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Risk sharing in hydropower development: case study of the Chukha Hydel Project in Bhutan

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Abstract

The Himalayan rivers have an enormous hydropower potential that is still not exploited fully for the benefit of the region. Bhutan and Nepal together have an economically feasible potential of 60,000 MW of hydroelectric power generation capacity but are too weak financially to bear the risks associated with the development of their hydro resources alone. India is the only potential market for the electricity supplied from these sources. The power purchase agreement framework for the 336 MW Chukha Hydel Project in Bhutan could serve as a model for the transfer of risks, management of risks and sourcing of finance in exchange for sharing the economic rents associated with such projects. India undertook the costs and risks of constructing the hydroelectric dam and power plant in exchange for a reduced purchase price of electricity from the completed facility. This paper contains a financial and economic assessment of the Chukha Hydel Project. While India is in a position to exercise monopsonic power in this electricity market, this analysis shows that it is possible to have an agreement for sharing the risks and returns between India and the Himalayan countries that is highly beneficial to all the stakeholders.

Keywords: Bhutan; Economic rents; Electricity; Electricity exports; Himalayas; Hydropower; India; Power purchase agreement; Risk sharing

Introduction

The Himalayan rivers that flow south into Ganges and Brahmaputra plains have enormous untapped hydropower potential. The estimated theoretical hydropower potentials of these rivers in eastern and central Himalayas are: Bhutan, 30,000 MW; Nepal, 84,000 MW; Sikkim, 8,000 MW; and Arunachal Pradesh, 80,000 MW. The combined potential of the western Himalayan Indian states is 40,000 MW. So far only some 20,000 MW of hydropower generation capacity has been developed in all these

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rivers combined. An additional 20,000 MW of generation capacity is now under construction, mainly in the Indian Himalayan states. Nepal's developed hydropower generation capacity stands today at 550 MW (Gautum & Karki, 2006).

India's demand for electricity is growing rapidly and this growth in demand is almost certain to continue. At the end of March 2012, India's installed generation capacity of all types was 182,345 MW (CEA, 2011). The current rate of economic growth is rapidly increasing the demand for electrical energy. In 2010, India's average peak load capacity shortage was 9.8%, with 7% energy deficit of the total energy generated (CEA, 2011). To sustain the current trend in its economic growth rate, India will need to add another 100,000 MW of installed capacity by 2012 and another 100,000 MW by 2017. The Kirit Parikh Committee Report estimates that India's requirement for power generation capacity will be 778,000 MW by 2032 (Talmiz, 2006).

Large hydropower project sites, particularly those with lower per MW investment costs, are now being examined for development. Investment opportunities in hydroelectric projects will increase with the growth of India's electricity demand as the real cost of alternative sources of energy increases. It has been estimated that India would require US$250 billion and US$280 billion, respectively, to add new capacity during the 11th Plan (2007–12) and the 12th Plan (2013–17) (PFC, 2009). Potentially, a considerable portion of this investment could come to Bhutan and Nepal where low-cost hydroelectric sites are relatively close to India's power grid.

India has recognized the need to build the necessary infrastructure for long distance electricity transmission in order to establish the inter-connectivity of its five electricity regions. Energy generation resources in India are not evenly distributed. Its vast reserves of coal are mainly located in the eastern electricity region[1] while the bulk of the potential hydropower generation sites are located in the Himalayas which are closer to the north eastern, eastern and northern electricity regions. The national grid facilitates the development of the Himalayan hydroelectric resources as the long distance transmission infrastructure is largely in place to bring the electricity to market.

Bhutan and India have progressed in their collaborative hydropower development since the completion of the 336 MW Chukha Hydel Project in 1989. In 2008 prices, India invested US$403.65 million in Chukha, US$1,267 million in Tala and US$181 million in Kurichu hydroelectric projects creating a total installed capacity of 1,410 MW in Bhutan. More recently India has signed a memorandum of understanding with Bhutan to develop an additional 5,000 MW of hydropower generating capacity by 2020. In contrast, Nepal has hesitated to enter into long-term power purchase agreements with India in the development of its vast hydropower resources, fearing that India will exploit its monopsonic power in the negotiation and implementation of these projects.

While there is little doubt about the visible impact of India's investment in hydropower projects in Bhutan, there has not been a rigorous analysis of how the financial and economic costs and benefits have been allocated between the two countries. India has invested the capital, built the projects on a turnkey basis and agreed to purchase the surplus electricity supplies. The project agreement has allocated all the completion and market risks to India, while providing Bhutan with a stable stream of revenue in exchange for the hydro energy from its rivers. Using historical data on investment costs, operating costs, hydrological data and price adjustments for inflation and cost escalation, this study estimates the financial and economic costs and benefits from the perspective of both Bhutan and India.

[1] Coal reserves in India are estimated at 200 billion metric tonnes.

The Chukha Hydel Project is a run-of-the-river scheme located on the Wang Chu gorge in Western Bhutan[2]. The physiography of the area permits the creation of a water head of 404 m. The dam has a storage capacity to generate 336 MW of peak load for 4 hours daily throughout the year. From June to September the monsoon rains increase the water flow so that during this period generation can be at a 336 MW level on a 24 hours a day basis. At other times of the year the facility is designed to utilize 336 MW of capacity to meet the morning and evening peak load demand while using only 84 MW of its capacity to meet the base load demand during off-peak hours. The contractual agreement does not differentiate between peak and off-peak energy. Instead, in order to fix the price of electricity export, it divides the total energy generation between firm and seasonal energy[3].

The project was financed entirely by India. The investment included preliminary works, civil works, buildings, production equipment, special construction equipment, labor, construction materials, environmental protection works and transmission lines. Expressed in 2008 prices, the initial estimated cost in 1974 was US$156.04 million. The project was completed at a cost of US$403.65 million, including the cost of another tail race tunnel, which was not included in the initial estimate. The cost overrun was nearly 159% in real terms[4]. Repeated cost revisions were the major concern for India. The successful completion of Chukha was crucial for its prestige and future cooperation on other major hydroelectric undertakings in Bhutan.

Contractual arrangement

The terms and conditions of the contractual agreement between the two countries are critical for allocation of the benefits of the projects flowing to each of the parties. The salient features of the Agreement between the Government of India and Royal Government of Bhutan regarding the Chukha Hydel Project (CHP, 1974) are paraphrased below for consideration in a financial and economic analysis:

1. The project was to be managed by the Chukha Project Authority (CPA) until the time of its completion. After its completion, the CPA will hand over the management to the government of Bhutan.
2. India will provide the total investment on the project, 60% as grant and 40% as a loan to Bhutan. Bhutan is required to repay the loan at a 5% interest rate in 15 equal installments, repayment beginning 3 years after the completion of the project.
3. Bhutan will provide free land, timber and firewood for the project and will not impose taxes on construction materials and capital goods procured for the project.
4. Employment at the project will be restricted to nationals of Bhutan and India. If necessary, low skilled staffs and laborers could be imported from a third country.
5. Taking into consideration the time-series data of the previous 20 years, both Bhutan and India agreed upon prices for firm and secondary energy. In 1988 prices, the selling price of firm energy would be US$0.0203/kWh and secondary energy US$0.0101/kWh. From its total generation, only 832 million kWh per year is to be considered as firm energy.

[2] In a run-of-the-river project, a dam is built across the river to divert water onto the turbines to generate base load only. If storage space is available upstream for construction of a dam, storage capacity could be built to store water for peak load generation every day in addition to the base load supply.

[3] The contract was reviewed in 1995 and a single negotiated price was agreed upon for sale of electricity to India.

[4] The cost overruns were due to additional engineering provisions in order to address concerns about geological surprises.

6. Electricity derived from the project is to be supplied only to Bhutan and India. For 99 years India will buy all the electricity generated from the project in excess of Bhutan's requirements. The sales price of electricity to India shall be revised by the two governments after the end of each 4 year period. The reviews are to be guided by the following criteria:
   (i) Increase in operation and maintenance costs of the Chukha project.
   (ii) The average percentage increase in the cost of generation of hydroelectric power during the previous 4 years in the eastern–north eastern region of India.
   (iii) Any other factor relevant at that time.
   (iv) No duty, surcharge or any other form of levy is to be charged by Bhutan on the power sold by Bhutan to India.
7. Any disputes concerning the arrangement are to be settled by an independent jury instituted jointly by Bhutan and India. Members of the jury are to be either citizens of Bhutan or India; the chairperson, however, is to be nominated by Bhutan.

Financial model

To model the financial cash flows of the project we consider that the project (p) generates Q_t^p million kWh of electricity annually. Of this quantity, an amount, equal to $Q_{t,}^A$ million kWh, where subscript 't' refers to time throughout, is used as auxiliary consumption (A), Q_t^d million kWh is supplied to domestic (d) consumers and Q_t^x million kWh is exported (x) to India. The annual production has varied from year to year depending upon the availability of water in the river. The energy balance is shown as:

$$Q_t^p = Q_t^d + Q_t^x + Q_t^A \tag{1}$$

To estimate the financial net present value (NPV) from the viewpoint of Bhutan, the project is evaluated for inflows and outflows including the residual values reported in 2024, the final year of the analysis. The present value (PV) of inflows from the beginning of the project through to 2024 comprises the discounted values of the capital subsidy (CS_t)[5], the domestic cost savings and revenue (DR_t) from the sales of electricity to Bhutan[6], the export revenue (ER_t) from the sales of electricity to India[7], the receipts and recovery (RR_t) during the construction period[8] and the residual values (RV_t) of the project

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[5] The annual capital inflows from India to finance the construction costs is CS_t.

[6] The domestic sales revenue can be expressed as $DR_t = Pd_t \times Qd_t$, where the price (Pd_t) and quantity (Qd_t) of sales to Bhutan are determined from the previous year's records adjusted for growth rate for that particular year. The project began to sell electricity from 1987 and would continue until 2024. From 2006 onward, the cap for quantity of domestic sales is fixed at 280 million kWh.

[7] The export sales revenue can be expressed as $ER_t = Px_t \times Qx_t$, where the export tariff (Px_t) and the quantity (Qx_t) sold to India are determined from the previous year's records adjusted for the growth rate for that particular year. The project began to export electricity from 1987 and would continue until 2024. In the past, the quantity of electricity exported to India declined with the growth rate in domestic demand.

[8] Receipts and recovery realized by the project during the construction period (*RR*t). It includes sales of used equipment, refund of advances to the contractors and other miscellaneous services provided by the project to outsiders.

in year 2024[9]. It can be expressed in 2008 values as:

$$\text{PV of inflows in 2008} = \left\{\sum(CS_t + DR_t + ER_t + RR_t + RV_t)\right\} \times (1+r)^{(2008-t)} \tag{2}$$

The present value of outflows comprises the discounted value of capital cost (CC_t)[10], recurring costs (RC_t)[11], the changes in working capital (ΔWC_t)[12], periodic capital investment costs ($PCIC_t$)[13] and loan repayments (LR_t)[14]. It can be expressed in 2008 values as:

$$\text{PV of outflows as of 2008} = \left\{\sum(CC_t + RC_t + \Delta WC_t + PCIC_t + LR_t)\right\} \times (1+r)^{(2008-t)} \tag{3}$$

The difference between the PV of inflows and outflows yields the NPV for Bhutan. The present values are calculated by discounting the net cash flows from 1974 to 2024 by using the real discount rate of 10.5%[15]:

$$\text{NPV in 2008} = [\text{PV of inflows} - \text{PV of outflows}] \tag{4}$$

Financial benefits to Bhutan

The project began power generation in 1987. India handed over the project to Bhutan in 1989 after commissioning all the generating sets at the power plant. On the average, from 1990 to 2008, the project generated annually 1,747 million kWh of electricity[16]. Upon completion of the additional tail race tunnel in 1993, annual energy generation has fluctuated from a minimum of 1,623 to a maximum of

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[9] Residual values that would be realized at the end of the economic life of the project in 2024 (RV_t). It is estimated at 10% of 77% of the civil investment costs in 1989; 10% of 77% of the investment costs on additional tail race tunnel; and the book value of the capital expenditures on replacement of mechanical and electrical equipment that would occur in 2009, depreciated annually at 5%. Land which was provided free to the project was estimated to have a market value at US$6,767 in 1974. The residual values would be realized in 2024 at constant real prices.

[10] The capital investment costs that occurred during the construction period (CC_t). These are annual outflows from 1974 to 1989 and cost of the additional tail race tunnel that occurred from 1990 to 1994. This additional cost was financed with revenue flows from the project, hence not included in the estimation of annual loan repayments.

[11] The recurring costs comprise overheads, maintenance costs and wheeling fee (RC_t). They cover the period from 1990 to 2004, during the operation period only.

[12] Changes in working capital (ΔWC_t) comprise the changes in accounts receivables, changes in accounts payables and changes in cash balance from 1990 to 2024. The working capital, which comprises accounts receivables, accounts payables and cash balance, were estimated at 8.33% of sales revenue and operating costs, respectively.

[13] The periodic capital investment cost ($PCIC_t$) is the cost of major repair and maintenance or replacement of mechanical and electrical equipment. The project had to invest US$3.02 million in 2002; US$9.30 million in 2003; and it required an investment of US$114.09 million in 2009 – all in 2008 prices.

[14] Loan repayments (LR_t) started in June 1993 and would end in June 2007.

[15] The real financial discount rate for Bhutan is considered to be the same as the social discount rate, which is approximated to equal to the social opportunity cost of capital for India.

[16] The complete set of financial and economic models of the project's financial and economic resource flows can be downloaded from www.queensjdiexec.org/publications/qed_dp_157.xls.

2,117 million kWh. The auxiliary consumption, on the average, has remained at 0.39% of the total generation (SYB, 2006).

The recurring costs of the project, paid for by Bhutan, are made up of overhead costs, maintenance costs and a wheeling fee. In 2008 prices, the average recurring costs of 18 years was 22.33% of the annual revenue. The annual real increases in overheads and maintenance costs averaged over the period were 6.93% and 7.91%, respectively (SYB, 2000, 2006). These increases primarily came from real wage increases, increases in the real prices of repair and maintenance costs and the cost of repairs to the infrastructure by damage caused by the monsoon rains. The wheeling fee paid to Bhutan's Department of Power is for delivery of the electricity to the Indian transmission network at the border.

Repayments of the loan were made on a bi-annual basis. As agreed in the contract, the total repayment was calculated based on 40% of the capital inflows from 1974 to 1989, using a fixed nominal interest rate of 5%. As the average inflation rate from 1993 to 2007 was 5.9% (SYB, 2006), the real values of annual repayments have been falling owing to the negative impact of inflation on the value of the real interest rate. Expressed in 2008 prices, the first bi-annual repayment made in 1993 amounted to US$3.75 million. By 2008 the real value of equal bi-annual repayment was eroded by inflation to US$1.72 million. Inflation reduced the real present value of the loan repayments by 35.7%[17].

From the commencement of power generation to the end of 2008 Bhutan has earned US$636.62 million (2008 prices). The annual revenue flows to Bhutan depended upon the revisions of the export tariff and availability of water on the river. On average, the annual real increase in export tariff was 7.3% although there was a time lag between the annual real average increase in recurrent costs (3.3%) and the subsequent increases in the export tariff. The export tariff in 2005 was negotiated to be Rs 2.0/kWh, which in 2008 prices translates to US$0.051/kWh. The levelized domestic sale price of electricity over the period from 1990 to 2008 was US$0.008/kWh (2008 prices). These values are projected to remain constant in real terms in the calculation of future revenue for Bhutan.

The financial NPV of the project in 2008 was estimated to be US$1,170.6 million (2008 prices). The project has had a comfortable cash position to service the loan. Its lowest annual debt service coverage ratio was 2.28 in 1994. There was a steady increase in total revenue generation because of the revisions in export tariff. The annual real revenue received by Bhutan (2008 prices) was a minimum at US$20.96 million in 1992 and a maximum of US$80.81 million in 2000. This provided a substantial net income for Bhutan after deducting the recurrent costs.

Economic net benefit for Bhutan

The contractual agreement stipulates that India will buy all the electricity generated by Chukha in excess of Bhutan's requirements. Figure 1 illustrates the movement of the demand for electricity in Bhutan over time. In 1987 when the project started generating electricity, the total requirement for electricity in Bhutan was 70 million kWh (SYB, 1991). This quantity of electricity, Q^b in Figure 1, was imported from India. The Department of Power, Royal Government of Bhutan, served as the sole supplier and distributor of electricity in the country.

The project supplied 5.64 million kWh to Bhutan in 1987 and 38.23 million kWh in 1988. Electricity from Chukha replaced the entire import of electricity from India by 1989 when the total consumption of

[17] The present value was calculated using a real rate of discount of 10.5% that was obtained from Shukla & Ranjan (1997)

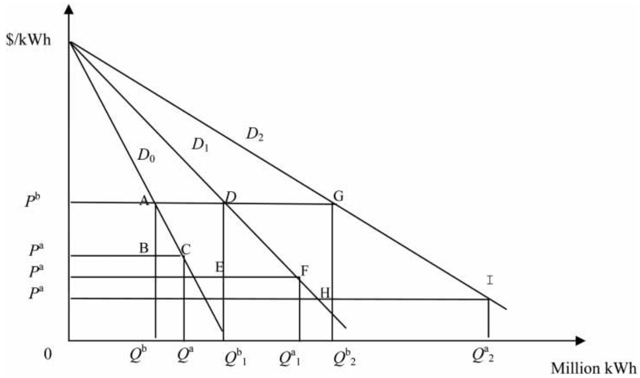

Fig. 1. Domestic supply with growth in demand.

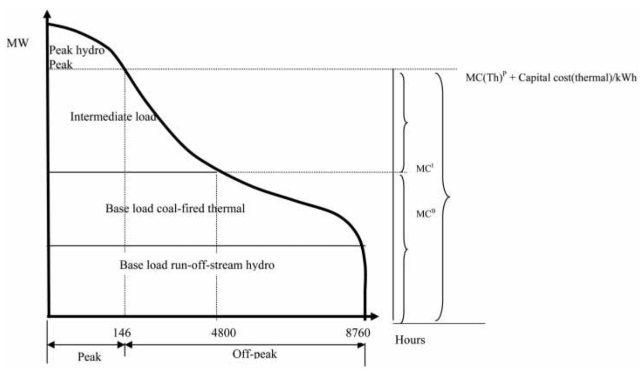

Fig. 2. Load duration curve of eastern electricity region, India.

electricity in the country rose to 130 million kWh (SYB, 1991). In the first 2 years when electricity generation from the plant was not at its full capacity, the project supply substituted for a fraction of the electricity previously imported.

From 1989 onwards the project not only replaced imports but made the electricity available at a lower price P^a. The gains for the country in terms of the savings from reduced electricity purchases at a price of P^b from India are shown in Figure 2. When the electricity price was reduced from P^b to P^a, the quantity of electricity demanded increased from Q^b to Q^a, where 'b' is before the project and 'a' is after the project. Thus, the total consumer surplus benefit to Bhutan in 1989 is shown by the area P^bACP^a. This includes the gain received from the reduced cost of the quantity previously imported, P^bABP^a, plus the gain in additional consumer surplus (ABC) from the increase in the quantity of electricity demanded due to the lower price.

The estimated value of P^b is derived from the price of electricity that the consumers paid without the project. In 1987, the consumers paid Rs 0.70/kWh (SYB, 1991). From these savings, the Department of Power spent Rs 0.17/kWh for transmission and distribution, in addition to transmission and distribution (T&D) loss of 15% (SYB, 1991). Hence, the value at the bus bar in 1997 of Chukha electricity derived from the cost of imported electric energy is:

$$\text{Tariff}_{(1989)} - TD_{\text{cost}} - P_0 \times TD_{\text{loss}} \text{ or } 0.70 - 0.17 - 0.105 = 0.43\,\text{Rs/kWh}$$

In 2008 prices this amounts to US$0.045/kWh. This is the maximum economic value per kWh of electricity from Chukha derived from the willingness to pay of domestic consumers for electricity. This value is assumed to remain constant in real terms for the entire evaluation period. We do not know what India would have charged Bhutan for electricity during the period if Chukha did not exist; however, it is highly unlikely to be a lower price.

In contrast, the project charged Bhutan's consumers at the bus bar Rs 0.10/kWh from 1989 to 1994 and maintained a constant nominal value of Rs 0.30/kWh from 1994 to 2007. This constant nominal price of electricity for domestic consumers has resulted in declining prices (P^a_t) in real terms from 1994 to 2007 due to inflation. The levelized value of the domestic tariff for the period 1990 to 2005 was US$0.008/kWh at 2008 prices. This value, maintained in real terms, was adopted for the estimation of the domestic tariff beyond 2009[18].

In addition, there are savings in expenditure on imported electricity owing to the growth in domestic electricity demand. On average, the electricity demand grew at 10.4% per year from 1990 to 2005 (SYB, 1995, 2000, 2006). It was fueled by the establishment of new energy intensive industries recording quantum jumps of 30% in 1992, 41% in 1995, 28% in 1996 and 46% in 2002. There was also a surge in rural electrification, particularly in western Bhutan, and an increase in the use of electrical appliances among the urban population. Thus, the quantity of electricity supplied by Chukha for domestic consumption increased from 130 million kWh in 1989 to 305 million kWh in 1995 to 483 million kWh in 2000 and to 450 million kWh in 2004[19] (SYB, 1991, 1997, 2000, 2006). From 2005 onwards, the supply from Chukha to the domestic market has been capped at 255 million kWh by an amendment of the project agreement with India (SYB, 2006)

The growth in domestic demand for electricity can be attributed to both the growth of income and the effect of lowering the real price of electricity. The income effect primarily causes the demand curve to rotate outward. The shift of the demand curve from A to D and from D to G in Figure 1 can be considered to be a measure of electricity growth in year 1 and year 2, respectively, owing to the income effects. The corresponding shifts from E to F and from H to I are due to the fall in the real value of electricity price from P^b to P^a to P^a_1 and P^a_2, respectively. The additional economic gains for Bhutan owing to the increase in domestic demand and the reduction in the real value of the tariff is measured by area $P^b\mathrm{DF}P^a_1$ for year 1 and area $P^b\mathrm{GI}P^a_2$ for year 2. These areas could be divided into economic gains due to the savings in tariff expenditures and increases in consumer surplus. Area $P^b\mathrm{DE}P^a_1$ measures the savings in tariff expenditures for year 1 and area $P^b\mathrm{GH}P^a_2$ gives savings for year 2. Similarly, area DEF measures the additional consumer surplus for year 1 and area GHI for year 2 that are brought about by the increase in the quantity of electricity demanded owing to the fall in the real price of electricity over time. Thus, the economic benefit from the increase in domestic consumption caused by the income effect for any time 't' can be estimated as: $STE_t = (P^b - P^a{}_t) \times Q^b{}_t$. Similarly, the economic benefit of an increase in domestic consumption caused by the price effect for any time 't' can be estimated as: $CS_t = 1/2 \times (P^b - P^a{}_t) \times (Q^a{}_t - Q^b{}_t)$.

The annual demand for electricity in Bhutan for the period 1990 to 2005 was as recorded (SYB, 1991, 1995, 2000, 2006) and the projection of demand for the years beyond that point was estimated by using

[18] Bhutan Electricity Act (2006) provides provision for periodic revision of the tariff to account for erosion in the real value due to price inflation or cost escalation.

[19] The decrease in Chukha supply to domestic consumers is attributed to production from other supply sources, particularly smaller hydro, from 2000 onward.

the relationship: $Q^{a}_{t} = Q^{a}_{t-1} \times (1 + g^{e}_{t})$, where g^{e}_{t} is the projected annual growth rate in electricity demand. The projected growth in electricity demand in Bhutan was estimated to be 8% per year based on the projected increase in Bhutan's real income over time (Planning Commission, 2001). The increase in electricity demand owing to income growth alone can be derived by using the relationship: $\Delta Q^{b}_{t} = Q^{b}_{t-1} \times \eta_{I} \times \Delta Y/Y$, where, η_{I} is the income elasticity of demand for electricity and $\Delta Y/Y$ is the real growth of gross national product, expressed as a proportion of the previous year's income. The income elasticity of electricity for Bhutan is assumed at 1.45, the growth rates in gross national product for the period 1990 to 2005 were as recorded (SYB, 1995, 2000, 2006) and the projection of the growth rate of GNP for beyond 2008 was estimated at 6% (SYB, 2006).

During the construction period Bhutan did not benefit much from the opportunities created by the capital investment. The Bhutanese economy did not have the required absorptive capacity and the goods and services used in the projects were exempted from any kind of taxes or import duties. There were hardly any Bhutanese employed by the project as most of the work contracts went to Indian nationals. After commissioning the project many Bhutanese were employed. In 1990 Bhutanese nationals constituted about 13% of the total workforce, but by 2005 they had increased to 75% (SYB, 2006). The Bhutanese workers at the Chukha project receive an additional allowance of 15% on top of their base wages while at the same time they are required to pay personal income taxes at a rate of 15% on their gross earnings. In addition, the government collects a 15% sales tax on the plant maintenance cost which constitutes, on the average, about 22.33% of the recurring expenditures. These tax externalities (TE_t) accrue as benefits to the government.

Thus, the present values of the net economic benefits (NEB) to Bhutan as of 2008 are made up of four components as expressed in Equation (5): the present value of cash flows from the project; the present value of savings (price differential) from the reduced imports of electricity; the present value of the consumer surplus from the increase in the quantity demanded; and the present value of tax externalities.

$$\text{NEB(Bhutan)} = NPV_{\text{f}}^{\text{b}} + \sum \{STE_t + CS_t + TE_t\} \times (1 + r)^{(2008-t)} \tag{5}$$

where $NPV_{\text{f}}^{\text{b}}$ is the financial net present value at 2008 prices, evaluated from 2008, to Bhutan while using an economic discount rate of 10.5%; STE_t is the expenditure savings on import of electricity from India from 1987 to 2023 because of the lower price of electricity from Chukha; CS_t is the consumer surplus generated by increase in the quantity of electricity demanded from 1989 to 2005; TE_t is the personal income tax from Chukha's employees and sales tax collected on recurring expenditure. The tax collections began only from June 1992 when the project was handed over officially to the Bhutan government; and $(1 + r)^{(2008-t)}$ is the discount factor, where $r = 10.5\%$ and 't' varies from 1974 to 2024.

The net present value of the economic benefit of the project to Bhutan evaluated in 2008 prices is estimated to be US$2,286.51 million[20]. Of this, consumers captured US$1081.18 million as consumer surplus, the Bhutan government received US$34.73 million in taxes and the project itself received a net present value of US$1170.60 million. These latter benefits will become part of the non-tax revenue of the government.

[20] It is assumed that the market value of land captures the foregone benefits of agricultural production and negligible costs or benefits are associated with this project from other sources.

Economic benefits for India

The Chukha project created a net present value of US$2,286.51 million as economic benefits for Bhutan with little of its own investment as India financed the entire capital cost within a turnkey arrangement. Of the total capital cost, 60% was given as a financial grant to Bhutan. Bhutan repaid the remaining 40% loan after 3 years of grace period, in 15 equal installments at a fixed nominal interest of 5%. Given these values we wish to find out what was the incentive for India to make such a large amount of investment in the Chukha Hydel Project and has it gained or lost from this investment?

Chukha's generation is supplied through a transmission line connected to India's eastern electricity region. In 2007, the region had 17,754.5 MW of installed capacity (Maheshwari, 2008). About 82% of the total capacity is made up by 112 thermal power plants, each with a capacity varying from 6 to 500 MW. These plants are operating at a capacity utilization factor varying from 45 to 80%. The component of gas-fired plants makes up a total of 183 MW, which have operated on the average at a plant load factor of 17%. Hydropower constitutes 3,175.5 MW of the total capacity, or 18% of the total, and contributes to both meeting the demand for peak load as well as the base load (Maheshwari, 2008). The region has developed most of its potential hydroelectric sites. Figure 2 depicts the characteristics of an annual load duration curve for India's eastern electricity region.

Gas-fired plants are the alternative to Bhutan's peak load hydroelectricity, fuel-efficient super-thermal coal-fired plants are the alternative to base load hydropower and fuel-inefficient, old thermal power plants, which have larger operation and maintenance costs, are the alternative to intermediate load electricity provided by Chukha. Table 1 below shows the breakdown of Chukha's annual electricity generation into consumption in Bhutan and electricity exports to India (SYB, 1991, 1995, 2000, 2006). These are average figures for the bracketed periods depicting the share of peak, firm and intermediate load electricity supplied from Chukha for the years 1989–93, 1994–98, 1999–2003 and 2004–24. There was no base load supply to India from Chukha from 1999 to 2003 because of the increase in electricity demanded by Bhutan.

The Chukha's engineering design provides an opportunity to use the full 336 MW of the capacity for 4 hours each day, generating annually 467.2 million kWh of electricity during the peak periods. This leaves 356.8 million kWh of firm energy to split between the consumption in Bhutan or export to

Table 1. Electricity generation, Chukha Hydroelectric Project.

Period	1989–93	1994–98	1999–2003	2004–24
Total availability (million kWh)	1,551.37	1,761	1,952.07	1,745
Supply to Bhutan (million kWh)	138.75	322.70	456.44	254.95
Supply to India (million kWh)	1,381.52	1,431.0	1,495.63	1,483.25
Peak load (million kWh)	467.20	460.32	414.96	467.20
Base load (million kWh)	226.05	48.98	000.00	109.85
Intermediate load (million kWh)	688.27	921.48	1,080.67	906.20
Share of peak load	0.34	0.32	0.28	0.31
Share of base load	0.16	0.03	0.00	0.07
Share of intermediate load	0.50	0.64	0.72	0.61

India as base load electricity[21]. The remaining is the seasonal energy which is supplied to meet the intermediate load demand during the monsoon months.

Thus, if α_t, β_t and δ_t are the share of peak, firm and intermediate loads from the annual electricity import from Chukha and if $C^{P}{}_{t}$, $C^{B}{}_{t}$ and $C^{I}{}_{t}$ are the avoided cost of supplying the peak, base and intermediate load electricity in the eastern electricity region, the economic value of Chukha electricity ($EVCE_t$) to India for any year, t, is:

$$EVCE_t = \alpha_t \times C_t^{P} \times Q_t^{I} + \beta_t \times C_t^{B} \times Q_t^{I} + \delta_t \times C_t^{I} \times Q_t^{I} \tag{6}$$

where:

$$\alpha_t + \beta_t + \delta_t = 1$$

$Q_t{}^{I} = Q_t{}^{X} \times (1–k)$; where k is the loss of electricity during the high voltage transmission from Bhutan. These losses are estimated at 4.5% of the total electricity delivered at the border, $Q_t{}^{X}$.

$\alpha_t = 0.34$ for 1989–93; 0.32 from 1994–98; 0.28 from 1999–2003; and 0.31 from 2004 onward. $\beta_t = 0.16$ for 1989–93; 0.03 from 1994–98; 0.00 from 1999–2003; and 0.07 from 2004 onward. $\delta_t = 0.50$ for 1989–93; 0.64 from 1994–98; 0.72 from 1999–2003; and 0.61 from 2004 onward.

There were outflows of capital from India from 1974–93 and inflows of repayments from 1993 to 2008. Thus, the stream of net investment cost for India can be shown as:

$$NIC_t = \sum CI_t - \sum REP_t \tag{7}$$

where CI_t are costs during the construction period and REP_t are loan repayments made to India by Bhutan.

India pays a flat tariff for delivery at the border for the electricity. In 2008 prices, export tariff (ET) was US$0.027 per kWh when the project began electricity generation. The tariff has been revised several times. Since 2005 India has been paying Rs 2.0 per kWh (0.051 US$ at 2008 prices) in nominal value. Thus, India's annual expenditure (AE) for import of Chukha electricity is:

$$AE_t = Q_t^{X} \times ET_t \tag{8}$$

Thus, the net economic benefit for India from the investment in the Chukha project is obtained from Equations (6) to (8) and adjusting for any externalities (EX_t) associated with the foreign exchange premium (FEP), taxes and subsidies in supply of goods and services and environmental benefits or costs

[21] Initially, the bilateral contract recognizes 832 million kWh as firm energy and 1,300 million kWh as seasonal energy from the total annual supply. The pricing policy did not differentiate between the firm and the seasonal energy after 1995. The capacity of the plant was expanded to 370 MW from 1994 onwards to take advantage of monsoon water flow for few months in some years. For our analysis we will treat the capacity of the plant as 336 MW.

associated with the supply of Chukha electricity. The present value of the net economic benefit to India in 2008 is expressed as:

$$\text{NPV} = \sum \{EVCE_t - (NIC_t + AE_t) \pm EX_t\} \times (1 + r)^{(2008-t)} \quad (9)$$

Avoided cost of peak load electricity

India has used Chukha's supply to meet its peak load electricity demand because the import price is the same whether the electricity serves peak load or base load demand. The substitute for peaking electricity from Chukha is generation from gas-fired plants. The generation cost of gas-based electricity supply can be split into capital cost (K_t), fuel cost (F_t), variable repair and maintenance cost (RMC_t)[22] and fixed maintenance and overheads (FMO_t)[23]. India imports natural gas. The cost of fuel needs to be adjusted for changes in its real price and for the cost of FEP [24]. Assuming the share of tradable content in the (RMC_t) is 80%, the estimate of the avoided economic cost of peaking electricity from a gas-fired power plant is:

$$C_t^{\mathrm{p}} = K_t + F_t(1 + g_t) + RMC_t + \rho_t \times \{K_t + F_t(1 + g_t)\} + 0.80 \times \rho_t \times (RMC_t + FMO_t) \quad (10)$$

where g_t is the real growth rate in price of natural gas and ρ_t is the FEP.

In 2008 prices, the capital cost of a gas-fired plant in India is US$580 per KW of installed capacity (Nuclear Energy Institute, 2008). The eastern electricity region had been experiencing a shortage of peaking load capacity. Assuming the opportunity cost of capital for the power sector at 9.5% (real), replacement cost of wear and tear at 5% of the capital cost and the average plant load factor of 17%, the financial capital cost (K_t)/kWh to substitute the peak load supply from Chukha is estimated to be US$0.056/kWh[25]. Specific fuel consumption for a gas-fired plant is 8.21 MJ kWh^{-1} and the international price of gas on the average over the project life is assumed to be US$10.0/GJ at 2008 prices. This yields the fuel cost (F_t) of US$0.10/kWh. Assuming the average FEP for India over the life of project at 10% and substituting the values of these variables in Equation (11), the avoided economic cost of peaking electricity from the Chukha supply is estimated to be US$0.17/kWh at 2008 prices[26]. In rupees it translates to Rs 7.18 per kWh.

[22] *RMCt* is the variable repair and maintenance costs, which is estimated to be US$0.8/MWh for the gas-fired plant in the eastern electricity region at 2000 prices. This translates to US$0.0008/kWh at 2008 prices.

[23] *FMOt* is the fixed maintenance and overhead expenses, estimated to be US$1670 per MW per month for the gas-fired plant in the eastern electricity region at 2000 prices. This translates into US$0.015/kWh at 2008 prices for 336 MW of peak power supplying 467.2 million kWh of electricity annually.

[24] The price of LPG has been volatile in the international market. The landed price of gas at the port in India was US$11.64/million BTU in 2000 prices, which is equivalent to US$13.83/GJ in 2008 prices. But the government maintains an administered price for gas, which is much lower than the cost of supply.

[25] Capital cost = US$380; peaking hours=1760; opportunity cost of capital = 9.5% real; replacement cost = 5%; and foreign exchange premium = 10%. On per kWh basis this amounts to US$0.056 of electricity supply at 2008 prices.

[26] In May 2001 the generation cost of Dobal Power Plant in Maharastra was Rs 8.75/kWh, which is a naptha-based base load generation plant. At an exchange rate of Rs 45/US$, the cost of generation translates into US$0.19/kWh at 2001 prices and US$0.23/kWh at 2008 prices.

Avoided cost of base load electricity

The avoided cost of firm electricity supply is equal to the fuel savings in super-thermal coal-fired power plants. Such super-thermal power plants are built near to large open-pit coal mines, avoiding the long-haul transportation cost. The average heat rate for Indian coal is 15,500 BTU/kWh (Guha, 2003) and the average cost of Indian coal at the pit head is estimated to be US$1.45/million BTU (IEA, 2000) at 2008 prices. This translates into the cost of fuel in a coal-fired super-thermal power plant being US$0.025/kWh at 2008 prices. In addition US$0.0016/kWh is required at 2008 prices to cover the non-fuel variable operating cost. This includes the cost of furnace oil to mix with pulverized coal to make the fuel spray and the cost of ash handling[27]. The Indian coal used in the power plant has an ash content between 35 and 50%[28] (IEA, 2000). Thus, the avoided cost of base load electricity supply in the eastern electricity region is:

$$C_t^{\mathrm{b}} = F_t^{\mathrm{c}} \times \left(1 + g_t^{\mathrm{c}}\right) \times (1 + \rho_t) + RMC_t + 0.80 \times \rho_t \times RMC_t \quad (11)$$

where $F^{\mathrm{c}}{}_t$ is the cost of coal per kWh, $g^{\mathrm{c}}{}_t$ is the real growth rate in coal price and RMC_t is the variable repair and maintenance cost per kWh.

With zero growth rate in the real price of coal, a FEP of 10% and substituting the values of other variables into Equation (11), the avoided cost of base load supply is estimated to be US$0.026/kWh at 2008 prices. In rupees this translates to Rs 1.25/kWh.

Avoided cost of intermediate load electricity

The avoided cost of using the seasonal electricity from Chukha can be assumed to be the fuel cost of the most fuel-inefficient thermal power plants that will be operated at a low plant load factor. Of 112 thermal power plants, there are 103 coal-fired plants with a wide variation in specific coal consumption from 0.56–0.99 kg kWh^{-1} of generation, the most fuel-inefficient being the 720 MW Muzaffarpur coal-fired plant in Bihar (CEA, 2004, 2011). Such plants have an annual planned maintenance schedule of 864 hours, which could be equivalent to 36, 54 or 108 days depending upon whether the working hours per day are 24, 16 or 8 hours, respectively. This means that secondary electricity generated during the monsoon months could be used as a substitute for the generation from such power plants scheduled for annual maintenance. Thus, if the electricity generated in the system is based on the optimal stacking method, the marginal cost of the intermediate load electricity from Chukha is the fuel cost of a gas-fired plant, which is equal to US$0.09/kWh, or equivalent to Rs 4.25 per kWh at 2008 prices.

Thus, the net economic benefit for India can be estimated from Equation (9) since the values of all the variables are known except for the environmental externalities. Chukha's economic rate of return for India is 13.72%, generating by 2008 an economic net present value of US$2,522 million at 2008 prices.

[27] Each kWh of electricity requires 6.1 ml of furnace oil.
[28] Each kWh of electricity generates 0.26 kg of fly ash.

Environmental externalities

Chukha project is a run-off river scheme with a small storage-cum-diversion dam for channeling the water to an underground power house. Except for the diversion dam, all other civil infrastructures are built underground, inputting little damage to the natural environment. In addition, the project involved hardly any human resettlements, including damage to the flora and fauna both in the upstream or downstream side. Therefore, environmental damage to Bhutan is negligible. But this project has positive externalities with regard to avoided cost of carbon emission and airborne pollutants since it has replaced the generation from fuel-inefficient thermal power generation. The government of India baseline emission survey for CO_2 emission has established that the weighted average specific emissions for coal-fired plants in the eastern grid is 1.02 MT of CO_2 per megawatt-hour of electricity generation (CEA, 2011). The estimate of avoided cost per tonne of carbon emission varied from US$22 at 1993 prices (Lovsoky *et al*., 2000) to US$167 at 2004 prices (Sathaye & Phake, 2004) for India. The estimates of avoided benefits range from 0.5 to 18 billion constant dollars estimated at a 2008 value during the operation period of the plant. This benefit is more global in nature although the gains could be attributed specifically to India.

Risk sharing and risk management

The bilateral contract provided India with the scope to manage the project risk to its advantage, while not penalizing the economic benefits of the project for Bhutan in the long run. India absorbed the construction risk and market risk by agreeing to provide the required capital, construct the project in a turnkey arrangement and off-take the excess supply of electricity from Chukha over the domestic consumption at a mutually agreed upon price subject to periodic revisions for inflation and cost escalation. The calibration of the import price of electricity *vis-à-vis* the hydroelectricity rent associated with Chukha Hydel Project has been the basis of risk sharing and management for India.

Hydroelectricity rents in theory are the economic surpluses created by the difference between the economic costs of supply from hydroelectric sites and the avoided costs of electricity supply from alternative sources. Therefore, the hydroelectricity rent is dependent not only on the economic cost of generation from a specific site but also on the cost of electricity from alternative sources to replace the hydroelectricity of Chukha.

India provided 60% in grants and 40% in loans to finance the required capital cost. The loan carried a 5% fixed interest rate to be repaid in 15 equal installments beginning the first repayment in June 1993. The net present value of capital cost (real), including its opportunity cost, for India in 2008 was given as:

$$CC(\text{India}) = \left\{\sum CI_t \times (1+r)^{(2008-t)}\right\} - \left\{\sum REP_t\right\} \times (1+r)^{(2008-t)}\} \quad (12)$$

where CI_t are the streams of capital inflows to the project as investment subsidy from 1974 to 1993. The estimation was carried out in 2008, taking into account the opportunity cost of funds 'r'. REP_t are the streams of repayments received by India from 1993 to 2008. India in return received a reliable source of hydroelectricity supply at a negotiated price. The contract for the supply is valid for 99 years. The levelized investment cost K_c for India is estimated to be US$0.044/kWh (2008 prices) by using the relationship given in Equation (13):

$$K_c = \left[\left\{\sum CI_t \times (1+r)^{(2008-t)}\right\} - \left\{\sum REP_t\right\} \times (1+r)^{(2008-t)}\right\}\right] / \left[\left\{\sum Q_t^{I}\right\} \times (1+r)^{(2008-t)}\right] \quad (13)$$

where Q^I_t is the quantity of electricity imported by India from 1987 to 2024, REP_t is the repayment of loan from 1993 to 2008 and CI_t is the capital inflow from 1974 to 1993.

In addition to the investment cost, India pays a negotiated export tariff (ET_t) and bears the marginal cost of transmission (MCT) from Bhutan to its consumption centers in the eastern electricity region. Hence, the supply price (P^s_t) of Chukha electricity for India is: $P^s_t = K_c + ET_t + MCT$. The supply price is estimated at US$0.066/kWh in 1990 including a bulk transmission loss of 4.5% and a wheeling cost of US$0.005/kWh at 2008 prices. As discussed in the economic analysis, the avoided cost (AC_t) of Chukha supply to India can be approximated as: $AC_t = \alpha_t \times C^P{}_t + \beta_t \times C^B{}_t + \delta_t \times C^I{}_t$. The avoided cost is estimated to be US$0.098/kWh in 1990 at 2008 prices.

Figure 3 depicts the estimate of hydroelectricity rent associated with the project. Area ABCD estimates the rent to India when the export tariff per kWh is ET, the MCT per kWh is MCT and the levelized capital subsidy per kWh is K_c. Similarly, area CBEF measures the rent accruing to Bhutan from the export of electricity. The hydroelectricity rent accruing to India would change with changes in the supply price, which in turn is dependent on the negotiation of the ET. Hence, the present value of hydroelectricity rent (HR) can be estimated as:

$$\text{PV of HR(India)} = \sum\left[\left\{\alpha_t \times \left(C_t^{P} - P_t^{s}\right) + \beta_t \times \left(C_t^{B} - P_t^{s}\right) + \delta_t \times \left(C_t^{I} - P_t^{s}\right)\right\} \times Q_t^{I}\right] \times (1+r)^{(2008-t)} \quad (14)$$

Figure 4 depicts the profile of hydroelectricity rent accruing to India from 1990 to 2008. The share of hydroelectricity rent to India was higher in the 1990s compared to the later years. The trend in the share reflects the impact of inflation on the negotiated tariffs.

India's strategy might be to manage the diplomatic goodwill of the Bhutan government by calibrating the import price of electricity *vis-à-vis* the relationship in Equations (13) and (14). Given that India has strategic and economic interests in developing the vast, untapped hydropower potential of 30,000 MW

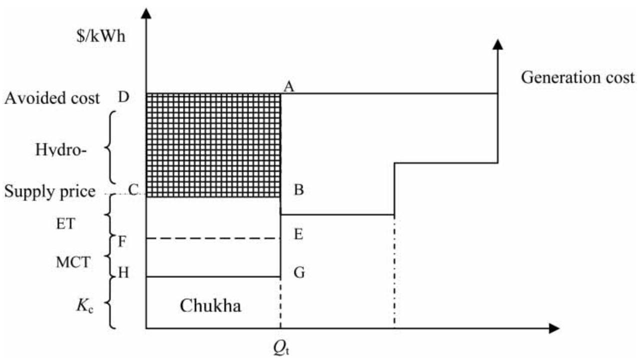

Fig. 3. Hydroelectricity rent from Chukha as perceived by India.

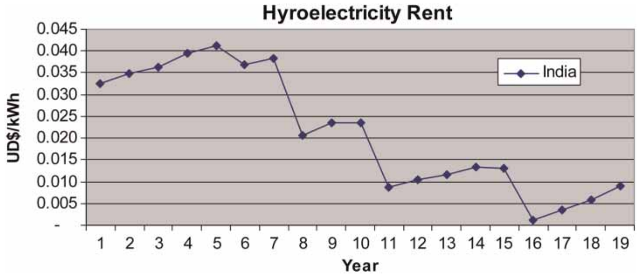

Fig. 4. Profile of hydroelectricity rent accruing to India.

in Bhutan, the calibration of the import price was an important consideration in the bilateral negotiations. Chukha has been a major industrial project for Bhutan, contributing as much as 45% of the total revenue collected by the government in 2005 (ADB, 2006). Obviously, India was not in favor of depriving Bhutan of its substantial electricity revenue by accelerating the recovery of its investment costs by taking a bigger share of the total hydroelectricity rent of the Chukha Hydel Project in the early years of the project operation.

India calibrated the import price based on its assessment of the need to recover the capital investment with its opportunity cost. A part of the investment cost was paid by Bhutan in loan repayment. But the part of the investment costs that was given as a grant was in fact recovered by the capture of part of the hydroelectricity rent by the low purchase price of electricity. India completed the recovery of the investment cost with its economic opportunity cost by 1997. This was the year India agreed to double the electricity export price paid to Bhutan. The last negotiation of the import price split the rent in the ratio of 48:52 between Bhutan and India. If this price is kept constant for the remaining life of the project, Bhutan and India will be sharing the hydroelectricity rent almost on an equal basis. The share of economic benefits to India would be higher if the benefits of avoided atmospheric pollution, ash handling and carbon emissions are taken into account.

Conclusion

The Chukha Hydel Project is an excellent example of bilateral cooperation in which both countries have gained economically. It would not have been possible for Bhutan alone to bear the financial risks in order to develop this project. India provided the technology and the finance, bore the completion risks and received, in turn, a low-cost reliable source of hydroelectricity for its eastern electricity region. The fruit of the cooperation is that Bhutan receives a substantial amount of revenue annually from a sustainable export of electricity and India is able to conserve its scare fossil fuels while obtaining a real economic internal rate of return of at least 14%. The present value of net economic gains in 2008, evaluated at 2008 prices, has been US$2,286.51 million for Bhutan and US$2,521.78 million for India. Bhutan received US$636.32 million in cumulative revenues since the commencement of the project up until 2008. By 2007 India had recovered its capital investment along with its opportunity cost through the receipts of loan repayments and the share of hydroelectricity rent generated at the project because of lower import prices. When all the economic costs and economic benefits are taken into account, Bhutan and India end up sharing the net economic gains created by Chukha Hydroelectricity Project in the proportion of 48:52.

To date Nepal has avoided entering into an agreement with India to develop its hydropower resources as it has feared getting into an unbalanced arrangement where India might secure an unfair advantage. The experience of the Chukha dam in Bhutan might serve as a real life example of how such a power purchase agreement might be structured so as to yield a result that would be advantageous to both parties.

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