly important role in determining the extent of backward linkages during the construction phase.[31] While Nepali companies are capable of building

[31] Pandey, B. (1996). "Local Benefits from Hydropower Development," *Studies in Nepali History and Society*, 1(2): 313-344.

smaller scale projects, large scale projects such as those being considered for hydropower export purposes are beyond their reach. Furthermore, these large-scale projects require complex machinery and other inputs that have to be imported from abroad. Past experience with large hydropower projects built by the National Electricity Authority with foreign aid shows little evidence of substantial backward linkages into the national economy.[32]

The bulk of the linkage benefits from hydropower should come from its forward linkages with the various domestic industries, including extractive, manufacturing and certain service industries such as tourism. Electricity availability alone is not, of course, a sufficient condition to spark industrial development. But it definitely increases the possibility of industrial growth if the energy can be supplied at a competitive price. The benefits to the nation from these forward linkages are, however, lost in the case of hydropower developed primarily for export. These losses must, therefore, be taken into account when the export price of electricity is determined (also refer to sections 6.3 and 6.4).

4.6 Employment Benefits

4.10 Employment benefits denote the economic value gained from the increased employment opportunity from new jobs created to construct, operate and maintain the hydropower project. A related effect is the increased employment opportunity induced by the project output. Project output may also stimulate investment opportunity on the farms and in the industries and within the communities where it is used. It is important to note that since employment is directly related to the outputs of the different sectors of the economy, there is a danger of double-counting output benefits when the value of employment is estimated. Hence, the monetary valuation of employment must be done with proper caution. Some analysts may prefer to include employment benefits as a part of public benefits.

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[32] Pandey, B. (1996). "Local Benefits from Hydropower Development," *Studies in Nepali History and Society*, 1(2): 313-344.

4.7 Public Benefits

Public benefits are realized in the achievement of secondary goals such as economic stabilization, income redistribution, regional development, social equity and justice, etc. Construction and operation of a hydropower project can promote regional development, as the project site is usually located in a remote and underdeveloped area. Improvements of health and education due to supply of electricity are a part of social equity and justice.

4.8 Disbenefits

Disbenefit from a hydropower project is mainly the permanent loss of annual agricultural and forestry products from the land utilized by the project. Though there will be compensation for the land so utilized at market price or with similar parcel of land elsewhere. Such compensation is at owner's or individual's level to provide the displaced person/family with an alternative source of income. However, the value of the products from such land utilized by the project is lost forever at the national level. Since economic analysis is done from a national perspective such disbenefit need to be taken into account in the analysis. A storage power project may have other disbenefits. Decayed vegetation from the lake may produce greenhouse gases and sediment free water downstream of the dam may scour the river embankments. Emission of greenhouse gases from decayed vegetation from man-made lakes is a subject matter of extensive study and once such effect is established these values can be taken into account in the economic analysis as in the case of thermal plants. Complete mitigation of environmental impacts by the project may not be possible and some environmental impacts may have to be tolerated for the sake of overall total net benefit from the project. Some analysts may prefer to take disbenefits as a part of the project cost[33].

4.9 Distribution of Benefits

The distribution of benefits from hydropower development depends on four factors—a) the tariff structure, b) the link between hydropower

[33] It does not make any difference in the case of calculating net benefit but in the case of calculating benefit/cost ratio, taking disbenefits as a part of cost stream will produce comparatively lesser benefit/cost ratio than taking it properly as a part of benefit stream.

development and local development, c) the distribution of human and physical capital among the population, and d) revenue distribution policies of the government.

One way to address the issues of social equity and distributive justice directly is by devising a tariff structure that is pro-poor. The existing tariff structure in Nepal does indeed favor the poorer segments of the society by charging higher rates to consumers who use more electricity. This approach to helping the poor could, however, be inefficient from an economic efficiency perspective since charging higher rates to larger consumers lowers aggregate demand. Similarly, as indicated in sections 2.4 and 4.7, requiring projects to incorporate local development and rural electrification in their plans can further boost local and regional development and have a positive impact on the lives of the poor, especially when the project is located in remote and underdeveloped areas. The impact of such requirements on potential investors is, of course, a major issue as additional costs is involved.

The distribution of human and physical capital among the population determines how secondary benefits, including employment benefits, get distributed among the population. For example, who benefits how much from enhanced productivity of the land due to a storage project depends on how the land is distributed in the first place; the owners of larger tracts of land in the irrigated areas will enjoy larger net benefits than smaller farmers. Similarly, the induced benefits from increased industrial production go largely to the owners of physical capital. As for the benefits going to workers, the distribution is heavily skewed towards those employees with higher levels of education and skills (human capital). Hence, the distribution of secondary benefits depends largely on the overall socio-economic structure of the society.

Finally, the government's policies regarding the redistribution of tax and royalty revenues earned from hydropower projects also play a crucial role in promoting distributive justice. Although the Nepali government does not yet have schemes aimed at redistributing hydropower revenues to poor households, the Hydropower Development Policy 2001 does have some limited provisions for redistributing benefits to the poorer geographical areas. More specifically, it stipulates that 10% of the total royalty received from a hydropower project should be transferred to the District Development Committees (DDC) of the districts affected by the construction of the project. If the government were to implement a more comprehensive and efficient redistributive scheme, then it may not even be necessary to rely on the current distortionary tariff structure to help the poorer segments of society.

5. Allocation of Costs in Multipurpose Project

5.1 Multipurpose Project

A water infrastructure project which stores large volumes of water behind (upstream of) its dam and where such waters are used for various other purposes besides power generation, e.g., irrigation, drinking water supply, recreation etc. is known as a multipurpose project. A storage hydropower project will have an inherent quality of flow regulation in the downstream reaches due to storage of water during low power demand season and its release during high power demand season. This feature produces other direct benefits also such as irrigation, water supply, flood control etc. Such project is therefore, termed as a multipurpose project though its basic function remains as production of power. Similarly, a storage irrigation or water supply project may be termed as a multipurpose project where power generation is strictly controlled by the quantum of flow released for irrigation or water supply purpose. In such cases, naturally the question that arises is that what proportion of the costs should be allocated by the various benefit components (e.g., power, irrigation, flood control etc.) of the multipurpose project.

5.2 Need for Cost Allocation

Whenever a project produces multiple outputs, its total cost needs to be divided among the respective project purposes so that proper pricing of the outputs can be done. Often, the cost of a single purpose project also needs to be divided among responsible groups. The procedure for dividing the total cost of a project among the respective project purposes is called cost allocation. The allocation of cost among various benefit components may be called cost sharing. Such cost allocation is needed to decide how much each beneficiary group of each purpose must pay to use one's output based on the 'Beneficiaries Pay' principle. If such cost allocation is not done then the total cost of the multipurpose project will be loaded to the main output user group, which is the user of electricity in the present context. In other words, the electricity users will be subsidizing the other users such as irrigation users, water supply users, etc. In the long run, all the users will not be using their products efficiently, i.e., electricity users will not be utilizing electricity to its optimum use and other users will be utilizing water excessively than needed. Such situation will eventually produce distortion in the national economy through the "unoptimized" use of water resources.

Cost allocation becomes even more important when outputs of a multipurpose project are shared between two or more countries. There might be a situation where one type of output is used by one country while other country uses other type of output. There might be a storage project in a country where power produced is totally exported while irrigation water or other outputs are totally consumed within the country or shared by the two countries. Reverse case may also occur where power produced in a country is totally consumed domestically while other outputs are totally used in the other country or again shared by the two countries.

5.3 Allocation Methods

In cost allocation, there is no unique and correct method. A look at current practice shows that there is no standardized method either. Nevertheless, the basic goal of a development project such as hydropower is achieving improved social and economic efficiency. Cost allocation affects the price of project output. Price affects use. Efficient use occurs when price equals marginal cost. Price affects income distribution. Thus, cost allocation directly affects social and economic efficiency.

In a multipurpose project, each distinct physical feature of the project such as powerhouse, tunnel, etc. is called a project element. Direct costs are the costs of project elements serving only one particular purpose. For example, powerhouse with generating equipment is the direct cost related to power output only. If a project element serves more than one purpose, the difference in its cost with and without serving a purpose is the separable cost of that element with respect to that purpose. For example, the separable cost of power in a dual-purpose power and irrigation project is the cost of the dual-purpose project less the cost of a single-purpose irrigation project. Conversely, the separable cost of irrigation is the cost of the dual-purpose project less the cost of a single purpose power project. Economies of scale and complimentarity among project purposes will normally cause the sum of the separable costs to be less than the total project cost. The difference between total project cost and the sum of the separable costs is the non-separable cost. Now this non-separable cost needs to be allocated among various purposes.

Such non-separable cost can be allocated by many methods. It can be divided equally among the purposes, but it would shift a large share of the cost to minor purposes. It can be divided according to the amount of facility use that would require finding an acceptable unit of use. But in a multiple-purpose hydropower project there are many facilities whose uses are expressed in different units. Entire non-separable cost can be allocated to the priority purpose, but it would hardly be fair to make one purpose bear the whole cost. Non-separable cost can be divided proportionally to the net benefits where the net benefits equal the gross benefits less the direct costs assigned before allocation. Allocation by benefits has great appeal because of inherent fairness in it provided benefits can be calculated in a clear and concise manner. Still, it poses several problems. Should all benefits be used or just direct benefits? Secondary benefits accrue to the general public rather than to the output users. Is it fair to make those directly served pay for the benefits they do not receive? The imprecision in the benefit calculation means benefits will vary widely according to the method of benefit evaluation used. Non-separable cost can also be divided proportionally to the excess cost of the cheapest alternative that can provide the same output. It avoids the calculation of benefits that cannot be adequately defined or that are largely intangible in nature. However, difficulty in defining proper alternatives makes the method subject to abuse. The other method is to combine the last two methods and allocate the non-separable cost by the smaller of excess benefits or excess alternative costs. This method thus, combines the best features and eliminates some of the worst features of the last two methods.

In a multipurpose project, the chosen allocation method may also depend on the level of study and analysis done for the alternative projects that give the same outputs individually as the single multipurpose project under consideration. Usually, a storage hydropower project is optimized for maximum net (power) benefit though topographical and geological constraints also play a large part in project size selection. Other benefits like irrigation, flood control, etc. can be said to be a bye-product of that decision. Analysis of alternative project that gives the same power output as the multipurpose project is invariably done but analysis of alternative projects that give the same irrigation or other outputs may not have been done. In such a situation, it may not be possible to evaluate separable costs and non-separable cost. But direct costs can be evaluated. The difference between the total project cost and the sum of such direct costs is the residual cost or the common cost. Instead of non-separable cost, this residual cost can now be allocated according to the chosen method. As alternate project analysis to serve other purposes than power is not usually done, the residual cost can be allocated according to net benefits.

6. Key Issues in Hydropower Pricing

6.1 Power Pricing Approach

At present, hydropower projects with different ownership structure such as: public, private, public-private partnership, domestic-foreign partnership and foreign investor are allowed in the country to meet domestic as well as foreign demand for power. Although, a single developer no longer monopolizes hydropower generation, the environment is still far from competitive. Since a hydropower project is highly capital intensive, it needs to have a long-term interest of increasing or expanding its share of the market. In the long run, the optimal allocation of resources for a project is achieved when price (or marginal revenue) is equal to marginal cost. The "marginalist approach" of setting the short-run marginal cost equal to marginal revenue to maximize short-term profit, on the other hand, does not meet the interests of hydropower projects since the short-run marginal cost curve does not take into account the capital costs. Furthermore, it is difficult to estimate the marginal revenue due to insufficient information on consumer demand. Hence, although the demand side is important, it does not play a leading role in the determination of wholesale electricity price in practice.

So far as the selection of pricing approach is concerned; most of the industries at present use cost-plus pricing approach to fix the price of their products.[34] Hydropower projects also use this approach to fix the prices of their product. In this approach, a firm sets its desired price equal to its total average cost plus a certain net profit margin.[35]

In this study an effort is made to fix the price only from the supply (mainly generation) side of the power just before the entry to its markets: domestic or foreign. This is the desired or planned or budget price to offer for sale of power in the market. Consumers' behaviour is still unknown. The price is a wholesale price. The actual tariff will be later determined by the equality between the demand and supply of the product in the market. Therefore, the desired price needs not tally with

[34] Price in this Section refers to the desired, planned, budget or mark-up price.
[35] Symbolically, P = AVC + AFC + NPM, where, P = Price, AVC = Average variable cost, AFC = Average fixed cost and NPM = Net profit margin, which is fixed on the basis of past experience or practice.

the equilibrium price in future. The continuity of the project depends on the fulfillment of the condition that equilibrium price is not less than the desired price if the firm does not have the possibility to reduce the net profit margin.

6.2 Avoided Cost versus Cost-Plus Pricing Approaches

The cost-plus price is, actually, the supply price, which may not necessarily coincide with the demand price. The demand price is based on the user's (consumer's) willingness to pay. But from the developer's point of view, cost-plus pricing is good as it guarantees minimum reasonable profit. No doubt, profit guarantee may be possible only if there is sufficient demand for the power. However, this approach may be taken as the starting point for price bargaining with users in a competitive market, at least in the initial period. Some economists believe that under the cost-plus pricing, power generation with high cost generates higher profit and vice versa because profit margin is estimated as a certain percentage of total cost. An increase in cost of production is, in turn, due to an increase in production inefficiency. Thus, cost-plus pricing rewards the inefficient production management[36].

The avoided cost of producing the power is the cost of producing the power through next alternative production technology, which is just avoided. The present production technology may be followed only in that case if the actual cost of production is lower than the avoided cost. The difference between the average cost and average avoided cost is the average net benefit of selecting the present production technology. The hydropower pricing based on the avoided cost ignores the actual cost structure of hydropower production. It is worth mentioning that in the avoided cost pricing approach the production efficiency is not linked with the avoided cost because this cost is not related with the actual cost of production. Therefore, the pricing based on avoided cost is not realistic if it is used alone. Besides, the avoided cost of generating power in power importing country is also difficult to estimate by the power exporting country due to lack of sufficient data, which is required for fixing the price of power export.

The avoided cost price is usually used to reap the net benefit from technological change in hydropower generation. Thus, the developer can

[36] This is known as the Ayear-Johnson effect.

seize the user's or consumer's surplus by using this pricing approach. No doubt, this net benefit will gradually reduce to zero, when the price based on avoided cost converses to the price based on cost-plus. This conversion may happen with the increase in power supplied either by the same developer or by his rival producers using the same production technology. Both pricing approaches: cost plus and avoided cost will gradually converse to the market equilibrium price or competitive price in the long run if the market becomes competitive. Therefore, the power developer should fix its price considering both cost-plus and avoided cost approaches at least to start with price bargaining with power users, who bargain on the basis of willingness to pay.

6.3 Need for Consideration of Economic Aspects

An equilibrium price is the agreed price by both the hydropower suppliers and the hydropower users. Price is the motivating factor for the hydropower suppliers to meet the demand on one hand, and on the other hand it is a tool for an efficient demand side management in the different uses of hydropower (i.e., efficient utilisation of the hydropower minimising its wastage). In the past, it was a common practice to consider only the financial aspects in fixing the hydropower price because socio-economic and environmental impacts of the hydropower projects on people and the surroundings were not paid sufficient attention. Non-monetary benefits and costs of hydropower projects were simply ignored.

Recent development on the project evaluation has stressed on the internalization of non-monetary or social costs and benefits along with the consideration of monetary value of costs and benefits. The economic analysis of the project investment has started to include the analysis of both monetary and non-monetary (social and economic and environmental) aspects. The consideration of socio-economic aspects is a must for, at least, public sector investment on any project because the responsibility of the public sector is more related with the economic welfare of the people. It is also the responsibility of the State to analyze the socio-economic impact of the new project launched by the private sector on the society. Economic analysis of any project is differentiated from its financial analysis due to some discrepancies. The sources of discrepancy may be, among others, market imperfections (due to rationing, minimum wage rate policy and foreign exchange rate policy), externalities (both positive and negative), taxes and subsidies, differential value on savings and consumption, distribution of benefits across different groups in the society, and merit wants (social goals and preferences). Besides, the implementation of a project usually influences the people (employees, consumers, proprietors, local inhabitants, local authority, general public or the government), location, nature and quality of products and as well as contemporary politics.

The objectives of economic considerations are, among others:

- to identify and measure the net non-monetary (social) contribution of an individual hydropower project, which includes not only the social costs and benefits internalized by the project, but also those arising from externalities and affecting different social segments and
- to help determine whether an individual project's strategy and practices, which directly affect the stocks of resources and status of individuals and communities, are consistent with social priorities on the one hand and individual's aspirations on the other.

In the process of determining the hydropower price, both full costs and full benefits of the hydropower project should be considered. The full costs consist of associated costs (production costs which includes the costs of land, engineering structures and equipment and their operation and maintenance), induced costs (costs needed to mitigate the adverse impact produced by the economic as well as environmental externalities of the project on nature, people and existing ground conditions), external costs (costs needed for smooth construction and operation of the project) and opportunity cost associated with the alternative use of the natural resources.

The economic values or benefits from a hydropower project consist of direct benefits (i.e., benefits from the hydropower project such as: power and non-power benefits like, irrigation, flood control, water supply, navigation and recreation in case of multipurpose storage hydropower project), indirect benefits (such as: emission credit or carbon credit benefits,), land-enhancement benefits, secondary benefits from the forward and backward production linkages in the economy, employment benefits and public or social benefits from income redistribution, regional development, social equity and justice, etc.

Similar to other products, the tariff (equilibrium price) of hydropower is the price where long run marginal benefit equals the marginal cost. Economic efficiency or total net benefit to the society is maximized at this price, i.e., the difference between the total benefits to the consumers at this price and the total costs incurred in hydropower production will be maximum at this price. As a result of social and political pressures, it may be the reverse case, i.e., full benefits may be lesser than the full costs in certain unestablished situation. Hence, although the price determined using the approach outlined in this paper is based on costs, it is also important to analyze the benefits and costs to make sure that the former outweigh the latter. Besides, the regularity in the supply of hydropower products also influences the hydropower price.

Hence, it can be concluded that both monetary and non-monetary costs and benefits should be considered in hydropower pricing. The benefits should include not only power but also non-power benefits of the hydropower project. Then, consumers of hydropower will not be overloaded with the high tariff and the prices of other non-power benefits are subsidized at the cost of hydropower consumers. Social justice among the consumers of power and non-power benefits will be achieved. Thus, the consideration of economic (financial and non-financial) aspects helps to fix a realistic, affordable and competitive hydropower price.

6.4 Application of Export Premium

Comparatively, Nepal has a very large potential for producing hydropower. But the existing domestic electricity market is too small to fully exploit the existing hydropower development potential. The northern part of the neighboring country, India is suffering from power deficit. These above-mentioned situations encourage implementing export-oriented hydropower projects in the country. Hydropower export may be one of the major sources of foreign currency earnings as well as balancing the recurring trade deficit with India.[37]

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[37] In 1999-00, India's share in total foreign trade of Nepal was about 40% and trade deficit with India was Rs. 18.3 billion.

However, there is also another school of thought that advocates the export of value-added products by using power as a raw material instead of exporting power itself. There is no denying the fact that exporting value-added products will benefit the country more than exporting power itself. Clearly, compared to the impacts of an export-oriented hydropower industry, the multiplier effects (output as well as employment and income) of local value-added products will be much more significant. From a poverty alleviation perspective, strategies that seek to enhance the income generating potential of individuals through the development of the nation's productive capacity are always preferable to strategies that rely on income transfers. Hence, compared to an export-oriented energy policy, which generates cash income without necessarily increasing the productive capacity of the nation, a policy promoting domestic industrial development using hydropower would be more consistent with the nation's poverty reduction goals. It should also be pointed out that unlike manufacturing industries that generate and redistribute income through employment possibilities, large export-oriented hydropower projects will not directly address the issue of income redistribution and social justice. The export earnings from this type of project will be captured first by the distributor, and then by the government through the application of taxes and export premiums. Hence, the government also needs to have clear provisions for appropriately redistributing the earnings from export-oriented hydropower projects. Focusing on value-added products—whether for export or for internal consumption—will, furthermore, enhance the competitiveness advantage of the economy in the long run through the "learning-by-doing" process. It would, therefore, be worthwhile to seriously consider promoting hydropower development alongside industries whose competitiveness could be significantly enhanced if cheaper hydropower were made available. It is just the question of amount of investment and its timing. It may not be possible for a country like Nepal to initially attract funds for both large-scale hydropower projects and large-scale, export-oriented industries that consume the power. Once a track record has been established in attracting funds for large scale export-oriented hydropower projects, it would be easier to attract funds for large-scale, export-oriented industries that consume the power.

One more school of thought advocates the development of hydropower projects only for the domestic need and wait for an opportune time to develop export-oriented projects when there is a good export market price. It is true that the present subsidized market price for power in India is not conducive for development of export-oriented hydropower projects in Nepal. But export-oriented hydropower projects are not going to come quickly. They need lengthy preparation (studies, design and construction) and negotiation between the parties concerned. If one starts preparation for an export-oriented hydropower project now, it will take almost a decade for a medium size hydropower project (up to 1000 kW installed capacity) to materialize and much longer time for a larger project (i.e., thousands of kW of installed). Meanwhile, the Indian power situation is expected to improve, particularly in the tariff and institutional reform fronts, as the Indian government is fully aware of the serious situation its power sector is in. Therefore, one has to start now in preparing for an export-oriented hydropower project to take the benefit of open and competitive power market in future India.

Economic effects of hydropower projects for domestic supply and export on the national economy are different especially in terms of secondary benefits. Secondary benefits in hydropower projects result from forward and backward production linkages. Secondary benefits of hydropower projects for both domestic supply and export resulting from backward production linkages (to the extent of utilizing local goods, material, equipment, labor, manpower, etc.) will be in the economy of the producing country itself. Secondary benefits of hydropower projects for domestic supply resulting from forward production linkages are in the economy of the producing country as well. But the importing country will reap secondary benefits of hydropower projects for export resulting from forward production linkages. In other words, the importing country through extending the forward production linkages in its country will reap the economic multiplier effects of imported hydropower. Thus, economic multiplier effect of hydropower project for domestic supply on the national economic development is higher than that of export-oriented hydropower project. This leakage in the multiplier effect of exporting the hydropower can be compensated to some extent through imposing a premium on export of hydropower. The term export premium rather than export tax or duty is more suitable. In other words, the export premium equals the opportunity cost of exporting the power instead of supplying it in the domestic market. The reasons behind using the export premium are as follows: (1) The concept of export tax or duty is more suitable if it is imposed for government revenue and is used as a measure to control its export in order to increase the supply of the hydropower to meet the domestic needs. (2) " Since Nepal has also joined the World Trade Organization (WTO), the imposition of export tax or duty may be a controversial issue if, in the future, the country decides to open its hydropower market.

In the Electricity Act, 1992 there is a provision for export duty. According to the Act, the export duty on hydropower is to be fixed by an agreement between the government and the exporter. However, in the new Hydropower Development Policy 2001, both the capacity and energy royalties for export-oriented projects are fixed remarkably high compared to the royalties for domestic consumption projects. The reason for this appears to be to also include export premiums in the royalties for export-oriented projects. Therefore, there is no mention in the new Hydropower Development Policy 2001 regarding export tax or export premium separately for export-oriented projects. This might be one solution to cover the compensation of lost of secondary benefits from the export of power provided that the difference between the royalties of domestic consumption and export-oriented projects does cover the export premium sufficiently. An alternative solution is to fix the same royalty rate for both type of projects: domestic consumption and export-oriented ones and charge additional export premium from the export-oriented projects.

It is the considered opinion that royalty for both domestic consumption and export-oriented projects should be the same because the royalties for using the same volume of natural resources for both the projects are the same. However, the secondary benefits to the nation from domestic consumption project are higher than that from export-oriented project of the same size and type. To reap equal total benefits from these two types of projects, the loss of secondary benefits by exporting the power should be compensated through the imposition of export premium. It is in fact justifiable and reasonable. Thus, it would be justifiable to collect both royalty and export premium from export-oriented hydropower projects at the currency of electricity trading. However, the difference between royalty and export premium should be clearly recognized. Royalty is the surplus or rental value including opportunity cost of utilizing the natural resources of the nation to produce hydropower. Export premium is in lieu of the secondary benefits lost by the nation by exporting hydropower.

To date Nepal has not exported hydropower in a substantial way except under the power exchange agreement with India along the border. Such exchange of power can be termed more as a barter trade. The first export-oriented hydropower project taken in Nepal is the West Seti Hydroelectric Project by a private sector developer.[38] In this project the developer and HMGN have reached an agreement whereby, the developer will supply 10% of the gross energy generated by West Seti to HMGN in lieu of export duty by constructing anther dedicated hydropower plant.

The royalty should be excluded from the total cost while calculating the export premium amount (in both cases of royalty payment, i.e., either in the form of cash payment or in the form of free electricity). Export premium should be paid as a percentage of gross revenue from export of power/energy, net of royalty. The logic is that royalty can be taken both as cash or free power/energy. The export premium should remain the same in both the cases. Only difference is that taking royalty as cash enters the cost stream and taking as free power/energy enters the revenue stream in the financial analysis.

Fixation of export premium in case by case basis may be untenable in the international trade though it is implied in the Electricity Act, 1992.[39] The concept of export premium as a compensation for the lost secondary benefits by the nation resulting from the forward production linkages in another country also implies that there can be only one kind of export premium. There cannot be two different kinds of lost secondary benefits due to two kinds of export of power – either by storage project or by

[38] This is a 750 MW storage project in the Far Western Region of Nepal. It will generate annually 3,137 GWh of energy and will cost about US $ 811.6 million at 1997 price. The government has signed a Project Agreement and an Export Agreement with the developer, SMEC West Seti Hydroelectric Corporation Ltd. in 1997 for the development of and export of power from this project. It is understood that the developer is negotiating with Power Trading Corporation, a government-owned entity of India for export of power, which is to be fed to the Northern Regional Grid of India.

[39] There cannot be any discrimination among the parties or countries in fixing export duty or import duty on commodities to be exported or imported respectively, according to the WTO to which Nepal is trying to become a member.

run-of-river project. Royalty is taken care of in the two kind's projects by charging higher royalty for storage projects. Thus, the export premium could be fixed as a standard percentage of the gross revenue from hydropower export net of royalty. As has been decided in one case, that percentage figure (10%) should be applicable for all such future projects.

When a multipurpose hydropower project realizes non-power revenue separately and thus, power revenue is proportionately reduced, one might ask what should be the export premium. Even then export premium has to be applied on gross revenue realized from all uses, be it power, irrigation, flood control, etc. because secondary benefits will be realized in all the cases. Export premium on non-power revenue can be looked at as a premium on export of regulated water that has created non-power benefits. Hence, export premium should be applied to gross revenue from all sources net of royalty.

6.5 Application of Emission Trading Benefits

Since the last two decades the adverse effect of 'greenhouse gases' on the world climate has been recognized.[40] Concrete steps to control the emission of such greenhouse gases started only from 1992 when United Nations Framework Convention on Climate Change (UNFCCC) was signed. It has come into force in 1994. Almost all the member countries of the United Nations including Nepal are signatories to it. In the UNFCCC, 38 developed countries have committed themselves, inter alia, on the mitigation of climate change by limiting their anthropogenic emissions of greenhouse gases. It was followed by the Kyoto Protocol in 1997. This Protocol introduces the concept of emission trading. As of 11 December 2001, 105 countries have signed and 46 countries have ratified or acceded to the Kyoto Protocol. Nepal has not yet signed this Protocol. Except for Maldives and Bangladesh other member countries of SAARC also have not signed the Protocol either. The coming into force of this Protocol in the near future has become doubtful due to the

[40] 'Greenhouse gases' are those gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and re-emit infrared radiation. CO_2 is the most prevalent greenhouse gas. Unit of measurement of such greenhouse gases is gram of CO_2 equivalent.

reluctance by USA in ratifying it.[41] Leaving aside this issue, it should first be understood how the emission trading works.

Under the Kyoto Protocol the developed countries have committed to reduce their emission of greenhouse gases by at least 5% below the 1990 level in the commitment period 2008 to 2012. Demonstrable progress has to be shown by 2005 in achieving their commitments. Certified emission reductions from 2000 to 2008 can be used in achieving compliance in the first commitment period. Besides taking domestic actions in reducing their emission of greenhouse gases the developed countries can comply with their commitments by acquiring emission reduction units from other countries, particularly developing countries. Such reduction can be achieved by adopting 'Clean Development Mechanism' (CDM). Hydropower generation is one such mechanism. It displaces alternate thermal plant emitting greenhouse gases that would have otherwise occurred. A party developing a hydropower project can transfer the amount of greenhouse gases that would have otherwise been emitted by an alternate thermal plant to another party that needs to reduce its emission of greenhouse gases. Such transferred amount of greenhouse gases is then counted as a part of another party's commitment to reduce its emission of greenhouse gases. Both public and private entities can be such parties. Converting such amount of greenhouse gases into monetary terms creates emission trading. Emission trading needs the approval of both the parties and emission reduction has to be certified by a competent authority.

There are many issues involved in the practicality of emission trading. First, the Kyoto Protocol has not yet come into force. Even after it comes into force, it is not clear whether parties not signatory to it can do

[41] Kyoto Protocol will come into force when not less than 55 countries incorporating 38 developed countries as listed in the Convention, which account for at least 55% of the total carbon dioxide emissions for 1990 of these developed countries, have ratified the Protocol. Among developed countries only Romania representing 1.5% and Czech Republic representing 1% of the required 55% emissions that would bring the Protocol into Force, have ratified the Protocol. The USA, the country with the largest emission of greenhouse gases (33.3%), has declared that the country is withdrawing from the Kyoto Protocol citing its national interest of having energy security. And Japan, the country with the third largest emission of greenhouse gases (6.7%), is reluctant to ratify unless the USA reenters the Protocol. The last Conference of the Parties to the Convention have agreed to revise the level of reduction to be achieved from 5% to 2% and allowed Russia, the country with the second largest emission of greenhouse gases (16.8%) some concessions. It is now hoped that the Kyoto Protocol will be ratified in due course of time.

emission trading. Second, it is not clear what will be the mechanism for payment in emission trading. Developed countries may like to pay after certification of emission reduction annually during operation of the project while developing countries may like to get a lump sum amount representing the emission benefit in the life of the project in the beginning of the construction to ease the financial burden. Third, in export-oriented hydropower project it is not clear who will trade emission reduction units, the producer in one country or the consumer in other country. Producer may argue that due to its project, emission benefit is occurring while the consumer may say that unless he consumes energy there is no energy production and hence, no emission benefit. Fourth, though the Kyoto Protocol is clear that even private parties can do emission trading it is debatable whether such benefit should go to the private investor or to the nation. After all, it is the use of the natural resource of the developing nation that is helping the developed nation to comply with its emission reduction commitment under the Kyoto Protocol. Resolution of all these issues and reaching consensus will take time as all decisions under the UNFCCC or the Kyoto Protocol are to be taken on consensus. Hence, application of emission trading in financial analysis of hydropower pricing at present time does not seem practical though emission benefit is being considered in economic analysis. One may even question the consideration of emission benefit in economic analysis unless issues enumerated above are resolved satisfactorily.

Apart from the practicality issues discussed above, a crucial question is whether or not hydropower projects in Nepal can qualify as CDM projects. There are a number of eligibility criteria that have to be fulfilled by a project before it can be certified as a CDM project by the CDM Executive Board. The first criterion is that the technology used by the project should not be in the excluded technology list of the Board. As only nuclear power projects have been specifically excluded so far, hydropower projects can easily pass this eligibility test. The second criterion requires that the project contribute to sustainable development in the host (developing) country. Within the context of Nepal, hydropower projects are indeed considered to be consistent with the nation's sustainable development goals. Since the host country's government is responsible for certifying that the project meets the sustainable development criterion, this eligibility rule too would not pose much of a problem in qualifying hydropower projects for CDM.

Satisfying the third criterion, which requires projects to pass what are called additionality tests, is however much more challenging.

The purpose of the additionality criteria is to prevent the "free-rider" problem in the CDM context—that is, prevent carbon credits from going to projects that would have been developed even without CDM. There are two types of additionality tests that potential CDM projects must pass. The first type, referred to as financial additionality, requires that funding for the CDM project be "additional to official development assistance, including contribution to the Global Environmental Facility."[42] Clearly, meeting this criterion could be tricky in cases where the hydropower project is developed by the government. In cases where the project is financed by private capital, however, it should be easier for hydropower projects in Nepal to pass this test.

The second type of additionality test is the environmental additionality test. To pass this test, the emissions reductions due to the project must be additional to the reductions that would have occurred in the absence of the project. In other words, the project developers must show that the baseline emissions, or future emissions without the CDM project, would be higher than the emissions with the CDM project. It is not difficult for hydropower projects to pass this test in countries where thermal plants play a major role in generating electricity. In the case of Nepal, however, electricity is generated primarily by hydropower, and there is little interest in developing new thermal plants to satisfy future electricity demand. There is, thus, little room to argue that a new hydropower project will reduce emissions to levels that are below the baseline scenario. Hence, it will be difficult for Nepalese hydropower projects to qualify for CDM and reap benefits from the sales of carbon credits. It may, however, be possible for hydropower projects to satisfy the environmental additionality criterion if they have been developed primarily for power export to India. The reason is that thermal plants using fossil fuels are the main sources of electrical power in India. As such plants in India produce a substantial amount of greenhouse gases[43] it can be argued that, from a regional perspective, development of

[42] Spalding-Fecher, R. (Editor) (2002). *The CDM Guidebook: A Resource for CDM Project Developers in Southern Africa*. Cape Town: Energy and Development Research Centre.

[43] Coal, which is the primary fossil fuel used by Indian thermal plants, produces more carbon than most other fossil fuels. Hence the reduction in greenhouse gases that can be achieved by replacing thermal plants in India with hydropower plants could be substantial.

export-oriented hydropower projects in Nepal does lead to additional reductions of greenhouse gases. The benefits from the sales of the carbon credits in this case would have to be shared by India and Nepal according to some mutually acceptable principle.

6.6 Capacity Price and Energy Price

In any power system, within a given period there is a maximum capacity demand that occurs at a certain hour (i.e., peak load) and the energy demand is the sum of hourly capacity demands, which are obviously less than the maximum capacity demand of the peak hour. This implies that the demand load factor is always less than unity. To meet such pattern of demand, power plants with enough capacity have to be installed. These power plants will be operating in accordance with the energy demand requirements. Therefore, for any power plant in a year there is a capacity price for power, i.e., the annuitized cost of installation of the power plant and an energy price, i.e., the cost of operating the power plant in the year. Capacity price can be looked at as a guarantee fee for having capacity available on demand. In a thermal plant these two prices look somewhat balanced due to the cost of fuel as a part of the operating cost. But in a hydropower plant the operating cost is just a small fraction of the installation cost. Hence, in a hydropower plant the energy price will be just a small fraction of the capacity price.[44] Financial considerations like debt servicing, taxes, return on investment, etc. will narrow the difference between the capacity price and the energy price. Usually the capacity price of hydropower will remain higher than that of the comparable thermal power while it will be the opposite in case of the energy price. However, in very large hydropower project where economy of scale comes into the picture, both capacity price and energy

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[44] The Upper Karnali Hydroelectric Project in Nepal with an installed capacity of 300 MW and generating annually 1,874 GWh will cost about US $486.6 million at 2001 price and will have an annual operating cost of only US $5.5 million. An alternative combination of combined cycle and gas turbine thermal power plants of 388 MW will cost only US $273.1 million while its annual operating cost including fuel will be US $139.3 million to generate the same amount of energy as the hydropower project. The Karnali (Chisapani) Multipurpose Project with an installed capacity of 10,884 MW and generating 21,496 GWh (including reregulating power plant) will cost about US $5,836.0 million at 2001 price and will have an annual operating cost of US $58.4 million. An alternative combination of coal-fired and gas turbine thermal power plants of 13,300 MW will cost about US $8,939.5 million while its annual operating cost including fuel will be US $1,288.7 million to generate the same amount of energy as the hydropower project.

price of the hydropower plant may be lower than that of the comparable thermal power plant.

In a supply constrained power market; there is a need to attract the developer in the power sector. It is more so in hydropower where installation cost is high; there are risks associated with hydrology and geology; long construction period and unforeseen delays etc. The most important aspect from a developer's viewpoint is to have enough funds to service his debt even if the power plant is not operating due to circumstances beyond his control. The developer can forego his returns on investment in such a situation but he still has to pay back his lenders. A capacity price or capacity availability payment that is related to debt repayment, interest payment, insurance fee, guarantee fee during repayment, interest tax and capacity royalty would resolve this issue. Then energy price or energy payment would relate to operating expenses, energy royalty, corporate tax, returns on the investment and other variable expenses. This way he will be encouraged to generate energy efficiently and he will continue to bear the hydrological risks. This type of price structure is more important in a storage project where regulation of storage is essential to optimize the generation.

6.7 Premium on Hydropower Price

Hydropower has some unique characteristic compared to thermal power. A hydropower unit can be started and pick up the load in 1 to 2 minutes and similarly, it can be shut down quickly. It can quickly take up the fluctuations in the load. Whereas a thermal unit takes much longer periods to start up and shut down, particularly in case of a coal-fired thermal unit. Thermal unit is best operated at nearly a constant load at or near maximum efficiency. Thermal plant generation becomes very expensive at low capacity factor, say 25% or below. Due to these factors hydropower is more suited to take up the peak load in a mixed hydro-thermal power system. In other words, hydropower displaces the inefficient thermal power at peak load and allows it to operate more efficiently at base load. Hence, a premium may have to be added to the peaking hydropower price to reflect this characteristic. A counter-argument may be laid that such peaking hydropower plant has its generation price already increased due to increases in installed capacity and size of waterways and such increase in price can be treated as the premium and hence, no additional premium is needed. This argument may not be true in all the cases. At a specific site due to economy of scale, combination of available head and river discharge may produce cheaper energy in a larger storage project than a smaller one, or even in a run-of-river project at the same site. Though full analysis has not been done for all such alternatives, such situation may occur at the site of the Karnali (Chisapani) Multipurpose Project. Value of such premium is a matter of conjecture best left to the judgement and negotiating skill of the developer when he tries to sell his peaking power in the available power market where thermal power is dominant.

When a hydropower project, particularly a run-of-river project is running partly at base load and partly at peak load then this question of premium on peak load price becomes more important during the dry season. In fact, such premium may decide the size of the project. A good premium may attract the developer to go for a daily peaking plant with enough pondage. Otherwise, he will settle for a simple run-of-river plant in order to minimize his capital outflow. A price structure with a high peak price and a low off-peak price of energy will include such premium where the difference between the two prices will be the premium on the peak price. In fact, in economic analysis of hydropower projects such differentiation is recognized and values of peak energy benefit and off-peak energy benefit have been derived from Long-Run Marginal Cost study of the power system in Nepal. Peak energy benefit can be as much as 65% higher than the off-peak energy benefit as can be seen from the current NEA tariff structure for high voltage (66 kV & above) and medium voltage (11 kV) consumers. A developer may or may not be offered such high premium but it shows the limit to which such premium can go. A nascent power system like Nepal's where domestic load is predominant during peak period may have resulted in such high premium. A more matured power system where industrial load is predominant may not need such high premium.

6.8 Some Financial Aspects

When hydropower pricing is being considered, its financial aspects also need to be considered. The ultimate objective of building a hydropower project is to earn revenues by selling its output (i.e., electrical energy), which has to be marketable, and its price has to be competitive as well as affordable. In order to achieve this objective, appropriate financing to build the project has to be arranged. Previously, construction of hydropower projects was thought to be in the domain of the government as the supply of electricity was thought to be the government's responsibility. Therefore, hydropower projects used to be financed by the government through its revenue or grant aid or soft credit from foreign donors. There was no consideration at all for any return on the investment made by the government on building such hydropower project and its output was priced just to cover operating expenses. It was thought of as a public edifice built by public sector with public money for public benefit. Now this concept is changing mainly due to constraint of financial resources with the government and demand by other sectors (particularly social sectors) on the government's limited resources. Now the private sector is being encouraged to invest in hydropower construction and many incentives and facilities are being offered to attract private sector participation. A hypothetical question that remains is that had there been enough resource with the government to continue building hydropower projects along with fulfilling the demands of other sectors, would the government have changed its concept of developing hydropower through private participation?

6.8.1 Return on Equity

When a private investor is invited to build a hydropower project, the mode of financing becomes an important issue. Usually, it is financed by a combination of equity and debt – equity being the money invested by the private investor and debt being the money borrowed from financial market at certain conditions, for example, interest rate, repayment period, etc. In a rare case such a project is financed one hundred percent by equity. The private investor expects some return on his investment, which is called 'return on equity' or 'internal rate of return'. Such rate of return will always be higher than the market interest rate on loans. Repayment of debt with the given conditions being a constant factor, the expected return on the investment plays a crucial role in determining the price of hydropower. As a corollary, debt-equity ratio plays the crucial role in determining such price. In general for a given loan conditions, higher the debt-equity ratio, lower is the hydropower price. However, the lenders will not allow a higher debt-equity ratio than a certain limit in order to minimize its investment risk and to ensure the financial capability of the investor.

As return on equity plays such a crucial role it is tempted to fix a figure for it. But what should be the appropriate figure is a case for subjective judgement based on many factors perceived by the investor. Such factors can be risks associated with building a hydropower project, risks associated with investing in a particular country, investment opportunities in other sectors (or countries) relative to the sector (or country) in question, current market price of electricity in the country and its expected trend, future scope of demand for electricity and hence, future investment in electricity in the country, etc. The investor expects return on his investment somewhat above the market interest rate on loans as he can always lend his money in the market without taking additional investment risks. Whatever may be the current market price of electricity, regulating a fixed return on equity will make any negotiation on price between the buyer and the seller of electricity pointless as long as other factors such as the cost of the project, etc. related to price calculation are beforehand agreed. Electricity price based on such regulated fixed return may have no relation with the current market price. Unnecessary and time consuming discussion to agree on the cost of the hydropower project will be required though it is a known fact that such cost is very site specific and cannot be standardized like the cost of a thermal plant. It may be argued that to attract an investor it is necessary to guarantee a fixed return on his investment. Then this argument should be extended and a fixed price to the consumer should also be guaranteed whatever be the cost of the project. Obviously, this is not possible. Private investor is basically a risk-taker. He evaluates the risks associated with making an investment and makes his decision. If he feels satisfied with whatever return he gets on his investment with the present situation there is no need to regulate a fixed return on investment.

In Nepal the electricity tariff commission generally regulates the electricity tariff to the end consumers.[45] In principle such a commission should be an independent and impartial. The commission should take into account among other factors, both the utility's requirements and the consumers' affordability. The commission's decision on tariff is and should be mandatory. The private investor has to work within this

[45] In Nepal such a commission is working since 1994. The commission has representatives from the government, electric utilities, industries, consumers and economists and is headed by a non-government person having experience in the power sector. Till now the commission has increased the electricity tariffs thrice. Main reason for increase in tariffs is the necessity to generate enough internal funds for investment in power system expansion.

system and he has to choose and build his project keeping the wholesale price of electricity in mind. This applies equally to the public sector developer. In other words, the wholesale price of electricity, decides the return on the investment. This method can be abused where there is a monopoly buyer or a monopoly seller of electricity in the market. A monopoly buyer may offer such a price that no investor is interested in building a hydropower project with the consequence that power development activity will suffer. Similarly, a monopoly seller will set marginal revenue equal to marginal cost, and will charge a price that is equal to the consumer's willingness to pay and thus tariff will be high due to lack of competition. Thus, a number of both buyers and sellers of wholesale electricity in the market is a prerequisite for this method to work properly. Although, the end tariff is fixed by the Tariff Commission, the wholesale electricity price can be made competitive by involving multiple buyers and sellers. Therefore, an environment needs to be created and proper decisions taken to have such an arrangement evolve from the present monopoly buyer market of electricity in the country by involving the private sector in electricity distribution as well. Sooner such an arrangement evolves; faster will be the pace of development of the electricity sector and more efficient will it be besides being competitive.

6.8.2 Foreign Exchange Risk

Another important issue from the financial viewpoint is the foreign exchange risk to be born by the investor during repayment of loan and dividend distribution. It arises from the depreciation of the national currency with respect to the foreign currency. Inflow of foreign currency may be involved when building a hydropower project. If it is built by public sector, it may be in the form of either foreign grant or foreign loan to the government. If it is built by private investor, it may be in the form of either foreign equity or foreign loan brought in by the investor. When public sector is building a hydropower project, the government usually bears the foreign exchange risk during repayment of loan and it is not passed on to the public utility and subsequently, to its consumers. When private investor is building a hydropower project, he cannot absorb such risk and it is inbuilt in his electricity price. Thus, the foreign exchange risk is passed on to the utility who buys power and subsequently, to the consumers.

One school of argument is that why the utility or the consumer should suffer for the inability of the government to control the depreciation of its national currency vis-à-vis foreign currency. The government is responsible for overall management of the national economy and it is its duty to see that the nation's economy remains strong, or in other words, the nation's currency remains strong. Hence, the government should bear such foreign exchange risk. The counter-argument is that there are other various players also, over which the government has no control that can influence the national economy. Further, a nation's economy cannot be looked at in isolation; it is inter-related with other nations' economy due to international trade. Sometimes, it may be in the overall national interest to depreciate the national currency. If the government takes foreign exchange risk, it is indirectly subsidizing the electricity price. On the basis of the 'Users Pay' principle, the consumers should bear such foreign exchange risk. One may again counter this argument by saying that there are other benefits besides power like secondary benefits, employment benefits, public benefits, etc. that are being generated by construction and operation of a hydropower project and not reflected in the hydropower price. By positively influencing the national economy, these benefits are ultimately generating additional revenue to the government. Considering this aspect, the government should bear the foreign exchange risk.

One may also say that foreign exchange risk may be insured. First, it may be difficult to find a commercial insurance company who may cover such risk. Second, if such a company is available its premium rate may be as high as the expected rate of depreciation of the local currency vis-à-vis foreign currency. That makes the solution no better than the problem. Therefore, this issue needs to be resolved by taking the only option left. Taking into account both the inability of the investor to take foreign exchange risk and the affordability of the hydropower price to the consumers, i.e., the consumers and the government should share such risk. This sharing may be from the beginning of the operation period till the end or one may bear the foreign exchange risk during one part of the operation period while other may bear it for the rest of the period. Logic behind this sharing holds good as long as the hydropower project serves the domestic market only. In an export-oriented project, secondary benefits, employment benefits, public benefits, etc. will occur more in the power importing country than the exporting country. Therefore, sharing of foreign exchange risk should be limited to the projects serving domestic needs only. In export-oriented project, foreign exchange risk should be born by the consumers of the importing country unless their government decides to share such risk.

6.8.3 Domestic Financial Market

One way to reduce the foreign exchange risk and consequently, the foreign exchange burden on the nation's economy is to arrange financing of hydropower projects from domestic financial market as much as possible, particularly for the domestic supply oriented projects. Experience of the private investors in this field has been mixed.[46] It is not that there are not enough funds with the commercial banks in the country to cater for small and medium size hydropower projects for domestic need.[47] The main problem seems to be that these commercial banks do not have access to that kind of funds which they can lend with long maturity periods, a necessity for hydropower projects due to long construction periods. In addition, hydropower projects need long repayment periods also to make their products saleable in the power market. Thus, a need is being felt to have a financial institution in the country that can provide loans on commercial terms to power sector with long maturity period. Such institution should have access to easy funds to provide such loans. Such funds should be in both foreign currency and local currency so that loans could be provided in both the currencies. Providing loans in foreign currency should be on easier terms than that available in the foreign market. Such financial institutions will also be the catalyst in attracting the commercial banks of the country to co-finance the hydropower projects.

Recognizing such a need the government is in the process of establishing a fund called the Power Development Fund (PDF) with

[46] The first two private sector hydropower projects in the country, Khimti (60 MW) and Bhotekoshi (36 MW) could not raise any finance from the domestic financial market due to high investment costs. Both the projects raised full finance from international financial market and are now completed and under operation. The other two projects, Chilime (20 MW) and Indrawati (7.5 MW) were successful in raising finance from the domestic financial market – Chilime from Employee Provident Fund and Indrawati from a consortium of commercial banks. Both the projects are under construction. Both the projects are issuing bonds to raise further finance from domestic financial market. Successes of such bonds are yet to be seen.

[47] In mid-March, 2001, deposits with the commercial banks in the country was Rs. 167.5 billion while loans to private sector was Rs. 110.7 billion, out of which 45% was for industrial purpose and 33% for commercial purpose. – Nepal Rastra Bank

initial funding of US $ 70 million from the World Bank.[48] It is learned that the government is requesting other donor agencies to channelize their aid in the power sector through the PDF. Similarly, to provide loan in local currency, an initial Rupees funding is required with timely addition in the future. The government should provide such initial funding to launch local currency loans. For future addition to the PDF, royalty that accrues annually to the government from hydropower generation can be a good source of such funding.

6.8.4 Refinancing of Loan

Another issue that is important from the viewpoint of hydropower pricing during the operation of the project is refinancing of the loan any time during the repayment period. Benefit of such refinancing can be taken when the terms of the loan in the financial markets are much easier during any time in the repayment period than when original loan was agreed.[49] In addition, project-specific risks during construction such as project technology and project location are over when the power plant is completed. The developer can retire the remaining portion of the original loan and take up new loan to cover it with much easier terms. Preponing of loan amount is usually a part of the original loan agreement and hence, retiring of such loan amount is not a big issue. Reduction of debt service cost thus achieved can then be shared between

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[48] The PDF will supplement private financing available for the development of Nepal's power sector to meet the domestic demand for electricity. It will provide long-term debt financing for power projects and contribute to the acceleration of the hydroelectric power development in the country by (i) overcoming the lack of sufficient debt financing for power projects; (ii) overcoming the inadequate maturity of available debt financing; and (iii) providing additional comfort to private investors wishing to promote power projects. The PDF will be pooled fund with initial contribution from the World Bank and, eventually, from other international funding agencies and domestic sources, together with inflows of debt service payments from borrowers. It will not be a major provider of funds for any project, rather it will co-finance projects with international and domestic lenders, including commercial banks, investment funds, export credit agencies and multilateral institutions. The aim of the PDF will be to act as a catalyst to maximize the inflow of private capital.

[49] Khimti project has raised loans with interest rate as high as 11.48% from international financial market. Bhotekoshi project has also done likewise. These projects should be encouraged to go for refinancing of their loans, as money is available in the international financial market at present, at much lower interest rates. In fact, the Project Agreement between the developer and the government on Bhotekoshi project has such a provision for refinancing. Any monetary gain made by the developer due to such refinancing is to be mutually shared between the developer and the government.

the developer and the consumers by reducing the hydropower price appropriately. This way both the parties receive the benefits; the developer will get higher returns on his investment than expected originally and the consumers (through the utilities) will get lower tariffs from the date of refinancing. It should be left to the parties (i.e., developer and the utilities) themselves to decide what this benefit sharing ratio should be.

7. Hydropower Pricing Mechanism

7.1 Background

According to the economics of hydropower pricing, the tariff should be affordable for the consumers to consume up to their requirements and the wholesale price be sustainable for developers to continue the generation to meet the consumers' demand. Both criteria; consumers' affordability and developers' sustainability can be met through competition. Competition among the developers makes hydropower price (and eventually the tariff) competitive.

Since the last decade of the previous century, public responsibility for generating and distributing the electricity has been gradually shifting to the private sector due to the limitation in national treasury and management inefficiency of public sector, especially in the countries that have liberalized their economic polices. The movement towards economic globalization has further aggravated the spatial specialization in productive activities on a comparative advantage basis. Thus, the possibility of involvement in the hydropower generation and distribution has been opened up to both sectors: public and private as well as public-private partnership. Keen competition among these forces them to fix the hydropower price most competitively in order to maintain their existence. The proposed opening up of the South Asian Regional Power Pool will create the competitive environment for both generators and distributors of power in the region. Thus, a proper hydropower pricing has become urgent and inevitable for power trading inside and outside the country.

A run-of-river type of hydropower project generates only power and does not produce any non-power benefits. A multipurpose hydropower project generates power and produces other non-power benefits such as irrigation, water supply, navigation and recreation as by-products. All itemised costs incurred in the project during its construction and operation cannot be separated on the basis of all products. Separable and non-separable (common) costs are incurred in the project. As far as data availability permit, the power generation cost of the project should be separated from the cost of producing other by-products/non-power products in order to make power price affordable and reasonable for consumers along with sustainability of the project in generating hydropower. As discussed earlier, the inclusion of the entire cost of the project (in a multipurpose project) in the power price makes the power costly and users of other non-power benefits will be subsidised at the cost of power consumers, which is also not justifiable.

Hydropower price is basically a function of two costs – one, cost of building the project and two, cost for operating it. The discussion below is based on cost plus pricing approach. Since, the cost for operating the project will be recovered by the project itself from the revenue stream, the important part is to arrange the fund required to build the project. The project cost is arranged usually, from a combination of debt and equity. Rarely is the project cost fully arranged from equity only. When debt is involved, financing costs related to debt, i.e., interest during construction, fees of the lenders such as establishment fee, commitment fee, etc. need to be added to the project cost. When debt and/or equity is arranged from outside the country, then some kind of guarantee fee during construction to cover non-commercial risks such as breach of contract, war and civil disturbance in the host country also needs to be added to the project cost. Though the government guarantees against these risks in order to attract foreign investment, the developer feels more comfortable by insuring against such risks and paying the required premiums (which is relatively high and thus contributes towards tariff increase). Such fees are covered during the operation period from the revenue generated by the project.

For both domestic and export markets, the elements that enter in the calculation of hydropower pricing are basically the same except for consideration of export premium if applicable, on export of power. The discussion below is based on the cost-plus pricing approach. Hydropower pricing can be done by using one of the following two practices: (a) capacity price and energy price or (b) average energy price. The second practice is widely used. Energy price can be further subdivided as (i) peak energy price and (ii) off-peak energy price. Hydropower pricing mechanism for the above mentioned practices is presented below:

7.2 Capacity Price

Capacity price of power is the annuitized cost of installation per unit of power (kW) of the power plant, which is in fact a guarantee fee for having capacity available on demand. The installation cost consists of all components of associated costs and induced costs incurred during the construction phase. The inclusion of external costs in the capacity price is debatable because it depends on the size, type, location and total cost of the project and most important determinant, the realization of government responsibility towards the development. For example, the cost of the access road incurred during the construction phase may be included in the capacity price if:

- the project is located at remote area and access road is essential;
- the road does not serve any other purpose (e.g., access for significant local population); or
- the cost of the access road is nominal compared to the total cost of the project.

The same principle may be applied for the communication line that is required for the construction phase of the project. Since possibilities of installing most of hydropower projects are in the remote and underdeveloped areas of the country, it may be socially justifiable to include the costs of local development, rural electrification and watershed management incurred during the construction phase into the capacity price if the sum of these costs constitutes a small portion of the total installation cost.

In practice, the capacity price is related to debt repayment, interest payment, guarantee fee during repayment, interest tax, insurance fee, and capacity royalty. That means the capacity price covers the debt portion of the installation cost. Hence, the capacity price is the annuitized installation cost of the hydropower project that includes the debt repayment, interest payment; guarantee fee during repayment; interest tax, insurance fee and capacity royalty. A formula for calculating capacity price for time, t, can be written as follows:

$$CP_t = \frac{1}{Q_t}[D_t + IP_t + GF_t + IT_t + CR_t + IF_t] \ldots\ldots\ldots\ldots\ldots\ldots \quad (1)$$

Where,

CP = Capacity price per kW,
D = Debt repayment,
IP = Interest payment,
GF = Guarantee fee during repayment,

IT = Interest tax,
CR = Capacity royalty,
IF = Insurance fee,
t = Unit of time period and
Q = Installed capacity of hydropower plant in kW.

7.3 Energy Price

The energy price is the cost of annual operation of the hydropower plant per unit (kWh). In addition, it also covers the equity portion of the installation cost. The cost of operating hydropower plant is related with operation and maintenance expenses, energy royalty, return on the investment, corporate tax, dividend tax and export premium, if applicable. The energy price for a particular time is calculated on the basis of operating expenses of the project, government policy relating to energy royalty, corporate tax, dividend tax, export premium if applicable, and profit policy of the developer. It may also include environmental mitigation expenses and watershed management costs incurred during the operation phase. In case of a multipurpose hydropower project, as discussed earlier there are other non-power benefits as well along with the power benefit. Hence, such multipurpose projects need additional considerations.

There is no difficulty in identifying the cost of producing hydropower from a multi-purpose project in case of separable costs. Non-separable cost of the multipurpose project can also be distributed between power and non-power products of the project proportionately on the basis of their expected gross benefits. Using this approach the cost of non-power products produced from the multipurpose project can be traced out. If these costs of non-power products are deducted from the total cost of multipurpose project while fixing the hydropower price, the end tariff will certainly come down. This approach is not practicable because such reduced price cannot cover the entire project cost whereas the total project cost of the multipurpose hydropower project has to be arranged by the developer himself. Thus, the hydropower price should be reduced by the amount equal to the revenue (not the cost) obtained from the non-power benefits. In case of a run-of-river hydropower project, the "revenue from non power benefits" (RNPB) is zero because this project produces only power. Here, time may be year, month, week, day or hour depending on the level of efficiency of the existing power market. The formula for calculating energy price for the time, t, can be written as follows:

$$EP_t = \frac{1}{U_t}[OC_t + ERI_t + ER_t + CT_t + DT_t + HEP_t - RNPB_t]........(2)$$

Where,

EP = Energy price per unit (kWh),
U = Units of energy production (kWh),
OC = Operating expenses,
ERI = Expected return on investment,
ER = Energy royalty,
CT = Corporate tax,
DT = Dividend tax,
HEP = Hydropower export premium, if applicable,
RNPB = Revenue from non-power benefits and
t = Unit of time (may be year, month, week, day, or hour).

7.4 Average Energy Price

In this practice, single price system that is average energy price is charged. It is simple for both developers and users. The average energy price is nearly equal to the average of capacity and energy prices. It is related with both capacity cost (CC) and energy cost (EC). In addition, it also includes expected return on investment and hydropower export duty (in case of export). The revenue from non-power benefits is zero for run-of-river type hydropower project whereas, it is positive for multipurpose hydropower project. The value of the non power benefits is deducted from the price. The formula for calculating the average energy price is presented below:

$$AEP_t = \frac{1}{U_t}[CC_t + EC_t + ERI_t + HEP_t - RNPB_t]........(3)$$

Where,

AEP_t = Average energy price per unit (kWh) in time t,
$CC_t = [D_t + IP_t + GF_t + IT_t + CR_t + IF_t]$ = Capacity cost in time t and
$EC_t = [OC_t + ER_t + CT_t + DT_t]$ = Energy cost in time t.

7.5 Peak and Off-Peak Energy Prices

Peak and off-peak energy prices can be applicable to both energy price and average energy price. Peak energy price is related to the peak time energy production and off-peak energy price to the off-peak time energy production. Peak energy price has some premium over the off-peak energy price. The sum of peak time energy production and off-peak time energy production is the total energy production at a particular time period, t. In order to calculate peak and off-peak prices, the following formulae will be applicable when average energy price practice is followed:

$$AEP_t \; x \; U_t = PEP_t \; x \; PU_t + OEP_t \; x \; OU_t \; \ldots\ldots\ldots..(4)$$

Where,

PEP = Peak energy price per unit (kWh),
PU = Units of energy production at peak time (kWh),
OEP = Off-peak energy price per unit (kWh),
OU = Units of energy production at off-peak time (kWh),
a = Premium of peak energy price over off-peak energy price,
$U_t = PU_t + OU_t$ and
$PEP_t = (1 + a) \; x \; OEP_t$.

Where capacity price and energy price practice is followed, average energy price (*AEP*) will be replaced by energy price (*EP*) in equation (4) above.

7.6 Treatment of Emission Benefits

When the Kyoto Protocol becomes effective and the emission benefits are being realized, then its treatment in hydropower pricing will be the same as revenue from non-power benefits if the developer is to get the credit for such benefits. Such emission benefits will be applicable to both run-of-river and multipurpose projects. However, as explained in section 6.5, it is unlikely that hydropower projects in Nepal will qualify for emissions credits.

7.7 Hydropower Markets

Hydropower market can be classified into two categories: domestic and export. The two types of hydropower projects: run-of-river type and multipurpose hydropower projects can supply their products to these markets. Both run-of-river and multipurpose hydropower projects can sell their products in both domestic and export markets. The hydropower pricing mechanism of these two types of projects for the two markets (i.e., domestic and export) are discussed below:

7.7.1 Hydropower Prices for Run-or-river Projects in Domestic Market

Components of each of the prices: capacity price, energy price and average energy price for run-of-river hydropower projects for domestic needs are almost the same as those dedicated for export purposes except hydropower export premium (HEP) in energy price and average energy price. The HEP is zero for domestic market. The RNPB is also zero for run-of-river type project unless emission benefit is realised.

7.7.2 Hydropower Prices for Run-of-river Projects in Export Market

For export-oriented, run-of-river type of projects, components of each of the prices are the same as the above mentioned formulae. The RNPB, in this case is zero unless emission benefit is realized, as it is a run-of-river type project.

7.7.3 Hydropower Prices for Multipurpose Projects in Domestic Market

As in the case of run-of-river hydropower projects for domestic needs, components of the capacity price, energy price and average energy price for multipurpose hydropower project for domestic supply are the same but the revenues from non-power benefits (RNPB) and emission benefit, if any, are required to be deducted from both energy price and average energy price. HEP is zero as there is no export of power.

7.7.4 Hydropower Prices for Multipurpose Projects in Export Market

For export-oriented, multipurpose type of projects, components of each of the prices are the same as the above-mentioned formulae. Both HEP and RNPB including emission benefit, if any, need to be considered because it is an export-oriented, multi-purpose type project.

7.8 Pricing in Market Economy

Elements that enter into hydropower pricing and types of projects and markets that affect such elements have been discussed above. Apart from cost plus pricing approach discussed earlier, pricing of a product in a market is also based on mutually agreed price between the buyer and the seller whether the market is competitive or not and whether the product is in short supply or in excess compared to its demand. This applies equally well to hydropower. The price is determined according to the buyer's willingness to pay for the electricity and the seller's willingness to accept it, at a certain price. In all markets, the demand curve represents the buyer's willingness to pay, and the marginal cost curve (or supply curve in a competitive market) represents the seller's willingness to accept. One who can correctly gauge the absolute need of the other to buy or sell the product will naturally have the pricing decided in his favor. Therefore, the hydropower pricing also needs to be flexible enough to capture the opportunities available in the power market.

8. Case Studies

8.1 Overview

Two case studies of hydropower projects are taken up – one for domestic needs and other for export. A 300 MW Upper Karnali Hydroelectric Project is to be developed to meet the domestic demand for power and energy while a 10,800 MW Karnali (Chisapani) Multipurpose Project is to be developed to meet the needs of the Indian power system and to provide some irrigation and flood control benefits to both Nepal and India.

8.2 Upper Karnali Hydroelectric Project

Upper Karnali Hydroelectric Project is located in the Far Western Zone of Nepal. It utilizes a natural bend in the Karnali River to create a substantial head for power generation. The catchment area at the project site is 20,120 km^2 and the long-term annul average flow is 500 m^3/s. It is a peaking run-of-river type of project with a 27 m high concrete barrage. At full supply level, the surface area of the headpond behind the barrage is 1.1 km^2 and the length along the river is 7 km. Its design flow is 236 m^3/s and the rated head is 141 m. The length of the headrace tunnel is 2.2 km and that of the tailrace channel is 57 m. An underground powerhouse accommodates five 60 MW generating units, i.e., the total installed capacity is 300 MW. The annual average energy generation from the project is 1,874 GWh taking into account the minimum release downstream of the barrage due to environmental reasons. At January 1998 price, the cost of the project including transmission lines to feed the domestic power market is US $456.7 million[50]. As the project is located in a remote area far off from the system load center, the cost of transmission lines is almost 20% of the project cost.[51]

In order to evaluate the project, its cost is updated to US $486.6 million at January 2001 price. This cost includes all associated costs and induced costs as well as external costs such as local development, rural electrification and watershed management. Conception cost and

[50] This is the capital cost from 2003 to 2010 in Appendix A brought to January 1998 base price

[51] Upper Karnali Hydroelectric Project Feasibility Study, NEA, June 1998.

decommissioning cost are not included, as these have not been provided in the study report. Induced and external costs are only about 3.4% of the total project cost. In the economic analysis the direct benefit from the project - power and the indirect benefit - emission benefit are considered. Power benefit is the costs of construction, operation and maintenance including fuel cost of the least cost alternative thermal project. In this case, it is a combination of gas turbine and combined cycle thermal plants with a total installed capacity of 388 MW producing same amount of power and energy as the hydropower plant. Secondary benefits are not taken into account, as there are no data to calculate it. Disbenefit such as loss of production from land though very minimal compared to the total benefit, is taken into account. Natural resource use cost is taken as 10% of gross benefit as the opportunity cost of using water as the natural resource. Economic analysis is done for a 50-year period (from start of commercial operation) with a discount rate of 12% discounted to year 2001. Results of the economic analysis are shown in Table 8.1. From the result, it is evident that this project is economically viable. Though emission benefit is not crucial in making a decision on the project, nevertheless, it contributes about 12% in the net benefit. Three sensitivity analysis cases are also presented – one, increase in resource use cost to 20%, two, increase in total costs by 10% combined with decrease in benefits by 10% and three, decrease in fuel cost by 40%. In all the cases, the project remains economically viable. If this project is dedicated for export of power to India, the least cost alternative thermal project for economic analysis may be a combination of gas turbine and coal-fired thermal plants. Furthermore, the installed capacity of the project may also need to be increased to suit the Indian power market as this project at 300 MW installed capacity will be running at a high plant capacity factor of 71.3% for the domestic market[52].

[52] In the Indian power market the peak load demand is considerably higher than the off peak requirements and thus, the project needs to build at higher installed capacity which lowers the plant capacity factor

Table 8.1 Upper Karnali Hydroelectric Project
Results of the Economic Analysis

Economic Indicators	With Emission Benefit	Without Emission Benefit
Base Case		
Net Benefit, Million US $	250.010	218.798
Benefit-Cost Ratio	1.79	1.70
EIRR	20.87%	19.99%
Increase in Resource Use Cost by 20%		
Net Benefit, Million US $	204.960	177.216
Benefit-Cost Ratio	1.56	1.50
EIRR	19.58%	18.74%
Cost +10%, Benefit –10%		
Net Benefit, Million US $	169.818	141.727
Benefit-Cost Ratio	1.50	1.42
EIRR	17.71%	16.89%
Fuel Cost –40%		
Net Benefit, Million US $	145.388	114.176
Benefit-Cost Ratio	1.47	1.38
EIRR	17.72%	16.66%

Financial analysis is done on the basis of so-called ‘project financing’ where project assets are the only collateral for the loan and debt service payment is made only from the revenue earned by the project. In the financial analysis, the project cost includes taxes and duties and price escalation during construction.[53] In the operation phase besides operation and maintenance cost, insurance cost, royalties, export duty if

[53] The largest tax applicable during construction is the value added tax (VAT) that is applicable at the rate of 10% of the contract amount on all the contracts that the developer has for the implementation of the project, be it civil works, electro-mechanical works or engineering services. There is no VAT applicable on the provision of electricity services, i.e., on the electricity bills.

applicable, corporate tax and other applicable taxes such as tax on interest and dividend tax (currently applicable in Nepal) are considered. Debt/Equity ratio is set at 75/25. Financing costs such as interest during construction, establishment fees and commitment fees of the lenders and Multi-lateral Investment Guarantee Agency (MIGA) guarantee fees are also considered.[54] Commercial interest rate is set at some basis points above the six-month US Dollar ($) deposit London Inter-Bank Offered Rate (LIBOR) to cover the risks associated with the project. Such risks may be both country-specific and project-specific. In this project's case it is set at 400 basis points, i.e., 4%. With the present six-month US $ LIBOR at around 3%, the interest rate will be 7%. Future US $ inflation both in costs and tariffs is assumed at 2.5% per annum. Financial closure is assumed to occur in the beginning of 2003 and commercial operation is assumed to occur in the beginning of 2011. Repayment period for loan and financial analysis period are taken as 15 years and 25 years respectively from the date of commercial operation. Real return to the investor is set at 18% excluding dividend tax.

In the base case scenario with total capital cost (including cost of financing) of 828.403 Million US$[55], i.e., based on the present tax regime of the country the average energy tariff will be US cent 6.31/kWh. It is to be noted that this tariff includes both generation and transmission price where transmission cost is almost 20% of the project cost. In case of charging separately for capacity and energy, capacity tariff will be US $208/kW/year and energy tariff will be US cent 2.91/kWh. It is interesting to note that capacity tariff contributing about 54% of total tariff will give only 6.3% return on equity to the investors while major portion of return will come from energy tariff. In case a premium on peak energy tariff is applicable (70% on top of off-peak energy tariff) peak tariff will be US cent 8.86/kWh and off-peak tariff

[54] MIGA is a sister organization of the World Bank that guarantees some of the non-commercial risks associated with the investment from one country to other country, particularly in developing country. Such risks are (a) restriction on transfer of foreign currency outside the host country, (b) action or omission by the host government which deprives the investor of his investment or a substantial benefit from it, (c) repudiation or breach of contract by the host government with the investor and (d) military action or civil disturbance in the host country. In no case, MIGA covers the risk of devaluation or depreciation of currency of the host country. Nepal has been a member of MIGA since 1994.

[55] The capital cost of 828.403 Million US$ takes into account financing costs (~25% of project cost), such as interest during construction, establishment fee, commitment fess of the lenders, MIGA guarantee fees, taxes, duties and price escalation.

will be US cent 5.21/kWh.[56] All tariffs are at 2001 price. Results of the financial analysis are shown in Table 8.2 for various other cases.

Table 8.2 Upper Karnali Hydroelectric Project
Results of the Financial Analysis

Cases	Total Capital Cost (incl. Cost of Financing) Million US $	Average Energy Tariff at 2001 Price US cent/kWh	Minimum Debt Service Ratio
Base Case	828.403	6.31	1.75
No VAT during Construct.	756.594	5.77	1.75
No MIGA Guarantee	786.639	5.81	1.84
Return on Equity 16%	828.403	5.69	1.57
Debt Equity Ratio 80/20	843.829	6.03	1.54
Construction Period -1 year	783.660	5.69	1.61
Higher Royalty	828.403	6.90	1.73
Interest Rate +1%	850.809	6.64	1.70
Constant Tariff	828.403	9.14	2.00
Emission Trading Payment	828.403	5.68	1.75
Export Premium 10%	828.403	7.01	1.75

Results of the financial analysis are quite revealing. When base case energy tariff is factored with high system loss, the tariff to the consumer will be US cents 8.38/kWh.[57] Whereas the average tariff to the consumer in year 2000-01 was US cent 8.15/kWh. In general it can then be said that the cost of the project has to come down in order to sell its energy in the domestic market. Or the developer has to reduce his expectation on the returns on investment, or it can be a combination of both. If the transmission costs were not included in the project cost (i.e., assuming

[56] Peak time is taken as 5 hours in a day. Peak time energy is 30% of the total energy in a day.

[57] In 2000-01, the country's official system loss figure was 24.7% of the energy supply. About half of this figure is assumed to be theft. In some particular areas, system loss is almost half of the energy supply. In order to tackle this situation, Nepal's Parliament has recently passed an Electricity Loss Control Bill that will make an unauthorized tapping of electricity a public crime.

the transmission line could also be used by other hydropower projects in the future) the average energy tariff would be around US cent 5/kWh. The peak and off-peak tariff would also be reduced accordingly. It should also be noted that the financial analysis for the base case assumes a 12% discount rate and an 18% return on equity both of which contribute to increasing the tariff.

If the government does not make VAT applicable on the construction of hydropower projects, then the base case tariff will decrease by more than 8%. Reduction of the financial cost, i.e., almost 25% of the total project cost, is dependent upon the risks perceived in the project and in the country by the developers and the lenders. If the developers and the lenders are happy with the guarantee given by the government against non-commercial risks, then the tariff will decrease by about 8%.[58] Reducing the return on equity to 16% will decrease the tariff by about 10%. Other options to decrease the tariff are either to increase the debt equity ratio or to shorten the construction period. Increasing the debt equity ratio to 80/20 will decrease the tariff by a little more than 4%. Shortening the construction period by one year will decrease the tariff by about 10%. Present royalty scenario has low royalty in the first 15 years of operation and high royalty thereafter (as per the Hydropower Policy 2001). Taking higher royalty for the whole analysis period will increase the tariff by about 9%. Increasing the interest rate by 1% will increase the tariff by a little more than 5%. One interesting case is the constant tariff scenario. Considering the inflation, the tariff at the time of commissioning in year 2011 will be US cent 8.08/kWh and at the end of the analysis period in year 2035 will be US cent 14.61 /kWh i.e., an increase of almost 81% within 25 years in the base case scenario. If inflation is not considered for the entire period, the tariff will increase by a little more than 13% of the 2011 tariff. Emission trading benefit amounting to US $11.581 million at 2001 price, if it materializes, will decrease the tariff by 10%. If this project is dedicated for export, then export duty will be levied. Assuming an export premium of 10% on the gross revenue net of royalty, the tariff will increase by 11%. In all the

[58] In Khimti and Bhotekoshi projects, the government has guaranteed against such non-commercial risks as those guaranteed by MIGA by agreeing to buy out the projects in case of those risks occurring in the projects during construction and loan repayment periods. It is doubtful whether the government will be able to give such kind of guarantees to larger projects with large investments.

cases, the minimum debt service ratio is more than 1.50 that the lenders look for in these types of financing.

8.3 Karnali (Chisapani) Multipurpose Project

Karnali (Chisapani) Multipurpose Project is located in the Mid Western Zone of Nepal. It is a seasonal storage project in the Karnali River where it disgorges from the hills to the plains. The catchment area at the project site is 43,679 km^2 and the long-term annual average flow is 1,389 m^3/s. A 270 m high embankment dam will create a large man-made lake. At full supply level, surface area of the lake will be 339 km^2. Live storage of the lake is 16.2 billion m^3 (37% of average annual runoff). An underground powerhouse accommodates eighteen 600 MW generating units, i.e., the total installed capacity of 10,800 MW. The annual average generation from the project is 20,875 GWh. A 6 km long and 24 m high reregulating barrage is located 8 km downstream from the main dam. The surface area of the lake behind the reregulating barrage is 6.5 km^2. A powerhouse in the reregulating barrage will have an installed capacity of 84 MW and will generate 621 GWh annually. Five 765 kV transmission lines and one 220 kV transmission line will transmit the power to India from the project. At 1988 price, the cost of the project including transmission lines was US$ 4,890 million. At 2000 price, the cost of the project has increased to US $ 5,836 million (an annual increase of 1.48%). This is mainly due to a substantial decrease in the cost of turbines, generators and valves in the world market. Transmission lines costs are only about 8% of the total project costs. This project is conceived primarily for export of hydropower to India with flow regulation (fourfold increase in dry season flow) providing increased irrigation and flood control in both Nepal and India. This project provides potential irrigation benefits to 191,000 ha in Nepal and 3,200,000 ha in India. This project requires resettlement of 70,500 people at present level and thus creates substantial environmental and social impacts.[59, 60]

[59] Karnali (Chisapani) Multipurpose Project Feasibility Study, His Majesty's Government of Nepal, December 1989.

[60] Karnali (Chisapani) Multipurpose Project Feasibility Study Update Draft, His Majesty's Government of Nepal, September 2001. In the final report the cost of the project and its implementation schedule may change and subsequently, the economic analysis and the financial analysis will change.

The project cost includes all associated costs as well as induced costs and external costs. Here too, conception cost and decommissioning cost are not included as these are not provided in the study report. Induced and external costs are about 7.7% of the total project cost. Comparatively, this cost percentage is much higher than that of the Upper Karnali Project but whether this is sufficient for this type and size of project remains questionable. In the economic analysis direct benefits from the project are power, irrigation and flood control benefits. Water supply benefit is not considered since the project is not designed for such a purpose. Navigation and recreation benefits are very negligible compared to other benefits and hence, are not considered. Indirect benefit is the emission benefit due to greenhouse gases that would have been produced by alternative thermal power plants. Power benefit is the cost incurred in construction, operation and maintenance including fuel cost of the least cost alternative thermal power project. In this case, it is a combination 2,500 MW of coal-fired and 10,800 MW of gas turbine thermal power plants producing same amount of power and energy as the hydropower plant. Irrigation benefit in both Nepal and India is the incremental economic value of the crops that can be produced due to water flow regulation provided by the project. Associated costs such as construction, operation and maintenance of the irrigation systems in both the countries, necessary to realize the irrigation benefit are considered in the economic analysis. Flood control benefit is the economic value of the damages produced by river flooding under natural conditions in both Nepal and India which is eliminated by the flow regulation provided by the project. No associated costs are required to realize flood control benefit. Secondary benefits and other benefits are not considered, as no data are available. Disbenefit such as the loss of production from land is considered but disbenefits due to emission of greenhouse gases and scouring of embankment downstream of the dam are not considered, as no data are available. Natural resource use cost is taken as 15% of the gross benefit because not only the natural resource, water, is used but it is also stored for more beneficial use. Economic analysis is done for a 50-year period (from the start of commissioning) with a discount rate of 12% discounted to year 2001. Results of the economic analysis including sensitivity analysis are presented in Table 8.3.

Table 8.3 Karnali (Chisapani) Multipurpose Project
Results of the Economic Analysis

Economic Indicators	With Emission Benefit	Without Emission Benefit
Base Case		
Net Power Benefit, Mill. US $	1,817.740	1,548.255
Net Irrigation Benefit, Mill. US $	255.077	255.077
Net Total Benefit, Mill. US $	2,072.817	1,803.332
Benefit-Cost Ratio	1.95	1.85
EIRR	24.11%	23.03%
Increase in Resource Use Cost by 30%		
Net Power Benefit, Mill. US $	1,423.468	1,201.539
Net Irrigation Benefit, Mill. US $	255.077	255.077
Net Total Benefit, Mill. US $	1,678.545	1,456.616
Benefit-Cost Ratio	1.65	1.59
EIRR	22.66%	21.66%
Cost +10%, Benefit –10%		
Net Power Benefit, Mill. US $	1,301.194	1,058.657
Net Irrigation Benefit, Mill. US $	255.077	255.077
Net Total Benefit, Mill. US $	1,556.271	1,313.734
Benefit-Cost Ratio	1.68	1.58
EIRR	20.65%	19.60%
Fuel Cost –40%		
Net Power Benefit, Mill. US $	1,432.727	1,163.242
Net Irrigation Benefit, Mill. US $	255.077	255.077
Net Total Benefit, Mill. US $	1,687.804	1,418.319
Benefit-Cost Ratio	1.80	1.69
EIRR	22.71%	21.49%

Note: 1. In all the cases net flood control benefit of US $ 4.044 million is included in net irrigation benefit.

2. In the case of cost +10%, benefit –10%, such changes are applied to power cost and benefit only.

The results show that in all the cases the project is quite beneficial. Emission benefit contributes about 13% in net total benefit. Though main benefit from the project is power, other non-power benefits, i.e., irrigation and flood control are not negligible. Table 8.4 shows the distribution of net power and non-power benefits from the project in base case scenario without emission benefit. This aspect is important for allocation of cost of the project to its different purposes. Results show that power contributes 85.9% of the net total benefits whereas non-power i.e., irrigation and flood control contributes only 14.1%, which is not an insignificant proportion when cost allocation is taken up.

Table 8.4 Karnali (Chisapani) Multipurpose Project Distribution of Total Net Benefits

Item	Net Benefits in Million US $	Percentage
Power	1,548.255	85.9%
Non-power	255.077	14.1%
Total	1,803.332	100.0%

As non-power benefits are realized by both Nepal and India it is interesting to note the distribution of such net benefits to these two countries. Table 8.5 shows the distribution of such net benefits to the two countries. This aspect is important when costing of power is based solely on the benefits accrued. From the table, it can be seen that Nepal has negative net non-power benefit. The reason is that Nepal has to invest in building completely new irrigation system to realize the irrigation benefit. Whereas India already has its irrigation system operating and capable of handling the regulated flow from the project with only some minor investment.

Table 8.5 Karnali (Chisapani) Multipurpose Project Distribution of Net Non-Power Benefits

Net Benefits	Nepal	India	Total
Irrigation, Million US $	-38.598	289.631	251.033
Flood Control, Million US $	0.374	3.670	4.044
Total Non-Power, Million US $	-38.225	293.302	255.077

In order to allocate the cost of the project to its different purposes, first, the cost breakdown of the project is scrutinized and direct costs related only to power and to irrigation and common costs that cannot be apportioned to a particular purpose are separated. For example, diversion facilities, cofferdams, main dam, spillway, waterways, access roads & bridges, reregulating dyke and spillway, diversion gate, intake equipment, etc. are common costs. Underground powerhouse, transformer gallery, access tunnel and other tunnels, shafts, switchyard civil works, powerhouse electro-mechanical equipment, switchyard equipment, reregulating barrage powerhouse electro-mechanical equipment, etc. are direct costs related to power. Emergency irrigation facilities, tunnel emergency outlet irrigation, reregulating barrage irrigation outlets etc. are direct costs related to irrigation. The common costs are then shared between power and irrigation based on the percentage of net benefit as shown in Table 8.4. Lastly, the costs thus apportioned to power and irrigation directly and as a share of common costs are added up to reach at the costs allocated to power and irrigation. Table 8.6 tabulates the result for the Karnali (Chisapani) project. As can be seen from the table the cost allocated to power is 91.7% of the total project cost while that allocated to irrigation is only 8.3% whereas irrigation contributes 14.1% of net total benefits. This implies that the irrigation component is making the project economically more beneficial.

Table 8.6 Karnali (Chisapani) Multipurpose Project Allocation of Project Costs

Item	Cost in Million US $	Percentage Share
Direct Cost Allocated to Power	2,666.590	45.7%
Direct Cost Allocated to Irrigation	39.173	0.7%
Common Cost	3,130.221	53.6%
Total Project Cost	5,835.983	100.0%
Common Cost Allocated to Power	2,687.459	85.9%
Common Cost Allocated to Irrigation	442.762	14.1%
Total Common Cost	3,130.221	100.0%
Total Cost Allocated to Power	5,354.049	91.7%
Total Cost Allocated to Irrigation	481.935	8.3%
Total Project Cost	5,835.983	100.0%

Note: Cost allocated to irrigation includes that for flood control also.

The financial analysis for Karnali (Chisapani) is done on the same basis as that for Upper Karnali, the only difference being;

(a) export premium will be applicable in all the cases, as the project is totally export-oriented and
(b) due to a large number of units to be installed the developer will be making equity investments as well as earning dividends in the first five years from the date of commissioning of the first unit.[61]

[61] Eighteen units of the project will be commissioned at the rate of three units in the first year of commissioning, four units each in the second, third and fourth years and three units in the fifth year.

Base case scenario is done where full cost of the project is taken for tariff calculation. Other alternate cases are variations on the base case as in Upper Karnali. In this project, emission trading benefit amounts to US $194.506 million at 2001 price. One alternate case is done where India separately pays revenue annually for non-power benefits. Such revenue will be the higher of US $ 293.302 million (net non-power benefits to India) or amount equal to energy sold multiplied by 8.3% of the average energy tariff (this percentage being the share of the non-power cost in total project cost) at 2001 price. In the case of the Karnali (Chisapani) project, the amount of net non-power benefits is higher than the amount of non-power share of average energy revenue based on cost allocation.

In the base case scenario, the average energy tariff will be US cent 10.88/kWh. It should be noted that this tariff contains both generation and transmission where transmission cost is about 8% of the total cost. In case of charging separately for capacity and energy, the capacity tariff will be US $88/kW/year and energy tariff will be US cent 6.57/kWh. Capacity tariff contributing a little more than 39% of the total tariff will result in a return on investment of only about 7.64 % while most of the return will come from energy tariff. It should also be noted that the contribution of the capacity tariff has gone down (percentage wise) in the case of the Karnali (Chisapani) compared to the Upper Karnali project, which is expected as the Karnali (Chisapani) project will operate at only 22.5% plant capacity factor while Upper Karnali will operate at 71.3%. In case a premium on peak energy tariff becomes applicable (30% on top of off-peak energy tariff) peak energy tariff will be US cent 12.90/kWh and off-peak energy tariff will be US cent 9.92/KWh.[62] All tariffs are at 2001 price. The results of the financial analysis are shown in Table 8.7 for various other cases.

[62] It is assumed that in the Indian Hydropower Policy 30% premium is allowed for the peak power. About 43% of power produced by the project will be used during peak time and rest 57% during off-peak time.

Table 8.7 Karnali (Chisapani) Multipurpose Project
Results of the Financial Analysis

Cases	Total Capital Cost (incl. Cost of financing) Million US $	Average Energy Tariff at 2001 Price US cent/kWh	Minimum Debt Service Ratio
Base Case	16,214.7	10.88	2.04
No VAT during Construct.	14,842.9	9.96	2.04
No MIGA Guarantee	13,829.3	8.62	2.03
Return on Equity 16%	16,214.7	9.10	1.69
Debt Equity Ratio 80/20	17,061.0	10.44	1.74
Construction Period -1 year	15,310.0	10.85	2.10
Higher Royalty	16,214.7	11.87	2.01
Interest Rate +1%	17,227.4	11.58	1.93
Constant Tariff	16,214.7	18.16	2.08
Emission Trading Payment	16,214.7	9.86	2.03
Non-Power Bene. Payment	16,214.7	9.26	2.01

In the Karnali (Chisapani) project, the cost of financing is almost 48% of the total project cost due to a long construction period of 18 years. The trends of the results of other cases relative to the base case scenario are comparable to the Upper Karnali project case except in the case of reduction of construction period by one year. No appreciable reduction in the energy price is seen due to reduction of the construction period by one year in the Karnali (Chisapani) project. The reason is that the reduction in the construction period has occurred in the commissioning of the eighteen units of the project from five years to four years while the first unit is commissioned at the same time as before. This implies that the debt service has started one year earlier with the result that there is almost no change in the energy price though the total project cost has come down by about US $905 million. Construction period of the civil works has to be reduced and thus, the first unit needs to be commissioned earlier in order to get the benefit of energy price reduction due to the reduction of the construction period.

From the results of the financial analysis it is evident that the project is not saleable at the present tariff situation in India. In addition to decreasing the project cost and lowering the expectation on returns from the project by the developer, dramatic change in the power tariff situation in India has to occur in a short period to make this project viable for the Indian power market. And Nepal may also have to lower the expectation of revenues from this project if the project is to be saleable in the Indian power market or Nepal may have to wait for an opportune time to take up this project.

If the transmission costs were not included in the project cost (i.e., assuming the transmission line could also be used by other hydropower projects in the future) the average energy tariff would be around US cent 10/kWh. The peak and off-peak tariff would also be reduced accordingly. It should also be noted that similar to the Upper Karnali case, the financial analysis for the base case here assumes a 12% discount rate and an 18% return on equity both of which contribute to increasing the tariff. For example a decrease in expected return in equity from 18% to 14% would reduce the average tariff by US cents 2/kWh.

One option to reduce the project cost significantly is to reduce the scale or size of the project. Reducing the dam height, or reducing the installed capacity or a combination of both can reduce the costs. A study has shown that it is economically a better option to reduce the installed capacity than the dam height. Moreover, it is easy to install additional capacity at a later date but practically impossible to raise the dam height. Furthermore, non-power benefits would not be reduced if the dam height is not reduced. For the given dam height of the project (270 m), the minimum installed capacity will 5,400 MW, i.e., at this installed capacity the energy generation remains the same as in the larger project. For the 5,400 MW capacity project, the cost will be reduced by about US $1.28 billion, i.e., a reduction of about 22% at 2000 price.[63] Furthermore, the full commissioning of the project can occur at least two years earlier. These factors will considerably reduce the financial cost as well. The financial analysis of this reduced size of the project may result in a tariff that is saleable in the present Indian power market. As discussed earlier, the installed capacity can then be increased at a later date when the Indian power market can afford a higher peaking tariff.

[63] A quick analysis of the cost estimate of the project shows that the civil works will be reduced by about 10%, electro-mechanical works by 44% and transmission lines by 35%.

Other options lower the tariff is to decrease the cost of financing and allocate a larger proportion of the total cost to the irrigation/non power components of the project.

9. Conclusions and Recommendations

9.1 Encouragement of Hydropower Development

In order to realize the vast hydropower potential of the country, Nepal should encourage the development of hydropower projects – both run-of-river type and storage type – both for domestic needs and for export purpose[64]. On the domestic front, it would be beneficial to coordinate hydropower development policy with industrial development policy to promote domestic industries that can eventually gain a competitive edge due to low energy cost. The benefits of such an approach to hydropower development have been discussed in section 6.4. Though the present Indian power tariff situation is not conducive for export of power, it will take time to materialize export-oriented hydropower project and meanwhile, the tariff reform along with the institutional reform could occur in India. Power Trade Agreement signed between the two countries also needs to be ratified expeditiously. Formation of South Asia Regional Power Pool in the future is likely to be beneficial for export of power from Nepal.

9.2 Reduction of Hydropower Project Costs

Both for domestic and export market, the present hydropower price based on normal financing conditions, is high because the project costs and the financing costs are high and furthermore the developers' expected return on equity is also high. In order to make hydropower saleable in the market, both the developer and the government should take a few steps to reduce such costs. The developer should redesign the project and implement and operate it with maximum input of local material, equipment, labor and professional manpower in order to reduce the cost. The developers should explore the financial market to receive the best terms of loan also lower their expectation on return on investment. The government should reconsider the application of VAT on construction of hydropower projects, as there is no VAT on

[64] This recommendation is fully consistent with Nepal's Hydropower Development Policy 2058 whose objectives include tying up "electrification with economic activities" and developing "hydropower as an exportable commodity

consumers' electricity bills.[65] The government should reconsider the values of royalty applicable to hydropower projects.

One way to reduce the project cost can be the adoption of a legal provision in the country that makes it mandatory for a foreign contractor to have a joint venture with a local partner in order to get any contract in the country, be it civil construction works, equipment supply and erection or provision of services[66]. The government should prescribe minimum percentage of local partner's share in such joint venture from time to time. It should be low in the beginning and increased gradually as the local partners gain experience and exposure.

9.3 Need for Conducive Environment

The government should create conducive climate in the country to attract and retain the investors, both foreign and local. This will help in reducing country specific risks perceived by the developers and the lenders and thus, reduce project costs. Political stability, security of life and property and transparency in the decision making process are essential for to establish such conducive climate. It is not sufficient to have a fair legal framework for sectoral development and investment in the country; it is all the more important that these are implemented honestly in letter and spirit without any external impediments.

9.4 Option for Refinancing Debts

The developer should be encouraged to opt for refinancing of his debt during any time in the loan repayment period when new loans are available at much easier terms than previously. Reduction in debt service cost thus achieved should be shared between the developer and the consumers at a mutually agreed way by reducing the tariff appropriately from the date of refinancing. Project or implementation agreement between the developer and the government or power purchase agreement between the developer and the utility should have such a provision.

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[65] According to new Hydropower Development Policy, 2001, VAT is not applicable on imported equipment, machinery and their spare parts on the basis that there is no VAT applicable on electricity tariff.

[66] The assumption here is that the overhead cost of the local contractor will be lower than the foreign contractor and thus the joint ventures would reduce total project costs

9.5 External Costs

Cost of access road should be included in the hydropower project cost only if:

- the project is located at remote area and access road is essential;
- the road does not serve any other purpose (e.g., access for significant local population); or
- the cost of the access road is nominal compared to the total cost of the project.

Costs for local development, rural electrification and watershed management during construction should be limited to a small percentage of the project cost. During operation, a part of the royalty generated by the project should be shared with the local development bodies (as is done presently) and watershed management organization for continuation of such activities. The government should prescribe these matters after wide consultation with all the parties concerned.

9.6 Need for Multiple Generators and Distributors

A number of generators and distributors of power should be introduced and encouraged in the country instead of having a monopolistic and dominant player in order to bring competition and efficiency in the power market. These generators and distributors may have their own hydropower prices; it is not necessary to have a single wholesale price all over the country.

9.7 Consideration of Power and Non-power Benefits

Hydropower pricing for run-of-river project and storage project is different from the point of view of non-power benefits. This consideration arises from the need to have optimum use of both electricity and water, which can occur only when proper pricing is done for both the uses. This implies that economical analysis and cost allocation becomes a must for storage project to know the present value of the net non-power benefits. Usually, a developer does not undertake economic analysis as well as cost allocation, as he is concerned only with the financial viability of the project. In such a case, the government may have to do such analysis and allocation based on the project cost data supplied by the developer. This is because although a private developer may not directly receive any "non-power benefits", these do occur to certain segment of the population (society) in the project area and thus the economic value of the non-power benefits should be accounted for and reflected in the wholesale energy price and the tariff. Such analysis and allocation should be done for both domestic use projects and export-oriented projects. Results of such analysis and allocation should be taken into account while fixing the prices for different outputs from the storage project.

In a storage project where there are non-power benefits besides power, tariff for power should be charged by considering the revenues earned due to the non-power benefits as discussed above. That means the non-power beneficiaries of a multipurpose project should be charged separately for receiving such benefits. Revenues from non-power benefits should be the higher of the amount of net non-power benefits from the economic analysis of the project or the amount of non-power share of average energy revenue based on cost allocation.

Consideration of natural resource use cost should be made a part of the economic analysis in hydropower project as an opportunity cost of the use of the natural resource – water – in the project. Resource use cost should be fixed as a percentage of the gross benefits. This percentage should be less for run-of-river project and more for storage project, as the storage project permanently submerges other natural resource – land. In financial analysis royalty takes the place of the natural resource use cost.

9.8 Royalty Issues

Royalty should be related to the gross revenue earned from all the sources by the hydropower project rather than to the energy price or revenue earned by the energy generation only. Revision in the Electricity Act, 1992 and the new Hydropower Development Policy, 2001 is needed in order to cover the possibility of such project earning emission trading revenue or non-power revenue in future and thus, reducing the energy price to which the energy royalty is related at present.

Theoretically, same rate of royalty should be charged from the very beginning of the operation of the project till the end, as same amount of water is being used for power generation from the beginning till the end. It is the government's prerogative to charge different rates of royalty at different periods in a project, but it should be understood that lower royalty in the initial operation phase is an exemption to the developer when he also needs to service his debts. For equal installed capacity projects, the royalty for storage project should be higher than that for run-of-river project.

Royalty should not be charged on technical losses as these are inherent in a power system and hence, the consumers (or distributor) do not get the benefit of equivalent hydropower even though the natural resource – water – is used. Royalty should be charged on non-technical losses since it is due to inefficiency of the utility and with proper actions these losses can be fully eliminated.

9.9 Capacity and Energy Prices

As far as practicable, capacity price and energy price should be applicable so that the developer configures his project to suit the system demand and optimizes his generation. Similarly, in the energy price, peak energy price and off-peak energy price should be applied. The developer should be given clear guidelines on what cost items are to be covered by the capacity price and what others by the energy price. Similarly, the developer should know beforehand the premium of peak energy price on off-peak energy price. Such premium should be guided by the system demand characteristics.

9.10 Return on Equity

There is no need to guarantee a fixed return on equity to the developers. Once the government provides suitable incentives and facilities to the developers for investment and does not control the wholesale electricity price, the developers have to work within the existing environment and offer their prices that the market can bear. In other words, the market should control the price. Tariff commission should be strengthened and made more independent in order to discharge its functions properly.

9.10.1 Foreign Exchange Risk

For domestic use project, foreign exchange risk should be shared between the consumers and the government because there are additional revenues generated to the society due to the effect of secondary benefits of the project in the national economy. Besides, there are employment benefits and public benefits that impact positively on the national economy. A mechanism for sharing such risk may take any form mutually acceptable to the government and the utility or the government and the developer. For export-oriented projects, foreign exchange risk should be borne by the consumers of the power importing country unless their government decides to share such risk. Alternatively, PPAs could be based on hard currency for export oriented projects.

9.11 Support to Power Development Fund (PDF)

The government should provide initial funding in Rupees to the Power Development Fund (PDF) being established shortly, in order to provide loan in local currency in association with local commercial banks. In order to provide continuous funding of Rupees to the PDF for such purpose, the government should transfer the royalty from power generation that accrues annually.[67]

9.12 Export Premium

Basically, the elements that enter in the calculation of hydropower pricing for domestic use project and export-oriented project are the same except the consideration of applicable export premium for the export-oriented project. This consideration arises from the need to capitalize on some part of the secondary benefits that will accrue to the power importing country due to forward production linkages associated with the use of power. In addition, there are employment benefits and public benefits from the use of power. Same consideration applies to other non-power uses created by the flow of regulated water. Export premium for all types and sizes of the export-oriented project should be the same in

[67] An example has been started by the new Hydropower Development Policy, 2001, which states that a 'Rural Electrification Fund' will be established by apportioning some part of the royalty from power generation for micro hydropower development and rural electrification.

order not to discriminate between the developers. Export premium should be some percentage of the gross revenue earned from all the sources net of royalty.

9.13 Implications due to Nepal's entry into World Trade Organization (WTO)

The development and pricing of hydropower in Nepal should be done with the recognition that the sector could, in the future, face some new opportunities and challenges as a result of the changes taking place in the global trading environment under the aegis of the WTO. The declared purpose of the WTO is to facilitate international trade in goods and services by removing obstacles to trade and establishing trading rules. Hence, bringing down import tariffs and export subsidies is one of the main requirements for WTO members. When it comes to service sectors, individual countries are generally given the flexibility to choose the sectors they want to open up. As the power sector has not been included among the sectors the Nepali government has committed to open up, the nation's accession to the WTO should not have a direct impact on hydropower in the near future. Over the long run, however, hydropower could face tough competition from thermal plants if, as a member of the WTO, Nepal significantly lowers import tariffs on fossil fuels. The challenge could be even more serious if India—Nepal's potential hydropower export market—does the same. At the same time, however, the lowering of trade barriers due to WTO membership should increase the possibilities for exporting value added products utilizing hydropower, especially to India. The changing international trade environment is therefore another reason why Nepal should give adequate attention to coordinating hydropower development with industrial development.

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Glossary

Associated cost: Associated costs are costs that result due to construction, operation and maintenance of a project. In case of hydropower project, associated costs during the construction phase occur due to construction of the infrastructures (dam, powerhouse) and preparatory works (camps, access roads etc). Operation and maintenance costs are associated costs during the operation phase of a hydropower project.

Capacity factor: The ratio of the power generated from a power plant over the installed capacity (i.e., maximum possible power output) for a given period or at a particular time is called capacity factor. Thus, capacity factor becomes unity when the plant is operated at installed capacity.

Catchment area: Catchment area is the area covered by a river basin system, which drains the runoff that occurs over it.

Clean Development Mechanism: The Kyoto Protocol established the CDM Clean Development Mechanism (CDM), which enables Annex I countries (developed countries and economies in transition) of the United Nations Framework Convention on Climate Change (UNFCCC) meet their greenhouse gas (GHG) reduction targets at lower cost through projects in developing countries. Should the Kyoto Protocol enter into force, carbon will become a tradable commodity with an associated value. One tone of carbon dioxide (CO_2) reduced through a CDM project, when certified by a designated operational entity, is known as a Certified Emission Reduction (CER) and can be traded.

Demand load factor: In any power system, the demand for electrical power/energy is not constant but varies over the seasons as well as over the hours of the day. The demand load factor is the ratio of the demand for electrical power/energy at a certain period (hour) over the peak demand for electrical power/energy of the system.

Developer/Producer /generator: Developer is a legal entity that develops or desires to develop a hydropower project. A producer or a generator is a legal entity that generates electricity from a hydropower plant. The terms developer, producer and generator are often used (and interchanged) to refer to the owner of a hydropower plant.

Energy: Energy is the product of power and time. In the hydropower/electricity sector kWh, MWh or GWh are commonly used as units of energy.

External cost:	External costs are costs that are not directly related with the project and may also serve other purposes, but are essential for the construction and operation phases, e.g., road infrastructure required for accessibility to the project site.
Head:	Head is the drop or vertical height of water used to operate the turbines (and consequently generate electricity) in a hydropower plant.
Induced cost:	Induced costs are costs to the society which result due to the implementation of a project, i.e., indirect costs induced by the project. Costs such as resettlement of population and relocation of infrastructure or environmental impact mitigation are induced costs.
Kyoto Protocol:	From 1-11 December 1997, more than 160 nations met in Kyoto, Japan, to negotiate binding limitations on greenhouse gases for the developed nations, pursuant to the objectives of the Framework Convention on Climate Change of 1992. The outcome of the meeting was the Kyoto Protocol, in which the developed nations agreed to limit their greenhouse gas emissions, relative to the levels emitted in 1990. Should the Protocol enter into force, the emissions targets for the developed countries would have to be achieved on average over the commitment period 2008 to 2012.

Marginal cost: Marginal cost is the added (marginal) cost associated with each extra unit of production.

Marginal revenue: Marginal revenue is the added (marginal) revenue associated with each extra unit of sales

Natural resource use cost: This is a fee that the government charges (such as royalty) to a developer for use of natural resources (e.g., water in case of hydropower) which is owned by the state.

Power: Power is defined as the time rate of doing work. In a hydropower plant, power can be viewed as the ability derived from the combination of "head" and "flow of water" to rotate a given size turbine and subsequently the generator to produce electricity. kW and MW are the common units of power used to denote the size of a hydropower plant.

Royalty: Royalty is a fee or rent that is levied by the government for use of a natural resource (e.g. water in case of hydropower).

Runoff: Runoff is the amount of rainfall that remains on the surface and eventually drains into a nearby river system. Part of the rainfall also enters into the groundwater system and thus runoff, is always less than the total rainfall volume.

Runner replacement: The runner is the rotating part of a hydroelectric turbine. The runner needs to be replaced after a certain operating period due to abrasion (from sediments) and metal fatigue.

Sediment load: Sediment load refers to the amount of sediment carried by a river system at a particular location such as at the intake of a hydropower plant. Parts per million (PPM) or kg of sediment per m^3 of water (i.e., kg/ m^3) are the general units used to quantify sediment load.

Specific runoff: Specific runoff is the runoff that occurs on a unit catchment area of a river basin system. Generally runoff per km^2 of catchment area is used to denote specific runoff.

Tariff: Tariff is the price charged (Rs.) to the consumer by the Utility for use of one unit of electricity (kWh).

Utility/distributor: Utility/distributor is a legal entity such as a company or a corporation which is engaged in the business of supplying electricity to the consumers.

Watershed management: Watershed management refers to the management of a river basin area including the protection of flora and fauna, generally for the purpose of ensuring flow availability and environmental protection.

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