RRP:NEP 26362

ASIAN DEVELOPMENT BANK

REPORT AND RECOMMENDATION

OF THE

PRESIDENT

TO THE

BOARD OF DIRECTORS

ON A

PROPOSED LOAN

AND

TWO TECHNICAL ASSISTANCE GRANTS

TO THE

KINGDOM OF NEPAL

FOR THE

KALI GANDAKI "A" HYDROELECTRIC PROJECT

June 1996

CURRENCY EQUIVALENTS

(as of 15 June 1996)

Currency Unit	--	Nepali Rupees (NRs)
NRs1.00	=	$0.0179
$1.00	=	NRs55.75

For the purpose of calculations in this Report, the rate of $1.00 = NRs56.00 has been used, which was the rate prevailing during appraisal in March 1996.

ABBREVIATIONS

ACRP	-	Acquisition, Compensation and Rehabilitation Plan
CIDA	-	Canadian International Development Agency
CSP	-	Commercialization Strategic Plan
C1	-	Dam and Desanding Basins
C2	-	Headrace Tunnel
C3	-	Power Station
EDC	-	Electricity Development Center
EIA	-	Environmental Impact Assessment
EIRR	-	Economic Internal Rate of Return
EMIS	-	Environmental Management Information System
ETFC	-	Electricity Tariff Fixation Commission
FINNIDA	-	Department for International Development Cooperation (formerly Finnish International Development Agency)
FIRR	-	Financial Internal Rate of Return
FY	-	Fiscal Year
KfW	-	Kreditanstalt für Wiederaufbau
KGA	-	Kali Gandaki "A" Associates
KGEMU	-	Kali Gandaki Environmental Monitoring Unit
LCGEP	-	Least-cost Generation Expansion Plan
LRMC	-	Long-run Marginal Cost
MMMP	-	Mitigation Management and Monitoring Plan
MOWR	-	Ministry of Water Resources
NEA	-	Nepal Electricity Authority
NEA-ED	-	Nepal Electricity Authority-Environment Division
NGO	-	Nongovernment Organization
OECF	-	Overseas Economic Cooperation Fund
PAF	-	Project Affected Family
PIC	-	Project Information Center

NOTES

(i) The fiscal year of the Government and Nepal Electricity Authority ends on 15 July. "FY" before a calendar year denotes the year in which the fiscal year ends, e.g. FY1995 ends on 15 July 1995.

(ii) In this report $ refers to US dollars.

POE-E&S	-	Panel of Experts for Environmental and Social Aspects
POE-S&T	-	Panel of Experts for Safety and Technical Aspects
SEIA	-	Summary Environmental Impact Assessment
SPAF	-	Seriously Project Affected Family
TA	-	Technical Assistance
UNDP	-	United Nations Development Programme
VAG	-	Village Advisory Group

WEIGHTS AND MEASURES

m^3/sec	(cubic meter per second)		
GWh	(gigawatt-hours)	-	1,000 megawatt-hours
kV	(kilovolt)	-	1,000 volts
kVA	(kilovolt-amperes)	-	1,000 volt-amperes
kW	(kilowatt)	-	1,000 watts
kWh	(kilowatt-hour)	-	1,000 watt-hours
masl	(meter above sea level)		
mm	(millimeter)		
m^3	(cubic meter)		
Mm^3	(million cubic meter)		
Mt	(million metric tons)		
MW	(megawatt)	-	1,000 kilowatts
MWh	(megawatt-hour)	-	1,000 kilowatt-hours
MVA	(megavolt-amperes)	-	1,000 kilovolt-amperes
MVAR	(megavar)	-	1,000,000 vars
t	(ton)		
V	(volt)	-	unit of electric voltage
VA	(volt-amperes)	-	unit of electric power
VAR	(volt-ampere reactive)	-	unit of reactive power
W	(watt)	-	unit of effective electric power

CONTENTS

LOAN AND PROJECT SUMMARY

Borrower	:	Kingdom of Nepal
Project Description	:	With its installed capacity of 144 megawatts (MW), the Project will generate 842 gigawatt-hours (GWh) of renewable energy annually using the flow of the Kali Gandaki River.
Classification	:	Primary Objective—Economic Growth
Environmental Assessment	:	Category A An environmental impact assessment (EIA) was undertaken, and the summary EIA was circulated to the Board on 25 March 1996.
Rationale	:	The rationale for the Project lies in the need to meet the growing power demand in Nepal in a least-cost manner. This will be done by harnessing water resources of the Kali Gandaki River to generate renewable energy with minimal environmental and social impacts. The Project is specially designed to minimize load shedding by building in year-round capability to meet daily peak load requirements. Also, such a design will complement smaller non-peaking, run-of-river projects without pondage envisaged in the private sector.
Objectives and Scope	:	The main objective of the Project is to help meet the demand for electric power in Nepal at the least cost in an environmentally sustainable and socially acceptable manner. Other aims of providing the loan in support of the Project are (i) institutional and financial strengthening of Nepal Electricity Authority (NEA), and (ii) improved cost recovery to promote efficiency in power consumption. Between Mirmi and Beltari, which are just 6 kilometers (km) apart on land, the Kali Gandaki River flows in a U-loop over a length of about 50 km. The drop in elevation in this section of the river is about 124 meters (m). The Project will utilize this fall to generate electric power. A dam will be constructed at Mirmi just after the confluence of the Andhi Khola and Kali Gandaki rivers to divert part of the river flows into a tunnel. The tunnel will convey the water to Beltari, where a 144-MW power station will be located. The Project will have some storage behind the diversion dam sufficient to operate at full capacity for six hours a day even during the dry season.

The Project comprises the following key components: (i) civil works comprising (a) a 44-m high concrete gravity diversion dam and gated spillway, and an adjacent intake and desanding basin; (b) a 5.9-km long concrete-lined headrace tunnel with a diameter of 7.4 m; and (c) a surge shaft, pressure shaft, tunnel leading to the power station and the power station; (ii) mechanical and electrical plant and auxiliaries for the three 48-MW turbo-generating units, transformers, and switchgear to be installed at the power station; (iii) hydraulic steelwork including the supply of gates for the spillway, desander, headrace tunnel, power station, and steel liners for the pressure tunnel; and (iv) two 132-kilovolt transmission lines, one to Pokhara (61.4 km) and the other to Butwal (44.3 km). An access road of 28.5 km length from the Pokhara-Butwal highway to the dam and power station sites has already been constructed by NEA out of its own funds.

The Project also provides for construction engineering services; Project management services; a system loss reduction component; a panel of experts for safety and technical aspects (POE-S&T); a panel of experts for environmental and social advisory aspects (POE-E&S); and a Kali Gandaki Environmental Monitoring Unit (KGEMU).

Cost Estimates :

($ million)

Item	Foreign Exchange	Local Currency	Total Cost
A. Base Cost			
1. Preliminary Works[a]	—	4.7	4.7
2. Civil Works	166.5	30.6	197.1
3. Electromechanical Equipment	72.2	2.7	74.9
4. Transmission Lines	10.5	2.9	13.4
5. Construction Engineering	13.0	2.1	15.1
6. Project Management	2.1	6.1	8.2
7. Environmental Mitigation	2.3	3.0	5.3
8. Loss Reduction Component	2.3	0.9	3.2
9. Taxes and Customs Duties	—	18.3	18.3
Subtotal	268.9	71.3	340.2
B. Contingencies			
1. Physical	24.9	5.3	30.2
2. Price	18.3	7.2	25.5
Subtotal	43.2	12.5	55.7
C. Interest During Construction	7.9	49.0	56.9
Total	**320.0**	**132.8**	**452.8**
Percent	70.6	29.4	100.0

[a] Does not include access road already completed by NEA at its own cost.

Financing Plan :

($ million)

Source	Foreign Exchange	Local Currency	Total Cost	Percent
Bank	160.0	—	160.0	35.3
OECF	160.0	—	160.0	35.3
NEA[a]	—	132.8	132.8	29.4
Total	**320.0**	**132.8**	**452.8**	**100.0**

OECF - Overseas Economic Development Fund
[a] Includes Government funding.

Loan Amount and Terms : The Bank will provide a loan of SDR110.942 million equivalent in various currencies (about $160 million) from its special funds resources. The loan will have a repayment period of 40 years, including a grace period of 10 years, and a service charge of 1 percent per annum.

Relending Terms : The Borrower will relend the proceeds of the Bank loan to NEA, denominated in Nepalese rupees, at an interest rate of 10.25 percent per year and with a repayment period of 25 years, including a grace period of 5 years. The foreign exchange risk will be borne by the Government.

Period of Utilization : Until 15 July 2001.

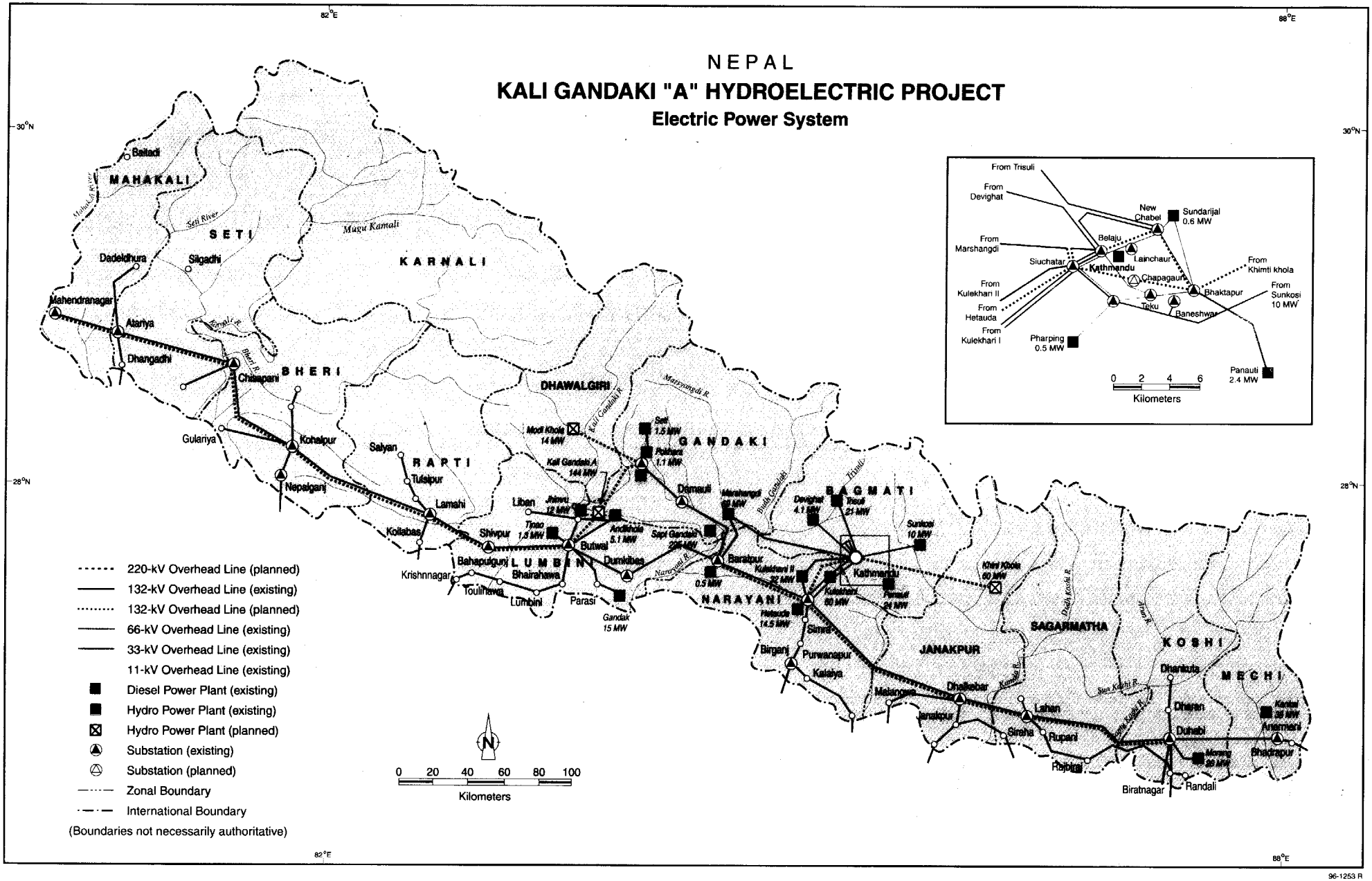
Implementation Arrangements : NEA has established a separate office for Project implementation. The office is headed by a Project director and is in the process of expanding its staffing. NEA will be assisted in implementation of the Project by consultants.

The POE-S&T and the POE-E&S will advise NEA during the construction period. The KGEMU will monitor environmental and resettlement aspects.

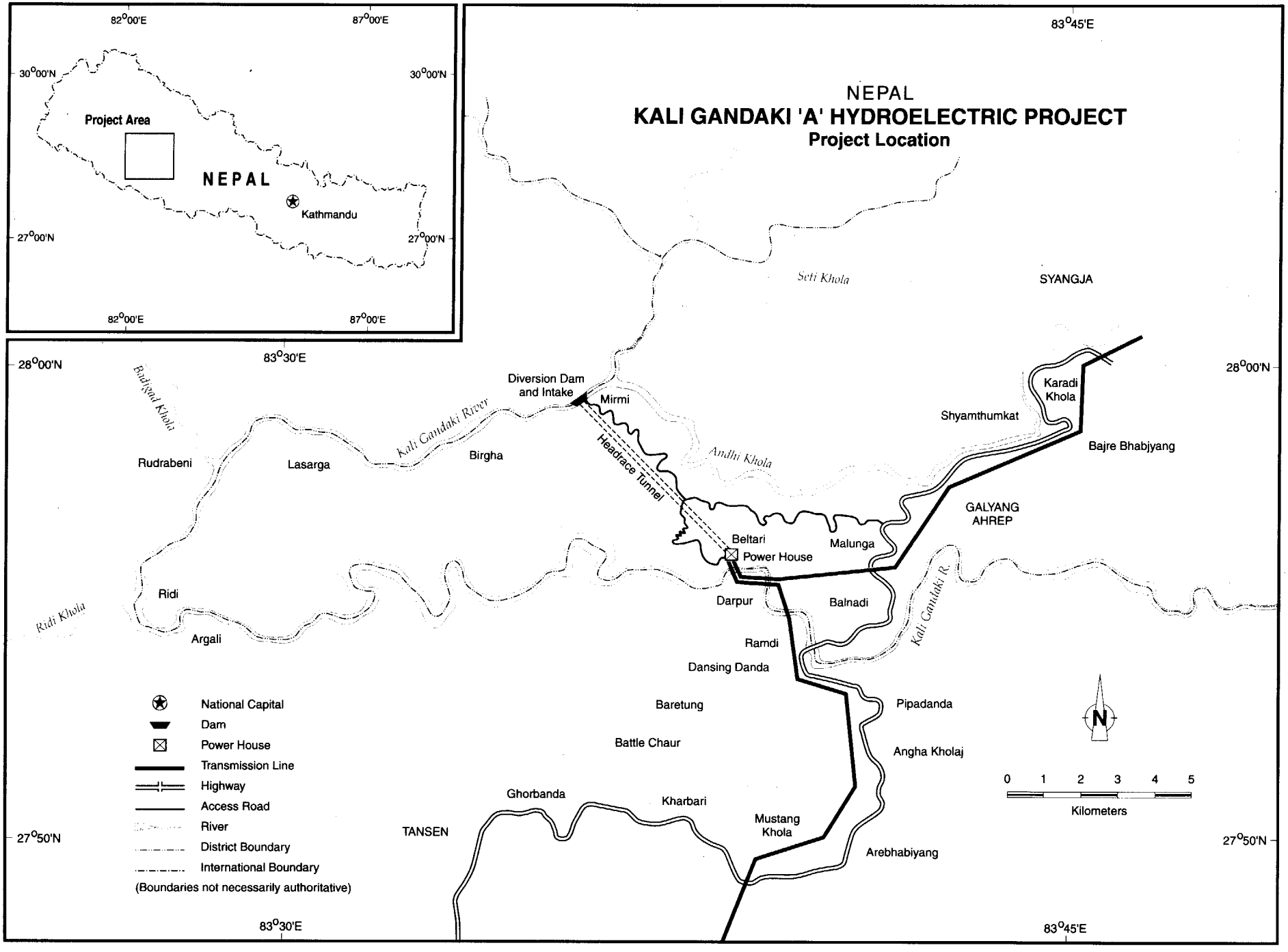
Executing Agency : Nepal Electricity Authority

Procurement : The Bank loan will finance the foreign exchange cost of (i) civil works for the dam and desanding basins, (ii) civil works for the power station, (iii) construction engineering, (iv) Project management, (v) environmental mitigation, (vi) loss reduction component, and (vii) interest during construction.

Consulting Services	:	The detailed engineering design and tender documents for the Project are nearing completion by a joint venture of three international consulting firms. For reasons of continuity and smooth implementation of the Project, NEA proposes to retain the joint venture as "Engineer" for the construction phase to prepare construction drawings, supervise construction, and manage the contract works.
Estimated Project Completion Date	:	15 January 2001
Benefits and Beneficiaries	:	The Project is a least-cost option for expanding NEA's generation system. Based on conservative estimates, the Project will have a financial internal rate of return of 9.8 percent in real terms, which is above the estimated real cost of capital of 5.4 percent for the Project. The economic internal rate of return is 15.0 percent in real terms, which is higher than the opportunity cost of capital of 10 percent. Both rates of return will be able to withstand reasonable movements in key variables. Industrial, commercial, residential, and agricultural consumers in Nepal will benefit directly from the electricity generated by the Project. The Project will also contribute to reduced load shedding and fewer interruptions in power supply. Other benefits include employment opportunities during the construction of the Project.
Technical Assistance	:	Two technical assistance grants to the Government are envisaged (i) $534,000 for Institutional Strengthening of NEA's Environment Division; and (ii) $600,000 for a Power System Master Plan. The Executing Agency for both of them will be NEA.


NEPAL
KALI GANDAKI "A" HYDROELECTRIC PROJECT
Electric Power System
82°E
88°E
30°N
28°N
MAHAKALI
SETI
KARNALI
BHERI
RAPTI
DHAWALGIRI
GANDAKI
LUMBINI
NARAYANI
BAGMATI
JANAKPUR
SAGARMATHA
KOSHI
MECHI
Baitadi
Dadeldhura
Silgadhi
Mahendranagar
Atariya
Dhangadhi
Chisapani
Gulariya
Kohalpur
Nepalganj
Salyan
Tulsipur
Lamahi
Kolabas
Krishnnagar
Bahapuguri
Shivpur
Liban
Tinau
1.5 MW
Butwal
Bhairahawa
Toulihawa
Lumbini
Parasi
Gandak
15 MW
Modi Khola
14 MW
Seti
1.5 MW
Pokhara
1.1 MW
Kali Gandaki A
144 MW
Andhikhola
5.1 MW
Sapi Gandaki
226 MW
Dumkibas
0.5 MW
Baratpur
Damauli
Marshyangdi
69 MW
Devghat
4.1 MW
Trisuli
21 MW
Sunkosi
10 MW
Kulekhani II
32 MW
Kulekhani
60 MW
Kathmandu
Panauti
24 MW
Khimti Khola
60 MW
Hetauda
14.5 MW
Simra
Birganj
Purwanapur
Kalaiya
Malangwa
Dhalkebar
Janakpur
Lahan
Siraha
Rupani
Rajbiraj
Dharan
Duhabi
Morang
36 MW
Kankai
32 MW
Anarmani
Bhadrapur
Biratnagar
Randali
Dhankuta
From Trisuli
From Devighat
From Marshangdi
From Kulekhani II
From Hetauda
From Kulekhani I
Pharping
0.5 MW
New Chabel
Sundarijal
0.6 MW
Belaju
Lainchaur
Siuchatar
Kathmandu
Chapagaun
Bhaktapur
Teku
Baneshwar
From Khimti khola
From Sunkosi
10 MW
Panauti
2.4 MW
0 2 4 6
Kilometers
220-kV Overhead Line (planned)
132-kV Overhead Line (existing)
132-kV Overhead Line (planned)
66-kV Overhead Line (existing)
33-kV Overhead Line (existing)
11-kV Overhead Line (existing)
Diesel Power Plant (existing)
Hydro Power Plant (existing)
Hydro Power Plant (planned)
Substation (existing)
Substation (planned)
Zonal Boundary
International Boundary
(Boundaries not necessarily authoritative)
N
0 20 40 60 80 100
Kilometers

96-1253 R



Map 2

96-1261 HR

I. THE PROPOSAL

1. I submit for your approval the following Report and Recommendation on a proposed loan to the Kingdom of Nepal for the Kali Gandaki "A" Hydroelectric Project. The Report also describes proposed technical assistance for (i) Institutional Strengthening of the Environmental Division of the Nepal Electricity Authority (NEA), and (ii) a Power System Master Plan, and if the proposed loan is approved by the Board, I, acting under the authority delegated to me by the Board, shall approve the technical assistance.

II. INTRODUCTION

2. The Project has for long been an integral component of NEA's Least-Cost Generation Expansion Plan (LCGEP) and a prime candidate for hydropower development of the Kali Gandaki River in Nepal. The first feasibility study was completed in 1979 and updated in 1992 with assistance from the United Nations Development Programme (UNDP). NEA proceeded thereafter to the next stage of detailed engineering and preparation of tender documents with Bank assistance for consulting services.[1] The Project is included in the Bank's lending program as a firm project for 1996. Fact-finding was conducted from 22 January to 9 February 1996 and appraisal from 21 March to 1 April 1996.[2] A follow-up appraisal mission was fielded from 26 to 28 May 1996. Loan negotiations were held in Manila from 10 to 13 June 1996. This report is based on the findings of these various missions.

III. BACKGROUND

A. Energy Sector and Power Subsector

1. Energy Overview

3. Nepal's total energy supplies come mainly from fuelwood (68 percent), agricultural waste (15 percent), dung production by livestock (8 percent), and commercial sources (petroleum [7 percent], coal [1 percent], and hydro electricity [1 percent]).[3] Except for some lignite deposits, Nepal has no known oil or coal deposits. All fossil fuels (mainly petroleum and coal) are imported, either from India or international purchases routed through India, and absorb over one-fifth of Nepal's foreign exchange earnings.

4. Nepal's per capita annual consumption of commercial energy is around 30 kilograms of oil equivalent and among the lowest in the region. Growth in commercial energy consumption in recent years is estimated at around 5 percent per year, which is slightly higher than the growth in gross domestic product. The main consumers of commercial energy are households (91 percent), followed by transport (3 percent), industry (3 percent), and other sectors such as commercial establishments and agriculture (3 percent).

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1 Savings under Loan No. 670-NEP(SF): Fifth Power Project, for $20 million, approved on 14 December 1983, along with cofinancing from UNDP and the Department for International Development Cooperation (FINNIDA), were used for financing the consulting services.

2 The Appraisal Mission comprised H. S. Rao (Mission Leader), J. Boyd (Senior Counsel), R. Casinader (Project Engineer-Staff Consultant), S. Ho (Country Economist), J. Kuiper (Senior Project Economist), M. R. H. Powell (Financial Analyst), and W. Staub (Senior Social Development Specialist). J. D. Taylor, Director-Infrastructure Department (West) and M. A. Shah, Resident Representative-NRM, participated in the Mission and provided advice to the Mission.

3 In FY1993, total energy supplies in Nepal were estimated at about 6.4 million tons of oil equivalent.

5. Because Nepal has no oil or coal deposits, the main thrust of the Government's energy policy is to develop the large economically exploitable hydropower potential estimated at around 43,000 megawatts (MW) to provide a renewable source of energy for domestic use and for exports. Other important objectives of the energy policy include (i) promoting the use of other indigenous renewable energy sources such as biogas, solar power, and wind energy; (ii) increasing the end-use efficiency of energy by improved designs of cooking stoves, motors, lighting, and water mills; (iii) gradually replacing imported fossil fuels; (iv) making commercial energy supplies available to the rural population; (v) maintaining a regional balance in the production and distribution of energy supplies; and (vi) ensuring that the development and consumption of energy do not have significant adverse effect on the environment.

2. The Power Sector

a. Institutional Setup

6. The Ministry of Water Resources (MOWR) has overall responsibility for all activities related to electricity generation and supply. Key agencies assisting MOWR in this task are NEA, the Electricity Development Center (EDC), and the Electricity Tariff Fixation Commission (ETFC). Previously, the sector had been characterized by fragmentation of responsibilities and lack of coordination among the various agencies involved. Following a reorganization study of the power sector conducted by Bank-financed consultants,[1] NEA was established under the NEA Act of 1985 through the merger of the Nepal Electricity Corporation, the Electricity Department of the MOWR, and the Small Hydro Development Board, to undertake generation, transmission, and distribution throughout Nepal. EDC was established in July 1993 following the adoption of the new Hydropower Development Policy (see para. 9). EDC's functions include (i) ensuring transparency in the application of the new regulatory framework; (ii) promoting private sector participation in the power sector; (iii) promoting and developing binational and multipurpose projects; (iv) preparing basin-wide water resource master plans; (v) developing safety guidelines and codes of practice for construction works, and quality control of power generation, transmission, and distribution facilities; (vi) providing advisory assistance in the refinement of existing rules and regulations for the efficient and effective development of the power sector; and (vii) approving licenses for power projects. ETFC was set up in 1994 as an autonomous body comprised of six members drawn from various sectors of the economy. It is mandated to fix tariffs within a 90-day period after a request is made for tariff adjustment/fixation. Recently, ETFC acted on NEA's proposal to allow a 20 percent tariff increase effective 14 May 1996.

7. Power exchange between Nepal and India is coordinated through MOWR. A joint subcommission on water resources is headed by the Secretaries from each country's responsible ministry. Reporting to the subcommission is a power exchange committee comprising representatives from India (the Central Electricity Authority and the State Electricity Boards of Bihar and Uttar Pradesh), and from Nepal (EDC and NEA).

b. Regulatory Framework

8. MOWR estimates that Nepal's economically exploitable hydropower potential is about 43,000 MW, of which only about 250 MW has been developed. To increase the exploitation of water resources, MOWR formulated a hydropower development policy in 1992.

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[1] TA No. 160-NEP: Second Power Project, for $230,000, approved on 11 December 1975.

The legal framework to facilitate implementation of this policy was established through the approval of three acts in 1992 (i) the Water Resources Act, which provides for the management of water resources and the issuing of licenses to corporate bodies for the use of water resources; (ii) the Electricity Act, which covers the management and development of electricity;[1] and (iii) the amended 1984 Nepal Electricity Authority Act, which covers the establishment, capital, management, functions, duties, and powers of NEA.

B. Government Policies and Plans

9. The Government recognizes the need to expand and diversify Nepal's power system (i) to provide power to more people in both the urban and rural areas, and (ii) reduce consumption of fuelwood and help conserve forests. The Government, therefore, adopted the Hydropower Development Policy in 1992 (the Policy), which aims to develop the large hydropower potential in an environmentally sustainable manner for (i) meeting the country's energy needs, and (ii) exporting electrical energy to generate revenues for the country. The Policy encourages private participation, both domestic and foreign, in all areas of the power sector. The Policy also aims to (i) expand transmission and distribution systems, including rural electrification to assist in agricultural production and cottage industries; (ii) improve the quality and reliability of the power supply, and reduce system losses; (iii) develop small hydropower projects and district-level projects under decentralization schemes to meet demand in hilly and remote areas; (iv) utilize indigenous labor, skills, and resources to complement foreign investment and technology; (v) develop transport based on electric power to reduce petroleum imports; and (vi) rationalize tariffs.

10. A key long-term goal of the power sector is to transform itself from a domestic-supply oriented system to one capable of significant exports. The main market for exports is India. Recently in January 1996, India and Nepal agreed to jointly develop the water resources of the Mahakali River basin in Western Nepal. Special mention is made therein of the large 6,000-MW Pancheswar hydropower project to be set up by the two countries based on a sharing of costs and benefits. Other large export-oriented projects are also proposed, such as the 10,000-MW project at Chispani. The large funding requirements of such projects will require innovative project structuring and financing, and any multilateral financing is likely to form only a small part of the total financing.

11. Because of the long time required for developing large projects and the considerable uncertainties involved therein, Nepal's power system planning in the medium-term needs to be focused on first meeting the in-country demand through economic medium- and small-sized hydropower projects.[2] Medium-sized run-of-river projects with some seasonal/daily storage to provide year-round peaking capability are required to complement the smaller run-of-river projects that have low dry-season peaking capability. Increasing private sector participation is required, both local and foreign, initially in the smaller projects and later through joint ventures

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[1] The Electricity Act is comprehensive and covers items such as issuing licenses for the generation (above 1000 kW), transmission, and distribution of electricity; standards for providing electricity and maintaining equipment; royalties; foreign exchange arrangements; relief from income tax; establishing the ETFC; and the power to develop rules and regulations.

[2] The term "small-sized" hydropower project refers to a capacity of 10-50 MW and "medium-sized" to 51-500 MW.

in the larger projects. This approach is expected to achieve development of Nepal's power system at the required pace and in a least-cost manner.

C. External Assistance to the Power Sector

12. Nepal has received substantial amounts of external assistance for the development of its power sector. The Bank has so far provided 10 loans totaling $189.5 million (including $35.1 million for a private sector project) and 13 technical assistance (TA) grants totaling $7.09 million (see Appendix 1). Most of this assistance has been used to develop an interconnected transmission system and expand the distribution networks in Nepal. The World Bank has financed seven projects in the sector for a total amount of $271 million: two for project preparation; four for hydropower development, including the Kulekhani and Marsyangdi hydroelectric projects; and one for a sector project. The World Bank projects attracted significant cofinancing, mostly in the form of loans, involving the Canadian International Development Agency (CIDA), the European Union, Kuwait Fund for Arab Economic Development, Kreditanstalt für Wiederaufbau (KfW), Overseas Economic Cooperation Fund of Japan (OECF), Saudi Fund for Development, and UNDP. India provided assistance for development of the Trisuli, Gandak, and Devighat hydropower projects. The United Kingdom's Overseas Development Administration (ODA) is supporting the rehabilitation of the Hetauda diesel plant. The Bank, together with the Department for International Development Cooperation (FINNIDA), Government of France, and Japanese International Cooperation Agency (JICA), provided assistance mainly for transmission and distribution. Funds for mini hydropower development have been received from bilateral and multilateral sources, including the Bank and various nongovernment organizations (NGOs). CIDA made a major contribution to the institutional development of the sector by financing the Water and Energy Resources Development Project, which focused on overall strategies for water and energy resource development and improvement of planning capabilities in the energy sector. The United States Agency for International Development (USAID) has assisted the Government in developing private sector rules and regulations. Aid coordination in the power sector has been close and effective, with the Bank, the World Bank, KfW, and OECF generally pursuing consistent and mutually reinforcing policy objectives.

D. Lessons Learned

13. Most of the Bank-assisted projects in the power sector suffered delays in meeting conditions of loan effectiveness, recruiting consultants, and awarding contracts. However, once the contracts were awarded, implementation proceeded smoothly. The postevaluation of three power projects concluded that they were generally successful. A key lesson is that project processing should provide for advance recruitment of consultants and for advance procurement. This lesson has been followed for the Project.

14. Except for one mini hydropower project, the Bank loans have been used to expand transmission grid and distribution networks in urban and rural areas. Also, the loans have included components aimed at addressing institutional weaknesses in the power sector, particularly in NEA (e.g., by setting up a commercial accounting system). Most of the 13 TA grants served for project preparation. One TA helped NEA improve its capability in distribution planning and commercial operations. NEA has also received TA from other agencies for training NEA staff and implementing a loss reduction program in the Kathmandu Valley. The institutional assistance to NEA has not been as productive as expected, partly because staff lack motivation.

To address this, NEA is required under the Project to introduce result-oriented incentive schemes. This, coupled with institution building TA envisaged along with the Project, is expected to support human resource development and promote a stronger commitment among NEA staff.

E. The Bank's Sectoral Strategy

15. The Bank's operational strategy for Nepal focuses on reducing poverty by (i) promoting broad-based, labor-absorbing economic growth that is sustainable and environmentally sensitive; (ii) enhancing the policy environment to promote greater private sector participation in development; (iii) augmenting basic social services; and (iv) protecting the environment. The current shortage of power is a major constraint on the Government's efforts to promote economic growth and generate adequate employment opportunities for the burgeoning population, which is growing at 2.1 percent per annum. Thus, a key element of the Bank's strategy is to help Nepal develop its power sector.

16. The Bank's strategy aligns closely with the Government's approach to power sector development. The strategic objective is to assist Nepal to develop its abundant water resources in an efficient and cost-effective manner, with minimal environmental and social impacts, to provide adequate power for domestic consumption and eventually as a major export. Because of the significant investments required, the public sector will not be able to fund all of the investments. Therefore, and to improve competition and efficiency in the power sector, the Bank is encouraging the Government to promote the role of the private sector in power generation and to develop appropriate private sector power policies. The Bank proposes to assist projects in the private and public sectors. The Bank has recently approved loan assistance of $35.1 million for the 60-MW Khimti Khola hydroelectric project in the private sector.[1] In the public sector, the Bank proposes to provide assistance for the Project. Another area that will receive the Bank's attention is transmission and distribution to reduce system losses and improve access to electricity.

17. A key aim of the Bank is also to improve the technical and financial efficiency of the sector institutions, particularly by promoting the autonomy and commercialization of NEA. Given the large investments in hydropower included in NEA's LCGEP, an important sector objective is to improve NEA's internal resource generation so that it can make an adequate contribution to these investments.

F. Policy Dialogue

18. Policy dialogue with the Government and NEA related mainly to future development plans for the power sector (see paras. 10 and 11), macroaffordability of power development plans, enhancement of private participation in the sector, tariffs, and improvement of NEA. These discussions have provided a strong basis for institutional strengthening and operational improvement of NEA, and improved cost recovery. Consequently, NEA's self-financing capability is expected to improve significantly and result in macroaffordability of NEA's power plan with decreasing dependence on the Government budget.

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[1] Loan Nos. 7123 and 7124-NEP: Himal Power Limited, for $36.5 million, approved on 23 January 1996.

1. Macroaffordability

19. The Project is relatively large in the context of Nepal's economy and it could exert pressure on the fiscal budget. At the macro level, the main area of concern is to ensure that domestic resource mobilization, both from general revenue collection and NEA's self-financing, would be able to support an adequate capital investment program for NEA without jeopardizing other sector development expenditures, particularly in the social sectors. To achieve this objective, the core projects in the social sectors are given priority in expenditure programming, with funds for the power sector investment program being made available only out of the residual funds. Based on this approach and the macroeconomic framework agreed between the Government and the International Monetary Fund (IMF), the proposed power sector investment plan is affordable (see Appendix 2).

20. The continued affordability of the power investment plan, however, is contingent upon two main conditions. First, the Government must adopt measures aimed at tightening expenditure management by redirecting funds to the identified core development projects, while reducing fund releases to noncore projects. Second, the Government must continue to mobilize domestic resources and monitor revenue collection and be prepared to adopt extraordinary measures should revenue shortfalls occur. To this effect, the Government has agreed under the Project that the macroeconomic framework for public expenditure planning and the resource supply envelope for the power sector would be reviewed jointly every year, and appropriate adjustments in future commitments for the public capital expenditure program, including the power sector expenditure program, would be made.

2. Enhanced Private Sector Participation

21. A key feature of the Government's policy for the power sector is promotion of greater private participation. Investments are encouraged from the private sector in generation, transmission, and distribution, with local/foreign investors allowed full ownership. Joint ventures with the Government are also allowed. The policy states that a private hydropower project will not be nationalized during the period of validity of the license. Fiscal incentives are provided to private projects, such as income tax exemptions, concessional finance for up to 1-MW projects in rural areas, low custom duty (1 percent) on imported equipment and assured availability of foreign exchange for debt service and dividend/equity repatriation.

22. Recognizing the need for independent regulation of the power sector, the Government established EDC in 1993 and ETFC in 1994 (see para. 8). EDC has granted licenses for 20 private sector projects with a total installed capacity of over 1,300 MW. Of these, memorandums of understanding have been signed for four projects totaling 540 MW, including the 60-MW Khimti Khola Project, which has also reached the next stages of signing the Power Purchase Agreement with NEA and financial close. Most other projects are as yet at the stage of survey. Given the difficulties in identifying promoters and arranging long-term private sector funding for such projects, an estimated four private sector projects with a total capacity of 153 MW may be commissioned by FY2004.

23. The Bank actively supports private sector projects and has been instrumental in bringing the first and only private project to date — Khimti Khola — to successful financial closure. In considering further private sector projects, a proper mix of peaking and nonpeaking

plants needs to be taken into account. Also, the power purchase agreements need to be so structured that generation of less costly power from NEA's existing stations is not adversely affected. Since memorandums of understanding do not constitute an irrevocable commitment to construct and deliver power, a minimal pipeline of public sector projects needs to be maintained. This will particularly help if unforeseen events lead to a large number of private sector projects not materializing and will act as a safety net to minimize the consequent shortfall in new capacities. These, and other aspects, are under discussion between the Bank and the Government.

3. Tariffs

24. Appropriate tariff levels are essential for NEA to achieve satisfactory financial performance. This is necessary for NEA to (i) pay for all debt-service costs and achieve a reasonable rate of return on capital investments, (ii) provide net earnings that can finance a significant proportion of capital costs for system expansion, (iii) operate NEA as a financially sound enterprise that can borrow funds for expansion, and (iv) improve the credit-worthiness of NEA as a client for independent power producers for new hydro projects. Adequate tariff levels combined with an appropriate tariff structure are also necessary to send price signals to consumers on the real economic costs of power supply in order to encourage more efficient power consumption and voluntary demand-side management practices.

25. The Government is committed to achieving tariff levels required to improve NEA's self-financing capability and profitability. Since 1991, tariffs have been increased by 240 percent in nominal terms and 75 percent in real terms. Currently, the average tariff is about 78 percent of long-run marginal cost (LRMC) and is expected to reach close to the LRMC in FY2004 with the projected increase in tariffs. The Government is also committed to avoid undue cross-subsidization by maintaining residential tariffs at close to overall average retail tariff and not expanding the first lifeline block beyond 20 kilowatt-hours (kWh) per month. A more detailed discussion of tariffs is provided in paras. 71 to 74.

4. Strengthening of NEA

26. Discussions for strengthening NEA have focused mainly on enhancing autonomy, introducing private participation, improving productivity, and complying with Bank covenants, all with a view to raising NEA's efficiency and performance and making NEA more commercially oriented. Understandings were reached on introducing incentive schemes, targeting productivity improvements (such as a higher consumer-employee ratio and lower system losses) and undertaking institution-building measures covering a wide range of NEA's operations. These are discussed in greater detail in paras. 75 and 76.

IV. THE PROJECT

A. Rationale

27. The rationale for the Project lies in the need to meet the growing power demand in Nepal in a least-cost manner. This will be done by harnessing water resources to generate renewable energy with minimal environmental and social impacts. The Project is specially designed to minimize load shedding by building in year-round capability to meet daily peak load

requirements. Also, such a design will complement nonpeaking, run-of-river type smaller projects envisaged in the private sector.

B. Objectives and Scope

28. The main objective of the Project is to help meet the demand for electric power in Nepal at least cost in an environmentally sustainable and socially acceptable manner. Other aims of providing the loan in support of the Project are institutional and financial strengthening of NEA, and improved cost recovery to promote efficiency in power consumption.

29. Between Mirmi and Beltari, which are just 6 km apart on land, the Kali Gandaki River flows in a U-loop over 50 kilometers (km). The drop in elevation in this section is about 124 meters (m). The Project will utilize this fall to generate electric power. A dam will be constructed at Mirmi just after the confluence of the Andhi Khola and Kali Gandaki rivers to divert part of the river flows into a tunnel. The tunnel will convey the water to Beltari, where a 144-MW surface power station will be located. The Project will have behind the diversion dam sufficient storage to operate the full capacity for six hours a day even during the dry season.

30. The Project has the following key components:[1] (i) main civil works comprising (a) a 44-m high concrete gravity diversion dam and gated spillway, and an adjacent intake and desanding basin (Lot C1); (b) a 5.9-km long concrete-lined headrace tunnel with a diameter of 7.4 m (Lot C2); and (c) a surge shaft, pressure shaft, tunnel leading to the power station and the power station (Lot C3); (ii) hydraulic steelwork (Lot 4) including the supply of gates for the spillway, desander, headrace tunnel and power station, as well as the steel liners for the pressure tunnel; (iii) electrical (Lot 5) and mechanical plant (Lot 6) and auxiliaries for the three 48-MW turbo-generating units, transformers, and switchgear to be installed at the power station (Lot 4); and (iv) two 132-kV transmission lines (Lot 7), one to Pokhara (61.4 km) and the other to Butwal (44.3 km).

31. The Project also provides for construction engineering services, Project management services including two panels of experts (one for technical and safety aspects, and the other for environmental and social aspects), and the Kali Gandaki Environmental Monitoring Unit (KGEMU). Additionally, the proposed Bank loan will partly finance a system loss reduction program.

C. Technical Justification

1. Project Preparation

32. Feasibility study for the Project was completed in 1979 and detailed feasibility study in 1992. In December 1992, a joint venture of three consulting firms under the name of Kali Gandaki "A" Associates (KGA) was engaged to carry out detailed engineering (including site investigations and hydraulic model studies) and prepare tender documents. KGA has prepared various reports (including for Project design, and environmental and social impact mitigation)

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[1] Access road of 28.5 km length from the Pokhara-Butwal highway to the dam and power station site has already been constructed by NEA at a cost of about $5 million without any external assistance.

and tender documents. KGA was guided in this task by NEA and the four-person Panel of Experts (POE) established in May 1993 to advise on all aspects of the Project. The reports are based on extensive site investigations, model studies, and detailed design work, and have been intensively reviewed before finalization in 1996. In parallel with KGA's Project preparatory activities, NEA has completed the access road to the dam and the power station with the help of local contractors.

2. Project Location

33. The Project is in the midlands of the lower Himalayas in the western region of Nepal, about 180 km west of the capital, Kathmandu. The Kali Gandaki River, immediately after being joined at Mirmi Village by the Andhi Khola River, flows westward and then loops back at Riri Bazaar to flow eastward parallel to its upstream course but some 6 km to the south at Beltari where the power station will be located (see Map 2 on page vii).

3. Key Technical Features

34. The length of the dam is about 100 m, and its maximum height about 44 m. The dam height has been carefully selected to ensure that the water storage level does not inundate the holy rock and the bazar at Seti Beni upstream of the river. The dam will enable active storage of 3.1 million cubic meters (m^3) of water, which will be sufficient to operate the Project at full capacity for six hours a day even in the dry season. The heavy sediment charge in the Kali Gandaki River, as in all Nepalese rivers, necessitates a specially designed intake to keep sediment out of the headrace tunnel and the turbines. Coarser material will be excluded by a forebay and screen, and finer material will be removed in a substantial desander structure on the left side of the dam. To provide sufficient space for the desander, a large excavation will be required.

35. The 7.4-m diameter concrete-lined headrace tunnel leads off from the desander and will be excavated in rock that includes slate material. Because of the high rock cover over the tunnel line, boreholes have only been possible at each end. The tunnel geology and hydrogeology have therefore had to be inferred from the geology at the surface above the tunnel line. Because precise information is not available on the rock conditions that will be encountered, the POE has conservatively recommended the use of an observational method, the New Austrian Tunnelling Method, for the design of the primary support of the tunnel while it is being excavated. At the downstream end of the headrace tunnel, a vertical pressure shaft and horizontal pressure tunnel will convey water to the power station. These pressure conduits will be of reinforced concrete, only a short length upstream of each turbine being concrete-lined. The POE considers this satisfactory, as measurements of in situ stress in the rock indicate that significant cracking of the reinforced concrete lining will not occur.

36. The power station will be located on the surface. This was decided after taking into account the higher cost of locating the station underground under the difficult geological conditions existing at the site.

D. Cost Estimates

37. The cost estimates of the Project are summarized in Table 1 (for details see Appendix 3):

Table 1: Summary of Project Cost Estimates ($ million)

Item	Foreign Exchange	Local Currency	Total Cost
A. Base Cost			
1. Preliminary Works[a]	—	4.7	4.7
2. Civil Works	166.5	30.6	197.1
3. Electromechanical Equipment	72.2	2.7	74.9
4. Transmission Lines	10.5	2.9	13.4
5. Construction Engineering	13.0	2.1	15.1
6. Project Management	2.1	6.1	8.2
7. Environmental Mitigation	2.3	3.0	5.3
8. Loss Reduction Component	2.3	0.9	3.2
9. Taxes and Customs Duties	—	18.3	18.3
Subtotal	**268.9**	**71.3**	**340.2**
B. Contingencies			
1. Physical	24.9	5.3	30.2
2. Price	18.3	7.2	25.5
Subtotal	**43.2**	**12.5**	**55.7**
C. Interest During Construction	7.9	49.0	56.9
Total	**320.0**	**132.8**	**452.8**
Percent	70.6	29.4	100.0

[a] Does not include access road already completed by NEA at its own cost.
Source: NEA and the Bank.

38. The civil works cost estimates have been prepared by KGA based on detailed build-up of unit rates (1995 rates, corrected for January 1996) for the various items of work after taking into account the cost of labor, materials, and plant. Electromechanical equipment costs are based on KGA's inquiries from manufacturers and modified subsequently based on recent bids for similar equipment in other countries. Construction engineering costs relate to the cost of consultants for Project supervision (see para. 43). Project management costs include the cost of the POEs for the construction period. Environmental mitigation costs include, among other things, the cost of compensating and relocating Project-affected families (PAFs), measures for mitigating impacts on the fish, and environmental monitoring during construction. The loss reduction component is envisaged to reduce nontechnical system losses of NEA and provides mainly for equipment, materials, and consulting services. Provision has been made for physical and price contingencies as per Bank guidelines.

E. Financing Plan

39. The financing plan for the Project is shown in Table 2. The foreign currency expenditures are envisaged to be financed in equal proportions by the Bank and OECF, with the local expenditures to be wholly financed by the Government and NEA. The proposed Bank loan of $160 million will finance foreign currency expenditures amounting to 35.3 percent of the total Project cost.

Table 2: Financing Plan
($ million)

Source	Foreign Exchange	Local Currency	Total	Percent
Bank	160.0	—	160.0	35.3
OECF	160.0	—	160.0	35.3
NEA[a]	—	132.8	132.8	29.4
Total	**320.0**	**132.8**	**452.8**	**100.0**

[a] Includes funding from the Government.
Source: NEA and the Bank.

40. The proposed Bank loan of $160 million equivalent from the Bank's Special Funds resources will have a repayment period of 40 years, including a 10-year grace period, and will carry a 1 percent service charge. The Borrower will be the Kingdom of Nepal, and the proceeds will be relent to NEA pursuant to a subsidiary loan agreement with terms and conditions acceptable to the Bank. The terms will include a repayment period of 25 years, including a 5-year grace period to cover the construction period, and an interest rate of 10.25 percent. The foreign exchange risk will be borne by the Government.

41. The Bank loan will finance the foreign exchange cost of (i) Lot C1 (civil works for the dam and desanding basins); (ii) Lot C3 (civil works for the power station); (iii) construction engineering; (iv) Project management; (v) environmental mitigation; (vi) the loss reduction component; and (vii) interest during construction. The OECF loan will be relent by the Government to NEA on the same terms applicable under the Bank loan and will finance the foreign exchange cost of (i) Lot C2 (tunnel); (ii) electromechanical equipment (Lots 4, 5, and 6); and (iii) transmission lines (Lot 7).

F. Implementation Arrangements

1. Project Management Organization

42. NEA will be the Executing Agency for the Project. The Managing Director of NEA will be responsible to NEA's Board for management of the Project. The day-to-day management of the Project will be the responsibility of the Project Director under a clearly defined level of delegated authority. Details of the Project Management Organization are provided in Appendix 4.

43. The Project management system is of the "Owner-Engineer-Contractor" type, with NEA acting as the Owner and a consultant as the Engineer. NEA proposes to retain the KGA joint venture to act as the Engineer for construction supervision to ensure continued responsibility for the Project design. The Engineer's duties (see Appendix 5) will include issuing construction drawings, supervising construction, and certifying payments to the contractors. A total of 520 person-months of foreign consultancy and 1,218 person-months of local consultancy is envisaged for Project supervision over a period of four years.

44. NEA will also appoint two POEs for the construction phase, one for safety and technical aspects of the Project (POE-S&T) and the other for environmental and social aspects (POE-E&S). The three-member POE-S&T will include expertise in civil engineering of hydropower projects, tunnel construction, geology, and hydraulics. The POE-S&T will provide independent advice to NEA during the construction phase on technical and safety aspects relating to the Project including detailed design, construction methodology, implementation schedule, dam surveillance, and safety. The two-member POE-E&S will include expertise in environmental and social impact monitoring. It will provide advice on all environmental and social matters related to the Project with particular emphasis on effective and timely implementation of the various mitigation measures.

45. NEA will establish the KGEMU for environmental monitoring of the Project. The KGEMU will be advised by an expert in environmental and sociological aspects of project development. A total of 15 person-months of foreign consultancy and 392 person-months of local consultancy is proposed for the KGEMU. The consultants will be recruited in accordance with the Bank's *Guidelines on the Use of Consultants*.

2. Procurement

46. All procurement financed by the Bank will be undertaken in accordance with the *Guidelines for Procurement*, while procurement financed by OECF will follow OECF's procurement guidelines. Some local competitive bidding is envisaged for the preliminary works and for a small but critical part of the excavation at the dam site to be taken up before the start of the international competitive bidding contracts. Local contractors are available and capable of such works. The rest of the procurement will be through international competitive bidding. The contract packages will be divided between the Bank and OECF to facilitate parallel financing in accordance with their procurement requirements (see Appendix 6).

3. Implementation Schedule

47. The construction program for the Project is closely related to monsoon river flows, which are high during the wet season (June to October) and low during the dry season (November to May). Because of the seasonal nature of the river flows, timing of some activities related to C1 is highly critical. These include (i) timely completion of excavation and desanders to ensure temporary diversion of the river flow at the start of the dry season; and (ii) dam excavation and concreting in the riverbed during the dry season before the onset of the high flows. For the three main civil works (C1, C2, and C3), the Bank completed prequalification in June 1995. Bids were invited on 31 March 1996 from the 13 prequalified international contractors for each separate lot under the financiers' guidelines. Following a request from some of the bidders, the bid closing date has been extended to 15 July 1996. Taking into account the time

required for bid evaluation and contract award, the C1 contractor is unlikely to commence work before January 1997. It is, therefore, envisaged that a local contractor, under a local competitive bidding package, will undertake advance excavation work at the dam site starting in October 1996. This will enable the first generating unit to be commissioned in July 2000 and the two other units by November 2000 (see Appendix 7). The implementation schedule is tight but achievable with close Project supervision by NEA with the help of the Engineer, the POE-S&T, and the POE-E&S. A midterm review of Project implementation will be conducted in 1998 by NEA and the Bank.

4. Benefit Monitoring and Evaluation

48. NEA will carry out annual benefit monitoring, and evaluation of the Project pursuant to relevant provisions of the Bank's *Benefit Monitoring and Evaluation: A Handbook for Bank Staff, Staff of Executing Agencies and Consultants*. In particular, the Project Director will ensure that physical and socioeconomic conditions are monitored with reference to the Acquisition, Compensation, and Resettlement Plan (ACRP) and Mitigation Management and Monitoring Plan (MMMP), and the results are incorporated into an annual progress report. NEA will furnish the Bank a copy of such annual progress report within 60 days of the end of the fiscal year under review and promptly take into account any Bank comments on the contents of the progress report.

G. The Executing Agency

1. Organization and Management

49. As noted earlier in para. 6, NEA was established in 1985 through the merger of three agencies. It is governed by the provisions in the Nepal Electricity Authority Act of 1985. Because of shortcomings in the Act, which restricted NEA's autonomy and accountability, the Act was amended in 1992 to enable NEA to operate as a commercial entity. The amended Act provides for sale of NEA's shares to the public, with a further provision that once 10 percent of NEA's shares is sold to the public, an annual general meeting will be convened and the Board of Directors elected at such a meeting.

50. Management of NEA is vested in an eight-member Board of Directors. NEA is wholly owned by the Government. As a result, the Board of Directors is constituted by the Government. Currently, it comprises three Government officials (the Minister of Water Resources, the Secretary of MOWR, and the Secretary of the Ministry of Finance); four appointees from outside of the public sector (one representing industry, commerce or finance; one from among consumers of electricity; and two from the power sector); and the Managing Director. The Chairman of the Board is the Minister of Water Resources. The present Managing Director assumed office in November 1995. While his appointment is recent, he is fully conversant with NEA and its workings because he served as NEA's Managing Director once before.

51. Day-to-day operations of NEA are the responsibility of the Managing Director. He is assisted in this task by a Deputy Managing Director for Development, another for Operation, a Director-in-Chief for human resource development, and a Chief for Finance and Accounts. The organization chart of NEA is given in Appendix 8.

2. Staffing and Training

52. NEA has 7,818 staff, including 412 contractual staff and 637 officers. This represents a sizeable reduction from the 9,247 employees in 1993. Technical staff account for 61 percent of the total. While the present staff strength is below the approved strength of 8,419, indicators such as consumer-to-employee ratio (60 in FY1995) point to the need for no immediate increase in staffing, except in some specialized areas such as the environmental division. However, if NEA expands the rural electrification system significantly, the staff requirements will need more careful review.

53. After five years of World Bank-funded TA, NEA now has the essential elements to develop appropriate training activities to meet its training needs. NEA has created a Human Resources Department, with two divisions: Training and Manpower. Training activities are undertaken at three centers: Bhirkuti Mandap, the Panauti Hydroelectric Power Station, and the Balaju Mechanical Training Center. Eight instructors in Distribution, Generation, and Maintenance are at work, two in Computers and General Sciences, and four in Administration and Finance. During FY1995, about 937 staff were trained, of whom 412 received training in technical matters, 439 in seminars conducted in Nepal, and 82 in overseas training and other types of courses. Although there has been a significant improvement in training in the last few years, the lack of a central training center facility hampers the provision of more and better services. NEA proposes to construct a new training center and has already acquired land for the purpose. NEA is hiring local consultants for its design and civil engineering, and engaging foreign consultants to review the list of equipment, specifications, and bidding documents. Construction is expected to start in 1996.

3. Accounting and Audit

54. Over the years, the Bank and the World Bank have provided assistance to enhance NEA's accounting and financial functions. Consultants engaged under a previous Bank loan[1] introduced new commercial accounting systems, but, owing to the paucity of qualified and motivated staff, improvement has been less than expected. Problems to be resolved in the Finance Department have been recognized by NEA's new management, and consultants have been appointed to (i) review NEA's existing accounting systems; (ii) recommend appropriate modifications and prepare revised accounting manuals (in English and Nepali); (iii) implement the modified systems fully; and (iv) provide on-the-job training to NEA's accounting staff. Based on the consultants' findings for (i) and (ii), NEA has prepared an action plan to implement the modified systems, including a detailed implementation schedule and assessment of financial requirements. The objective of the action plan is to have the accounting systems fully operational in 1996. Further work by the consultants is planned to complete the training and implementation.

55. NEA has been generally slow in the preparation of its accounts and audits. Until the early 1990s, NEA required well over a year after close of the fiscal year to finalize its accounts. There has been considerable improvement in recent years following the appointment of a qualified accountant as Director of Finance in FY1992 and the appointment of international auditors to perform the FY1992 and FY1993 audits. This was a major step forward and resulted

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[1] Loan No. 670-NEP(SF): Fifth Power Project, for $20 million, approved 14 December 1993.

in the audited FY1993 accounts being submitted to the Bank within the covenanted period of nine months for the first time since NEA was established. Also, the auditors highlighted deficiencies in NEA's financial management and control and the shortcomings in NEA's accounting system, leading to the appointment of management consultants to help NEA make its financial systems fully operational. NEA also recognized that it did not have sufficient staff capable of efficiently implementing its internal audit function. Hence, a Nepalese firm of accountants was appointed in January 1994 to be responsible for this function, and to train NEA staff and create an audit manual. The training program has been completed and a Chief Internal Auditor with suitable staff has been appointed. Notwithstanding these measures, submission of audited accounts to the Bank for FY1994 was delayed by a month after the covenanted date. For FY1995, NEA was able to submit its unaudited accounts in time. Submission of audited accounts, however, has gone beyond the covenanted date mainly due to a change in the international auditor. NEA proposes to take concerted action in the coming year to achieve timely submission of its accounts to the Bank.

4. The Existing Power System

56. Nepal's interconnected power system comprises 16 small- and medium-sized generating plants, 22 transmission lines forming grid components or links with generating plants, and a distribution system covering 46 districts in 13 zones of the country.[1] Currently, the total installed generating capacity of NEA's system is about 293 MW (see Appendix 9). Over half of this capacity is accounted for by three hydropower plants (the 60-MW Kulekhani I, the 32-MW Kulekhani II, and the 69-MW Marsyangdi), with the rest of the capacity distributed over a number of small hydropower and thermal plants. Due to derating of some of the plant capacities, restrictions on some plants' output, and seasonal variations of water flow, the dependable capacity of the system is about 256 MW, of which 231 MW (90 percent of the total) is hydro capacity and 25 MW (10 percent) is thermal capacity consisting of diesel and multifuel-fired plants. All hydropower plants are of the run-of-river type except for Kulekhani I and II, which operate in tandem and have seasonal storage.

57. The interconnected transmission grid consists of a 132-kV system superimposed on a 66-kV ring system around the Kathmandu Valley. Primary power distribution is provided through a combination of 33-kV and 11-kV networks. The 132-kV system runs along the southern plains (Terai) from Mahendranagar in the far west of Nepal to Anarmani in the far east. Interconnection with India takes place at Ramnagar at 132 kV and at 14 other points along the India-Nepal border, at the distribution levels of 33 kV or 11 kV. The Nepal power system is not run in synchronism[2] with Bihar or Uttar Pradesh State Electricity Boards on the border. The exchange of energy is arranged on an ad hoc basis, depending on availability of supply, with the area receiving supply being isolated from the home country's system during such periods. Under the present interconnection agreement with India, up to 50 MW can be transferred either way, but until a new 132-kV single circuit transmission line is commissioned in 1996 between Duhabi (in Nepal) and Kataiya (in Bihar State), the maximum transfer is limited to 20 MW.

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[1] Outside the interconnected system, NEA is responsible for a number of isolated mini hydropower plants with a total installed capacity of 4.2 MW. In 1993, five of these isolated hydropower plants were handed over to private operators.

[2] Synchronism is when two separate electrical systems are connected and operated together and maintain the same frequency.

5. Past and Projected Power Consumption

58. Nepal's annual per capita electricity consumption of 45 kWh is the second lowest in the region.[1] Only about 14 percent of its 20 million population is connected to the electricity grid. Nepal is still at an early stage of electrification, and growth rates in power demand are accordingly high, with an average annual increase of over 11 percent in energy sales and peak demand during FY1983 to FY1995 (see Appendix 10). In FY1995, peak demand was 244 MW and energy sales 830 GWh. In FY1994 and FY1995, there was significant load shedding, mainly because of water shortage at the Kulekhani I and II hydropower stations after several dry years, shutdown of Kulekhani I and II for five months for repairs of flood damage, and the shutdown of Trisuli and Devighat power stations for upgrading. The situation improved considerably in FY1996 with the restoration of these projects, good river flows, and the commissioning of 23 MW additional capacity (12 MW at Jhimruk and 11 MW Trisuli/Devighat Upgrading).

59. At the end of FY1995, NEA had about 460,000 consumers, of whom 95 percent were residential consumers accounting for 39 percent of the power consumption in the country. Industrial consumers were about 3 percent of the total number but had the largest share in total consumption of 41 percent. Commercial consumers (8 percent of the total consumption), noncommercial consumers (7 percent), and other minor categories (5 percent) account for the remaining 20 percent consumption in the country. In addition, exports to India amounted to about 5 percent of total sales of NEA.

60. In view of expected resource constraints in developing new generation facilities, the Bank and other international funding agencies agreed with NEA in October 1993 on a load forecast (see Appendix 10) that reflects continuing constraints in power supply. This load forecast estimates that NEA's in-country sales will increase at an average annual rate of 11.2 percent to 2,125 gigawatt-hours (GWh) in FY2004. Gross generation requirements are forecast to increase at an average rate of 10.3 percent annually over the same period, after taking into account a gradual reduction in system losses. Peak annual loads are forecast to increase at a slower rate of 8.9 percent annually, because of increasing annual load factors as the power loads mature. Based on this, the peak demand in FY2004 is expected to reach 549 MW.

6. Development Plans

61. Following the shelving of the 201 MW Arun III Hydroelectric Project (Arun III) in August 1995, NEA has revised the generation expansion plan (see Appendix 11).[2] Installed capacity is expected to more than double, from 293 MW in FY1996 to 629 MW in FY2004. The main additions over this eight-year period are Khimti Khola (60 MW in FY2000), Kali Gandaki (144 MW in FY2001), Bhote Khoshi (36 MW in FY2003), and Upper Marsyangdi (43 MW in FY2004). At least two of these projects (Khimti Khola and Bhote Khoshi) are expected to be set up in the private sector.

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1 In comparison, the annual per capita electricity consumption in Cambodia is 26 kWh; in Bangladesh, 53 kWh; in Lao People's Democratic Republic, 89 kWh; in Sri Lanka, 196 kWh; and in Pakistan, 300 kWh.

2 The Arun III Hydroelectric Project was being examined by a World Bank-led consortium of aid agencies including the Bank. In August 1995, the World Bank unilaterally stopped further consideration of Arun III, resulting in the shelving of the Project by the Government.

62. NEA's transmission development plan is based upon the results of load flow studies for the above load forecast and an assessment of the annual peak demands at each transmission substation. The implementation of the plan will (i) increase substation capacity by an additional 928 MVA by FY2004; (ii) convert several 132-kV single-circuit lines with a total length of 473 km to double-circuit lines by stringing a second circuit; (iii) construct 289 km of additional single-circuit 132-kV transmission lines; and (iv) establish a computer-based system control and data acquisition load dispatching center.

7. NEA's Past Performance

63. NEA's past and projected financial performance, including the profit and loss, and cash flow statement, and balance sheet, is given in Appendix 12. NEA's past performance for the five-year period FY1991 to FY1995 is summarized in Table 3.

Table 3: NEA's Past Performance

Fiscal Year ending 15 July		1991	1992	1993	1994	1995
Generation and Imports	(GWh)	906.3	981.1	969.8	1,034.2	1,125.7
System Loss	(%)	26.1	24.8	24.3	25.9	26.3
Energy Sales	(GWh)	669.4	737.4	733.8	765.9	829.5
Revenue per Unit (NRs/kWh)		1.40	1.99	2.54	3.38	3.96
[Annual Increase (%)]		[1.8]	[41.6]	[27.8]	[33.1]	[17.4]
Total Revenues (NRs million)		992.6	1,514.2	1,904.5	2,611.8	3,464.7
Net Profit/(Loss) (NRs million)		(424.7)	(50.5)	106.2	101.0	222.7
Rate of Return on Revalued Assets (%)		(1.9)	(0.5)	0.2	1.6	2.3
Debt-service Coverage Ratio (times)		3.3	6.3	1.5	1.7	1.4
Self-Financing Ratio (%)		9.9	9.1	35.8	46.3	13.0

Source: NEA and the Bank.

64. NEA's financial performance during the initial years of the period under review was not satisfactory, mainly because of high system losses, over staffing, and inadequate tariffs. Tariffs and staffing have improved in recent years. Significant tariff increases have been provided since 1991 (60 percent in November 1991, 25 percent in March 1993, and 38 percent in March 1994) and staffing has been reduced by about 15 percent. As a result, NEA started making profits from FY1993. Profits declined marginally in FY1994 because Kulekhani I and II were out of commission for five months from flood damage. NEA's financial performance in FY1995 was encouraging in spite of high system losses. This was mainly due to higher electricity generation/sales and higher tariffs.

8. Performance Against Key Covenants Under the Seventh Power Project

65. NEA's performance against key covenants under the last loan, Loan No. 1011-NEP(SF): Seventh Power Project, is shown in Appendix 13 and summarized in Table 4.

Table 4: Covenant Compliance Statement for NEA — FY1991 to FY1995

Fiscal Year ending 15 July		1991	1992	1993	1994	1995
Accounts Receivable	- [Covenant (months)]	[3.00]	[3.00]	[3.00]	[3.00]	[3.00]
	- **Actual (months)**	**6.95[a]**	**5.98[a]**	**3.19[a]**	**2.81**	**2.53**
Accounts Payable	- [Covenant (months)]	[3.00]	[3.00]	[3.00]	[3.00]	[3.00]
	- **Actual (months)**	**0.80**	**0.60**	**0.50**	**0.60**	**0.50**
System Losses	- [Covenant (%)]	[25.5]	[24.0]	[22.0]	[20.0]	[20.0]
	- **Actual (months)**	**26.1[a]**	**24.8[a]**	**24.3[a]**	**25.9[a]**	**26.3[a]**
Self-financing Ratio	- [Covenant (%)]	[7.0]	[7.0]	[10.0)	[11.0]	[12.0]
	- **Actual (%)**	**9.9**	**10.0**	**10.0**	**45.1**	**13.0**
Rate of Return	- [Covenant (%)]	[6.0]	[6.0]	[6.0]	[6.0]	[6.0]
(Historical Assets)	- **Actual (%)**	**-3.7[a]**	**-1.1[a]**	**0.5[a]**	**4.0[a]**	**6.4**
Debt-service	- [Covenant (times)]	[1.2]	[1.2]	[1.2]	[1.2]	[1.2]
Coverage Ratio	- **Actual (times)**	**3.3**	**6.3**	**1.5**	**1.7**	**1.4**

[a] Denotes noncompliance with the covenant.
Source: NEA and the Bank.

66. NEA's performance in relation to key covenants improved significantly during the period under review. In FY1995, NEA was in compliance with all but one covenant, that for system losses. While the level of system losses in FY1995 was not very different from that in FY1991, the shortfall vis-a-vis the covenanted requirement was much higher because the target was tightened from 25.5 percent to 20.0 percent over the period. System losses are broadly divided into two categories: nontechnical and technical. Nontechnical losses arise from inaccurate or tampered-with meters and connections, unrecorded consumers, and pilferage. Technical losses arise during transfer of power through wires and cables, and during stepdown or stepup of voltage for transmission and distribution. While quantification of nontechnical losses is difficult, rough estimates place the figure at about a third of the total losses.

67. Technical losses are attributed to a number of factors: transformation loss, transmission line loss, increase in load density, long distribution lines, unbalanced load, poor power factor, low quality of joints and connections, long service line lengths, and old equipment with poor operational efficiencies. NEA envisages various measures to reduce technical losses: substation and feeder metering; rehabilitation, upgrading, and addition of conductors; phase balancing; relocation and reinforcement of transformers; and geographical information system mapping. Nontechnical losses present a greater problem and require intervention at a higher level. Accordingly, a special committee has been constituted recently under the chairmanship of the Assistant Minister of Water Resources, with the Secretary, MOWR, and Managing Director of NEA as members, to directly monitor loss reduction activities. Disconnection of habitual offenders, particularly large consumers, will receive special attention of the committee. Other loss reduction activities will include metering of unmetered supplies starting with large customers, resealing of consumers' meter boxes and use of underground cables in place of overhead wires to avoid tapping. NEA will implement a loss reduction component for nontechnical losses (see Appendix 14), which will be financed under the loan in the amount of $2.3 million. NEA has also drawn up a detailed action plan at a cost of $4.3 million to reduce technical losses. Further

measures are being worked out to increase accountability of staff by setting predetermined targets for reduction of losses and to reward and motivate performing staff through incentive schemes. Based on these measures, NEA expects to achieve the covenanted 20 percent level of system losses by FY2000. Accordingly, a modified covenant is proposed under the Project to target phased reduction in losses as follows: FY1997 — 23 percent; FY1998 — 22 percent; FY1999 — 21 percent; and FY2000 and onwards — 20 percent.

9. Proposed Key Covenants Under the Project

68. The covenants under the Seventh Power Project for debt-service coverage ratio (at least 1.2 times), accounts receivable (at most 3 months), and accounts payable (at most 3 months) are proposed to be adopted for the Project without any change. The system loss covenant is proposed to be modified as indicated in paragraph 67. The existing rate of return covenant of at least 6 percent based on historical assets is proposed to be strengthened under the Project from FY1998 to at least 6 percent on revalued assets[1] to provide NEA a more commercially-oriented return and make it attractive for eventual private sector participation. The existing covenant for self-financing ratio of at least 14 percent in FY1996, 22 percent in FY1997, and 23 percent in FY1998 and thereafter is proposed to be modified to avoid the sharp increase in FY1997 and allow a more gradual build up as follows: at least 14 percent in FY1996, 18 percent in FY1997, 20 percent in FY1998, and 23 percent in FY1999 and thereafter.

10. Projected Performance of NEA

69. NEA's projected financial performance is summarized in Table 5 (for details see Appendix 12).

Table 5: NEA's Projected Performance

Fiscal Year ending 15 July		1996	1997	1998	1999	2000	2001	2002	2003	2004
Generation and Imports	(GWh)	1,235.5	1,392.7	1,533.2	1,688.1	1,862.9	2,049.1	2,262.0	2,499.2	2,762.5
System Loss	(%)	25.2	23.0	22.0	21.0	20.0	20.0	20.0	20.0	20.0
Energy Sales	(GWh)	923.9	1,072.4	1,195.9	1,333.6	1,490.3	1,639.3	1,809.7	1,999.3	2,210.0
Revenue per Unit (NRs/kWh)		4.16	4.75	5.13	5.45	6.08	6.08	7.30	9.06	9.06
[Annual Increase (%)]		5.0	14.2	7.9	6.2	11.7	0.0	19.9	24.1	0.0
Total Revenues (NRs million)		3,970.6	5,244.6	6,343.7	7,468.6	9,512.9	11,418.9	14,553.4	19,521.8	21,725.6
Net Profit/(Loss) (NRs million)		897.6	1,509.3	1,726.1	2,335.2	2,676.6	4,047.4	3,452.8	5,911.2	6,787.4
Rate of Return on Revalued Assets (%)		3.1	6.0	6.0	7.3	8.0	11.2	10.8	12.2	13.2
Debt-service Coverage Ratio (times)		2.2	2.3	2.3	2.8	2.7	3.3	1.8	2.4	2.4
Self-financing Ratio (%)		28.9	23.9	21.4	23.0	23.0	29.0	23.0	23.0	24.0

Source: NEA and the Bank.

[1] For purposes of revaluation, 80 percent of the assets are assumed to be foreign cost based and will be escalated at foreign inflation rate. The balance 20 percent is assumed to be local cost based and will be escalated at local inflation rate.

11. NEA's Capital Investment Plan

70. NEA's capital investment program, including interest during construction of NRs10.2 billion, is estimated to amount to NRs130.6 billion during FY1996 to FY2004. The foreign costs of NRs98.9 billion are expected to be financed by loans and grants to be secured by the Government from multilateral and bilateral sources (see Table 6). The loans will be relent to NEA as long-term debt on commercial terms to mobilize domestic resources for the Government. The policy dialogue with the Government and NEA on financial strategy has focused on improving NEA's capacity to self-finance an increasing portion of its investment program. The objective is to allow NEA to cover all its operating expenses, meet its debt-service requirements and progressively move towards financing the total local cost, including IDC, of its capital investment program. The ability of NEA to achieve this objective will depend on the actual timing and amount of tariff increases made, as well as on NEA taking necessary complementary measures with regard to cost control, accounts receivable collection, and system loss reduction.

Table 6: Financing of Capital Expenditure
(FY1996 - FY2004)

	Amount (NRs million)	Percent
Capital Expenditures		
Foreign	98,932	75.7
Local	21,500	16.5
IDC	10,216	7.8
Total	**130,648**	**100.0**
Financing		
Foreign Loans	82,126	62.9
Foreign Grants	16,806	12.9
The Government	3,145	2.4
NEA Internal Cash Generation	28,571	21.8
Total	**130,648**	**100.0**

IDC - interest during construction.
Source: NEA and the Bank.

12. NEA's Tariffs: Past and Projected

71. The trend in NEA's average tariff since 1984 is summarized in Table 7. Tariffs were quite low up to FY1991. Since then, several large tariff increases were provided: 60 percent in November 1991, 25 percent in March 1993, and 38 percent in March 1994. More recently, a tariff increase of 20 percent was provided in May 1996 after a two-year gap. Tariffs have hence increased substantially in current or nominal prices, and to a lesser extent in constant terms after adjusting for inflation. These tariff increases were significant but were required to restore NEA's financial performance and improve compliance with covenanted requirements.

Table 7: Average NEA Tariff Levels (excluding exports)

Fiscal Year ending July of	1984	1986	1988	1990	1991	1992	1993	1994	1995	1996
Current Prices (NRs/kWh)	0.80	1.16	1.20	1.38	1.40	1.99	2.54	3.38	3.99	4.75*
Constant 1995 Prices (NRs/kWh)	2.53	3.31	2.61	2.54	2.31	2.85	3.08	3.68	3.99	4.42

* Effective 14 May 1996
Source: NEA and the Bank.

72. NEA's current tariff structure is shown in Appendix 15. The ratio of average residential tariffs to average overall tariffs is reasonably good in Nepal (100 percent) as compared with the ratios for neighboring countries such as India (70 percent), Pakistan (60 percent), and Sri Lanka (68 percent), which are lower because of cross-subsidization. It is important, however, that this tariff structure is at least maintained and for this purpose, suitable covenants are proposed under the Project (see para. 74).

73. A comparison of NEA's current tariff with the long-run marginal cost (LRMC) of power supply in Nepal is given below in Table 8.

Table 8: Comparison of NEA's Tariff versus LRMC

Category	Percentage Share of Total Consumers (%)	Percentage Share of In-country Sales (%)	Average Revenue (NRs/kWh, May 1996)	Percentage (below) or above the Overall Average Tariff (%)	Comparison with LRMC		Economic Subsidy (%)
					LRMC (NRs/kWh)	Percentage of LRMC (%)	
Residential	95.4	39	4.75	(0.5)*	7.90	60	40
Industry	2.5	41	4.63	(3.0)	4.40	105	(5)
Noncommercial	1.2	7	6.52	36.4	6.00	109	(9)
Commercial	0.4	8	6.35	32.9	6.00	106	(6)
Water Supply and Irrigation	0.2	3	3.07	(35.7)	5.20	59	41
Street Light	0.1	1	3.52	(26.4)	6.50	54	46
Miscellaneous	0.2	1					
Total	**100.0**	**100**	**4.75**	**0**	**6.10**	**78**	**22**

* (0.5) denotes that tariff for the consumer category is below the overall average tariff by 0.5 percent.
Source: NEA and the Bank.

74. NEA's current average tariff level is about 78 percent of the estimated average LRMC for electricity sales in Nepal. The current average residential tariff is 60 percent of the LRMC for this category. This points to a need for increases in average real residential tariffs in the long run, and ensuring in the short run that average residential tariffs are set no lower than the average overall tariff level. NEA and the Government have accordingly agreed to include new covenants under the proposed Bank loan requiring that the average residential tariff will be no

less than the average overall retail tariff (which is now just met) and that the subsidized first lifeline block for residential consumers will be limited to 20 kWh/month (which reflects the current tariff structure).

13. Autonomy, Productivity, and Institutional Strengthening of NEA

75. Discussions are ongoing between the Government and the Bank on measures to strengthen NEA's autonomy. This may require change in NEA's ownership. An approach under consideration is diversification of NEA's ownership by offering part of NEA's shares to the public as a first step for broader private sector participation. Another important area receiving attention is improving productivity through motivation of staff. NEA has agreed to introduce incentive schemes and target an improved consumer employee ratio of 75 by FY2000 (as compared with the current figure of 60).

76. Various measures are envisaged for all-round institutional strengthening of NEA. The Bank proposes to assist NEA in the environmental and social areas, and in upgrading its system planning capability (including both software and hardware), through TA to be processed in conjunction with the Project. The Bank also proposes to assist in reduction of nontechnical system losses through specific provision of a part of the Bank loan to finance consultancy services and materials. Some other areas that need to be addressed are computerization of billing,[1] materials management, accounting, corporate planning, budgeting, and human resource development. The requirements of assistance in these and other areas (such as customer service, planned maintenance, and productivity) has been assessed in the paper "Commercialization Strategic Plan" (CSP) for NEA, prepared by the Nepal Administrative Staff College in October 1994. The Bank supports the general thrust of the CSP. The CSP aims to raise the overall level of NEA performance by running it as a well-managed commercial enterprise. NEA has approached the World Bank for assistance to implement the CSP, mainly for improving the accounting system, materials management, and computerization of consumer billing. These measures are expected to result in overall institutional strengthening of NEA and making it a more self-sustaining and profitable institution.

H. Environmental and Social Aspects

1. General

77. The Project's environmental and social aspects have been carefully addressed to comply with Bank policies and procedures in regard to environmental and social concerns. The major documents on social and environmental issues include: (i) environmental impact assessment (EIA); (ii) summary environmental impact assessment (SEIA); (iii) MMMP, and (iv) ACRP. Clauses have been incorporated into the tender documents that describe the responsibilities of contractors in relation to environmental safeguards, preferences for employment of labor from within the Project area, and for maintaining order and social harmony in the construction camps. The Project includes measures for monitoring and mitigating environmental and social impacts that cannot be avoided.

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[1] The Bank has provided some assistance in this area under the Fifth Power Project.

78. The SEIA was circulated to the Board on 25 March 1996 based on data available during fact-finding. Following a more comprehensive enumeration exercise completed recently, the total number of PAFs is now placed at 617 (as compared with 1,033 in the SEIA) including 125 PAFs who have been or will be physically resettled. The reduction is mainly at the dam site and the power station. Nevertheless, the original provision of $5.3 million in the Project cost (for details, see Appendix 16) for mitigation and management programs during construction has been retained. An additional $100,000 will be provided by NEA annually during the operation stage. A total of about 200 hectares of land will be required by the Project including for the access road.

79. Long-term monitoring will be an essential aspect of the environmental management program because only with accurate monitoring can the success of the proposed mitigation measures be evaluated and their scope changed, if necessary, to ensure that the Project is environmentally sustainable throughout construction and operation. Monitoring during construction will largely be the responsibility of the KGEMU, which will be located in the office of the Project Director, to ensure that evidence of noncompliance is dealt with quickly and authoritatively, and that any required modifications to mitigation or compensation programs are acted on. It will be staffed by eight local professionals who will receive full-time guidance and training from an international expert in environmental management during the initial year with backstopping support in subsequent years. At the end of the construction phase, it is expected that at least three KGEMU staff will return to NEA's Environment Division. Additionally, institutional strengthening measures for the NEA Environment Division will be supported through TA.

2. Environmental Aspects

80. Potential Project impacts have been investigated since 1991. Based on the results of the investigations, a comprehensive MMMP has been developed and will be implemented as an integral Project component. The Project's approach to potential environmental impacts is based on the following principles: (i) avoid impacts where possible; (ii) mitigate impacts where unpreventable; and (iii) for impacts that cannot be avoided or mitigated, compensate. The Project's major potential impacts on the physical environment and the associated mitigation measures are described in Appendix 17 and summarized in the following paragraphs.

81. The largest impact will be on the aquatic environment of the Kali Gandaki River because of a reduction in water flow, mainly in the first 13 km of the 50-km stretch of river between the dam and the power station. A compensatory flow of 4 m^3/sec will be released during the dry season to mitigate the loss of riverine habitat, and will primarily benefit the first 13 km of the river below the dam. Farther downstream, natural flows from tributaries will lessen the Project's impact on the river system. Models of before and after scenarios indicate that overall habitat conditions will continue to be acceptable after Project completion. A number of options for mitigating impacts on migrating fish were explored. The trap and haul method, where fish are captured near the base of the dam and trucked past the dam for release (or for hatcheries), was selected as the most appropriate option. This method provides flexibility (trapping can be done for a range of species and sizes), low technology that can be easily transferred, and low cost. Movement of fish downstream will be assisted by modifying the trash rack in conjunction with a bypass system, grating of the collector channels, and monitoring. These methods have been successfully used in developed countries. Adaptation of these

methods for the Project will help Nepal to improve the mitigation of fisheries impacts, a subject not adequately addressed in past hydropower projects. Additionally, a fish hatchery program will be implemented to rear and release species indigenous to the river and to provide local employment and income generating opportunities through labor and development of small-scale fish ponds. These operations will be undertaken with the close involvement of local beneficiaries, and they will include intensive training and monitoring.

82. Approximately 8.6 million tons of spoil will be generated. Disposal of spoil will be strictly controlled. After an exhaustive investigation of alternatives, a decision was taken to use three main disposal methods: (i) on-land disposal, with some sites being filled; (ii) placement of spoil in berms along the river edge to allow a gradual release of spoil; and (iii) disposal in the river. About one third of the spoil during the first year of construction, when the bulk of total Project spoil will be generated, will be placed away from the river. Studies done during EIA preparation indicate that the proportion of spoil to the normal sediment and bed load of the river will not be significant.

83. Although the loss of terrestrial resources, particularly trees, will be comparatively modest, special efforts will be focused on conserving tree species of particular concern through careful staking of facility sites and minimum tree felling. Trees that must be felled will be enumerated and a planting program will be undertaken using native species. Five seedlings will be planted for every tree lost. A protected area will be established in good forest habitat above the dam site with cooperation from and participation of local communities.

84. Site selection and the design of transmission line alignments have been based on a study of alternatives to ascertain the least possible impact on the land, vegetation, and other natural resources. Bioengineering techniques will continue to be used at sites of land disturbance, and strict measures for controlling erosion and runoff have been included in the EIA and the contracts. As a general measure, the contract documents for Project contractors have been carefully formulated to include environmental safeguards and stiff penalties if they are breached.

3. Social Aspects

85. The Project is located in a rural environment with a long history of intensive human use. The principal facilities (access road, dam, and powerhouse) will be located in nine villages, with about 7,900 households and a population of about 45,000. The Project has conducted extensive work to minimize the amount of resettlement, and enable the communities in the Project area to benefit from the Project.

a. ACRP for the Access Road

86. Land for the construction of the access road was acquired in 1992 and 1993 from about 333 PAFs, including about 75 who were required to be resettled.[1] Most families whose

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[1] The SEIA reported that 15 families were resettled on the basis of information available during fact-finding. Since then, NEA has prepared a completion report for the ACRP for the access road. This report shows that residences were acquired from 67 families, including many families who used compensation for their homes to reassemble or construct new residences on the same homestead. Additionally, a group of 8 families were resettled as a contiguous community on nearby land.

houses were acquired used the compensation to construct new homes or to move their existing homes to a new location on the existing homestead. An additional eight landless families were resettled as a contiguous community in homes and on land that was provided for them by NEA. The ACRP for the access road is substantially implemented, with the exception of payment of compensation to absentee owners of land and owners of parcels for which documentation of ownership is incomplete. NEA has deposited the proceeds for paying the absentee landowners into a fund from which disbursements can be made when the landowners submit their claims for reimbursement. NEA has prepared the completion report for the ACRP for the access road.

87. Informal groups were established in each village to facilitate negotiations and processing of claims for resettlement and/or acquisition of land. The informal groups have worked well, and NEA has recognized them as Village Advisory Groups (VAGs). The VAGs are expected to serve more broadly as a vehicle for communication between the affected families and NEA on any matter of mutual interest in relation to the Project.

88. Prior to the construction of the access road, the communities in the Project area could only contact other people by hiking out. This has now changed, with buses plying regularly to and from nearby towns and market places. The construction of the access road also provided employment opportunities for about 200 laborers from the Project areas. The opening of the access road in 1994 stimulated a substantial amount of economic development within the communities, promoting the establishment of many new enterprises and substantially reducing the cost of basic materials.

89. PAFs are generally satisfied with compensation that they received for their property and/or residences that were acquired by the Project. A few PAFs (referred to as seriously project-affected families [SPAFs]) may need additional support to reestablish their livelihood. NEA is seeking to identify the SPAFs with help from the VAGs so that the necessary support may be provided. The families will be provided access to jobs that may be created by the Project and support for the establishment of a new family enterprise.

b. ACRP for the Facilities and Transmission Lines

90. The ACRP for the facilities and transmission lines continues to evolve, with the most recent revision providing for the resettlement of a smaller number of people than was estimated during fact-finding and reflected in the SEIA. Based on current figures, about 53 ha of privately owned land will be acquired from 284 PAFs. About 50 families are expected to have to relocate their residences due to the acquisition of land for the facilities and transmission lines. SPAFs, who may need assistance to rehabilitate their income, will be given preference in employment with the Project and support for establishing a new livelihood through training and access to capital from a micro-enterprise revolving fund that is being established under the Project. The needs of SPAFs for rehabilitation support are expected to differ among families, and NEA will seek assistance from the concerned VAG to access the needs of individual SPAFs. The implementation of the ACRP will be monitored by the KGEMU.

c. Gender Issues

91. Focused group discussions with women in the Project area revealed that a significant number of households are headed by women because many working age males are employed outside of the Project area in the military service or as construction laborers. The

major interest of the women is in employment opportunities that may be provided through the Project, so that their spouses could obtain employment in the Project area. Some women also indicated a desire for employment as construction laborers, and to establish a small handicraft, trading, or manufacturing enterprise.

92. The Project will promote the employment of laborers from within the Project area. Accordingly, NEA has worked with the Project-affected communities to compile an inventory of workers with skills that may be required by contractors. In addition, clauses have been incorporated into draft contracts that provide for preference to be given to persons from within the Project area in regard to employment.

d. Public Consultations

93. Public consultations for the Project have been in progress since the early 1990s. The first widely-attended public hearings were held at the Project site in 1994. Since then, NEA has been in close consultation with the people at the Project site. With Project preparation moving into the advanced stages, NEA extended its consultation efforts to Kathmandu. In 1996, three well-attended public consultation meetings were held in Kathmandu. These were complemented by two meetings at the Project site in March and June 1996. Project Information Centers (PICs) were established in Kathmandu (January) and at the Project site (February). The PIC in Kathmandu was shifted to NEA's premises in March 1996 to provide easier access to the public. Also, full-time NEA personnel were posted at the PIC to attend to requests for information.

I. Technical Assistance

1. Institutional Strengthening of NEA's Environment Division

94. A summary of the TA for the Institutional Strengthening of NEA's Environment Division is given in Appendix 18. The objective of the TA is to build NEA's capacity to ensure that environmental and social issues are adequately addressed in the design, construction, operation, and monitoring of power development projects in Nepal. The TA will be implemented over a period of 12 months, and will assist NEA to (i) formulate an environmental and social management framework with special emphasis on environmental guidelines, social assessment, and public participation; (ii) identify and participate in appropriate in-country and external staff training programs; (iii) develop an environmental management information system; and (iv) acquire essential logistic support and reference documents. Consulting services will consist of 12 person-months of international consultants and 11 person-months of local consultants with expertise in EIA, social assessment, data base systems, and training. The consultants will be recruited in accordance with the Bank's *Guidelines on the Use of Consultants*. Simplified technical proposals will be used for recruitment of consultants taking into account the straight forward nature of the terms of reference. The consultants will coordinate closely with the KGEMU to maximize training and experience-building opportunities. The cost of the TA is estimated at $580,000, including $455,000 in foreign exchange, of which the Bank will finance, on a grant basis, the entire foreign exchange cost and part ($79,000) of the local cost for a total of $534,000. The remaining TA costs will be financed by the Government.

2. Power System Master Plan

95. A summary of the TA for the Power System Master Plan is given in Appendix 19. The TA will prepare a new power system master plan for Nepal, with emphasis on generation planning. The TA will also provide on-the-job training to NEA staff. About 18 person-months of international consultancy services will be required in load forecasting, generation planning, and transmission system planning. The consultants will be recruited in accordance with the Bank's *Guidelines on the Use of Consultants*. Simplified technical proposals will be used for recruitment of consultants taking into account the straight forward nature of the terms of reference. The TA will be implemented over a 12-month period at an estimated cost of $650,000, comprising $582,000 in foreign exchange. The entire foreign exchange and $18,000 of the local cost will be financed by the Bank, on a grant basis, for a total of $600,000. The remaining $50,000 will be financed by NEA in the form of facilities, staff salaries, and other counterpart assistance costs.

V. PROJECT JUSTIFICATION

96. The justification for the Project lies in the need for new generation capacity to meet the growing demand for power. NEA's analysis shows that the Project is part of the Least-cost Generation Expansion Plan (LCGEP) under various alternative scenarios. A key factor favoring selection of the Project for the LCGEP is its peaking capability, which complements the other, mainly nonpeaking, run-of-river projects without pondage which have lower firm capacity during the dry season. Another favorable factor is that, because Project preparation is in an advanced stage, the Project can be commissioned in July 2000, just when sizeable power deficit will again start to be felt. The Project's environmental and social impacts are relatively low and manageable, and its financial and economic indicators are satisfactory.

A. Financial and Economic Analysis

1. Alternative Generation Options

97. The options for electric power generation include nuclear, geothermal, solar, windpower, thermal, hydro, and other sources. Most of these options, except for thermal and hydro, are either technically infeasible or not adequately studied or economically unviable in Nepal, and hence are not considered for the present in the LCGEP analysis. Thermal power is a feasible option but is not preferred by NEA because Nepal has no fossil fuels. Because Nepal is landlocked, fuel has to be imported by land from ports over long distances and through difficult hilly terrain. Hence, fuel supplies are uncertain and the delivered cost high. More importantly, fuel imports for power generation will increase import dependency and recurrent outgo of precious foreign currency. Also, the thermal option increases the risk of forced outages because of the complex technology and Nepal's lack of experience in operating gas turbines. Further, thermal plants would add to the already acute problem of air pollution in the Kathmandu valley and other areas. As a result, hydropower remains by far the best alternative for Nepal.

98. Nepal has significant economically exploitable hydropower potential, estimated at around 43,000 MW. However, less than 1 percent of this has been exploited to date. Exploitation of this hydropower is not as easy or cheap as in many other countries. The geology of the Himalayan ranges is relatively young and hence uncertain and unfavorable. The terrain is often steep and difficult. Sediment load in the rivers is very high. Equipment and materials

have to be imported through distant ports and transported through difficult terrain. There is considerable seasonal variation in the water flows in the rivers, with the lowest dry season flow (March) less than 5 percent of the peak wet season flow (August), as in the case of the Kali Gandaki River. These features add to the capital and generation costs of hydropower in Nepal.

99. Hydropower plants in Nepal can be classified broadly into three types: seasonal storage, run-of-river with pondage, and run-of-river without pondage. Seasonal storage projects with large reservoirs such as the Kulekhani project, are most versatile and store the surplus river flows during the wet season for use during the dry season, when river flows are low. Generation from such projects can be regulated to meet peak loads. Run-of-river projects with pondage, such as the Project, store water during the nonpeak hours of the day for use during the peak hours of the day. Run-of-river projects without pondage such as the Khimti Khola project, have no water storage capability and hence experience a sharp drop in generation capacity during the dry season. The firm capability of such plants in the dry season is low, for instance, the dependable capacity of the Khimti Khola project falls to around one-third of its installed capacity during dry season. While run-of-river projects without pondage have no regulatory capability and hence are least preferred from a peaking consideration, they usually have lower capital cost (hence lower cost of generation) and less environmental impacts because they have no dam or reservoir for water storage.

100. By size, hydropower plants in Nepal could be broadly classified into mini (below 10 MW), small (10-50 MW), medium (51-500 MW), and large (above 500 MW). Generally, run-of-river projects without pondage are of mini or small size. Run-of-river projects with pondage and storage projects are generally in the medium and large categories. There have been suggestions from time-to-time in Nepal that mini hydroelectric projects could constitute an alternative to larger projects. Some 33 hydropower plants with an installed capacity ranging from 0.3 MW to 11.4 MW were suggested under a mini hydroelectric master plan developed in 1993 under German technical assistance.[1] Of these, 13 were considered potentially suitable for integration into the national transmission grid. However, only two of the identified sites have been studied beyond the prefeasibility level; most of the others are at the early reconnaissance stage. The installed capacity of all 33 plants combined would only amount to about 66.3 MW. Even if they had all been proven to be technically sound and ready for implementation, and even if the technical capacity existed to implement them all simultaneously, they could not meet a major portion of Nepal's incremental demand for electricity over the next decade. Instead, mini hydroelectric projects should be viewed as preferred options for supplying isolated small load centers located far from the NEA grid.

101. For hydro projects in the small- and medium-size categories, studies have been conducted from time-to-time since the 1970s and over one hundred potential project sites have been identified. Less than one-fifth of these potential projects have been studied to prefeasibility stage and beyond. These projects are located mainly in the three major river basins, namely the Gandaki, Karnali and Kosi basins. Other river basins include the southern basin and the Mahakali River basin. Nineteen hydro projects with total capacity of 1,935 MW are considered as candidate projects for the LCGEP and are shown in Table 9.

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[1] NEA/German Agency for Technical Cooperation (GTZ). August 1993. "Small Hydropower Master Plan in Nepal" (2 volumes). Kathmandu, Nepal.

Table 9: Candidate Hydropower Projects for LCGEP

	Run-of-river without Pondage (MW)		Run-of-river with Pondage (MW)		Storage (MW)		Total MW (%)
Design Stage	Puwa	6	Chilime	20			
	Khimti Khola	60	Kali Gandaki "A"	144			
	Modi Khola	14	Arun 3/Phase I	201			
	Upper Bhote Khoshi[a]	36	Arun 3/Phase II	201			
Subtotal		**116**		**566**		—	**682** (35%)
Feasibility Stage	Upper Modi	14	Middle Marsyangdi	42	Kulekhani 3	13	
			Chamelia Gadh	30	West Seti	360	
			Upper Arun	335			
Subtotal		**14**		**407**		**373**	**794** (41%)
Prefeasibility Stage			Khimti II	26			
			Upper Karnali	240			
Subtotal		—		**266**		—	**266** (14%)
Reconnaissance Stage	Upper Marsyangdi	43					
	Tama Koshi 3	70					
	Lower Bhote Koshi	80					
Subtotal		**193**		—		—	**193** (10%)
Total MW		**323**		**1,239**		**373**	**1,935** (100%)
(%)		(17%)		(64%)		(19%)	(100%)

[a] Design at preliminary stage.
Source: NEA and the Bank.

102. Given the immediate need to expand the generation capacity by 40-50 MW per year in the medium term, NEA attaches high priority to the level of preparatory work carried out on a project. The time required to progress through the various stages of reconnaissance, prefeasibility, feasibility, and design is significant and can be 3-5 years even for small projects. To this has to be added the time required to achieve financial closing before the implementation of a project can be undertaken in real earnest. Nepal's external funding options are limited and it is not easy or quick to obtain the necessary funding, particularly for private projects relying on local and foreign capital markets. Hence, not all candidate projects are likely to progress successfully through all stages.

103. In evaluating alternatives, NEA fully recognizes the importance of maximizing the use of local technology and resources (people, materials, and money). A system based wholly on local technology and resources will depend, at least for the foreseeable medium term, on mini and small projects. Implementation of a large number of such local-resource-based projects fast enough to add 40-50 MW per year may not be practical with the limited skills, materials, and money currently available in Nepal. Also, too many private projects funded by costly foreign commercial borrowings are likely to result in recurrent outgo of precious foreign exchange and to burden the foreign exchange debt-service capability of Nepal. From a technical view point, a power system built wholly with numerous mini and small generating stations would be difficult to operate. Taking all these factors into account, NEA considers that an optimal mix of

generation projects is required: public and private; mini (for remote loads), small (mainly private), and medium and large (mainly public); and, run-of-river without pondage, run-of-river with pondage, and storage. Large projects in the private sector will be encouraged, as local capabilities and capital markets are expanded.

2. Least-cost Analysis

104. NEA periodically reviews the demand forecast for power in Nepal and based thereon, updates the power system expansion plan to meet such demand. For addition of generation capacity, the LCGEP is formulated taking into account the forecast demand for power, feasible generation options available to meet the power demand, and the capital and operating costs of such options. All cost streams are expressed in economic terms and discounted to a base year at a rate equal to the economic opportunity cost of capital for Nepal (currently estimated at 10 percent). The present value of total costs so derived for alternative investment programs are compared, and the alternative with the least total cost is selected. The LCGEP analysis is carried out by NEA using the Wein Automatic System Planning (WASP III) computer program.[1]

a. Load Forecast

105. During FY1983 to FY1995, electricity sales grew by 11.8 percent per year and peak demand by 11.9 percent per year. Up to FY2004, sales are projected to grow annually by 11.2 percent and peak demand by 8.9 percent. These growth rates are considered reasonable, given the low electrification ratio of 14 percent[2] and the relatively low level of electricity consumption in Nepal, which is only 45 kWh per capita annually.[3] Nepal is clearly at a very early stage in the development of its electric power sector, and high growth rates in power demands are typical at such an early stage of development. Peak demand in FY2004 is projected to reach 549 MW, which is double the FY1996 level. This forecast assumes some improvement in the system load factor from the present level of 51.0 percent to 57.5 percent in FY2004 with improved load management. Reserve capacity margins will continue to be very low and close to zero until the Project can be commissioned in July 2000. NEA does not believe that it is economically justified to install additional thermal peak generating capacity, such as diesel units or gas turbines, before this date specifically in order to increase its reserve capacity. Once the Project is in operation, the reserve capacity margins will increase to about 5 percent, which is still low by normal standards.

b. Least-cost Generation Expansion Plan

106. Candidate projects for the LCGEP analysis include the hydro projects in Table 9 and some thermal (diesel and gas turbine) projects. The thermal projects, though not preferred

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1 The model is an optimization model that examines medium- to long-term generation options for meeting an assumed power demand and develops the economically optimum generation expansion plan.

2 By comparison, the proportion of households electrified in other countries is currently 38 percent in Indonesia (Java and Bali), 44 percent in Sri Lanka, 48 percent in Pakistan, 61 percent in the Philippines, 87 percent in Thailand, and 98 percent in Malaysia.

3 Average per capita consumption in other low income Asian countries is 188 kWh in Indonesia, 196 kWh in Sri Lanka, 281 kWh in India, 284 kWh in Pakistan, 337 kWh in the Philippines, and 854 kWh in Thailand.

for reasons stated in paragraph 97, have been considered because hydro projects are not available in the required optimum sizes and at the times required. This will be reviewed by NEA for replacement with hydro projects as and when new hydro projects became available. The recommended LCGEP up to FY2004 is shown in Appendix 11, assuming a minimum reserve margin of 5 percent to be achieved in FY2001 and taking into account realistic development schedules for the various candidate projects. If the Project is delayed by one year to July 2001, the LCGEP would include 50 MW of gas turbines in July 2000 and the total discounted cost would be higher. Moreover, this would entail thermal power generation, which NEA considers to be undesirable. Results of sensitivity analysis for this case and other cases confirms that the Project is an integral part of the least-cost power development plan for various scenarios and that it should be commissioned by July 2000.

3. Financial and Economic Internal Rates of Return

107. The financial and economic evaluation of the Project is described in Appendix 20. The financial internal rate of return (FIRR) is estimated to be 9.8 percent for the Project and is higher than the weighted average cost of capital for the Project, estimated at 5.4 percent in real terms. The economic internal rate of return (EIRR) of the Project is estimated to be 15.0 percent, which is above the opportunity economic cost of capital of 10 percent. As shown in Table 10 below, the FIRR and EIRR are able to withstand adverse movements in important parameters within reasonable limits, confirming thereby the financial and economic robustness of the Project.

Table 10: FIRR and EIRR Sensitivity Analysis

	FIRR (%)	SI	EIRR (%)	SI
Base Case	9.8	—	15.0	—
Benefits lower by 10 percent	8.7	1.12	13.7	0.87
Capital Cost higher by 10 percent	9.0	0.82	13.9	0.75
One-year delay in Project commissioning	9.4	0.16	14.2	0.21

SI = sensitivity indicator (ratio of percentage change in EIRR or FIRR to percentage change in sensitivity parameter).
Source: NEA and the Bank.

4. Risks

108. The investment in the Project is large in the context of the Nepalese economy and hence can give rise to risks at a macroeconomic level. Risks are also associated with the Project at the utility and Project level, as well as in relation to environmental and social aspects as discussed in paras. 77 to 93. The Bank has had extensive discussions with the Government and NEA on measures to deal with various risks.

a. Macroeconomic Risks

109. At the macroeconomic level, the risk of the Project expenditures crowding out expenditures in the priority rural and social sectors was examined. This risk is minimized by the

significantly higher self-financing requirements stipulated under the Project and the commitment of the Government to, among other things, provide the necessary tariff increases to meet these requirements. Government's equity contribution to NEA's funding requirements from FY1996 to FY2004 will be small. Studies have shown that NEA's development program is manageable provided that the Government's macroeconomic targets are achieved. The proposed annual review of Nepal's economic performance and the flexibility to adjust NEA's future capital investment program should keep the macroeconomic risks within acceptable levels. Also, the Government's macroeconomic efforts are being supported by the International Monetary Fund (IMF) under its Extended Structural Adjustment Facility (ESAF).

b. Institutional Risks

110. Shortfall in self-financing by NEA of the local cost of the Project is a risk but is manageable because of NEA's commitment to improve operational efficiencies and the Government's commitment to provide the necessary tariff increases. Political risks in providing the necessary tariff increases are considered manageable for two reasons. First, the tariff increases required are generally much lower than in the past and have been spread out over a longer period. Once the initial tariff adjustments are made, subsequent tariff increases during Project implementation will be small. Second, NEA is required under the Bank loan to become more efficient and thereby keep tariff increase requirements to the minimum.

111. Another risk related to NEA is its institutional capability to construct and operate the Project satisfactorily. This risk is considered manageable because NEA's in-house capability will be reinforced strongly in the required areas by provision of international consulting services: the POE-S&T for technical and constructional guidance; the POE-E&S for environmental and social aspects; Project supervision consultants for implementation; KGEMU for environmental and social aspect monitoring; and TA for in-house strengthening of NEA Environment Division. With these various support measures, and NEA's past experience in constructing hydropower projects, NEA's institutional capability is expected to be adequate to manage a medium-sized project such as the one proposed.

c. Project Risks

112. Project risks could relate to a number of areas: technical, implementation, cost/financing, environmental and social. The main technical risk arises from the difficult terrain and poor geological conditions in the Himalayan ranges in Nepal. To allow for unforeseen adverse geological conditions, the tunnel will adopt a conservative method of construction (see para. 35). Risk of cost overruns has been minimized through conservative physical contingency provisions of close to 20 percent for the power station civil works (C3) and 10 percent for the other civil works. The risk of cost overrun is hence assessed to be low. The risk of shortfall in financing that could arise from a significant cost overrun is hence also minimized.

113. The risk of delay in Project implementation cannot be ruled out, particularly because of unforeseen adverse geological conditions. To minimize this risk, a strong Project management organization is proposed, supported by international consultants and POEs. Advance procurement action has been taken for the civil works requiring the longest implementation time. Civil works for the dam and desanding basins (C1) must start by the end of 1996 or early in 1997 for timely Project implementation. Thus, steps are being taken to award the contracts by November 1996 as later awarding could delay the Project. To guard against

such delay, excavation work will be started by a local contractor in October 1996, with the contractor to continue work until the international contractor for C1 is ready to take over. While risks in C1 relate mainly to a late start, the tunnel (C2) and power station (C3) could present risks during implementation because of unknown geological conditions. This will need close monitoring.

114. Environmental and social risks are significantly minimized through various mitigation measures envisaged under the Project. The access road has been completed and most of the affectees duly compensated. Elaborate schemes have been drawn up for compensating and rehabilitating the affectees of the main facilities. NEA has taken advance measures to disseminate Project information by setting up Project Information Centers (PICs) and conducting public consultations. Project affectees and many local NGOs support the Project and are unlikely to hinder its implementation. Some NGOs, however, could raise issues in regard to spoil disposal into the river, the fish catching-and-trucking program, and downstream impacts of water diversion. NEA will continue to clarify on these issues.

B. Social Dimensions

115. When the Project is fully commissioned, NEA will serve about 900,000 local consumers, giving about 4.5 million people or about 20 percent of the population access to electricity. As the Project will be operating in an interconnected power system together with other existing and committed power plants, it is not possible to identify any specific group of consumers who will directly benefit from the Project. The expanded availability of power will encourage development of new businesses and industries, resulting in the creation of new employment opportunities. With a view to capacity building through transfer of technology, the Engineer will engage at least 1,000 person-months of local technical personnel. Also, NEA will invest at least 1 percent of net revenue from the Project for rural electrification in areas around the dam site and the power station.

VI. ASSURANCES

A. Specific Assurances

116. The Government and NEA have given the following assurances, in addition to the standard assurances, which are incorporated into the legal documents:

(i) The Borrower and the Bank will jointly review every year the macroeconomic framework for public expenditure planning with a view to ensuring macroaffordability of the power sector investment plan without jeopardizing other priority development expenditures, particularly social sector expenditures.

(ii) The Borrower and NEA will take appropriate action, including tariff adjustments, to enable NEA to achieve (a) a rate of return of at least 6 percent on net historical assets in FY1997 and 6 percent on net revalued assets in FY1998 and thereafter; (b) a minimum self- financing ratio of at least 14 percent in FY1996, 18 percent in FY1997, 20 percent in FY1998, 23 percent in FY1999 and thereafter; and (c) a debt-service coverage ratio of at least 1.2 times.

(iii) The Borrower and NEA will ensure that (a) the average residential tariff will be no less than the average overall domestic tariff, and (b) the first lifeline block for residential consumers will be limited to 20 kWh/month.

(iv) NEA will take appropriate action to ensure that system losses are not more than 23 percent in FY1997, 22 percent FY1998, 21 percent in FY1999, and 20 percent in FY2000 and thereafter.

(v) NEA will take appropriate action to maintain its accounts receivable at not more than three months' equivalent sales.

(vi) NEA will take appropriate action to maintain its accounts payable at not more than the equivalent of three months' cash operating expenses, excluding accounts payable for the purchase of energy.

(vii) NEA will provide each year for the Bank's review a draft corporate plan setting forth NEA's strategic plans, at least 90 days prior to the start of each fiscal year covering the subsequent three years. NEA will take account of the Bank's comments in finalization of the plan. Within nine months of the end of each fiscal year, NEA will publish an annual report for the information of the general public, describing performance pursuant to the provisions of its corporate plan.

(viii) NEA will (a) provide the Bank within six months of loan effectivity with a draft of its Commercialization Study Report, (b) take account of the Bank's comments in finalizing the report's recommendations, (c) submit a satisfactory implementation plan, and (d) implement the plan and each year report on progress achieved.

(ix) To monitor and evaluate internal controls, NEA will ensure that its internal audit function is carried out by competent qualified staff or by a competent firm of accountants, and will ensure that its findings are dealt with promptly.

(x) NEA will introduce incentive schemes and a target for a consumer employee ratio of 75 by FY2000.

(xi) Within six months of loan effectivity, NEA will provide to the satisfaction of the Bank a plan of action for the computerization of all of NEA's billing system and subsequently implement such plan as per the time table indicated therein.

(xii) NEA will maintain throughout the construction period of the Project the POE-S&T to review semiannually the adequacy of the engineering design and construction aspects of the Project, and the POE-E&S to review semi-annually the environmental and social aspects. The POEs will make recommendations on specific issues identified during such reviews.

(xiii) Within three months of loan effectivity, NEA will establish the KGEMU, maintain the KGEMU throughout the construction period, and carry out the recommendations made by the KGEMU in a manner satisfactory to the Bank.

(xiv) The Borrower and NEA will ensure that the Contractor/Engineer (a) carries out all environmental protection measures set forth in the Project's environmental documentation, tender documents, and engineering contract; and (b) provides the Bank with quarterly progress reports, within 30 days from the end of each quarter, and with evaluations of environmental problems and issues together with a list of corrective measures recommended and actions taken..

(xv) During Project implementation the Borrower and NEA will carry out an environmental monitoring program, satisfactory to the Bank, and will submit the results to the Bank, on a quarterly basis, within 30 days from the end of each quarter. The primary objective of the monitoring program will be to identify problem areas in sufficient time to initiate viable solutions.

(xvi) The Borrower and NEA will implement fully the ACRP and MMMP, and will submit quarterly progress reports to the Bank.

(xvii) The Borrower and NEA will ensure that a postconstruction environmental audit is carried out and that an action plan for corrective measures is prepared based on the audit results.

B. Conditions of Loan Effectiveness

117. The following conditions will be met by the Borrower and NEA for the Bank loan to be declared effective:

(i) The OECF loan agreement will have been duly executed and delivered on behalf of the Borrower and NEA, and all conditions precedent to its effectiveness will have been fulfilled.

(ii) The Subsidiary Loan Agreement, in form and substance satisfactory to the Bank, will have been duly executed and delivered on behalf of the Borrower and NEA, and shall have become fully effective and binding, subject only to the effectiveness of the Loan Agreement for the Bank.

VII. RECOMMENDATION

118. I am satisfied that the proposed loan would comply with the Articles of Agreement of the Bank and recommend that the Board approve the loan in various currencies equivalent to Special Drawing Rights 110,942,000 to the Kingdom of Nepal for the Kali Gandaki "A" Hydroelectric Project, with a service charge at the rate of 1 percent per annum and with an amortization period of 40 years, including a grace period of 10 years and such other terms and conditions as are substantially in accordance with those set forth in the draft Loan and Project Agreements presented to the Board.

MITSUO SATO
President

27 June 1996

APPENDIXES

BANK ASSISTANCE TO THE POWER SECTOR

	Project Name	Amount	Date of Approval
1. Public Sector Loans			
Loan No. 102-NEP(SF)	Gandak-Hetauda Power	$ 2.7 million	24 Oct 1972
Loan No. 249-NEP(SF)	Gandak-Hetauda (Supplementary)	$ 2.5 million	11 Dec 1975
Loan No. 250-NEP(SF)	Second Power	$ 3.8 million	11 Dec 1975
Loan No. 447-NEP(SF)	Third Power	$ 18.6 million	21 Dec 1979
Loan No. 512-NEP(SF)	Mini-Hydropower	$ 8.3 million	21 Apr 1981
Loan No. 533-NEP(SF)	Fourth Power	$ 19.4 million	08 Oct 1981
Loan No. 670-NEP(SF)	Fifth Power	$ 20.0 million	14 Dec 1983
Loan No. 708-NEP(SF)	Sixth Power	$ 28.1 million	20 Nov 1984
Loan No. 1011-NEP(SF)	Seventh Power	$ 51.0 million	11 Jan 1990
	Total	**$ 154.4 million**	
2. Private Sector Loans			
Loan No. 7123/7124-NEP	Himal Power Limited	$ 35.1 million	23 Jan 1996
	Total	**$ 35.1 million**	
3. Technical Assistance			
TA No. 77-NEP	Gandak-Hetauda Power	$ 40,000	24 Oct 1972
TA No. 160-NEP	Second Power	$ 230,000	11 Dec 1975
TA No. 333-NEP	Third Power [a]	$ 640,000 [b]	21 Dec 1979
TA No. 334-NEP	Mulghat Hydropower [a]	$ 920,000 [c]	21 Dec 1979
TA No. 399-NEP	Mini Hydropower [a]	$ 820,000 [d]	21 Apr 1981
TA No. 417-NEP	Fourth Power [a]	$ 740,000 [e]	08 Oct 1981
TA No. 418-NEP	Fourth Power Part B (Rural Electrification Study)	$ 150,000	08 Oct 1981
TA No. 420-NEP	Power Development Study	$ 45,000	13 Oct 1981
TA No. 478-NEP	Formulation of Fifth Power	$ 50,000	30 Aug 1982
TA No. 837-NEP	Formulation of Seventh Power	$ 75,000	24 Dec 1986
TA No. 1267-NEP	Institutional Support for Distribution Planning and Commercial Operations	$ 780,000	11 Jan 1990
TA No. 1394-NEP	Equitable and Efficient in Energy Pricing Study [f]	$ 600,000	23 Oct 1990
TA No. 1737-NEP	Kali Gandaki "A" Hydroelectric Detailed Design [g]	$ 2,000,000	28 Jul 1992
	Total	**$ 7,090,000**	

[a] Bank acts as Executing Agency for UNDP.
[b] Original amount approved was $624,000, but an additional amount of $16,000 was approved on 7 March 1980.
[c] Original amount approved was $650,000, but an additional amount of $270,000 was approved on 21 August 1980.
[d] Original amount approved was $750,000, but an additional amount of $70,000 was approved on 26 April 1985.
[e] Original amount approved was $1,000,000, but this was reduced to $740,000 on 19 January 1984.
[f] Original amount approved was $490,000, but an additional amount of $110,000 was approved on 25 October 1991.
[g] Bank acts as Executing Agency for UNDP $1,000,000 and FINNIDA $1,000,000. The balance of the cost of detailed design $5 million is financed from loan savings under Loan No. 670-NEP(SF).

Source: Staff estimates.

FISCAL AFFORDABILITY OF THE POWER INVESTMENT PROGRAM
(in million NRs unless otherwise specified)

Fiscal Year ending 15 July	Actual 1995	1996	1997	1998	1999	2000	2001
Baseline Projections (excluding Power Investment Plan):							
Total Resources for Development Expenditures [a]	18,196	22,999	27,977	32,343	37,102	42,250	47,651
Foreign [b]	9,510	10,645	12,816	13,155	12,796	15,145	14,997
Local	8,686	12,354	15,161	19,188	24,306	27,105	32,654
Revenue Surplus	6,708	9,999	12,493	15,284	18,942	23,238	28,270
Domestic Borrowing	1,663	1,155	1,288	1,422	1,586	1,768	1,971
Aid [c]	530	1,200	1,380	2,465	3,733	2,099	2,414
Overall Fiscal Deficit before Grants	-11,488	-14,020	-15,216	-16,293	-18,159	-19,033	-19,853
Power Investment Plan:							
Investment Requirements [d]	1,798	5,146	7,318	8,958	12,618	10,541	11,630
Foreign	1,305	3,748	5,139	6,436	9,814	8,272	8,765
Local	493	1,398	2,179	2,522	2,804	2,269	2,865
NEA	296	909	1,525	1,892	2,103	1,702	2,149
Government	197	489	654	631	701	567	716
Resources Available for Power Sector from Baseline Projections [e]	1,690	4,358	4,476	4,836	7,049	8,450	9,530
Foreign [e]	1,268	3,269	2,960	2,917	4,619	5,740	6,265
Local [e]	423	1,090	1,516	1,919	2,431	2,711	3,265
Surplus (+)/Financing Gap (-) for the Government [f]	+188	+121	-1,316	-2,231	-3,466	-389	+49
Foreign	-38	-480	-2,179	-3,519	-5,195	-2,533	-2,500
Local	+225	+600	+862	+1,288	+1,730	+2,143	+2,549
Including Power Investment Plan:							
Overall Fiscal Balance before Grants	-11,488	-18,257	-21,009	-23,360	-28,674	-27,872	-29,334
Foreign Financing for KGA Project	0	3,036	4,606	6,568	4,851	525	0
NEA Internal Funds Available for Financing of Investments [g]	404	1,376	1,708	2,059	2,462	2,667	4,018
MEMORANDUM ITEMS:				(in percent of GDP)			
Baseline Projections (excluding Power Investment Plan):							
Domestic Borrowing Requirement [h]	0.7	0.5	0.5	0.5	0.5	0.5	0.5
Overall Fiscal Balance before Grants	-5.2	-5.6	-5.4	-5.2	-5.2	-4.9	-4.6
Power Investment Plan:							
Surplus (+)/Financing Gap (-) for the Government	+0.1	0.0	-0.5	-0.7	-1.0	-0.1	0.0
Foreign	-0.0	-0.2	-0.8	-1.1	-1.5	-0.7	-0.6
Local	+0.1	+0.2	+0.3	+0.4	+0.5	+0.6	+0.6
Including Power Investment Plan:							
Overall Fiscal Balance before Grants	-5.2	-7.2	-7.5	-7.5	-8.3	-7.2	-6.8
Foreign Financing for KGA Project	0.0	1.2	1.6	2.1	1.4	0.1	0.0
NEA Internal Funds Available for Financing of Investments	0.2	0.5	0.6	0.7	0.7	0.7	0.9

GDP - Gross domestic product; KGA - Kali Gandaki "A" Project; NEA - Nepal Electricity Authority

[a] Includes "normal" expenditures for power.
[b] Obtained as a residual.
[c] Non-project aid is assumed to grow at 15 percent per annum beginning FY1996 plus the proposed Bank program loan.
[d] Cost of new power investments for Kali Gandaki "A", transmission, distribution, other "normal" power investments and interest during construction.
[e] Total resources available for development expenditures multiplied by the shares updated from the July 1992 World Bank Affordability study.
[f] Total resources available for the power sector minus cost of new power investment to the Government.
[g] Based on the Bank/Energy Department simulation of the financial model of the NEA.
[h] Domestic Borrowing Requirement according to IMF-ESAF targets, the baseline projection.

Source: Staff estimates.

Major Assumptions:
1. Projections on GDP growth and the budget are based on the latest IMF assessment (February 1996).
2. Percentage of Power Sector Available to Total Available for Development Expenditures (both foreign and local) updated from World Bank 1992 study.
3. Cost projections for Kali Gandaki as of March 1996.

PROJECT COST ESTIMATES
($ million)

	Base Cost [a]			Physical Contingency [b]			Price Contingency [c]			Total		
	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total
A. Preliminary Works	—	4.7	4.7	—	0.2	0.2	—	0.1	0.1	—	5.0	5.0
B. Civil Works												
Lot C1 (Dam and Desanders)	75.7	12.6	88.3	7.6	1.2	8.8	5.7	1.0	6.7	89.0	14.8	103.8
Lot C2 (Tunnel)	54.6	6.4	61.0	5.2	0.8	6.0	2.8	1.9	4.7	62.6	9.1	71.7
Lot C3 (Powerhouse)	36.2	11.6	47.8	6.5	2.1	8.6	2.9	0.9	3.8	45.6	14.6	60.2
C. Electromechanical												
Lot 4 (Hydraulic Steel Work)	21.6	0.9	22.5	1.2	0.1	1.3	1.4	0.4	1.8	24.2	1.4	25.6
Lot 5 (Electrical Equipment)	31.1	1.0	32.1	1.7	—	1.7	2.2	0.5	2.7	35.0	1.5	36.5
Lot 6 (Mechanical Equipment)	19.5	0.8	20.3	1.0	0.1	1.1	1.1	0.3	1.4	21.6	1.2	22.8
Lot 7 (Transmission System)	10.5	2.9	13.4	0.6	0.2	0.8	0.7	1.3	2.0	11.8	4.4	16.2
D. Other Project Costs												
Construction Engineering	13.0	2.1	15.1	0.7	0.1	0.8	0.9	0.1	1.0	14.6	2.3	16.9
Project Management	2.1	6.1	8.2	0.1	0.3	0.4	0.2	0.4	0.6	2.4	6.8	9.2
Environmental Mitigation	2.3	3.0	5.3	0.1	0.2	0.3	0.2	0.2	0.4	2.6	3.4	6.0
Loss Reduction Component	2.3	0.9	3.2	0.2	—	0.2	0.2	0.1	0.3	2.7	1.0	3.7
Total (A+B+C+D)	268.9	53.0	321.9	24.9	5.3	30.2	18.3	7.2	25.5	312.1	65.5	377.6
E. Taxes and Duties												
Contract Tax										—	16.8	16.8
Customs Duties										—	1.5	1.5
F. Interest during Construction										7.9	49.0	56.9
Total										**320.0**	**132.8**	**452.8**

FC - Foreign Currency; LC - Local Currency

[a] Base cost is based on January 1996 prices.

[b] Physical contingency is provided as follows: Lot C1 — 10 percent; Lot C2 — 10 percent; Lot C3 — 18 percent; Preliminary works — 4 percent; and all other items — 5-6 percent.

[c] Price contingency is provided at 2.7 percent for foreign exchange costs and 6.0 percent for local currency costs.

Source: NEA and Bank estimates.

PROJECT MANAGEMENT ORGANIZATION

A. Project Management

1. The Project Management System for the Kali Gandaki "A" Hydroelectric Project (the Project) is the owner-engineer-contractor type. Nepal Electricity Authority (NEA), the owner, as the Executing Agency is responsible for the management of the Project. Under this system, the contract will be between NEA and the contractor, in which the Engineer acts as an agent of the owner (NEA). The Engineer is provided under a consulting engineering services contract. Each contractor is construction manager for the work to be done under its contract and will be instructed, supervised, and certified by the Engineer. The coordination of the various contracts is directed by the Engineer acting for the owner by instruction to the various contractors under the terms of their individual contracts.

B. Role of NEA

2. The role of NEA in Project management during the construction phase will be as follows: (i) NEA will employ consultants and contractors for the technical and contractual functions, and ensure that the terms of these agreements and contracts are met by the contracting parties (consultants and contractors); (ii) NEA will be responsible for fulfilling its contractual obligations as set out in its agreements or contracts with the consultants and the contractors; (iii) NEA will be responsible for fulfilling its agreements with the funding sources with respect to the Project; and (iv) NEA will keep the Government regularly informed on the technical and financial status of the Project.

C. Role of the Managing Director

3. The Managing Director of NEA will delegate to the Project Director full responsibility for managing the Project but he will remain responsible to the Board. The Managing Director will monitor the Project Director's performance.

D. Proposed Financial Authority for the Project

4. The present financial authority results in considerable and unnecessary administrative effort and risk of delay through the time needed to obtain quotations and advertise for tenders for minor items. To avoid this, the limits will be raised to facilitate the purchase of office equipment, furniture, vehicles, the renting of office accommodation prior to the establishment of site facilities, and other similar preparatory and administrative activities. Expenditure on such items will be budgeted for and authority granted to the Project Director and the Project Procurement Manager on a specific basis. Purchase should always be within budget and from suppliers approved by the Project Director as follows:

(i) The Project Director will be given authority for direct purchase and from quotation. The amount that limits the direct purchase and purchase from quotation will be considerably raised from the existing limits, and these amounts should be revised from time to time in accordance with price escalation.

(ii) For purchase by tender, the Project Director will have the same status as the level immediately below the Managing Director level.

E. Role of the Engineer

5. The role of the Engineer in Project management during the construction phase will be as follows: (i) the Engineer will act as the sole agent of the NEA in the implementation of the Project; (ii) the Engineer will seek approval of the NEA before issuing approvals, decisions, instructions, or orders involving certain specified matters; and (iii) the Engineer will take full responsibility for the design and supervision of technical aspects of the Project. The Engineer's activities as the NEA's agent may be identified under four heads: two largely technical (instructing the work and quality control) and two managerial and administrative (contract management and project management).

BROAD TERMS OF REFERENCE FOR CONSTRUCTION STAGE ENGINEERING SERVICES

A. Objectives

1. The objectives of the construction stage engineering services will be (i) completing the civil works design of the Project in sufficient detail to facilitate construction; (ii) ensuring that the design of all electromechanical equipment complies with the performance and quality specifications; (iii) acting as the Engineer to the various contracts; and (iv) assisting Nepal Electricity Authority (NEA) in all matters to ensure successful and timely completion of the Project.

B. Scope of Services

2. The scope of services required to achieve the objectives will include, but not be limited to, the following: (i) management of the Project; (ii) assistance and advice to NEA in international procurement for electromechanical equipment contracts; (iii) inspection, testing, and delivery coordination of electromechanical equipment; (iv) preparation of civil works construction drawings and documents for use in construction; (v) review and approval of drawings and documents submitted by civil works and electromechanical equipment contractors; (vi) assistance and support to NEA and/or local consultants for supervision of preparatory works carried out by local contractors; (vii) supervision of construction of the main works by international contractors; (viii) inspection of the works during and at the conclusion of the maintenance period; (ix) certification of payments to international contractors; (x) assistance to NEA on environmental aspects of the Project; (xi) preparation of operation and maintenance manuals; (xii) assistance and advice to NEA on testings, start-up and initial operation of the Project; and (xiii) training of NEA's personnel for maintenance and operation.

C. Responsibilities of the Engineer

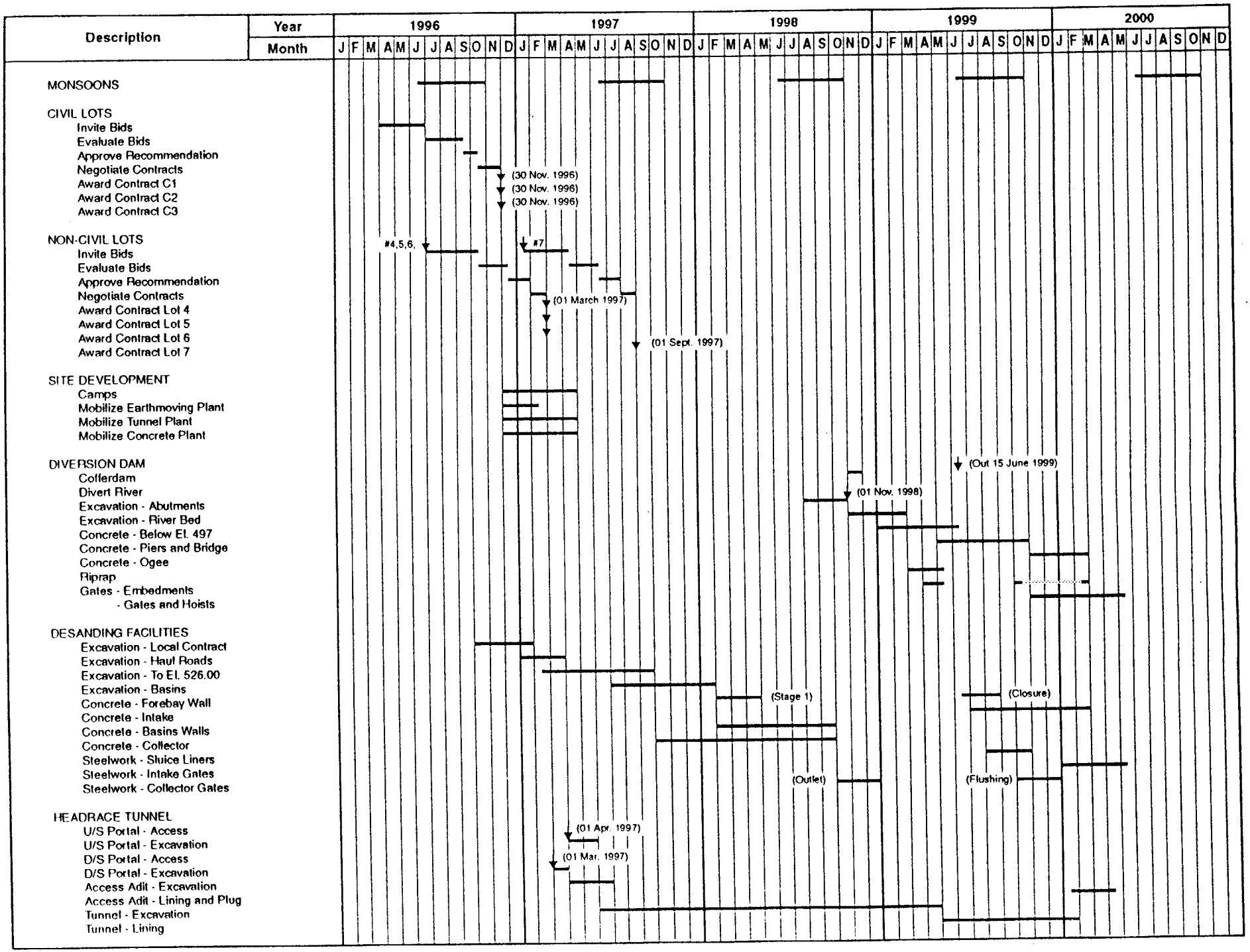
3. The consultants during the construction stage of the Project will (i) produce detailed construction drawings for the civil works, and assist NEA in seeking tenders for the electromechanical equipment, evaluating bids, awarding contracts, and reviewing the suppliers' designs and drawings; and (ii) act as Engineer to the contracts for both the civil works and electromechanical contracts, to supervise construction and equipment manufacture, and to certify payments to be made to the contractors.

PROPOSED CONTRACT PACKAGE ALLOCATION
($ million)

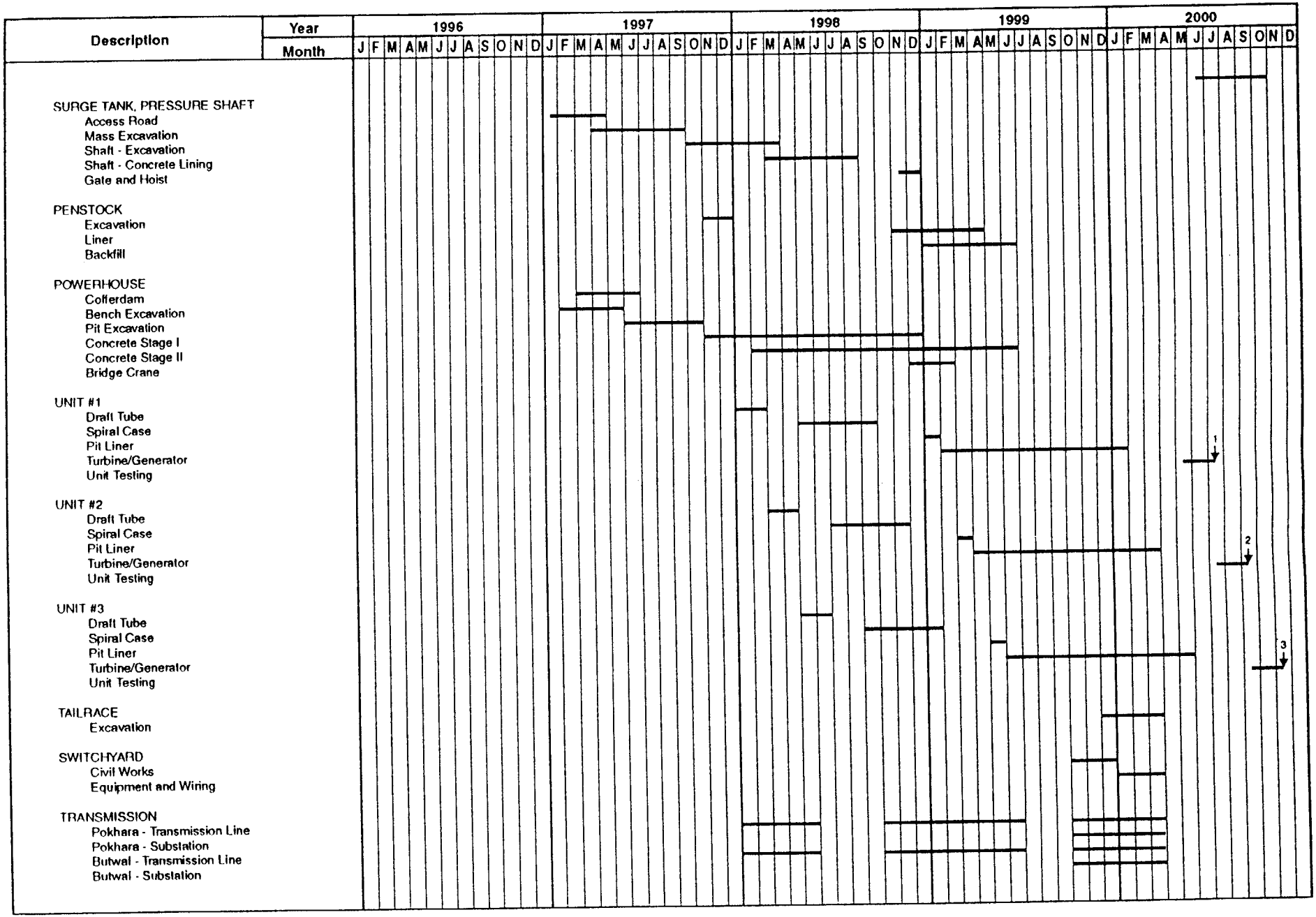
	Required Financing			Bank			Cofinancier			Government/NEA		
	FC	LC	Total	FC	LC	Total	FC	LC	Total	FC	LC	Total
A. Preliminary Work	—	5.0	5.0	—	—	—	—	—	—	—	5.0	5.0
B. Civil Works												
Lot C1 (Dam and Desanding Facilities)	89.0	14.8	103.8	89.0	—	89.0	—	—	—	—	14.8	14.8
Lot C2 (Headrace Tunnel)	62.6	9.1	71.7	—	—	—	62.6	—	62.6	—	9.1	9.1
Lot C3 (Powerhouse)	45.6	14.6	60.2	45.6	—	45.6	—	—	—	—	14.6	14.6
Subtotal of B	197.2	38.5	235.7									
C. Electromechanical Works												
Hydraulic Steel Works	24.2	1.4	25.6	—	—	—	24.2	—	24.2	—	1.4	1.4
Electrical Equipment	35.0	1.5	36.5	—	—	—	35.0	—	35.0	—	1.5	1.5
Mechanical Equipment	21.6	1.2	22.8	—	—	—	21.6	—	21.6	—	1.2	1.2
Transmission System	11.8	4.4	16.2	—	—	—	11.8	—	11.8	—	4.4	4.4
Subtotal of C	92.6	8.5	101.1									
D. Other Project Costs												
Construction Engineering	14.6	2.3	16.9	14.6	—	14.6	—	—	—	—	2.3	2.3
Project Management	2.4	6.8	9.2	2.4	—	2.4	—	—	—	—	6.8	6.8
Environmental Mitigation	2.6	3.4	6.0	2.6	—	2.6	—	—	—	—	3.4	3.4
Loss Reduction Component	2.7	1.0	3.7	2.7	—	2.7	—	—	—	—	1.0	1.0
Subtotal of D	22.3	13.5	35.8									
E. Taxes and Duties												
Contract Tax	—	16.8	16.8	—	—	—	—	—	—	—	16.8	16.8
Customs Duties	—	1.5	1.5	—	—	—	—	—	—	—	1.5	1.5
Subtotal of E	0.0	18.3	18.3									
F. Interest during Construction	7.9	49.0	56.9	3.1	—	3.1	4.8	—	4.8	—	49.0	49.0
Total	**320.0**	**132.8**	**452.8**	**160.0**	**0.0**	**160.0**	**160.0**	**0.0**	**160.0**	**0.0**	**132.8**	**132.8**

FC - Foreign Currency; LC - Local Currency; OECF - Overseas Economic Cooperation Fund
Source: NEA and Staff estimates.

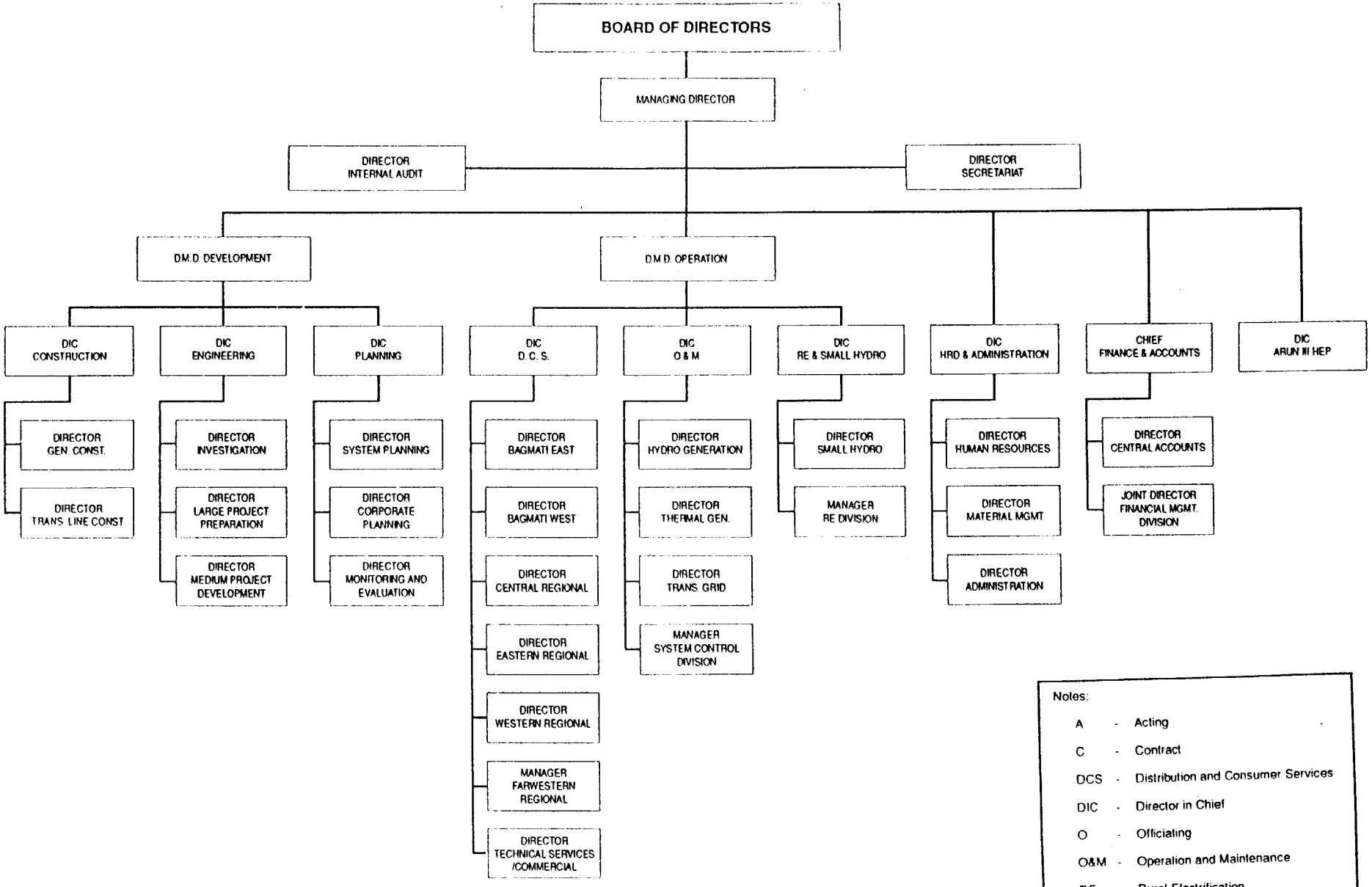
PROJECT IMPLEMENTATION SCHEDULE



Source: Nepal Electricity Authority


Description
Year
Month
1996
1997
1998
1999
2000
J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D
SURGE TANK, PRESSURE SHAFT
Access Road
Mass Excavation
Shaft - Excavation
Shaft - Concrete Lining
Gate and Hoist
PENSTOCK
Excavation
Liner
Backfill
POWERHOUSE
Cofferdam
Bench Excavation
Pit Excavation
Concrete Stage I
Concrete Stage II
Bridge Crane
UNIT #1
Draft Tube
Spiral Case
Pit Liner
Turbine/Generator
Unit Testing
UNIT #2
Draft Tube
Spiral Case
Pit Liner
Turbine/Generator
Unit Testing
UNIT #3
Draft Tube
Spiral Case
Pit Liner
Turbine/Generator
Unit Testing
TAILRACE
Excavation
SWITCHYARD
Civil Works
Equipment and Wiring
TRANSMISSION
Pokhara - Transmission Line
Pokhara - Substation
Butwal - Transmission Line
Butwal - Substation
1
2
3

ORGANIZATION CHART OF NEPAL ELECTRICITY AUTHORITY



Notes:

- A - Acting
- C - Contract
- DCS - Distribution and Consumer Services
- DIC - Director in Chief
- O - Officiating
- O&M - Operation and Maintenance
- RE - Rural Electrification

Source: Nepal Electricity Authority

Appendix 9

EXISTING POWER PLANTS OF NEPAL ELECTRICITY AUTHORITY (FY1996)

Name	Date in Service	Number of Units & Size (MW)	Installed Capacity (MW)	Available Capacity (MW)
Hydro Electric				
Trisuli	1962/1996	7x 3.0	21.0	21.0
Sunkosi	1973	3x 3.5	10.5	9.0
Gandak	1979	3x 5.0	15.0	4.0 [a]
Kulekhani I	1982	2x 30.0	60.0	60.0
Devighat	1983/1996	3x 4.7	14.1	14.0
Kulekhani II	1986	2x 16.0	32.0	30.0
Marsyangdi	1989	3x 23.0	69.0	70.0
Andhi Khola [b]	1991	3x 1.7	5.1	5.0
Jhimruk	1996		12.0	12.0
Misc. Small /Mini Hydro			12.1	5.8
Subtotal - Hydro			**250.8**	**230.8**
Diesel [c]				
Hetauda	1983	4x2.5 + 4.4	14.4	} 8.5
Misc. Diesel			2.0	}
Multifuel Diesel	1991	4x6.5	26.0	16.5
Subtotal - Diesel			**42.4**	**25.0**
Total (Hydro & Diesel) [d]			**293.2**	**255.8**

[a] Gandak system has no spillway resulting in that only a maximum of 2 units may be operated safely to avoid danger of flooding the powerhouse.

[b] Andhi Khola is owned and operated by the Butwal Power Company.

[c] Diesel rated capacity reflects the operating state of 32 existing plants in various locations throughout Nepal.

[d] Excludes small power plants in isolated systems.

Source: Nepal Electricity Authority

LOAD GROWTH FOR NEPAL: PAST AND PROJECTED

Fiscal Year ending July	Sales			System Losses[a] (%)	Gross Generation & Imports (GWh)	System Load Factor (%)	Peak Demand (MW)
	Nepal (GWh)	India (GWh)	Total (GWh)				
1983	218	6	224	32.9	334	59.0	66
1984	234	10	244	33.7	369	55.4	76
1985	272	11	283	29.8	403	58.0	80
1986	320	22	341	30.3	489	50.5	110
1987	390	21	411	28.1	572	51.5	126
1988	449	16	465	26.0	629	50.5	141
1989	479	18	496	26.2	672	50.1	150
1990	525	23	548	29.2	774	49.8	176
1991	589	81	669	26.1	906	50.8	204
1992	652	85	737	24.8	981	51.9	216
1993	674	59	734	24.3	970	51.7	214
1994	695[b]	71	766	25.9	1034	53.2	222
1995 - Actual	787[b]	42	830	26.3	1126	52.7	244
- Unrestricted	808	—	851	—	1145	51.5	254
Past Growth Rate[c] (%) FY1983-FY1995	**11.5**		**11.8**		**10.8**		**11.9**
1996	884	40	924	25.2	1239[d]	51.3[d]	275[d]
1997	1029	43	1072	23.0	1393	52.5	303
1998	1148	48	1196	22.0	1533	53.4	328
1999	1281	53	1334	21.0	1688	54.4	354
2000	1432	58	1490	20.0	1863	55.5	383
2001	1575	64	1639	20.0	2049	56.6	413
2002	1740	70	1810	20.0	2262	57.1	452
2003	1922	77	1999	20.0	2499	57.3	498
2004	2125	85	2210	20.0	2763	57.5	549
Projected Growth Rate (%) FY1996-FY2004	**11.2**		**11.2**		**10.3**		**8.9**

[a] System losses includes NEA's self-consumption.

[b] In FY1994, there was extensive load shedding due to generation limitations that reduced sales and the recorded peak demand. This continued during the first half of FY1995 due to the shutdown of Kulekhani I and II.

[c] Growth rates are based on unrestricted demand in FY1995 to take into account the load shedding described in footnote "b" above.

[d] This data for FY1996 is based on actual records for first 8 months and forecast for last 4 months of the year.

Source: Nepal Electricity Authority

GENERATION EXPANSION PLAN
(FY1997 to FY2004)

Fiscal Year	Capacity Additions	Generation Capacity (MW) Installed	Generation Capacity (MW) Dependable	Peak Demand (MW)	Surplus/(Deficit) before Import (MW)	Import[a] (MW)	Net Excess/(Shortfall) after Import (MW) but before Allowing for Reserve Margin
Committed Projects							
1997	—	293.2	255.8	303.0	(47.2)	50.0	2.8
1998	Diesel (13 MW) + Puwa (6.2 MW)	312.4	273.0	328.0	(55.0)	50.0	(5.0)
1999	Modi Khola (14 MW)	326.4	283.0	354.0	(71.0)	50.0	(21.0)
2000	Chilime (20 MW) + Khimti (60 MW)	406.4	329.6	383.0	(53.4)	50.0	(3.4)
Noncommitted Projects							
2001	Kali Gandaki "A" HEP (144 MW)	550.4	473.6	413.0	60.6	50.0	110.6
2002	—	550.4	473.6	452.0	21.6	50.0	71.6
2003	Bhote Khoshi (36 MW)	586.4	494.6	498.0	(3.4)	50.0	46.6
2004	Upper Marsyangdi (43 MW)	629.4	529.6	549.0	(19.4)	50.0	30.6

[a] Transmission interconnection capacity with India increased by 30 MW in February 1996 to raise total import capacity to 50 MW.

Source: Nepal Electricity Authority

FINANCIAL PROJECTIONS

A. General Notes and Assumptions

1. Escalation and Exchange Rates

1. The financial projections are based on the escalation rates (Table 1) for foreign and local currency, and for converting $1.00 with Nepalese rupees.

Table 1: Escalation Rates and Exchange Rates

Fiscal Year	Foreign Exchange (%)	Local Currency (%)	Exchange Rates (NRs/$)
1995	2.7	7.6	49.80
1996	2.7	7.5	56.00
1997	2.7	6.0	57.80
1998	2.7	6.0	59.66
1999	2.7	6.0	61.57
2000	2.7	6.0	63.55
2001	2.7	6.0	65.59
2002	2.7	6.0	67.70
2003	2.7	6.0	69.80
2004	2.7	6.0	72.12

B. Income Statement

1. Energy Generation

2. The forecast of hydro, thermal, and private generation required to meet the load demand over the 10-year period FY1994 to FY2004 was determined by the power system simulation program. This includes 4.2 gigawatt-hours (GWh) energy generation from the isolated small hydropower plants, which are not simulated in the general simulation program.

2. Energy Purchased

a. From India

3. The total energy purchased from India is based on agreements between the Government and India of the demand in those areas of Nepal connected to India. This will include 20 GWh of energy (free of cost) from Tanakpur powerhouse annually after completion of Mahendranagar-Tanakpur 132-kilovolt (kV) transmission line in FY1997.

b. From Nepal

4. (Other hydroelectric plants): Purchases from Andhi Khola are assumed at 24 GWh per annum. Starting FY1996, Nepal Electricity Authority (NEA) is expected to buy power from

other private sector generating plants; the total GWh purchase depends upon NEA's demand forecast, and the contractual agreement between NEA and the private sector participants. Transmission losses of 5 percent are assumed in the computation of these purchases.

3. NEA's Self-consumption

5. Forecasts assume that NEA's electricity consumption will amount to about 1 percent of total hydroelectric units generated plus 5 percent of total thermal units generated.

4. System Losses

6. Under NEA's System Loss Reduction Program, system losses, including NEA's own consumption, are projected to decrease from 26 percent of gross generation in FY1995 to 20.0 percent by FY2000.

5. Energy Sales

7. Sales within Nepal are based on the load forecast agreed during appraisal. Sales to India are according to existing arrangements to supply areas of India connected to the Nepal grid but based on availability of power. Additionally, part of the surplus hydro energy available during the wet season is assumed to be exported to India from FY1998.

6. Self-financing Ratio

8. Forecast average revenue is calculated on the basis that NEA set tariffs at levels which will provide funds to cover cash operating expenses, debt service, additional working capital other than cash, and self-finance a percentage of total capital investment (averaged over the past, the current and the next year) after including interest during construction, equal to at least 14 percent in FY1996, 18 percent in FY1997, 20 percent in FY1998, and 23 percent in FY1999 and thereafter.

7. Rate of Return Covenant

9. Under the rate of return covenant, starting FY1998, NEA is to earn rates of return on average net revalued fixed assets of not less than 6 percent.

8. Revenue from Electricity Sales

a. Nepal

10. Forecasts of revenue for FY1996 to FY2004 are based on the forecast electricity sales and the average revenue rate.

b. India

11. As agreed between the Government and the Government of India, starting January 1993, the average selling price of electricity between Nepal and India was fixed at Indian Rs1.25/kilowatt-hour (kWh) (NRs2.0/kWh @ Rs100 = NRs160). The agreement further stipulated an escalation rate of 8.5 percent per annum. Based on this agreement, the FY1996 price to India is estimated to be NRs2.55/kWh.

9. Other Operating Revenue

12. This revenue includes miscellaneous services to consumers such as transfer/replacement of meters, application fees, and fees for reconnection of services and are assumed to increase at 10 percent per annum.

C. Operating Expenses

1. Fuel Expenses

13. These have been projected on the basis of required thermal generation, specific heat rates and existing fuel prices (adjusted for inflation in future years) with a one time, 5 percent increase in FY1998 agreed with the Nepal Oil Corporation to cover investment of additional storage and supporting infrastructure.

2. Energy Purchases

a. From India

14. The purchase price from India is the same as the sale price (see para. 11).

b. From Nepal

15. NEA's purchase price from Andhi Khola and Jhimruk is based upon the agreement concluded for Andhi Khola. For the purchase price from other proposed private sector power generating plants, the purchase price assumed is $0.06/kWh in FY1995 prices plus a royalty of NRs100 per kilowatt of installed capacity and 2 percent of gross revenue for the first 15 years.

3. Salaries, Wages, and Allowances

16. Salaries, wages, and allowances are projected to increase at 10 percent per annum from FY1997.

4. Operation and Administration

17. These expenses comprise maintenance and general administration and overhead expenses other than salaries, wages and allowances, and royalties. Annual increases are estimated at 15 percent per annum from FY1997, except expenditure for royalties, which is expected to grow at 10 percent per annum.

5. Depreciation

18. Depreciation expense is forecast at 3.0 percent of average revalued gross fixed assets in service. Assets in service were valued in FY1989 and since then have been revalued annually using the foreign and local inflation rates and assuming that asset costs are comprised of 80 percent and 20 percent local cost.

6. Provisions

19. This provision is general and is projected to increase at 10 percent per annum.

7. Interest Expense

20. Interest expense consists of projected interest cost of all short- and long-term debts.

8. Income Tax

21. NEA now pays royalties, which is included in the operation and administration cost; hence no income tax is paid by NEA.

D. Balance Sheet

1. Fixed Assets

22. NEA has been revaluing its assets since FY1989. Eighty percent of the assets are escalated at the foreign inflation rate and the balance 20 percent at the local inflation rate.

2. Current Assets

a. Cash

23. Cash balances have been projected to remain at two months of cash operating expenses.

b. Inventories

24. Inventories consisting of stores, maintenance supplies, and fuel have been estimated to remain at 1.0 percent of average gross revalued fixed assets.

c. Accounts Receivable

25. Starting in FY1997, accounts receivable are conservatively projected to remain at the upper limit of three months of yearly sales.

d. Recoverable Advances

26. These advances consist of advances for letters of credit, official staff travel and expense, suppliers of stores and equipment, and services contracted. These amounts are projected to increase at 10.0 percent per annum.

e. Short-term Investments

27. Cash surpluses are assumed to be invested in short-term deposits.

3. Current Liabilities

a. Accounts Payable

28. Accounts payable are forecast at three months of cash operating expenses excluding energy purchases.

29. Accounts payable to the Government consist of outstanding royalties and six months of interest due within one year on on-lent funds.

b. Miscellaneous Deposits

30. These deposits include consumer deposits and suppliers' and contractors' deposits which are projected to remain at 2.0 percent of yearly revenue sales in Nepal.

c. Purchase of Energy

31. These are assumed to remain at three months of yearly purchases.

E. Sources and Application of Funds

1. Consumer Contributions

32. Consumer contributions are projected to increase 5 percent per annum.

2. Long-term Debt and the Government's Equity Contribution

33. Long-term debt is incurred to finance the foreign cost of NEA's investment program. It is projected that 100 percent of the foreign currency cost of NEA's investment program will be financed by long-term loans and grants (from the Government). Government contributions equivalent to 25 percent of the local cost of the investment program are assumed to be provided as equity.

3. Debt Service

34. Loan terms from FY1997 onwards for other than rural electrification are projected to include an interest rate of 10.25 percent per annum with equal annual debt service payments. All loans are assumed to be paid in 25 years including 5 years grace period. Rural electrification projects will carry an interest rate of 1.0 percent to be repaid in 25 years including a grace period of 5 years. Any foreign exchange risk that may arise during repayment shall be borne by the Government.

35. Interest charges during the construction period shall be capitalized and added to the asset value upon completion.

Table 2: NEA's Profit and Loss Statement
(NRs million)

Fiscal Year ending 15 July	Audited				Preaudit	Estimate	Forecast							
	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Energy Generated (GWh)														
- hydro	865.4	865.8	800.1	835.5	837.0	1,010.2	1,046.3	1086.3	1,190.6	1,054.6	1,354.1	1,484.7	1,453.0	1,725.9
- small hydro (Isolated)	4.8	4.2	4.2	4.2	8.7	24.0	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
- thermal (Diesel)	0.0	11.0	11.1	0.0	0.0	0.0	0.2	0.1	0.6	0.6	0.0	0.9	4.8	5.4
- thermal (Multifuel)	0.8	20.2	36.3	62.2	85.0	48.3	148.1	127.3	137.4	118.7	79.1	100.0	102.3	96.5
Total Energy Generated (GWh)	871.0	901.2	851.7	901.9	930.7	1,082.5	1,198.9	1,218.0	1,332.8	1,178.2	1,437.5	1,589.8	1,564.3	1,832.1
Energy Purchased from India (GWh)	33.7	55.0	88.3	101.5	110.0	80.0	89.1	73.6	113.6	93.0	19.9	80.6	97.2	92.7
Energy Purchased from Andhi/Jhimruk (GWh)	1.6	25.0	29.8	30.7	85.0	73.0	104.7	104.7	104.7	104.7	104.7	104.7	104.7	104.7
Energy Purchased from Others (GWh)			0.0	0.0	0.0	0.0	0.0	137.0	137.0	487.0	487.0	487.0	733.0	733.0
Total Energy Available (GWh)	906.3	981.1	969.8	1,034.2	1,125.7	1,235.5	1,392.7	1,533.2	1,688.1	1,862.9	2,049.1	2,262.0	2,499.2	2,762.5
Gross System Losses (GWh)	236.9	243.4	236.0	268.3	296.2	311.5	320.3	337.3	354.5	372.6	409.8	452.4	499.8	552.5
[Gross System Losses as a percentage of Average Energy (%)]	[26.1]	[24.8]	[24.3]	[25.9]	[26.3]	[25.2]	[23.0]	[22.0]	[21.0]	[20.0]	[20.0]	[20.0]	[20.0]	[20.0]
Energy Sold (GWh) - Nepal	588.8	651.9	674.4	694.8	787.1	884.3	1,028.8	1,148.0	1,280.9	1,432.3	1,575.5	1,739.5	1,922.2	2,125.1
- India	80.6	85.4	59.3	71.1	42.4	39.6	43.6	47.9	52.7	58.0	63.8	70.2	77.2	84.9
Total Energy Sold (GWh)	669.4	737.4	733.8	765.9	829.5	923.9	1,072.4	1,195.9	1,333.6	1,490.3	1,639.3	1,809.6	1,999.3	2,210.0
Additional Hydro-energy Sold to India (GWh)							11.6	30.3	24.0	94.7	349.8	288.4	303.5	335.6
Average Revenue Rate (NRs/kWh)	**1.40**	**1.99**	**2.54**	**3.38**	**3.96**	**4.16**	**4.75**	**5.13**	**5.45**	**6.08**	**6.08**	**7.30**	**9.06**	**9.06**
[Increase in Average Revenue Rate (%)]	[1.8]	[41.6]	[27.8]	[33.1]	[17.4]	[5.0]	[14.2]	[7.9]	[6.2]	[11.7]	[0.0]	[19.9]	[24.1]	[0.0]
Electricity Sales Revenue - Nepal	825.8	1,294.7	1,711.3	2,346.0	3,120.4	3,680.1	4,888.9	5,888.3	6,975.4	8,715.8	9,587.0	12,695.0	17,411.9	19,250.3
- India	135.1	145.8	75.5	91.4	95.9	100.8	147.0	225.9	240.6	519.4	1,526.3	1,436.0	1,653.9	1,982.4
Total Electricity Sales Revenue	960.9	1,440.5	1,786.8	2,437.4	3,216.3	3,780.9	5,035.9	6,114.2	7,216.1	9,235.1	11,113.3	14,131.0	19,065.8	21,232.7
Other Operating Revenue	31.8	73.8	117.6	174.4	248.4	189.7	208.7	229.5	252.5	277.7	305.5	422.4	456.0	492.9
Total Operating Revenue	992.6	1,514.2	1,904.5	2,611.8	3,464.7	3,970.6	5,244.6	6,343.7	7,468.6	9,512.9	11,418.9	14,553.4	19,521.8	21,725.6
Fuel	3.7	84.8	121.0	152.5	193.2	131.7	391.8	356.5	410.5	376.8	263.4	359.4	421.0	429.0
Energy Purchases	50.5	111.3	162.1	214.2	337.0	431.2	488.5	992.3	1,190.6	2,675.4	2,587.9	3,002.7	4,517.0	4,798.4
Salaries, Wages, and Allowances	279.2	294.3	324.2	331.0	383.3	497.3	547.0	601.7	661.9	728.1	800.9	881.0	969.1	1,066.0
Operation and Administration	96.9	120.2	159.7	213.6	447.3	555.1	576.6	652.1	737.8	835.2	945.8	1,071.6	1,214.6	1,377.3
Depreciation	879.7	953.6	1,026.0	1,202.4	1,243.5	1,400.0	1,413.2	1,615.7	1,741.5	1,850.3	2,064.0	2,698.6	3,252.1	3,530.3
Provisions	0.0	8.7	7.0	8.5	154.8	44.2	48.6	53.5	58.8	64.7	71.2	78.3	86.1	94.7
Reduction of Deferred Charges	56.6	45.1	53.6	66.5	82.5	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Operating Expenses	1,366.5	1,618.1	1,853.6	2,188.7	2,841.7	3,129.5	3,465.7	4,271.9	4,801.1	6,530.5	6,733.2	8,091.6	10,460.0	11,295.8
OPERATING INCOME	-373.9	-103.9	50.9	423.1	623.1	841.1	1,778.9	2,071.8	2,667.4	2,982.4	4,685.7	6,461.8	9,061.8	10,429.8
Interest	635.1	632.2	625.5	716.6	958.7	821.6	1,144.7	1,250.9	1,230.0	1,230.7	1,480.0	3,993.9	3,962.9	4,478.8
Prior Years' Adjustment/Others	15.4	75.6	-48.9	-411.7	-12.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transferred from Revaluation Surplus	568.9	610.0	729.7	869.3	650.7	900.0	958.5	1,007.3	1,061.6	1,120.1	1,182.3	1,251.6	1,342.3	1,451.5
Insurance Fund	0.0	0.0	0.0	0.0	80.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Contingency Reserve	0.0	0.0	0.0	0.0	0.0	2.0	63.4	82.1	143.7	175.2	320.6	246.8	509.9	595.1
NET PROFIT	-424.7	-50.5	106.2	101.0	222.7	897.6	1,509.3	1,726.1	2,335.2	2,676.6	4,047.4	3,452.8	5,911.2	6,787.4
Ratios:														
Operating Ratio (times) [a]	1.4	1.1	1.0	0.8	0.8	0.8	0.7	0.7	0.6	0.7	0.6	0.6	0.5	0.5
Rate of Return on Revalued Assets (%) [b]	-1.9	-0.5	0.2	1.6	2.3	3.1	6.0	6.0	7.3	8.0	11.2	10.8	12.2	13.2

NEA - Nepal Electricity Authority

[a] Operating Expenses Divided by Operating Revenue.

[b] Operating Income Divided by Average Revalued Assets in Service.

Source: NEA and the Bank.

Table 3: NEA's Balance Sheet
(NRs million)

Fiscal Year ending 15 July	Audited				Preaudit	Estimate	Forecast							
	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
ASSETS														
Fixed Assets														
Gross Fixed Assets	30,138.9	32,478.7	34,968.2	39,563.9	41,098.8	43,009.3	51,201.1	56,515.0	59,583.2	63,770.5	73,827.1	106,078.3	110,731.5	124,620.6
Less: Depreciation	7,772.1	9,294.1	10,842.0	12,669.4	14,299.9	16,223.3	18,214.0	20,441.7	22,870.1	25,488.8	28,409.2	32,062.3	36,391.8	41,144.8
Net Fixed Assets	22,366.7	23,184.6	24,126.2	26,894.5	26,798.9	26,785.9	32,987.1	36,073.2	36,713.1	38,281.7	45,417.9	74,016.0	74,339.7	83,475.8
Work in Progress	2,890.1	3,816.4	6,250.1	5,439.3	6,957.7	11,697.5	12,355.0	17,719.6	29,168.1	37,524.1	41,240.0	30,608.3	56,214.6	74,649.2
Total Net Fixed Assets	25,256.8	27,001.1	30,376.3	32,333.8	33,756.6	38,483.4	45,342.1	53,792.8	65,881.2	75,805.8	86,657.9	104,624.3	130,554.3	158,125.1
Deferred Charges	169.8	121.1	108.6	98.6	411.7	341.7	341.7	341.7	341.7	341.7	341.7	341.7	341.7	341.7
Current Assets														
Cash	174.5	67.1	160.5	122.9	133.9	130.0	342.1	442.7	509.9	780.0	778.2	898.8	1,201.3	1,294.2
Inventories	250.8	270.4	289.5	340.4	860.9	420.5	471.1	538.6	580.5	616.8	688.0	899.5	1,084.0	1,176.8
Accounts Receivable	556.1	718.3	474.8	569.9	678.6	945.2	1,259.0	1,528.5	1,804.0	2,308.8	2,778.3	3,532.8	4,766.5	5,308.2
Advances Recoverable	122.2	113.8	145.7	152.2	332.9	366.2	402.8	443.0	487.3	536.1	589.7	648.7	713.5	784.9
Total Current Assets	1,103.6	1,169.7	1,070.6	1,185.4	2,006.2	1,861.9	2,474.9	2,952.9	3,381.8	4,241.7	4,834.2	5,979.8	7,765.3	8,564.1
Investments in Bonds/Short-term Deposits	8.1	317.2	736.2	1,365.1	1,194.1	1,907.7	2,118.2	2,150.1	2,082.9	2,210.1	3,342.7	3,222.1	2,919.6	3,197.7
Long-term Investments (Out of Insurance Fund + Contingency Reserve)	0.0	0.0	0.0	0.0	80.0	102.0	185.4	287.5	451.2	646.4	986.9	1,253.7	1,783.6	2,398.7
TOTAL ASSETS	26,538.3	28,609.0	32,291.7	34,982.8	37,448.6	42,696.7	50,462.3	59,525.0	72,138.8	83,245.7	96,163.5	115,421.7	143,364.6	172,627.2
EQUITY AND LIABILITIES														
Equity														
Government's Capital Contribution and Foreign Grants	4,916.8	4,956.8	6,190.6	6,796.7	7,781.9	10,233.2	12,413.3	13,163.2	13,821.4	14,737.2	16,214.8	19,269.6	23,626.1	27,732.6
Capital Reserves	67.6	88.3	120.9	137.6	147.9	166.3	185.7	206.0	227.4	249.8	273.3	298.0	324.0	351.2
Insurance Fund + Contingency Reserve	18.6	18.6	18.6	18.6	98.6	120.6	204.0	306.1	469.9	665.0	1,005.6	1,272.4	1,802.3	2,417.4
Retained Earnings	-519.0	-569.4	-463.3	-362.3	-139.6	758.0	2,267.3	3,993.4	6,328.6	9,005.2	13,052.6	16,505.4	22,416.6	29,204.1
Revaluation Reserve	12,369.4	13,421.7	13,988.1	14,238.3	14,280.8	14,361.6	14,356.7	14,457.8	14,608.3	14,721.7	14,825.7	15,100.2	16,244.8	17,291.1
Total Equity	16,853.5	17,916.0	19,855.0	20,829.0	22,169.7	25,639.7	29,427.0	32,126.5	35,455.5	39,378.9	45,372.1	52,445.5	64,413.8	76,996.3
Long-term Debt	8,812.3	10,070.4	11,649.5	12,880.6	13,787.30	15,610.6	19,241.2	25,178.8	34,311.1	41,117.1	47,829.9	58,479.1	73,972.1	90,161.0
Current Liabilities														
Payable to the Government	269.4	60.1	354.9	875.4	1,024.8	546.9	792.3	867.4	881.2	908.2	1,062.1	2,351.2	2,371.2	2,668.1
Accounts Payable	69.7	53.0	28.0	37.0	52.1	307.1	391.0	416.0	467.3	501.2	520.3	597.6	672.7	741.8
Miscellaneous Deposits	46.1	68.0	126.9	219.2	333.6	73.6	97.8	117.8	139.5	174.3	191.7	253.9	348.2	385.0
Other Liabilities	297.1	280.6	272.7	129.9	74.7	411.0	431.6	653.2	685.8	720.1	756.1	793.9	833.6	875.3
Purchase of Energy	190.1	160.7	4.6	11.6	6.6	107.8	81.4	165.4	198.4	445.9	431.3	500.5	752.8	799.7
Total Current Liabilities	872.5	622.6	787.2	1,273.2	1,491.7	1,446.4	1,794.1	2,219.7	2,372.2	2,749.7	2,961.6	4,497.1	4,978.6	5,470.0
Total Liabilities	9,684.8	10,693.0	12,436.7	14,153.9	15,279.0	17,057.0	21,035.3	27,398.5	36,683.3	43,866.8	50,791.4	62,976.1	78,950.8	95,631.0
TOTAL EQUITY AND LIABILITIES	26,538.3	28,609.0	32,291.7	34,982.8	37,448.6	42,696.7	50,462.3	59,525.0	72,138.8	83,245.7	96,163.5	115,421.7	143,364.6	172,627.2
Ratios:														
Current [a]	1.3	1.9	1.4	0.9	1.3	1.3	1.4	1.3	1.4	1.5	1.6	1.3	1.6	1.6
Debt/(Debt+Equity) (excluding Revaluation Surplus) [b]	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Accounts Receivable (months) [c]	6.9	6.0	3.2	2.8	2.5	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0

NEA - Nepal Electricity Authority

[a] Current Assets Divided by Current Liabilities.

[b] Long-term Debt Divided by Long-term Debt Plus Equity less Revaluation Surplus.

[c] Accounts Receivable Divided by Average Monthly Sales Revenue.

Source: NEA and the Bank.

Table 4: NEA's Source and Application of Funds
(NRs million)

Fiscal Year ending 15 July	Audited				Preaudit	Estimate	Forecast							
	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
SOURCES OF FUNDS														
Internal Cash Generation														
Operating Income after Tax and Prior Years' Adjustment	-358.5	-28.3	2.0	-15.8	610.7	841.1	1,778.9	2,071.8	2,667.4	2,982.4	4,685.7	6,461.8	9,061.8	10,429.8
Depreciation	880.8	953.6	1,047.2	1,437.5	1,067.9	1,400.0	1,413.2	1,615.7	1,741.5	1,850.3	2,064.0	2,698.6	3,252.1	3,530.3
Reduction of Deferred Charges	56.6	45.1	54.8	74.6	99.3	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Internal Cash Generation	578.9	970.5	1,104.1	1,496.2	1,777.9	2,311.1	3,192.1	3,687.6	4,408.9	4,832.7	6,749.7	9,160.4	12,313.9	13,960.1
Sale of Short-term Deposits	0.0	3.5	0.0	0.0	306.2	0.0	0.0	0.0	67.3	0.0	0.0	120.6	302.5	0.0
Consumer Contributions	10.8	20.6	32.6	16.7	10.3	18.4	19.4	20.3	21.3	22.4	23.5	24.7	25.9	27.2
Long-term loans	6,430.2	1,279.5	1,651.9	1,403.6	1,497.2	2,029.2	3,852.8	6,281.9	9,497.3	7,355.8	7,286.9	11,678.7	16,631.8	17,511.6
Equity	770.0	40.0	1,233.8	606.1	985.2	2,451.2	2,180.1	749.9	658.2	915.8	1,477.7	3,054.7	4,356.5	4,106.4
TOTAL SOURCES OF FUNDS	7,790.2	2,314.2	4,022.4	3,522.7	4,576.8	6,809.9	9,244.4	10,739.7	14,652.9	13,126.6	15,537.7	24,039.1	33,630.6	35,605.4
Capital Investment														
Capital Expenditure (Foreign)	6,091.9	713.7	2,191.5	1,700.0	1,305.1	3,748.2	5,138.9	6,435.9	9,814.1	8,271.5	8,764.5	8,764.5	14,606.6	21,618.1
Capital Expenditure (Local)	815.7	178.4	92.5	438.3	326.3	1,083.1	2,064.3	2,434.2	2,599.2	1,825.1	2,212.6	3,018.0	3,272.9	2,990.5
Interest During Construction	73.4	143.4	242.2	237.7	166.1	314.6	115.1	88.1	204.4	444.7	652.7	1,514.4	2,888.6	3,994.6
Total Capital Investment	6,980.9	1,035.6	3,126.4	2,376.0	1,797.5	5,146.0	7,318.3	8,958.1	12,617.8	10,541.3	11,629.8	19,139.0	26,695.2	28,603.2
Investment in Government Bonds	0.0	309.1	419.0	628.9	135.2	713.6	210.5	31.9	0.0	127.3	1,132.6	0.0	0.0	278.1
Long-term Investments (Insurance + Contingency Reserve)	0.0	0.0	0.0	0.0	80.0	22.0	83.4	102.1	163.7	195.2	340.6	266.8	529.9	615.1
Marsyangdi Interest Charges	501.4	498.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Debt Service (Others) - Interest	133.7	133.6	625.5	716.6	958.7	821.6	1,144.7	1,250.9	1,230.0	1,230.7	1,480.0	3,993.9	3,962.9	4,478.8
- Amortization of Principal	40.6	21.4	72.8	97.1	590.5	170.1	186.5	308.6	329.3	514.0	538.4	993.7	1,102.9	1,287.1
Debt Service of Deferred Charges	0.0	0.0	42.3	75.5	0.0	35.7	35.7	35.7	35.7	35.7	35.7	35.7	35.7	35.7
Total Debt Service	174.3	155.0	740.6	889.1	1,549.2	1,027.4	1,366.9	1,595.2	1,595.0	1,780.4	2,054.1	5,023.3	5,101.6	5,801.7
Increase in Deferred Charges	0.0	0.0	0.0	0.0	412.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Changes in Working Capital														
Cash Increase	32.1	-107.4	93.4	-37.7	11.0	-3.9	212.1	100.6	67.3	270.1	-1.8	120.6	302.5	92.9
Other than Cash Increase	101.4	423.4	-357.0	-333.7	591.4	-95.1	53.1	-48.2	209.2	212.3	382.5	-510.6	1,001.6	214.4
Net Change	133.5	316.0	-263.6	-371.3	602.4	-99.0	265.2	52.4	276.4	482.4	380.6	-389.9	1,304.0	307.4
TOTAL APPLICATIONS OF FUNDS	7,790.2	2,314.2	4,022.4	3,522.7	4,576.8	6,809.9	9,244.4	10,739.7	14,652.9	13,126.6	15,537.7	24,039.1	33,630.6	35,605.4
Self-financing (%)														
On Annual Investment (including IDC)	4.26	32.56	24.93	47.39	22.47	26.73	23.34	22.98	19.51	25.30	34.36	23.02	21.38	25.72
On three-year Average Investment (including IDC)	9.90	9.08	35.77	46.28	12.96	28.93	23.92	21.38	23.00	23.00	29.02	23.00	23.00	23.98
Local Component (including IDC)	56.2	65.5	175.5	224.8	46.7	101.4	84.0	82.3	97.3	100.8	124.0	97.5	96.8	96.3
Debt Service Coverage (including IDC) (times) *	3.3	6.3	1.5	1.7	1.4	2.2	2.3	2.3	2.8	2.7	3.3	1.8	2.4	2.4

IDC - Interest During Construction; NEA - Nepal Electricity Authority
* Internal Cash Generation Divided by Total Debt Service.
Source: NEA and the Bank.

COMPLIANCE WITH LOAN COVENANTS

Covenant	Reference	Remarks
Project Implementation		
1. Appointment of a Project Director who shall be responsible in all matters related to Project implementation.	LA, Sched. 6, para. 1 (a)	Complied with.
2. To employ competent consultants and contractors acceptable to the Bank.	PA, Sec. II Art. 2.03 (a)	Complied with.
3. Borrower shall furnish quarterly reports on the carrying out of the Project.	PA, Art. II Sec. 2.08 (b)	Complied with.
Land Acquisition		
4. Timely action to acquire all land, rights over land and rights-of-way which are required for implementation of the Project.	LA, Sched. 6 para. 4	Complied with.
Financial Matters		
5. Responsibility for all assets, liabilities related to implementation and facilities shall be transferred to Nepal Electricity Authority (NEA) and reflected in its books of accounts before the end of FY1989/90.	LA, Sched. 6 para. 6	Complied with.
6. NEA shall: (i) implement the dated action plan agreed with the Bank for the placement of responsibility for all commercial, consumer-accounting and loss reduction functions under the Commercial Director, and (ii) complete the transfer for all financial management and accounting functions, except for consumer accounting at NEA's central office under the Director of Finance.	LA, Sched. 6 para. 7	Complied with.
7. NEA shall implement not later than 15 July 1990, the internal audit systems and procedures proposed by the management consultants under the Fifth Power Project, and shall appoint qualified staff to assist NEA's internal auditor.	LA, Sched. 6 para. 10	Not complied with on time. In Dec. 93, NEA contracted out its internal audit services to a professional firm.
8. The Borrower and NEA shall ensure that accounts receivable do not exceed the equivalent of sales revenue for 3.5 months by the end of FY1989/90 and 3 months by the end of each fiscal year and thereafter.	LA, Sched. 6 para. 12	Complied with. 2.53 months as of 15 July 1995.
9. NEA shall reduce its accounts payable to not more than the equivalent of three months' cash operating expenses, excluding accounts payable for the purchase of energy.	LA, Sched. 6 para. 13	Complied with. 0.5 months as of 15 July 1995.
10. NEA shall reduce electricity losses to: FY1989/90—26.5%; FY1990/91—25.5%; FY1991/92—24.0%; FY1992/93—22.0%; Thereafter—20.0%.	LA, Sched. 6 para. 15	Not complied with. System losses in FY1995 were 26.3 percent.
11. NEA to provide annually net internally generated funds as follows: FY1990/91—7%; FY1991/92—7%; FY1992/93—10%; FY1993/94—11%; FY1994/95—12%; FY1995/96—14%; FY1996/97—22%; thereafter—23%.	PA, Sec. 2.15 (a)	Complied with. 13 percent for FY1995.
12. Commencing FY1990/91, NEA to produce an annual rate of return of not less than 6 percent (based on historical assets).	PA, Sec. 2.16	Complied with. 8.5 percent on historical assets in FY1995.
13. Commencing FY1990/91, NEA shall achieve a debt-service ratio of 1.2 times.	PA, Sec. 2.17	Complied with. 1.5 times in FY1995.
Audited Accounts		
14. NEA to provide unaudited accounts within six months and audited accounts within nine months of each fiscal year end.	PA, Sec. 2.09 (a)	Unaudited accounts for FY1995 were received in January 1995. Audited financial statements for FY1995 were due 15 April 1995 but have been delayed because of change in auditors.

SUMMARY OF ACTION PLAN FOR REDUCING NONTECHNICAL DISTRIBUTION LOSSES

A. Objectives and Scope of Subproject

1. The plan will be financed as a component (subproject) under the proposed Bank loan for the Kali Gandaki "A" Project. The objectives of the action plan will be to design and implement a program to reduce nontechnical losses of the Nepal Electricity Authority (NEA).

B. Broad Terms of Reference for Consultants

2. Consultants will be engaged to undertake the following major tasks:

(i) **General Review and Plan Preparation**: Review the extent of nontechnical losses in NEA's various distribution districts, identify the major causes of nontechnical losses, and prepare detailed plans to reduce nontechnical losses.

(ii) **Design Incentive Schemes and Staff Disciplinary Schemes**: Design performance-based incentive schemes to encourage reduction of both technical and nontechnical losses. Make proposals to discipline staff who are found guilty of intentionally participating in power theft or are found to be grossly negligent in controlling nontechnical losses.

(iii) **Vigilance and Energy Audit Procedures**: Design procedures for monitoring, audit, and surprise check of energy consumption at substations and comparing this with energy sales of all consumers served by a substation, in order to determine losses.

(iv) **Establish Legal Measures for Prosecution of Defaulters**: Design measures to include additional authority to attach property, impose criminal sanctions, and strengthen protective measures.

(v) **Prepare Service Contract for Billing and Collection Operations**: The service contract will be for a private operator to conduct billing and collection operations in one of NEA's distribution districts.

(vi) **Training and Computer Software for Distribution System Planning**: Review the procedures and computer software programs that NEA is using for distribution system planning and design, and recommend how these procedures should be improved.

C. Study Tour

3. A study tour of about two weeks will be financed under the Project to enable four NEA staff to visit another electric utility or other utilities in Asia with a good record of reducing and controlling nontechnical losses, in order to discuss their experiences with nontechnical loss reduction measures.

D. Procurement of Equipment and Materials for Nontechnical Loss Reduction

4. The consultants and NEA will prepare a detailed list of the materials and equipment required to implement the above program for reducing nontechnical losses during 1996-2000. Broadly, the list will cover materials and equipment required for (i) vigilance and energy audit, (ii) computer software and hardware for distribution planning, and (iii) carrying out the nontechnical loss reduction activities.

E. Bank Financing

5. Details of Bank financing of $2.30 million are given in Table 1.

Table 1: Bank Financing of Nontechnical Loss Reduction Action Plan

Activities	Quantity		Unit Price ($)	Total Price ($)
Consulting Services				
1. General Review and Plan Preparation	4	PMI	25,000	100,000
	2	PML	4,000	8,000
2. Incentive Schemes	2	PMI	25,000	50,000
	2	PML	4,000	8,000
3. Vigilance and Energy Audit	4	PMI	25,000	100,000
	4	PML	4,000	16,000
4. Legal Measures	1	PMI	25,000	25,000
	1	PML	4,000	4,000
5. Prepare Service Contract	4	PMI	25,000	100,000
6. Training in Distribution Planning	4	PMI	25,000	100,000
Subtotal				511,000
Study Tour	4	people	3,500	14,000
Hardware and Supplies				
1. HT Meter and Metering Equipment	75	nos	2,850	214,000
2. Portable Standard Meter	6		8,000	48,000
3. Computer Software	7		8,000	56,000
4. Computer Hardware	8		3,650	29,000
5. Replacement of LT CT Meters	40		250	10,000
6. Replacement of LT 3 Phase Meters	1,200		120	144,000
7. Replacement of LT 1 Phase Meters	12,000		20	240,000
8. Miniature Circuit Breakers	80,000		4	320,000
9. ACSR Conductor for Street Lighting	600	km	300	189,000
10. Seals and Sealing Wire	LS			70,000
Subtotal				1,320,000
Tools and Equipment				
1. Pick-up Vehicles	7		13,000	91,000
2. Clamp on Frequency Meter	40		1,000	40,000
3. Clamp on Frequency Power Meter	40		550	22,000
4. H.V. Line Detector	20		2,000	40,000
5. Portable Earthing Kit (HV)	20		2,000	40,000
5. Portable Earthing Kit (LV)	20		2,000	40,000
6. Load Monitoring Equipment	20		2,000	40,000
7. Miniature Circuit Breakers	lot			20,000
Subtotal				313,000
Contingencies				142,000
TOTAL				**2,300,000**

ACSR - Aluminum Conductor Steel Reinforced;
CT - Current Transformer; LT - Low Tension; HT - High Tension;
HV - High Voltage; LV - Low Voltage
PMI - person-months of international consulting; PML - person-months of local consulting
Source: NEA and the Bank.

Appendix 15

CURRENT TARIFF STRUCTURE OF NEPAL ELECTRICITY AUTHORITY
(effective 14 May 1996)

Category A: Domestic Consumers			
A.1	Minimum Monthly Charges:	**Minimum Charge**	**Exempt**
	METER CAPACITY	**(NRs)**	**(KWh)**
	Up to 5 amperes	60	20
	6-30 amperes	160	40
	31-60 amperes	360	80
	Three phase supply	960	200
A.2	Energy Charge:		
	Up to 20 units	NRs3.00 per unit	
	21-250 units	NRs5.00 per unit	
	Over 251 units	NRs7.75 per unit	
Category B: Temples			
	Energy Charge	NRs3.60 per unit	
Category C: Industrial			
	Subcategory	Demand Fee (NRs/kVA)	Energy Charge (NRs/unit)
C.1	Low voltage (400/220 volt)		
	Rural and cottage	20.00	4.00
	Small industry	40.00	4.90
C.2	Medium voltage (11 & 22kV)	84.00	4.40
C.3	High voltage (> 66 kV)	76.00	3.50
Category D: Commercial			
D.1	Low voltage	100.00	5.80
D.2	Medium voltage	96.00	5.70
Category E: Noncommercial			
E.1	Low voltage	68.00	5.80
E.2	Medium voltage	76.00	5.70
Category F: Irrigation			
F.1	Low voltage		
	Up to 10 kVA	12.00	2.75
	Above 10 kVA	16.00	3.05
F.2	Medium voltage	20.00	3.05
Category G: Water Supply			
G.1	Low voltage	60.00	3.00
G.2	Medium voltage	64.00	2.95
Category H: Transportation			
H.1	Medium voltage	76.00	3.10
Category I: Street Lights			
I.1	Street lights with meter		3.60
I.2	Without meter	1,300.00	
Category J: Temporary Supply			
J.1	With meter		9.30

Source: Nepal Electricity Authority

PROJECT COST PROVISIONS FOR ENVIRONMENTAL AND SOCIAL IMPACT MITIGATION

Environmental Measure	Description of Measure	Timeframe for Implementation	Estimated Cost (in $)
KGEMU	Compliance monitoring and mitigation during construction	During Project construction	1,200,000
Suspension Bridge	Replace suspension bridge across the Kali Gandaki river	Prior to Project construction	70,000
Fish Hatchery	Hatchery to provide for 30 million eggs, 15 million fry, and 7 million fingerlings.	Life of Project	745,880
Fish Entrainment Measures	Bypass system and trash rack modification	During construction	561,000
Fish Trapping and Hauling Facility	Capturing migrating fish at the dam and collecting for hatchery and releasing others	Life of Project	25,000
Testing of Other Trapping Facility	Testing of the fish trapping and hauling systems at Andhi Khola or Marsyangdi during the KGA construction stage.	Project Construction	240,000
Rural Electrification	Electricity will initially be provided to 4 of the affected villages; to be extended to at least 6 others.	i) upon Project completion; ii) 1-2 years after Project completion	300,000
Job Training	Job training for project-affected residents to provide them with the skills necessary to be hired on during the construction, operations, or aquaculture operations stages.	To commence upon contractor's notification to proceed	(Included in Contractor's Cost)
Project Information Centers	Establish locations in Kathmandu and at the Project Site where information and status of the Project can be obtained.	To commence immediately	20,800
Primary Health Center	Construction of a primary health clinic for use by the Project during construction; to be operated by the local community upon Project completion.	During construction	357,800
Assistance in Improving Agricultural production	Compensation of loss of productive lands.	During construction	40,000
ACRP Land Acquisition and Rehabilitation Costs	Compensation costs for land, structures, lost agricultural production, etc., related to the Project.	Prior to commencement of construction for compensation, during construction for rehabilitation	650,000
Micro-Enterprise Revolving Fund	Establishment of a Revolving Credit Fund during the construction phase to increase opportunities for PAFs and SPAFs (including development of aquaculture)	During construction	54,000

Environmental Measure	Description of Measure	Timeframe for Implementation	Estimated Cost (in $)
Nature Reserve	Purchase of private in-holdings to develop an ecological preserve; trail and campsite construction and maintenance.	Prior to completion of construction	184,636
Fuelwood Supply Depot	Maintain areas at the dam and reservoir and power plant sites where low-cost, sustainably provided fuelwood is sold to workers and their families.	During construction	20,000
Boat Ramps	Provide boat ramps above and below the dam and the power plant sites.	Prior to completion of construction	63,000
Warning Sirens	Place warning sirens below the dam and power plant sites.	Prior to completion of construction	95,000
Tree Planting	Plant trees for all facilities' loss of trees	During construction	40,000
Revegetation Nursery	Establish a nursery to provide revegetation, slope stabilization, including listed and native species.	During construction	43,416
Contingency			670,000
TOTAL ESTIMATED COSTS			**5,345,072**

ACRP - Acquisition, Compensation and Resettlement Plan
KGA - Kali Gandaki "A" Project
KGEMU - Kali Gandaki Environmental Monitoring Unit
PAF - Project-affected Family
SPAF - Seriously Project-affected Family
Source: Nepal Electricity Authority

SUMMARY ENVIRONMENTAL IMPACT MATRIX

Table 1: Summary Environmental Impact Matrix for the Physical Environment

	Qualifier					
Impacts	**Magnitude**	**Extent**	**Duration**	**Phase**	**Mitigation**	**Responsibility**
1. Increased erosion and landslide due to land disturbance and linked effects to the ecological and socioeconomic environments.	H	L	S,M,L	C,O	Avoid risk by alignment and site selection. Reduce erosion and landslide events by use of state-of-the-art engineering and bio-engineering techniques to stabilize slopes. Minimize scheduling during the wet season. Establish preventative maintenance procedures. Monitor effectiveness of measures.	Contractor, NEA (pre-construction, access road)
2. Disposal of excess spoil (8.6 million tons) from tunnel, desander basin, and other Project facilities.	H	R	S	C	Suitable fill areas and quarry sites will be used for part of the spoil disposal. For the balance, armored berm will be placed on varial zone to control release of spoils into the river.	Contractor
3. Inundation of lands and riverine areas (65 ha).	H	L	L	O	Create a natural reserve.	NEA, DNPWC, DOF
4. Significant changes in hydrology down river of the dam due to diversion and linked impacts to aquatic ecology and economics.	H	R	L	O	Provide minimum riparian flows (4 cms) and hatchery to improve fish populations. Develop aquaculture. Provide additional flows during selected holy days. Monitor for effectiveness.	NEA
5. Changes in sedimentation patterns downstream of the dam due to flushing of desander basins.	L	R	L	O	Establish operational criteria to restrict sediment discharge during low flow periods.	NEA
6. Hydrologic effect of peaking flows immediately downstream of the power plant.	M	L	L	C,O	Inform and warn downstream users of peaking effects via education in advance of operations stage and through a siren warning system. Ramping at powerhouse at 1/m/hr.	NEA
7. Alteration of drainage patterns resulting in increased erosion and potential landslides.	H	L	S,M,L	C,O	See No. 1 above.	See No. 1 above.

Table 2: Summary Environmental Impact Matrix for the Biological Environment

	Qualifier					
Impacts	**Magnitude**	**Extent**	**Duration**	**Phase**	**Mitigation**	**Responsibility**
1. Impediment to migration and loss of spawning habitat to many species of migratory fish.	H	R	L	C,O	Provide a capturing and trucking facility to provide passage. Provide grate to minimize entrainment. Establish hatchery to mitigate for unavoidable impacts. Monitor effectiveness within the MMMP.	Contractor, KGEMU, NEA, FDD
2. Significant hydrological effects on approximately 50 km of riverine ecosystems.	M	R	L	O	Provide minimum riparian flows (4 cms). Provide hatchery for unavoidable impacts. Monitor flow and fish populations.	NEA
3. Significant reduction of flows (less than 10 percent of pre-project flows) for 13 km of riverine ecosystem for seven months of the year.	H	L	L	O	See No. 2 above.	
4. The inundation of 65 ha of riverine and terrestial ecosystems along the 5.3 km reservoir.	H	L	L	O	Establish a nature preserve.	NEA, DNPWC, DOF
5. The permanent and temporary disturbance of approximately 200 ha terrestrial and aquatic ecosystems.	M	R	L	C,O	Minimize disturbance through siting, and environmental clauses in tender documents. Establish nature preserve.	Contractor, KGEMU NEA, DNPWC, DOF
6. The impacts and loss of habitat to species listed by various authorities as "species of concern" (*e.g.*, river otter, python).	M	R/N	S,M,L	C,O	Minimize areas of disturbance. Establish nature preserve. Conduct additional listed species surveys at finalized quarry and construcion camp sites. Establish a nursery and replant listed plant species. See fish mitigation.	Contractor, KGEMU, NEA, DNPWC, DOF
7. Secondary impacts due to increased harvest and disturbance during project construction.	L	L	S	C	Provide guidelines to contractors on fish, wildlife, and forest protection. Monitor and police illegal harvest of fish, wildlife or trees. Set controls and guidelines for waste disposal. Operate fuelwood supply depots and encourage the use of kerosene for cooking.	NEA, KGEMU, Contractor, DOF, TCN
8. Alignment across waterfowl concentration areas or narrow valleys can cause avian mortality.	M-L	R	L	O	Avoid placing alignment in waterfowl concentration areas, major wetland areas, and major migratory areas.	Project Designers, Contractor, KGEMU
9. Cumulative impacts of other existing and proposed water projects on riverine ecosystems.	M	N	L	C,O	Provide riparian flows. Provide fish passage facilities. Provide fish hatchery. Monitor consequences.	Contractor, KGEMU, NEA, FDD

Table 3: Summary Environmental Impact Matrix for the Socioeconomic and Cultural Environment

	Qualifier					
Impacts	**Magnitude**	**Extent**	**Duration**	**Phase**	**Mitigation**	**Responsibility**
1. The permanent taking of private lands and the displacement of people. There are 617 PAF households, including 149 SPAF households. Of these, approximately 125 households require physical resettlement.	H	R	S	C,O	Implement the ACRP. Justly compensate for the take, use and damage to private property.	NEA, KGEMU
2. Changes in sociocultural patterns moving from subsistence to a market driven pattern.	M	R	L	C,O	Assist villages in planning for potential changes caused by the Project. Provide rural electrification. Educational program to train and employ local residents. Implement a micro-enterprise revolving fund.	Contractor, KGEMU, NEA, RDSC, UNDP (PA), AgDB, VAGs, DDCs
3. The potential loss of livelihood for fisherman of the Kali Gandaki and affected tributaries.	M	R	L	C,O	Provide fish passage. Provide fish hatchery. Develop a local aquaculture program in tandem with fish hatchery. Educational program to train and employ local residents. Implement a micro-enterprise revolving fund.	Contractor, KGEMU, NEA, FDD, UNDP (PA), AgDB
4. The disturbance of religious sites.	M	R	L	C,O	Minimize disturbance through siting and operation. Provide river flows during holy periods. Avoid inundation of holy rock at Seti Beni by limiting the height of the dam and reservoir elevation.	Contractor, NEA
5. Partial loss of 50 km of river available for rafting.	M	R/N	L	C,O	Provide warning signs and rafting ramp at dam. Assist in establishing zoning for white water use.	Contractor, KGEMU, NEA, NARA, MTCA
6. The midterm (circa 8 years) consequences of a temporary work force peaking at 2000-3000 on the local people and economy.	H	R	M	C	Constraints and guidelines on contractor for behavior and control of the work force. Educational program to train and employ local residents.	Contractor
7. The long-term beneficial effect of an estimated 350 person permanent work force.	L	L	L	O	No mitigation required.	
8. The long-term beneficial effects of improved road infrastructure, electrification and water supply.	M	R	L	O	No mitigation required.	
9. Electro-magnetic forces emitted from the higher voltage transmission lines.	L	L,R	L	O	When erecting the lines, maintain distance specifications from areas of habitation and facilities.	Contractor
10. The beneficial effects of meeting the power demand (Project purpose and need) on economic development and the people of Nepal.	H	N	L	O	No mitigation required.	

Table 4: Summary Environmental Impact Matrix for Interdisciplinary and Cumulative Impacts

	Qualifier					
Impacts	**Magnitude**	**Extent**	**Duration**	**Phase**	**Mitigation**	**Responsibility**
1. Nonimplementation of recommended mitigation measures.	H	L,R	L,M,S	C,O	The MMMP will ensure that mitigation described in the EIA and environmental clauses to the tender documents are carried out, along with an environmental audit.	See MMMP.
2. Inadequacy of proposed mitigation and unforeseen impacts.	H	L,R	L,M,S	C,O	The MMMP will evaluate the effectiveness of mitigation, monitor mitigation and, if people and natural resources are adversely affected, ensure they are adequately protected.	See MMMP.
3. Watershed and cumulative regional impacts.	M	L,R	L,M,S	C,O	Coordinate proposed project mitigation and ongoing and planned natural and socio-economic resource development and protection efforts in the region. Provide rural electrification and improved local water supplies.	NEA, KGEMU, DOF, AKP, UNDP (PA)

Magnitude
H = High
M = Medium
L = Low

Extent
L = Local
R = Regional
N = National

Duration
L = Long-term
M = Medium-term
S = Short-term

Phase
C = Construction
O = Operations

Abbreviations:

ACRP - Acquisition, Compensation and Resettlement Plan
AgDB - Nepal Agricultural Development Bank
AKP - Andhi Khola Project
DDC - District Development Committee
DNPWC - Department of National Parks and Wildlife Conservation
DOF - Department of Forestry
EIA - Environmental Impact Assessment
FDD - Fisheries Development Division
KGEMU - Kali Gandaki Environmental Management Unit
MMMP - Mitigation Management and Monitoring Plan
MTCA - Ministry of Tourism and Civil Aviation
NARA - Nepal Association of Rafting Agents
NEA - Nepal Electricity Authority
PAF - Project-affected Family
RDSC - Rural Development Services Centre
SPAF - Seriously Project-affected Family
TCN - Timber Corporation of Nepal
UNDP (PA) - United Nations Development Programme (Poverty Alleviation)
VAG - Village Advisory Group

Source: Nepal Electricity Authority

TECHNICAL ASSISTANCE FOR INSTITUTIONAL STRENGTHENING OF NEA'S ENVIRONMENT DIVISION

A. The Proposed Technical Assistance

1. Objective

1. The objective of the technical assistance is to build the capacity of the Nepal Electricity Authority (NEA) for ensuring that environmental and social issues are adequately addressed in the design, construction, operation, and monitoring of power development projects in Nepal.

2. Scope

2. Major activities to be undertaken under the technical assistance (TA) are summarized below:

(i) An assessment and review will be done of the existing environmental and social management framework in Nepal and in the context of NEA operations. This will include, among other activities, recommendations for amendments to the existing national legislative framework where appropriate. Special emphasis will be placed on issues related to hydropower development.

(ii) The consultants will assist NEA to formulate an environmental and social management framework that includes, inter alia, a five-year operational program, improved organizational efficiency and staff capability, an environmental impact assessment (EIA) procedure appropriate for NEA, detailed EIA guidelines and manuals, a reference library, identification of priority environmental projects, and other requirements. Special attention will be given to social assessment/mitigation procedures and mechanisms for fostering strong public participation in all project stages.

(iii) Training will be provided to all Nepal Electricity Authority - Environment Division (NEA-ED) staff and other selected NEA staff. The major emphasis will be provision of on-the-job training and of in-house training. External training will be provided to selected key NEA staff. There will be close coordination and collaboration with training activities to be provided for the environmental monitoring unit staff.

(iv) An environmental management information system (EMIS) will be established at NEA, and staff trained in its use and maintenance.

3. Implementation Arrangements

3. The TA will be implemented by NEA. As part of the arrangements made under the Project, the Government has agreed to increase staffing of the NEA-ED by the start of TA implementation. The Chief, NEA-ED will serve as Project Manager for the TA. The consultant team leader, in consultation with NEA, will be responsible for coordinating training under the TA with training programs associated with the Kali Gandaki Environmental Monitoring Unit (KGEMU) in order to optimize training opportunities.

4. The TA will be implemented over a period of 12 months. Consulting services, consisting of 12 person-months of international consultants and 11 person-months of local consultants will be undertaken by an international firm with extensive experience in EIA capacity building in Asia and with work experience in Nepal. The consultants will be recruited in accordance with the Bank's *Guidelines on the Use of Consultants*. Selected equipment and materials provided under the TA, particularly a 4-wheel drive vehicle and computer facilities, will be procured by the Bank on behalf of the Executing Agency prior to the beginning of the consultant services. Other equipment and materials will be specified and procured by the consultant in consultation with NEA and with the approval of the Bank.

B. Terms of Reference

5. The consultant team will include the following international experts: (i) EIA adviser/team leader with extensive experience advising government agencies in Asia in developing EIA procedures for energy development, especially hydropower projects, for a period of 6 months; (ii) social assessment adviser with experience in developing social assessment and public participation guidelines for major infrastructure projects and training in its use and development, for 4 months; and (iii) EMIS adviser with experience in developing EMIS systems for monitoring major development projects and programs, for 2 months. The team will also include four local consultants: an EIA expert (3 months), a sociologist (3 months), an environmental data base expert (2 months), and an environmental trainer (3 months) to assist the international consultants and especially to provide trouble-shooting assistance to NEA when the international consultants are absent from Nepal. Approximately six local resource persons will be provided under the training program. The exact number and their areas of expertise will be determined during the initial period of TA implementation in consultation with NEA and with approval from the Bank.

6. The consultants will provide intensive assistance to NEA during the first 3-4 months of the TA and then provide periodic follow-up assistance as NEA-ED staff put to practice the institutional changes made and the skills learned. The consultants will closely coordinate with the KGEMU to optimize training opportunities.

7. The initial task will be to develop a detailed work plan that will appropriately allocate time and responsibilities for the consulting team and their counterparts. This will be followed by a review and assessment of the existing national environmental management framework and NEA's role within the framework.

8. Following the review, the next major task will be development of an environmental and social management framework for NEA. This will include (i) assessing the adequacy of current technical and managerial skills and staff numbers related to environmental work and preparing a five-year human resource development plan; (ii) assessing internal linkages and reporting procedures and preparing recommendations for their reform, if necessary; (iii) assessing NEA's linkages with outside agencies in relation to environmental matters, and preparing recommendations for streamlining and strengthening these linkages; (iv) undertaking an inventory of NEA-ED equipment and supplies, and preparing a realistic plan for meeting any shortfalls; (v) assisting NEA to establish an internal EIA procedure; (vi) reviewing existing EIA guidelines and manuals and adapting these to better and more specifically fit NEA functions; (vii) establishing an environmental documentation and reference center, perhaps including connection with the Internet; and (viii) consolidating each activity into a five-year operational program.

9. The consultants will develop a training program in consultation with NEA and with approval of the Bank.

10. Reporting will include (i) an inception report within one month of TA start-up, (ii) an interim report in the sixth month, (iii) a draft final report after 10 months, and (iv) a final report one month after receiving Bank and Government comments on the draft.

C. Cost Estimates and Financing Plan

11. The total cost of the TA is estimated at $580,000 equivalent, of which $455,000 will be foreign exchange costs and $125,000 equivalent in local currency costs. The Bank will finance $534,000 on a grant basis, consisting of the entire foreign exchange cost and $79,000 equivalent in local currency costs. The balance of the local currency costs, including taxes and duties required for the procurement of equipment, amounting to $46,000 equivalent, will be met by the Government's own resources. Detailed cost estimates are provided in Table 1.

Table 1: Cost Estimates
(in $'000)

Item	Foreign Exchange	Local Currency	Total Cost
A. Bank Financing			
1. Consultants			
Remuneration and Per Diem			
International	262	—	262
Local		34	34
2. Travel Expenses			
International Travel	30	—	30
Local Travel		10	10
3. Equipment[a]	60	—	60
4. Report Preparation and Translation	5	—	5
5. Contract Negotiation	3	—	3
6. Training and Workshop Expenses			
Regional Study Tour	25	—	25
Incountry Training[b]	—	25	25
7. Reference Materials	10	—	10
8. Contingency	60	10	70
Subtotal	**455**	**79**	**534**
B. Government Financing			
1. Salaries	—	21	21
2. Travel Allowances	—	10	10
3. Office/Administration Costs	—	15	15
Subtotal	**—**	**46**	**46**
Total	**455**	**125**	**580**

[a] Equipment includes items essential for effective operation of the NEA-ED: One four-wheel drive vehicle, one photocopy machine, one desktop computer and one notebook computer with accessories suitable for geographical information systems and EMIS, and portable laboratory equipment.

[b] Includes all costs related to in-country training, e.g., materials, travel, and local resource persons except for the trainer.

Source: Staff estimates.

TECHNICAL ASSISTANCE FOR THE POWER SYSTEM MASTER PLAN

A. Objectives and Scope

1. The objective of the technical assistance (TA) will be to (i) prepare a new power system master plan for Nepal, including a new load forecast, generation expansion plan, and transmission master plan; and (ii) conduct on-the-job training of the engineering staff of Nepal Electricity Authority (NEA) in power system planning.

B. Broad Terms of Reference

2. **Load Forecast**: Review previous load forecasts prepared for Nepal. Compile records of actual loads served and estimates of unserved loads since 1983. Review prospects for economic growth and prepare revised long-term (15 years) load forecasts for Nepal. Develop alternative scenarios for total load growth, including a base case and high and low forecasts. Identify centers of load growth in Nepal and planned specific large new industrial and other loads. Prepare a ten-year forecast of peak loads for the main transmission substations in Nepal, consistent with the base-case long-term forecast for Nepal described above. Prepare ten-year load forecasts for each major consumer category, as required for other future studies on tariffs and financial projections. Transfer the models and data used for the load forecast to NEA and train NEA staff in their use.

3. **Generation Planning**: Review current generation expansion plans, establishing supply from existing plants and plants under construction. Determine the additional capacity requirements for the alternative load forecasts developed above. Determine the total installed capacity, dependable capacity, loss of load probability, expected unserved energy, and the firm energy of the planned power system, based on committed powerplants, for the period up to 2004. Prepare a load resources balance which compares the load forecast to the dependable resources, and show the surplus or deficit each year. Evaluate different scenarios where uncertainty exists regarding development of new generation projects, or the dependability of power imports from India. Review alternative candidate hydro and thermal projects that have been studied to date for future development. Review, and if necessary revise, project cost estimates to ensure that they are reasonably consistent, and that adequate contingency allowances are included which are appropriate for the level of study conducted for each project and the relative cost related uncertainties and risks for each project. Evaluate alternate generation expansion plans and determine the most economic plan for generation expansion in Nepal for the next 15 years for various scenarios. Review prospects for large scale power exports to India. Evaluate alternative methods for pricing such power exports. Evaluate strategies for sharing generation from large export-oriented hydro projects. Evaluate alternative generation expansion programs and advise NEA on whether another program should be used instead of Wien Automatic System Planning Computer Model (WASP III). Calculate the long-run marginal costs of power generation as a function of the time of year (i.e., wet season and dry season) and as a function of the time of day during a specified season (i.e., peak period, shoulder period, and off-peak period).

4. **Transmission System Master Plan**: Review previous transmission plans that have been developed for Nepal, design standards and procedures, and the required levels of reliability. Prepare a transmission system master plan for the next ten years for Nepal, based on the load

forecast and the generation expansion plan established as in paras. 2 and 3. Design an economic and reliable transmission system expansion plan to serve increasing substation loads and to connect new power plants, with justification for the level of reliability adopted. Determine NEA's requirements for computer programs for transmission planning and assist NEA with acquisition of additional computer software and hardware for this purpose. Provide on-the-job training to NEA staff in use of these programs.

C. Reporting Requirements

5. The reporting requirements will include an Inception Report 30 days after the commencement of services in the field; task reports for review of the load forecast within 3 months, of the generation plan within 6 months, and of the transmission master plan within 8 months; and a final report within 8 months that summarizes the results of all studies, with detailed task reports as annexures.

D. Consulting Services Required

6. The TA is estimated to require about 18 person-months of international consulting services. Most of the work should be done in Nepal. Local assistance will be provided by NEA staff. Consultants must have expertise in load forecasting, generation planning, and transmission system planning. The consultants will be recruited in accordance with the Bank's *Guidelines on the Use of Consultants*.

E. Cost Estimates and Financing

7. The cost of the TA and its financing plan are given in Table 1.

Table 1: Cost Estimates and Financing Plan
(in $'000)

Item	Foreign Exchange	Local Currency	Total Cost
A. Bank Financing			
1. Remuneration and Per Diem	396	—	396
2. Travel Expenses of Consultants	36	5	41
3. Communications, Reports, etc.	15	5	20
4. Computer Software	30	—	30
5. Study Tour and Training	25	5	30
6. Contract Negotiations[a]	5	—	5
7. Contingency	75	3	78
Subtotal	**582**	**18**	**600**
B. NEA Financing			
1. Office Facilities	—	20	20
2. Local Transportation	—	10	10
3. Expense of Local Staff	—	20	20
Subtotal	**—**	**50**	**50**
Total	**582**	**68**	**650**

[a] One representative from NEA will be invited.
Source: Staff estimates.

FINANCIAL AND ECONOMIC ANALYSIS

A. Cost Assumptions

1. Project Capital Cost

1. The financial internal rate of return (FIRR) for the Project is computed in constant FY1996 terms. The capital cost for the FIRR is derived after deducting interest during construction and price contingencies from the total Project cost of $452.8 million, and is estimated at $370.4 million at FY1996 price levels (see Appendix 7 for Project cost details).

2. The capital cost for computing the economic internal rate of return (EIRR) is estimated after deducting taxes and duties from the financial capital cost and converting local capital costs to border prices at a standard conversion factor of 0.90. The resulting total economic cost of the Project is estimated at $346.3 million at FY1996 price levels.

3. The economic and financial analysis of the Project includes an allowance for system transmission and distribution costs. This is estimated to be $740/kW of generating capacity on average, resulting in a total allowance of $106 million for the Project. Because the Project cost already includes $14.2 million for Project related transmission, the net additional cost of other system transmission and distribution development is estimated to be about $91.8 million.

2. Fixed Operation and Maintenance Costs

4. Fixed annual operation and maintenance costs are estimated based on NEA's experience.

3. Variable Operating Costs

5. FY1996 fuel prices for alternative thermal power are computed after including local transportation costs. In the EIRR analysis, local transportation and handling costs have been converted to border terms by excluding taxes and duties and by applying a standard conversion factor of 0.9.

6. The export or import of electricity to or from India in FY1996 is at $0.044 cents/kWh for supply at 33 kV. The present agreement includes an automatic escalation clause of 8.5 percent on the tariff in Indian rupees, and in the analysis, future prices have been adjusted to take account of this increase.

B. Valuation of Generation from the Project

7. For the financial analysis, the benefits from incremental sales have been valued in terms of the annual average tariff revenue in cents per kWh forecast in the financial model (Appendix 12) and then adjusted to constant FY1996 price levels. For the economic analysis, the economic benefits of electricity consumption for each major consumer category are based on (i) the alternative economic costs of other energy sources, such as kerosene lighting or diesel generator sets that will be displaced by using electricity; and (ii) valuing additional or induced energy consumption at the estimated average willingness to pay for electricity; based on a weighted average of the alternative costs of providing similar energy related services and the current electricity tariff. In valuing generation from the Project, a conservative assumption has

been made that part of the generation during the wet season may be surplus. Also, it has been assumed that in the initial years, generation from the Project will displace thermal generation and power imports.

C. Results of Financial and Economic Evaluation

8. The FIRR for the Project for the base case is estimated at 9.8 percent in real terms (see Table 1). This compares satisfactorily with the real weighted average cost of capital of 5.4 percent for the Project.[1] The EIRR for the Project for the base case is estimated at 15.0 percent in real terms (see Table 1), which is above the normative 10 percent opportunity cost of capital for Nepal.

9. Sensitivity analysis for FIRR and EIRR shown below in Table 2 demonstrates that the Project remains financially and economically viable even with adverse movements in some parameters such as lower Project benefits, increase in capital cost, and one-year delay in Project implementation.

Table 2: FIRR and EIRR Sensitivity Analysis

	FIRR (%)	SI	EIRR (%)	SI
Base case	9.8	—	15.0	—
Project Benefits decreased 10 percent	8.7	1.12	13.7	0.87
Capital cost increased 10 percent	9.0	0.82	13.9	0.73
One-year delay in Project commissioning	9.4	0.16	14.2	0.21

SI = sensitivity indicator (ratio of percentage change in EIRR or FIRR to percentage change in sensitivity parameter).
Source: NEA and the Bank.

[1] The Project will be financed 71 percent by debt-carrying interest rate of 10.25 percent in nominal terms, i.e., 4.25 percent in real terms, after allowing for long-term annual inflation of 6 percent. The remaining 29 percent financed from internal generation is assumed to have a return in real terms of 8.25 percent, i.e., 4 percent above the cost of debt. The weighted average cost of capital for the Project works out to 5.4 percent in real terms.

Table 1: Internal Rate of Return for the Project

Fiscal Year	Financial						Economic					
	Costs			Benefits		Net Cash Flow	Costs			Benefits		Net Cash Flow
	Capital Cost[a] ($ million)	O&M Cost ($ million)	Total Cost ($ million)	Net Sales (GWh)	Benefits ($ million)	Benefits-Costs ($ million)	Capital Cost[a] ($ million)	O&M Cost ($ million)	Total Cost ($ million)	Net Sales (GWh)	Benefits ($ million)	Benefits-Costs ($ million)
1996	1.45		1.45			-1.45	1.02		1.02			-1.02
1997	64.91		64.91			-64.91	59.53		59.53			-59.53
1998	93.38		93.38			-93.38	87.76		87.76			-87.76
1999	174.79		174.79			-174.79	164.66		164.66			-164.66
2000	104.93		104.93			-104.93	99.90		99.90			-99.90
2001	22.74	3.46	26.20	581	25.26	-0.94	21.57	3.28	24.86	581	36.53	11.68
2002		3.46	3.46	749	39.78	36.33		3.28	3.28	749	60.78	57.50
2003		3.46	3.46	712	58.03	54.58		3.28	3.28	712	84.36	81.08
2004		3.46	3.46	709	53.57	50.11		3.28	3.28	709	82.85	79.57
2005		3.46	3.46	692	53.57	50.11		3.28	3.28	692	82.85	91.72
2006		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2007		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2008		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2009		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2010		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2011		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2012		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2013		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2014		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2015		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2016		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2017		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2018		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2019		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2020		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2021		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2022		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2023		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2024		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2025		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2026		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2027		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2028		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2029		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2030		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2031		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2032		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2033		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2034		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2035		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2036		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2037		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2038		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2039		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2040		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2041		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2042		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2043		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2044		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2045		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2046		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2047		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2048		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2049		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2050		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
2051		3.46	3.46	692	60.27	56.81		3.28	3.28	692	95.00	91.72
	FIRR — 9.8%						EIRR — 15.0%					

[a] Includes system transmission and distribution capital cost.
Source: NEA and the Bank.