No.

Nepal Electricity Authority

Nepal

UPGRADING FEASIBILITY STUDY ON UPPER SETI (DAMAULI) STORAGE HYDROELECTRIC PROJECT IN NEPAL

FINAL REPORT

June 2007

JAPAN INTERNATIONAL COOPERATION AGENCY

ELECTRIC POWER DEVELOPMENT CO., LTD.
NIPPON KOEI CO., LTD.

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PREFACE

In response to a request from the Government of Nepal, the Government of Japan decided to conduct the Upgrading Feasibility Study on Upper Seti (Damauli) Storage Hydroelectric Project, and the study was implemented by the Japan International Cooperation Agency (JICA).

JICA selected and dispatched a study team headed by Mr. Yoshimasa Ishii of Electric Power Development Co., Ltd. (J-Power), and consist of J-Power and Nippon Koei Co., Ltd. to Nepal five times from February 2005 to June 2007.

The study team held discussions with the officials concerned of the Government of Nepal and Nepal Electricity Authority, and conducted related field surveys. After returning to Japan, the study team compiled the final results in this report.

I hope this report will contribute to stabilization of power supply in Nepal and to enhancement of friendly relations between our two countries.

I wish to express my sincere appreciation to the officials concerned of the Government of Nepal for their close cooperation throughout the study.

June 2007

Tadashi IZAWA
Vice President
Japan International Cooperation Agency

June 2007

LETTER OF TRANSMITTAL

Mr. Tadashi Izawa
Vice President
Japan International Cooperation Agency
Tokyo, Japan

We are pleased to submit to you the report on the Upgrading Feasibility Study on Upper Seti (Damauli) Storage Hydroelectric Project in Nepal. This study has been conducted by Electric Power Development Co., Ltd. in association with Nippon Koei Co., Ltd. under a contract to JICA in a period from February 2005 to June 2007.

This report presents a development of Upper Seti Hydroelectric Project with an installed capacity of 127 MW. Completion of the project can cope with peak power demand in the country and contribute to stabilization of power supply.

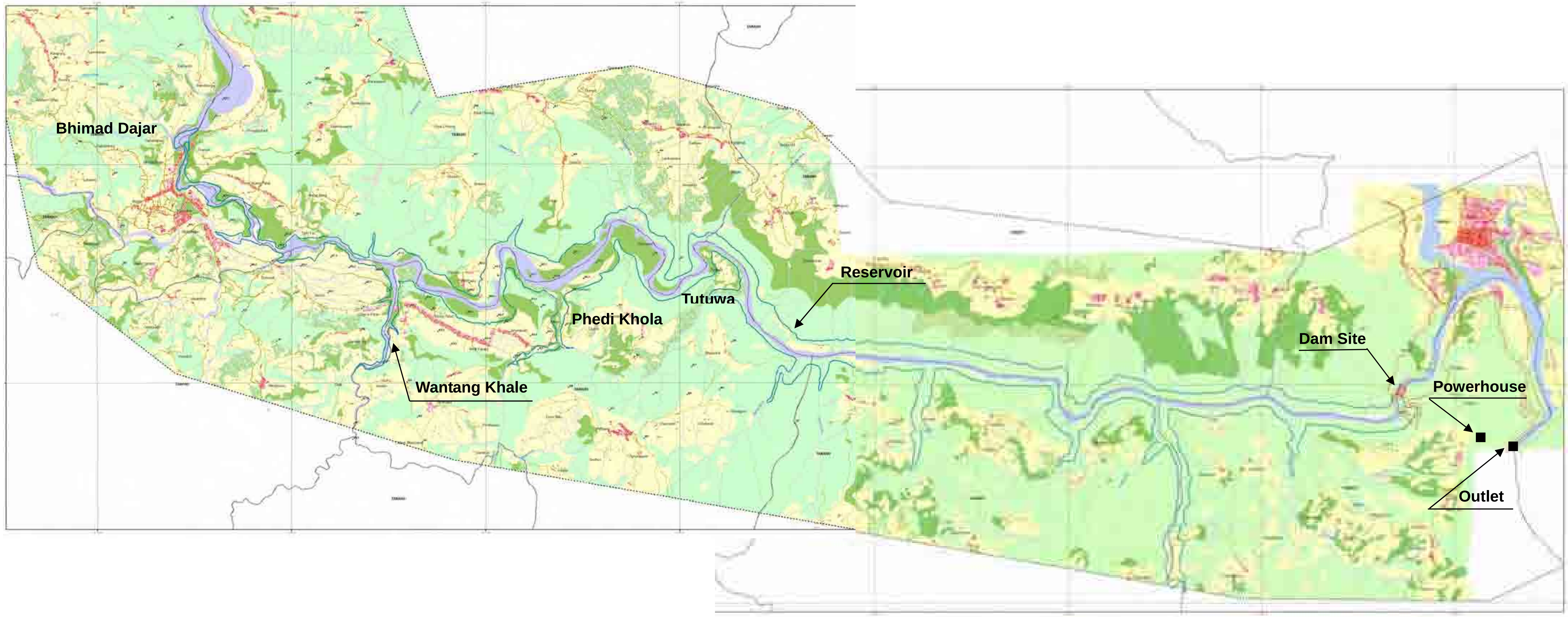
We dearly wish that our proposed project will contribute to the utilization of domestic energy resources and to the improvement of Nepalese people's living and economic activities.

We would like to take this opportunity to express our sincere gratitude to your Agency, the Ministry of Foreign Affairs and the Ministry of Economy, Trade and Industry of the Government of Japan. We are also most grateful for the cooperation and assistance from the officials and personnel concerned in Nepal Electricity Authority and the ministries concerned of the Government of Nepal.

Very truly yours,

Yoshimasa Ishii
Team Leader,
Upgrading Feasibility Study on Upper Seti
(Damauli) Storage Hydroelectric Project
in Nepal

Location Map



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Stakeholder Meeting in Damauli (2 June, 2006)

Stakeholder Meeting in Damauli (2 June, 2006)

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ABBREVIATIONS

Organizations

ADB	Asian Development Bank
BFRS	Begnas Fisheries Research Station
CBO	Community-Based Organization
CBS	Central Bureau of Statistics
CDO	Chief District Officer
DANIDA	Danish International Development Agency
DDC	District Development Committee
DFO	District Forestry Office
DHM	Department of Hydrology and Meteorology
DOED	Department of Electricity Development
FINIDA	Finish International Development Agency
INGO	International Non-Governmental Organization
IUCN	International Union for Conservation of Nature and Natural Resources
JBIC	Japan Bank for International Cooperation
JICA	Japan International Cooperation Agency
KfW	Kreditanstalt fur Wiederaufbau
KMTNC	King Mahendra Trust for Nature Conservation
LDC	Load Dispatch Center
LDO	Local Development Officer
MOEST	Ministry of Environment, Science and Technology
MOF	Ministry of Finance
MOFSC	Ministry of Forest and Soil Conservation
MOWR	Ministry of Water Resources
NEA	Nepal Electricity Authority
NGO	Non-Governmental Organization
NRCT	Nepal River Conservation Trust
VDC	Village Development Committee
UNDP	United Nations Development Programme
USBR	United States Bureau of Reclamation
WB	World Bank

General and technical terms

AFC	Automatic Frequency Control
AGC	Automatic Generation Control

AIDS	Acquired Immunodeficiency Syndrome
ASTM	American Society for Testing and Materials
B/C	Benefit-Cost Ratio
BOD	Biological Oxygen Demand
CITES	Convention on International Trade in Endangered Species of Wild Fauna and Flora
COD	Chemical Oxygen Demand
CPI	Consumer Price Index
D/D	Detailed Design
DEM	Digital Elevation Model
EIA	Environmental Impact Assessment
EIRR	Economic Internal Ratio of Return
EL.	Elevation
EMP	Environmental Management Plan
FC	Foreign Currency
FIRR	Financial Internal Ratio of Return
FSL	Full Supply Level
F/S	Feasibility Study
FY	Fiscal Year
GDP	Gross Domestic Product
GIS	Geographic Information System
GIS	Gas Insulated Switchgear
HEP	Hydroelectric Project
HIV	Human Immunodeficiency Virus
IEE	Initial Environmental Evaluation
IPP	Independent Power Producer
IRR	Internal Ratio of Return
INPS	Integrated Nepal Power System
JIS	Japanese Industrial Standards
LAN	Local Area Network
LC	Local Currency
LOLP	Loss of Load Probability
MOL	Minimum Operation Level
NPV	Net Present Value
O & M	Operation and Maintenance
ODA	Official Development Assistance
PMF	Probable Maximum Flood

PMP	Probable Maximum Precipitation
PPA	Power Purchase Agreement
PROR	Peaking Run-off-River
PRSP	Poverty Reduction Strategy Paper
RAP	Resettlement Action Plan
ROE	Return on Equity
ROI	Return on Investment
ROR	Run-off-River
SAP	Social Action Plan
SCADA	Supervisory Control and Data Acquisition
VAT	Value Added Tax
WPI	Wholesale Price Index

Units

A	Ampere
ha	Hect Are
Hz	Hertz (Cycles per second)
JRT	Japan tone of refrigiration
Lu	Lugeon Value
MCM	Million Cubic Meter
MVar	Megavar
m mol/L	Mili-mol per liter
m^3/s	Cubic meter per second
ppm	Parts per million
V	Volt
kV	Kilovolt = 10^3 V
VA	Volt Ampere
kVA	Kilovolt Ampere = 10^3 VA
MVA	Megavolt Ampere = 10^6 VA
W	Watt
kW	Kilowatt = 10^3 W
MW	Megawatt = 10^6 W
Wh	Watt Hour
kWh	Kilowatt Hour = 10^3 Wh
MWh	Megawatt Hour = 10^6 Wh
GWh	Gigawatt Hour = 10^9 Wh
NRs	Nepalese Rupees

US$	US Dollar
USc	US Cent

Conclusion and Recommendation

CONCLUSION AND RECOMMENDATION

This upgrading feasibility study was implemented with respect to the Upper Seti (Damauli) Storage Hydroelectric Project from February 2005, and the Project was judged feasible from technological, economical, financial and environmental perspectives for the following reasons as a result of the study. The details of the conclusion are discussed below.

Conclusion

(1) Necessity of Hydropower Development for Peak Load

The exploitable hydropower potential is estimated to be 42,000 MW, and water resources are the only energy resource in Nepal, due to the lack of any nationwide fossil energy reserves in the country. The Government of Nepal is implementing rural electrification and hydroelectric development, by using abundant water resources, in the Tenth Plan (FY 2002/03-to FY 2007/08) as one of the activities for poverty reduction which is the most important national issue to be solved.

The total installed capacity in Nepal is 614 MW as of July 2006, of which 93 % consists of hydropower. Hydropower shares 99 % of annual generated energy.

National power demand in the country has grown steadily, and the growth rates of annual generating energy and the maximum load in the past decade have been 8.3 % and 8.2 % on average, respectively.

The daily peak load in the country is recorded in the morning and from 5:00 to 10:00 in the evening, and daily load curves show typical examples where domestic demand dominates.

The annual maximum load is recorded in December or January during a dry season during which river discharge decreases. 85 % of hydropower facilities in installed capacity is consisted of Run-of-river (ROR) type hydropower plants which cannot seasonally regulate discharge for power generation against peak demand, and new power plants are necessary to cope with such peak demand.

Oil-fired/gas-fired thermal power plants are generally considered as power sources suitable to meet peak demand. Thermal power plants, however, are not considered as new power facilities, for the following reasons:

a. The expensive generation cost
b. The risk associated with fuel procurement and the foreign currency required for same
c. Priority for the utilization of rich national water resources

With the above in mind, reservoir type hydropower plants are under consideration as new power facilities to meet peak demand.

(2) Power Demand Forecast

In 2006, the NEA forecasts that both the required generating energy and the maximum demand will grow at an annual rate of 8.1 % right up to 2020.

In the latest the power development plan, demand will exceed supply capacity up to 2013, and shortage should be dealt with via power imports from India or load shedding, because some of projects to be implemented by Independent Power Producers (IPPs) have been delayed. Even after 2013, there is the potential for power shortages, if projects by NEA and IPPs are not advanced steadily.

The Upper Seti Hydroelectric Power Plant is planned as that for peak demand and is capable of supplying power for 6 hours during peak times throughout the year (also supplying power during off-peak times in the rainy season).

In addition, the plant can play roles in stabilizing system power voltage and system frequency during evening peak periods during which the power load increases rapidly. The new transmission line of the project will represent one of the very important steps for forming a strong 220 kV loop to enhance the power system reliability.

(3) Study Process

NEA carried out a study termed the Identification and Feasibility Study of Storage Project to identify storage type hydroelectric projects and to select priority project(s), in order to cope with increasing peak demand. In the study, an initial total of 102 new projects were identified through desk study. The Project was selected as the priority choice following coarse screening using the existing data and information and fine screening based on the site survey results.

NEA performed a feasibility study on the Project from July 2000 up to July 2001. In the study based on the site surveys (topography, hydrology, geology and environment), a development plan featuring 122 MW in installed capacity was concluded.

The upgrading feasibility study including site surveys (hydrology, geology and environment) was carried out and completed in July 2004. Based on the results of the above environmental survey NEA prepared an environmental impact assessment (EIA) in January 2003, and held a public consultation in Damauli located near the site in January 2004 in accordance with Nepalese regulations. The EIA was submitted to the Department of Electricity Development of the Ministry of Water Resources which is the supervisory organization of NEA.

(4) Natural Conditions

The Project site is located in the upper part of the Seti River, a tributary of the Trishuli River flowing in the central part of Nepal. The Seti River originates at the Annapurna (7,555 m height above sea level) of the Himalaya Mountains and flows about from north to south.

The length of the Seti River from the origin to the Dam site is about 120 km, and a catchment area at the Dam site is 1,502 km^2.

The average annual precipitation in the project basin is 2,973 mm of which about 80% falls between June and September due to the influence of the southwest monsoon. Annual sediment at the project site is estimated at 6,240 m^3/km^2. According to sedimentation analysis, the reservoir will not function due to sedimentation around 40 years after completion of the construction works, if sediment is not discharged from the reservoir. Hence sediment flushing facilities are to be installed in the dam.

(5) Environmental and Social Considerations

Although the environmental impact assessment (EIA) for the Project had been carried out by NEA, an environmental survey was performed in the Study to supplement to the existing survey results. The scopes of the supplementary survey were prepared based on the review results of the existing EIA, discussions with NEA, and the requirements of the JICA Guidelines for Environmental and Social Considerations.

Topographic maps of the following two regions were prepared by using satellite images, to effectively implement the environmental survey:

a. The Seti river watershed region at a scale of 1:25,000

b. Reservoir area at a scale of 1/5,000

Data obtained by satellite image analysis and collected during the survey were compiled in the geographic information system (GIS) data base.

Stakeholder meetings were held by the NEA with the assistance of the Study Team both in Damauli located near the site and in Kathmandu three times, during the preparation of scoping, submission of the interim report and submission of the draft final report, in accordance with the JICA Guidelines for Environmental and Social Considerations. The Study Team explained the scoping of the supplemental survey, field survey results, and the Study results, etc. according to the progress of the Study. Opinions and comments raised in the meetings were incorporated into the Study.

EIA was prepared based on the results of the supplementary survey, and required mitigation measures, monitoring programs, framework of resettlement plan, and social action program were prepared. The costs for these were estimated.

Regarding the resettlement plan, although NEA proposed to prepare it in their EIA during the detailed design stage, a framework of the plan had to be prepared during the feasibility study stage under the JICA Guidelines for Environmental and Social Considerations and those issued by other international organizations.

The Study Team reviewed the mitigation measures and the resettlement plan applied to Kali

GandakiA and Middle Marsyangdi hydropower projects in Nepal which are similar to the Project, in terms of mitigation measures and a framework of the resettlement plan, in order to apply measures suitable for Nepalese situations to the Project.

NEA's EIA does not include the transmission line from the power station to Bharatpur, where it will be connected to the NEA's power system. In the Study the initial environmental evaluation (IEE) was performed and basic mitigation measures were proposed.

A framework of the environmental management plan for the Project was prepared to surely implement the environmental mitigation measures and monitoring program proposed in the Study. It is proposed that the environmental management unit should be established in the NEA's Project management office. The unit will play the leading role in the environmental management.

(6) Optimization of Development Plan

In the study of optimization of power generation development, cost efficiency was compared to the maximum discharge for power generation at several full supply levels (FSL) for five alternative layouts, based on the peak hours required in terms of demand and supply being six hours obtained during an examination of power demand records. Compensation and mitigation costs are considered for each FSL.

As a result, FSL is to be EL. 425 m with the layout featuring a waterway passing in the mountains by using Seti River's meandering downstream of the dam selected. In addition, the minimum operation level (MOL) was lowered with .a intake portal structure to effectively use reservoir water and to reduce the effects on the environment. Consequently, FSL of EL. 415 m is selected as the optimum development plan, following comparison of both FSLs.

(7) Overview of the Development Project

The Project is of a dam-waterway power type power generation scheme. The dam will be a concrete gravity dam 140 m in height and approximately 890,000 m^3 in volume, which will regulate an annual average inflow of 3,380 × $10^6 m^3$ by the reservoir with an effective storage capacity of 167 × $10^6 m^3$.

With regard to the water for power generation, a maximum discharge of 127.4 m^3/s will be taken from the intake located around 400 m upstream of the dam and will be conveyed to the power station via a headrace tunnel 927 m long and a penstock of approximately 195 m in extension. Electricity with an annual energy production of 484 GWh will be generated at the maximum output (two units) of 127 MW and evacuated via a 220 kV transmission line to the new Bharatpur switchyard to be connected with 220 kV trunk lines that are under planning.

(8) Design at the Feasibility Study Level

The dam axis is selected in a narrow valley located 2 km from the conjunction of the Seti and Madi Rivers. The dam site is composed of the Pre-Cambrian to Paleozoic dolomite. Although the dolomite is generally hard and fresh, the highly jointed layers and small faults in the dolomite are distributed in places. The foundation rock of the dam site is judged to have a sufficient bearing capacity for the foundation of a concrete gravity dam of 140 m in height.

The basic shape of the dam was decided by calculating the dam stability against the design seismic coefficient and pressure exerted by sediments. Excavated rocks will be used for concrete aggregates for the dam and other structures.

Applying ordinary cement grouting to the dam foundation treatment will be enough to improve the permeability of the foundation.

The type of spillway will be the central overflow type with gates to release a design spillway flow of 7,377 m^3/s (PMF). Sediment flushing facilities will be installed in the dam to maintain the function of the reservoir.

The waterway from the intake up to the underground Powerhouse consists of a 927 m long headrace tunnel of 7.8 m in diameter, a Headrace Surge Tank, and a 195 m long Penstock ranging from 7.8 m to 3.1 m in diameter. Water will be discharged to the Outlet via the Draft Tunnel 81 m in length, a Tailrace Surge Tank, and a 373 m long Tailrace Tunnel of 8.2m in diameter. Due to topographic conditions the Headrace Surge Tank and Tailrace Surge Tank will be of the underground type.

Phyllite and dolomite are distributed in the tunnel route from the upstream (Intake side) to the downstream area via the waterway route. The two surge tanks and underground powerhouse are to be constructed in dolomite based on the results of geological surveys.

(9) Construction Plan and Construction Cost

The total project funding required is approximately US$341 million, based on the price index at the end of 2006, including the direct construction cost for preparatory works, civil works, hydromechanical equipment, electromechanical equipment and transmission line, and indirect costs such as compensations and environmental expenditures, among others, as well as overheads such as construction administrative costs and contingencies for variable quantities. The transmission line expense is included into the construction costs of a 39 km-long transmission line from this power station to the new Bharatpur Switchyard.

The construction period from the start of the preparatory works to the start of operation is six years. The Project is scheduled to be commissioned at the end of 2014.

(10) Economic and Financial Evaluation

For the purpose of this study, the following two kinds of benefits were adopted: one is the saved cost of alternative thermal power project (gas turbine), and the other is the long run marginal cost during wet season for the secondary energy. From this evaluation, the Economic Internal Rates of Return (EIRR) were estimated at 12.3 % which exceeded the opportunity cost of capital of 10 %. Thus it was evaluated to be economically feasible.

Financial benefit of the Project is the revenue to be earned by the electricity sale. On the condition that the average sale price will increase by 5 % per annum due to NEA's semi-automatic adjustment, Financial Internal Rates of Return (FIRR) is estimated at 10.3 %, and it was found out that the Project is found out to be financially feasible, when compared with the expected interest rate of 8% for use of on-lent loan from the Government.

According to the sensitivity analysis, FIRR is estimated as 8 % in the case that the tariff will raise by 5 % three times up to 2014.

Recommendations

In light of the electric power conditions of Nepal, where power demand exceeds supply capacity, the Upper Seti Storage Hydroelectric Project that provides response to peak hours should be promoted as a candidate for the next hydropower project.

This hydroelectric project is feasible from technical, economic/financial and environmental perspectives and can be developed as a power generation project which will also contribute to stability of the national power system. The operation can begin around at the end of 2014, given the time required for tasks to take place subsequent to this Feasibility Study, including geological investigations, hydraulic model tests, detailed design, funding arrangement and construction work, among others. The following will have to be completed before implementing this project:

(1) In the detailed design, the results of additional investigations as shown in **Chapter 14** “Future Investigations” of the final report should be sufficiently incorporated and at the same time documents for bidding and contracting of construction works with a higher accuracy of construction cost estimates.

(2) Arrangement of finance, bidding for construction works, and the selection of contractors will have to be performed before the construction of this project. In addition, the construction of the new road and improvement work of the existing road leading within the vicinity of the dam site will have to be completed before the construction launch of this project.

(3) Appropriate compensation should be provided to people whose houses will be affected by the immersion due to r the reservoir and by construction of the project facility, in accordance with the resettlement plan. Activities stipulated in the social action plan for the Project should be implemented.

MAIN FEATURES OF UPPER SETI STORAGE HYDROELECTRIC PROJECT

River	Name of River	Seti River
	Catchment Area	1502 km^2
	Annual Inflow	3,380 x 10^6 m^3
Reservoir	Full Supply Level	415.0 m
	Minimum Operation Level	387.2 m
	Available Depth	27.8 m
	Sedimentation Level	386.2 m
	Gross Storage Capacity	295.1 x 10^6 m^3
	Effective Storage Capacity	167 x 10^6 m^3
Dam	Type	Concrete Gravity Dam
	Height x Crest length	140.0 m x 170.0 m
	Volume of Dam	890 x 10^3 m^3
Spillway	Design Flood	7,377 m^3/s
	Type of Gate	Radial
	Size & Number of Gate	12.5 m x 12.5 m, 6
Intake	Type	Surface Intake
	Number	One (1)
Headrace Tunnel	Number	
	Inner Diameter x Length	7.8 m x 927 m
Penstock	Number	One (1) to Two (2)
	Inner Diameter	7.8 m to 3.1 m
	Total Length	195 m
Powerhouse	Type	Underground
	Size	Wide 22 m x High 42 m x Long 90 m
Development Plan	Intake Water level	410.0 m
	Tail Water Level	289.2 m
	Effective Head	112.5 m
	Maximum Discharge	127.4 m^3/s
	Install Capacity	127 MW
Turbine	Type	Vertical Shaft, Francis Turbine
	Turbine Output x Number	65,100 kW x 2
Generator	Type	Three-phases, Synchronous Generator
	Rated Output x Number	74,700 kVA x 2
Switchyard	Type	GIS (Gas Insulated Switchgear)
	Voltage	220 kV

Transmission Line	Length	39 km
	Voltage	220 kV
	Conductor Type	380 m^3 x ACSR (Bison)
Water for River Maintenance Generation Facility		
	Output	1,900 kW
	Effective Head	95 m
	Discharge	2.4 m3/s
	Turbine Type	Horizontal Type, Francis Turbine
	Generator Type	Horizontal Type, Three-phase Synchronous Generator
Annual Energy Production (with sediment flushing)		
	Primary Energy	216.9 GWh
	Secondary Energy	267.5 GWh
	(Including Generation Facility for Environmental Flow)	
Construction Period Including Preparatory Works		6 Years
Project Cost		341 x 10^6 US$

CHAPTER 1 INTRODUCTION

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CHAPTER 1 INTRODUCTION

The Upgrading Feasibility Study (hereinafter referred to as “the Study”) on the Upper Seti (Damauli) Storage Hydroelectric Project (hereinafter referred to as “the Project”) is to be carried out under the Scope of Work (S/W) and Minutes of Meeting (M/M) concluded in November 2004 between the Japan International Cooperation Agency (JICA) and the Nepal Electricity Authority (NEA).

1.1 Background of the Study

The Government of Nepal is implementing rural electrification and hydroelectric development, by using abundant water resource, in the Tenth Plan (FY 2002/03-FY 2007/08) as one of the activities for poverty reduction, which is the most important national issue to be solved.

The total installed capacity in Nepal was 611 MW as of July 2006, of which 90% is generated by hydropower, with run-of-river (ROR) type hydropower plants dominating capacity. Because ROR type plants cannot seasonally regulate discharge for power generation, a storage type hydropower plant must be constructed, which is capable of annually regulating discharge for generation against peak demand, to cope with increasing power demand.

NEA performed studies on storage type hydropower development and identified the Upper Seti Storage Project in the studies (see **Chapter 3**). The Government of Nepal requested that the Government of Japan to implement an upgrading feasibility study (Upgrading F/S) under the technical assistance of Japan.

JICA, the organization executing technical assistance of the Government of Japan, conducted a project formation study in July 2004 and a preliminary study in October 2004, respectively. S/W was concluded between NEA and JICA on November 24, 2004. Based on the S/W, the Study was commenced by the JICA Study Team in February 2005.

The study was suspended due to concerns on security at the site from April 2005 to January 2006 but restarted in February 2006.

1.2 Purpose of the Study

The Study aims at formulating an optimum plan and assessing the technical, economic and financial, and environmental viabilities of the Project, in carrying out the technology transfer to Nepalese counterpart personnel over the course of the Study and recommending the further process of the project implementation.

1.3 Schedule of the Study

The Study consists of the following three stages, namely the Preliminary Study Stage, Detailed Investigation Stage, and Feasibility Design Stage. The present schedule is shown in **Table 1.3-1** and **Fig. 1.3-1** and summarized as below:

- Preliminary Study Stage (February 2005 to May 2006)
- Detailed Investigation Stage (May 2006 to November 2006)
- Upgrading Feasibility Design Stage (September 2006 to June 2007)

The final report for the Study was submitted in June 2007.

Table 1.3-1 Work Schedule

Fiscal Year	FY2004			FY2005												FY2006												FY2007			
Period	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7	8	9	10	11	12	1	2	3	4	5	6	7
Total Month		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28		

[Preliminary Study Stage]

(1) Preparation Work in Japan
- 1) Collection and Review of Data and Information
- 2) Preparation of Inception Report
- 3) Preparation of Questionnaire

(2) 1st Field Work
- 1) Explanation and Discussion of Inception Report
- 2) Data Collection
- 3) Review and Analysis of the Existing Development Plan
- 4) Power Survey
- 5) Examination of Justufucation of the Project
  1. Examination of priority and commissioning timing of the Project
  2. Examination of Justification of the Project
  3. Preliminary Layout Design
- 6) Preparation of Detaled Investigation Plan

[Detailed Investigation Stage]

(1) 1st Study Period in Japan
- 1) Preparatory Work for Subcontracting of Field Investigations
- 2) Preparation of Progress Report

(2) 2nd Field Work
- 1) Explanation and discussion of Progress Report
- 2) Site Reconnaissance
- 3) Revison of planning for Field Investigation
- 4) Subcontracting of Field Investigations
  1. Topographic Survey (GIS)
  2. Geological Investigation
  3. Natural & Social Environmental Survey

(3) 3rd Field Work
- 1) 1st Stakeholder Meeting
- 2) Field Investigations and Studies
  1. Topographical Survey (Subcontract)
  2. Geological Survey (Subcontract)
  3. Natural•Social Environmental Survey (Subcontract)
  4. Seismicity Survey (Study Team)
  5. Hydrological Analysis and Seciment Analysis (Study Team)
- 3) Natural Environmental Impact Assessment
- 4) Social Environmental Impact Assessment
- 5) Explanation and Discussionof Interim Report
- 6) 2nd Stakeholder Meeting

[Upgrading Feasibility Design Stage]

(1) 2nd Study Period in Japan
- 1) Optimization of Development Scheme and Layout
- 2) Upgrading Feasibility Design for Optimum Layout
- 3) Preparation of Interim Report
- 4) Study on Construction Method and Preparation of Construction Schedule
- 5) Estimation of Project Cost
- 6) Economic and Financial Analysis
- 7) Conclusion and Recommendations
- 8) Preparation of Environmental and Social Consideration Study Report
- 9) Preparation of Draft Final Report

(2) 4th Field Work
- 1) Explanation and Discussion Draft Final Report *
- 2) 3rd Stakeholder Meeting

(3) 3rd Study Period in Japan
- 1) Preparation & submission of Final Report

Note: * Draft final report will be sent to NEA in early March 2007 and NEA's comments will be informed to Study Team in April 2007 during their visiting in Nepal.

Legend:
- Field Work Priod
- Study Priod in Japan
- Explanation of Report etc.

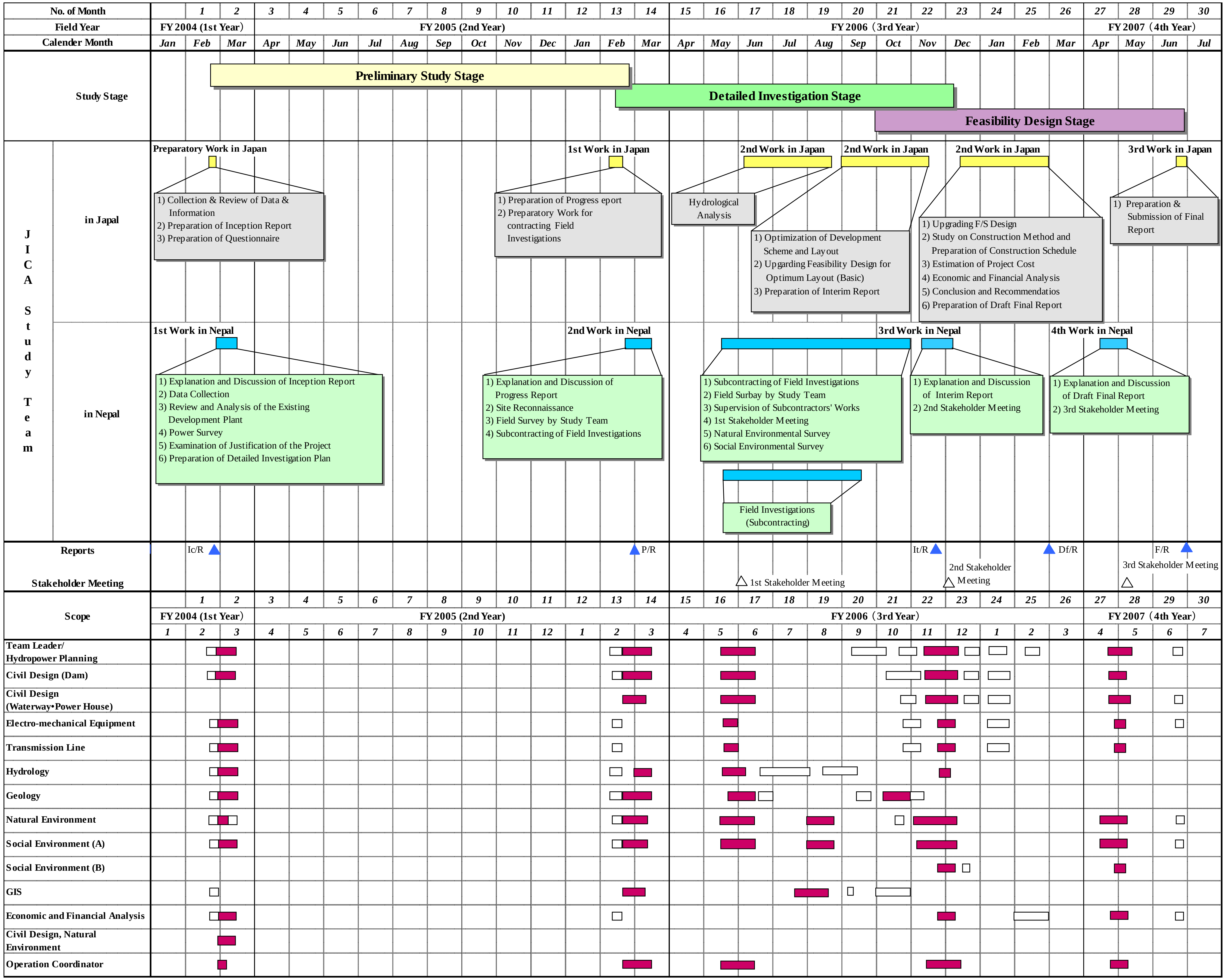

Fig. 1.3-1 Flow Chart of Study for the Upper Seti Storage Hydroelectric Project

1.4 Scope of the Study

The Study items at each stage are described as follows:

1.4.1 Preliminary Study Stage

(1) Preparatory Work in Japan

1) Collection and review of existing data, reports, and relevant information on the Project
2) Preparation of inception report
3) Preparation of questionnaire

(2) 1st Field Work in Nepal

1) Explanation / discussion of the inception report to/with NEA
2) Data collection
3) Review and analysis of the existing development plan
4) Power survey
5) Examination on justification of the Project observed from power development scheme
6) Preliminary study on project layout
7) Preparation of detailed investigation plan
8) Preparatory work for environmental survey

1.4.2 Detailed Investigation Stage

(1) 1st Work in Japan

1) Preparatory work for the subcontracting of field investigations
2) Preparation of progress report

(2) 2nd Field Work in Nepal

1) Explanation / discussion of progress report to/with NEA
2) Site reconnaissance
3) Bidding of Subcontracting for field investigations

(3) 3rd Field Work in Nepal

1) Field investigations and studies
2) 1st stakeholder meeting
3) Natural environmental studies
4) Social environmental studies
5) Explanation/discussion of interim report to/with NEA
6) 2nd stakeholder meeting

1.4.3 Upgrading Feasibility Design Stage

(1) 2nd Work in Japan

1) Optimization of the development scheme and layout
2) Upgrading the feasibility design for optimum layout
3) Preparation of the interim report
4) Study on the construction method and preparation of the construction schedule
5) Estimation of the Project cost
6) Economic and financial analysis
7) Examination on the feasibility of the Project
8) Conclusion and recommendations
9) Preparation of the environmental and social consideration study report
10) Preparation of the draft final report

(2) 4th Field Work in Nepal

1) Explanation / discussion of the draft final report to/with NEA
2) 3rd stakeholder meeting

(3) 3rd Work in Japan

1) Preparation and submission of the final report to JICA

1.5 Outline of Subcontracting for Field Investigations

The scopes of field investigations under subcontracting with the local consultants are summarized as below:

1.5.1 GIS Mapping

In the Study Geographic Information System (GIS) was utilized, and GIS-based digital maps and data were prepared in order to effectively implement the overall study on environmental and social considerations. The following two types of GIS-based data base were prepared:

a. GIS at a scale of 1/25,000 for the Seti River watershed
b. GIS at a scale of 1/5,000 for the reservoir and power in its vicinity

The principal specifications of each GIS are as mentioned in **Table 1.5.1-1**:

Table 1.5.1-1 GIS Database

Item	General mapping region	Detailed mapping region
Uses of GIS	Assessment for conditions of watershed, Preparation of watershed management plan, Preparation of environmental management plan	Social impact assessment, Resettlement assessment, Compensation assessment for land losses, Preparation of resettlement plan
Coverage area	1,502 km^2	150 km^2
Map scale	1:25,000	1:5,000
Satellite images	ASTER	QuickBird
Other information	Existing topographical maps (1:25,000, 1:50,000), Soil maps, Geology maps, Land use maps	Cadastral maps
GIS data from satellite image analyses	Land use, 20 m interval contour lines, Vegetation, NDVI, Landslides/collapses, Glaciers	Land use, 5 m interval contour lines, Houses and architectural structures, Gradients, Gradient directions, Rivers, lakes
GIS data from other information	Administrative boundaries, Roads, Rivers, Lakes, Gradients, Gradient directions, Soil classifications	Cadastres, Roads, Rivers, Lakes, Houses, Architectural structures

1.5.2 Geological Investigation

Geological investigation works, which were carried out by the Sub-Contractor, are as shown in **Table 1.5.2-1**;

- Investigation drilling (including permeability tests) at waterway and powerhouse site
- Laboratory test of a drilled core (physical property test, unconfined compressive strength test, tensile strength test)

Table 1.5.2-1 Geological Investigation Works

Item	Volume	Remarks
Investigation drilling	6 holes, Total length 380m	See **Table 1.5.2-2**
Laboratory tests of the drilled core	15 samples	Physical property test, Unconfined compressive strength test, Tensile strength test

Table 1.5.2-2 Details of Drilling

Name of Hole	Length (m)	Location	Remarks
No. 1	90	Intake	Including permeability test
No. 2	50	Division	
No. 3	50	Tailrace	
No. 4	90	Alternative Intake	Including permeability test
No. 5	50	Talus deposit distributed in the area downstream of the dam	
No. 6	50	Alternative Tailrace	
Total	380		

1.5.3 Environmental Survey

The scope of work for the environmental survey by the local consultant is summarized below.

(1) Natural Environment Studies

1) Examination of the eutrophication potential of the reservoir

- Collect all water quality data
- Take additional samples and analyze for specified parameters in the dry season (June) and rainy season (October) at four locations; downstream of Damauli, downstream zone affected by releases (dam site to the Madi River confluence), proposed dam site, and Bhimad Bajar
- Evaluate the potential for eutrophication of the reservoir by using an appropriate eutrophication model (Vollenweider)

2) Study on aquatic ecology and fishery aspects

- Sample fish and phyto- and zoo-plankton in the dry season (June) and rainy season (October) at the dam site, at Bhimad Bajar and downstream of the Madi River, and study the impacts on aquatic ecology and fish

3) Study on vegetation and forestry

- Study the impacts on vegetation and forestry, especially all community forests in the reservoir and areas not previously assessed

4) Study on wildlife resources

- Survey wildlife resources to delineate all species of mammals, birds, aquatic animals and insects and assess the conservation status and impacts of the Project on individual species or groups of animals

5) Assess the impacts of proposed alterations on the project design and operations

- Study and confirm the validity of the environmental flow to the downstream sector in the existing EIA, when the power plant is not operating
- Study and evaluate the risks of landslides or collapsing of reservoir terraces or cliffs due to fluctuating water levels, particularly in the reservoir's upper reaches and tributaries

6) Study for watershed management

- Investigate the overall features of the Upper Seti watershed by using GIS data and those of all known projects, including the area covered, the program sponsors and the duration of the programs
- Identify, from the viewpoint of natural environment, sensitive areas where additional programs are needed and prioritize these, based on GIS data and field surveys
- Investigate and document appropriate mitigation and enhancement measures
- Investigate and document appropriate environmental monitoring measures

(2) Social Environment Studies

1) Preparation of Framework of a Resettlement Plan

- Superimpose the cadastral maps onto the GIS mapping and specify the affected people
- Conduct a socioeconomic survey on the affected people
- Study compensation for resettlement effects, including the specification of house and assets, area of land, infrastructures, and livelihood
- Assist the Study Team in preparing a framework of the resettlement plan as per JICA Guidelines
- Collect information on resettlement for other similar projects in Nepal and analyze their issues

2) Preparation of a Social Action Plan (SAP)

- Study the impacts on social and cultural aspects, such as religious places, funerals or cremation venues, cultural properties, sightseeing spots, etc

- Examine the necessity of rehabilitation planning for vulnerable groups, including ethnic minorities
- Study white-water rafting and kayaking operations on the Seti River and inform the operators about the proposed stakeholder meetings
- Study local transportation and foot traffic and prepare mitigation plans for the loss of suspension and road bridges, if necessary

(3) Studies on the Environmental Impacts of Alternatives

- Study the natural and social environmental impacts of the agreed alternatives in terms of their layouts, scale of operation, the full supply level (FSL) and ancillary works associated with the option
- Specifically, study the number of land owners for land compensation and the number of resettlement households for 5 alternative FSLs of the reservoir, using GIS data

(4) Preliminary Study of the Environmental Impacts of Transmission Lines

- Implement IEE on the options for a 220 kV transmission line (T/L) and substation for evacuating the power from the Project to the NEA Bhaktapur sub-station

(5) Preparation of Framework for the Environmental Management Plan

- Summarize the natural and social environmental impacts of the Project, according to the existing EIA and revisions to all Project aspects of the Study
- Prepare the environmental management plan, including the revised mitigation and enhancement measures, in view of the adjusted environmental and social impacts
- Prepare the required and revised natural and social environmental monitoring plans for the operational phase of the Project
- Revise the framework of the environmental management plan (EMP) in the existing EIA to include up-to-date information on the Project as proposed
- Include SAP as a component of EMP if determined appropriate
- Define the institutional system and roles of each section of the Environmental Unit

(6) Physical and Social Environmental Costs Estimates

- Estimate the cost for the implementation of the environmental management plan, including recommended mitigation, enhancement and monitoring measures
- Estimate the cost for implementation of the social action and resettlement action plan, including all compensation and land acquisition

(7) Assistance in Stakeholders' Meetings

- Assist in preparing materials for the stakeholders meetings, including advertisements for the newspapers in Nepal
- Assist in setting up the meeting venue
- Attend the stakeholders' meetings and provide inputs during the same
- Provide a Nepalese moderator who speaks English and has sufficient knowledge of the environmental and social aspects to be involved at the stakeholders meetings

1.6 Record on Dispatch of Study Team

JICA commenced the Study in February 2005, based on S/W, and dispatched the Study Team to Nepal as described below:

- 1st Field Works in Nepal;		February 27, 2005 to March 16, 2005
- 2nd Field Works in Nepal;		February 22, 2006 to March 15, 2006
- 3rd Field Works in Nepal	(I);	May 13 2006 to June 11, 2006
	(II);	July 20, 2006 to August 24, 2006
	(III);	10th to 30th of October 2006
	(IV);	November 5, 2006 to December 10, 2006
- 4th Field Works in Nepal		April 15, 2007 to May 22, 2007

The Study Team submitted the following report on the Study to JICA/NEA:

- Inception Report; March 2005
- Progress Report; February 2006
- Interim Report; November 2006
- Environmental and Social Consideration Report, March 2007
- Draft Final Report and Summary; March 2007
- Final Report and Summary, June 2007
- Environmental and Social Consideration Report, June 2007

It is noted that the Environmental and Social Consideration (ESC) Report compiled the results of the supplemental environmental survey conducted based on the review results of the existing EIA prepared by NEA and include the following subjects:

- Environmental impact assessment
- Environmental mitigation measures
- Framework of resettlement plan
- Social action plan framework
- Costs for environmental mitigation measures and environmental monitoring programs
- Initial environmental evaluation on transmission line between Upper Seti and Bharatpur
- Environmental management framework

The ESC Report is construed as a separate volume of the final report of the Study.

1.7 NEA Counterpart and Study Team

1.7.1 NEA

The NEA counterpart is listed as below:

No.	Name	Title	Organization
1	Mr. Bhoj Raj Regmi	General Manager Engineering Services	
	(Alternative Layout, Hydropower Planning & Civil works)		
2	Mr. Birendra Kumar Pathak	Director (up to March 2005)	Project Development Dept.
3	Mr. V. B. Singh	Chief (after February 2006)	Project Development Dept.
4	Mr. Radhesh Man Pradhang	Manager (up to December 2006)	Project Development Dept.
5	Mr. Jagadishwar Man Singh	Manager (after April 2007)	Project Development Dept.
6	Mr. Bal Krishna Shrestha	Manager	Engineering Services,
7	Mr. Biswa Dhoj Joshi	Deputy Manager	Project Development Dept.
8	Mr. Mohan Shakya	Manager	Project Development Dept.
9	Mr. Shailendra Lal Pradhanang	Assistant Manager	Project Development Dept.
10	Mr. Mohamad Yusuf	Assistant Manager	Project Development Dept.
11	Mr. Nasib M. Pradhan	Assistant Manager	Project Development Dept.
12	Mr. Kiran Paudel	Assistant Manager	Project Development Dept.
13	*(Meteorology & Hydrology)*		
14	Mr. Damodar Bakta Shrestha	Deputy Manager	Project Development Dept.
15	Mr. Damodar Shrestha	Assistant Manager	Kali Gandaki 'A' Hydroelectric Project Kathmandu Office
	Mr. Parmar Diren	Hydrologist	Project Development Dept.
	(Geology)		
16	Mr. Shashi Sagar Rajbhandari	Director (up to December 2006)	Soil, Rock and Concrete Laboratory
17	Mr. Radhesh Man Pradhang	Chief (after April 2007)	Soil, Rock and Concrete Laboratory
18	Mr. J.M. Tamrakar	Deputy Manager	Soil, Rock and Concrete Laboratory
19	Mr. Sunil Shrestha	Geologist	Soil, Rock and Concrete Laboratory
	(GIS and Topographic Survey)		
20	Mr. S.R.C. Suwal	Deputy Manager	Project Development Dept.
	(Load Forecast, Generating Facility, Power System, and Transmission Line)		
21	Mr. Rajeswar Man Sulpya	Director	Power Trade Dept.
22	Mr. Soorya Bahadur Shrestha	Director	Corporate Planning Dept.
23	Mr. Jayaiswer Man Pradhan	Director	System Planning Dept.
24	Mr. Sher Sing Bhat	Chief	Load Dispatch Centre (Siuchatar Substation)
25	Mr. Bigyan P. Shrestha	Deputy Manager	Transmission Line/ Substation Construction Dept.
	(Environment)		
26	Mr. Shiv Chandra Jha	Director	Environmental and Social Studies Department
27	Mr. Satis Chandra Devkota	Economist	Environmental and Social Studies Department
28	Mr. Ganesh Neupane	Environmentalist (up to June 2006)	Environmental and Social Studies Department
29	Ms. Annu Rajbhandari	Deputy Manager, Environmental Engineer	Environmental and Social Studies Department
	(Economic and Financial Analysis)		
30	Mr. Sanjib Man Rajbhandari	Deputy Manager	Project Development Dept.

1.7.2 JICA Study Team

The JICA Study Team members are listed as follows:

	Name	Assignment	Firm	Remarks
1	Yoshimasa Ishii	Team Leader / Hydropower Planning	Electric Development Co., Ltd. (J-Power)	
2	Nobuaki Kawata	Civil Design (Dam)	J-Power	February to March 2005
3	Hiroshi Murashige	Civil Design (Dam)	J-Power	After February 2006
4	Hironobu Nishimiya	Civil Design (Waterway and Powerhouse)	Nippon Koei Co., Ltd.	
5	Hideaki Morishita	Electromechanical Equipment	J-Power	
6	Yukiteru Takeya	Transmission Line	J-Power	February to March 2005
7	Shoichi Ishiguro	Transmission Line	J-Power	After February 2006
8	Yutaro Mizuhashi	Hydrology	J-Power	
9	Nobuhiro Tsuda	Geology	J-Power	
10	Jack R. Prosser	Natural Environment	Nippon Koei Co., Ltd.	February 2005 to December 2006
11	Hiromi Yasu	Natural Environment	Nippon Koei Co., Ltd.	After April 2007
12	Tod Ragsdale	Social Environment	Nippon Koei Co., Ltd.	February 2005 to March 2006
13	Toshiko Shimada	Social Environment (A)	Nippon Koei Co., Ltd.	after May 2006
14	Kazuyuki Sato	Social Environment (B)	Nippon Koei Co., Ltd.	May to October 2006
15	Tomoo Aoki	Social Environment (B)	Nippon Koei Co., Ltd.	after November 2006
16	Kyoko Usuda	GIS	Nippon Koei Co., Ltd.	
17	Tetsuya Hirahara	Economic/Financial Analysis	J-Power	
18	Satoshi Otaki	Civil & Environment	Nippon Koei Co., Ltd.	February to March 2005
19	Shinji Shimizu	Operation Coordination	J-Power	February to March 2005
20	Yoichi Yahiro	Operation Coordination	J-Power	February to March 2006
21	Akio Kuwahara	Operation Coordination	J-Power	May to June 2006
22	Takahiro Kato	Operation Coordination	J-Power	November to December 2006
23	Tadashi Amano	Operation Coordination	J-Power	After April 2007

CHAPTER 2 GENERAL INFORMATION OF NEPAL

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CHAPTER 2 GENERAL INFORMATION OF NEPAL

2.1 Geography

2.1.1 Topography

Nepal is located between 80^o 4' and 88^o 12' East longitude and 26^o 22' and 30^o 27' North latitude and is a land locked country, comprising a total of 147,181 square kilometers of land, with average length 885 km east to west and average breadth 193 km from north to south. The country is bordered between India in the East, South, and West, and China in the North, while the elevation of the land ranges from 90 to 8,848 meters (Mt. Everest). The country is divided into three broad ecological zones, the Himalayan region, the Hills and mid-mountain region, and the Terai.

(1) The Himalayan Region

The Himalayan region has elevations from 4,877 m to 8,848 m and comprises 15% of the country's surface area, although the population in the region is only around 7% of the national total, due to the mountainous topography and climatic conditions.

(2) The Hills and Mid Mountain Region

The region is situated between the Himalayan region and the Terai; occupied by the Mahagharat Range and Siwalik Range. It comprises 68% of the country's land, and is home to nearly half the population. Kathmandu, the capital city, and the Project area are also located in this region.

(3) The Terai

The Terai is located south of the Siwalik Range, and is a flat area, forming the northern expansion of the Gangetic Plain in India. Although the region shares 17% of the country's land, it contains nearly half the national population.

2.1.2 Climate

There are marked variations in the climate due to the varied altitude and topography of the country. Climatically, Nepal can be divided into the following three categories:

(1) Subtropical

The Terai and lower foothills have a subtropical climate. The temperature in this area ranges from 5^o C to 47^o C, and rainfall is between 2,000 mm and 2,500 mm.

(2) Temperate

The area between the Mahagharat Range and the Himalayas has a temperate climate. The temperature in this area varies from 0^{o} C to 30^{o} C, and the average rainfall is around 1,500 mm.

(3) Alpine

The Himalayas and inner Himalayas have an Alpine, dry and arid type of climate. The temperature does not exceed 16^{o} C, even in summer, and the average precipitation is around 500 mm.

Annual rainfall totals around 3,000 m in elevation increase, with rising altitude. However, there are certain pockets with heavy rainfall, for example the Pokhara Valley. The plains and lower Himalayas receive more than 70% of their annual rainfall from early June to September, due to the summer monsoon.

2.1.3 River

There are, in Nepal, around 6,000 rivers and riverlets, which add up to a length of 45,000 km and finally flow into the Ganges River. The major river systems in the country are the Kosi, Narayani (Gandak) and Karnali Rivers, which originate in the Tibet Plateau. The Seti River meanwhile, on which the Project area is located, belongs to the Narayani River system.

Rivers in Nepal have the following characteristics, due to topographic and meteorological conditions:

- Steep river gradients
- Large catchment areas in comparison with their lengths
- Large discharge in comparison with their catchment areas (large specific discharge)
- Significant difference in the ratio of maximum and minimum discharges through a year

2.2 Administrative Regions

Nepal consists of five (5) Development Regions, comprising 75 Districts. The names of these regions and the number of districts they contain are as follows: the Eastern Development Region with 16 districts, the Central Development Region with 19 districts, the Western Development Region with 16 districts, the Mid-Western Development Region with 15 districts and the Far Western Development Region with 9 districts.

The total of 75 districts comprises 3,914 Village Development Committees (VDC), 54 Municipalities, 4 Sub Metropolitan and Metropolitan (Kathmandu). On a national basis, there are

14 Zones comprising several districts, but current circumstances mean zones do not have political and administrative functions and serve only to indicate the name of their regions. Each VDC is composed of 9 wards, and each municipality consists of 9 to 35 wards.

The Project area is located in the Tanahu District of the Western Development Region.

2.3 Population

The population of Nepal, as estimated by the Central Bureau of Statistics (CBS), was recorded at 25.3 million in FY 2004/05 and a census is carried once every decade. The population growth between the 1991 and 2001 censuses was recorded at 2.24% per annum.

In the 2001 census, Indo-Aryan language families comprised 79% of the population and Tibeto-Burman 18.4%. The national population encompasses 103 caste and ethnic groups, each of which has their traditional cultures, accommodating their living area, which varies widely from the Himalayan Region to the Terai. **Table 2-3-1** shows the shares of each caste and ethnic group according to the 2001 census.

Table 2.3-1 Caste/Ethnic Group of Nepal

Caste or Ethnic Group	% of Population
Chetri	15.80
Hill-Brahmin	12.74
Magar	7.14
Tharu	6.75
Tamang	5.64
Newar	5.48
Muslim	4.27
Kami	3.94
Yadav	3.94
Rai	2.79
Gurung	2.39
Others	29.12

Source: 2001 Census, CBS

2.4 Macroeconomics

2.4.1 Macroeconomic Situation

Nepal is one of the Least Developed Countries (LDC), where around 80% of the population live in rural areas, most of whom are engaged in agriculture to subsist on foods. The GDP per capita of the country was estimated at around US$ 280 in FY 2004/05 (refer to **Table 2.4.1-1**)

The GDP growth rate between FY1994/95 to FY 2004/05 was 3.9% per annum (refer to **Tables 2.4.1-2** & **-3**). Although the growth rate was recorded at 6.1% in FY 1999/00 and at 5.5% in FY 2000/01, respectively, negative growth was recorded in FY 2001/02 and recovery of economic growth remains a national issue. The macroeconomic performance in FY 2003/04 resulted in a growth rate of 3.8%, thanks to the positive performance of the agricultural sector, but the unstable political situation in FY 2004/05 prompted a lower growth rate of around 2% (refer to **Table 2.4.1-4**).

As shown in **Table 2.4.1-5**, the agriculture, fishery and forestry sector has a 39% share of GDP and is the largest sector in the country, followed by the community and social services sector, trade, restaurant and hotel sector, construction sector, finance and real estate sector, manufacturing sector, transport, communication and storage sector, which collectively have a share of around 10%. Those shares have not changed for the last ten years.

Regarding Government expenditure, “capital expenditure” for domestic development and “principal re-payment” for loans are major items other than “recurrent expenditure”. As the share of “recurrent expenditure” increases, that of “capital expenditure” decreases accordingly. On the other hand, because incoming funds do not tally with the financial expenditure, this generates a deficit. This shortage of receipts is supplemented by foreign aid (grants and loans) and domestic loans. The total amount of foreign grants and loans exceeds that of domestic loans, because the Government imposes a ceiling for the ratio of the domestic loan amounts to GDP, with macroeconomic stability in mind (refer to **Table 2.4.1-6**).

The consumer price index in FY 2005/06 is estimated to be 6.6% due to an increase in the oil product price, although the index had been less than 5% since FY 1999/00 due to Governmental policy restricting the index 4 to 5% per annum (refer to **Table 2.4.1-7**).

2.4.2 Foreign Trade and Foreign Debt

Most of the fundamental commodities in the country depend on imports, meaning the import amount exceeds that of exports and reaches more than 20% of GDP. The foreign trade deficit has amounted to 15% of GDP in recent years (refer to **Table 2.4.1-1**).

India is the largest partner country for both imports and exports, and its share reached 66% for the former and 59% for the latter in FY 2004/05, due to its increased dependence (refer to

Table 2.4.2-1).

Regarding the national balance of payments, the significant deficit existing in the balance of foreign trade is supplemented by workers' remittances and foreign grants. In particular, the volume of workers' remittances represents more than 10% of GDP, while revenue from tourism, which is an important source of foreign exchange as well as exports, is decreasing due to a drop in the number of tourists. Nevertheless, foreign reserves at the end of FY 2004/05 reached NRs 130 billion (US$ 1.83 billion), equivalent to around 11 months of imports (refer to **Table 2.4.2-2**).

Receipts of foreign aid, which varies by year, amounted to NRs 380 billion (US$ 5.4 billion) in FY 2004/05, while the total repayment of foreign loans (principal and interest) totaled NRs 8.0 billion (US$ 110 million) in the same fiscal year (refer to **Tables 2.4.2-3, 2.4.2-4**).

The amount of outstanding foreign loans in comparison to Government revenue corresponded to more than 300% of the latter in FY 2004/05 and around 40% of GNP (refer to **Table 2.4.1-1**). However, the debt service ratio was maintained at around 9.0% in the same fiscal year, as shown in the table below.

	FY 2000/01	FY 2001/02	FY 2002/03	FY 2003/04	FY 2004/05
Debt Service ratio (%)	6.8	9.3	11.4	9.0	9.0

Source: Asian Development Outlook 2004 - Nepal, ADB

Table 2.4.1-1 Major Economic Indicators (FY 1994/95 to FY 2005/06)

Item	Unit	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06 *1
GDP at Current Price	Million NRs	209,976	239,388	269,570	289,798	330,018	366,251	394,052	406,138	437,546	474,919	508,651	n.a.
Total Consumption/GDP	%	85.2	86.2	86.0	86.2	86.4	84.8	84.9	87.9	88.0	87.4	87.6	88.9
Total Investment/GDP	%	25.2	27.3	25.3	24.8	20.5	24.3	24.1	24.2	25.8	26.4	28.9	30.3
Receipt of Foreign Loan and Grant/GDP	%	5.1	5.7	5.4	5.5	4.7	4.6	4.6	3.4	3.5	3.8	4.4	n.a.
Outstanding Foreign Loan/GDP	%	51.6	51.4	47.1	53.6	49.6	50.2	48.7	52.1	48.9	46.9	41.2	n.a.
Outstanding Foreign Loan/ Government Revenue	%	459.8	459.0	434.9	489.4	454.9	444.6	409.9	436.4	397.4	373.5	313.2	n.a.
Debt Service/ Recurrent Expenditure	%	n.a	n.a	n.a	n.a	27.3	27.2	22.7	25.0	31.1	31.2	32.0	n.a.
Gross Domestic Saving/GDP	%	14.8	13.8	14.0	13.8	13.6	15.2	15.1	12.1	12.0	12.6	12.4	11.1
Budget Deficit/GDP	%	-4.8	-5.6	-5.1	-5.9	-5.3	-4.7	-5.9	-5.4	-3.6	-3.2	-2.7	-3.5
Total Export (Goods)/GDP	%	8.0	8.0	8.1	9.1	10.4	13.1	13.5	11.1	10.9	10.8	11.0	n.a.
Total Import (Goods)/GDP	%	29.1	30.0	33.4	29.6	25.6	28.6	28.1	25.4	27.2	27.4	28.0	n.a.
Total Export/Total Import	%	27.7	26.7	24.2	30.9	40.7	45.9	48.1	43.7	40.2	39.6	39.3	n.a.
Merchandise Trade Deficit/GDP	%	-21.1	-22.0	-25.3	-20.4	-15.2	-15.3	-14.6	-14.3	-16.3	-16.6	-17.0	n.a.
Current Account/GDP	%	-5.4	-8.6	-5.9	-5.0	0.1	4.5	4.9	4.3	2.5	2.9	2.2	n.a.
Exchange Rate*2	NRs/US$	50.7	56.5	57.0	67.9	68.5	70.9	75.0	78.3	77.8	74.0	71.1	n.a.
Total Population	Thousand	20,053	20,533	21,023	21,526	22,040	22,567	25,151	23,670	24,200	24,740	25,300	25,860
GDP per Capita	NRs	10,471	11,659	12,823	13,463	14,974	16,229	15,667	17,158	18,080	19,196	20,105	n.a.
GDP per Capita*3	US$	207	206	225	198	219	229	209	219	232	259	283	n.a.

Note: *1 Estimated based on first eight months
*2 Average rate of selling and buying rates in mid-July
*3 Estimated by JICA Team
Source: Economic Survey, MOF

Table 2.4.1-2 National Accounts Summary (FY 1994/95 to FY 2004/05) at Current Prices

Unit: Million NRs

No.	Description	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05*1
1	GDP at Producer's Price	219,175	248,913	280,513	300,845	342,036	379,488	411,275	422,807	456,675	496,745	533,538
2	Import Good and Services	75,850	88,996	105,775	101,949	101,648	123,055	129,104	127,961	140,522	158,150	173,753
3	Total Resources Available for Use (3=1+2)	295,025	337,909	386,288	402,794	443,684	502,543	540,379	550,768	597,197	654,895	707,291
4	Total Consumption	186,710	214,487	241,351	259,407	295,473	321,911	349,257	371,526	401,897	434,359	467,202
	Private Consumption	166,443	191,469	216,364	231,392	264,944	287,947	309,107	329,199	355,535	383,978	412,776
	Public Consumption	20,267	23,018	24,987	28,015	30,529	33,964	40,150	42,327	46,362	50,381	54,426
5	Total Investment	55,231	68,017	71,084	74,728	70,061	92,272	99,301	102,174	118,020	130,993	154,132
6	Gross Fixed Capital Formation	48,370	56,081	60,794	65,375	65,269	73,324	78,031	81,613	87,024	95,124	101,094
	Public	15,070	17,624	19,392	22,573	23,888	26,436	31,268	32,044	31,228	31,263	30,823
	Private	33,300	38,457	41,402	42,802	41,381	46,888	46,763	49,569	55,796	63,861	70,271
7	Change in Stock	6,861	11,936	10,290	9,353	4,792	18,948	21,270	20,562	30,996	35,869	53,038
8	Export Good and Services	53,084	55,405	73,853	68,659	78,150	88,360	91,821	77,068	77,280	89,543	85,957
9	Gross Domestic Savings	32,465	34,426	39,162	41,438	46,563	57,577	62,018	51,281	54,778	62,386	66,336
10	Net Factor Income	4,817	3,566	4,660	6,025	10,881	13,125	16,172	18,375	16,194	12,955	10,364
11	Net Current Transfer	819	900	1,009	1,158	1,205	1,319	1,456	1,701	1,885	2,158	-
12	Gross National Savings	38,101	38,892	44,831	48,621	58,648	70,702	78,190	69,656	70,972	75,341	76,700
13	GNP at Current Price	223,992	252,479	285,173	306,870	352,917	392,613	427,447	441,182	472,869	509,700	543,902

Note: *1 Provisional
Source: Economic Survey, MOF

Table 2.4.1-3 Gross Domestic Product by Source (FY 1994/95 to FY 2004/05) at 1994/95 Prices

Unit: Million NRs

No.	Description	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05*1	Change 94/95 to 04/05 (%)
1	Agriculture, Fisheries & Forestry	85,569	88,830	92,706	93,496	96,151	100,856	106,380	108,752	111,471	115,774	119,212	3.37
2	Mining & Quarrying	1,117	1,262	1,348	1,365	1,416	1,480	1,547	1,571	1,601	1,610	1,650	3.98
3	Manufacturing	19,555	21,322	22,826	23,607	24,856	26,646	27,649	24,892	25,384	25,822	26,494	3.08
4	Electricity, Gas & Water	2,862	3,414	3,475	3,331	3,520	4,025	4,727	5,200	6,234	6,437	6,748	8.96
5	Construction	23,093	24,733	26,372	26,953	28,786	31,550	31,823	32,180	32,757	32,816	32,801	3.57
6	Trade, Restaurant & Hotel	24,326	25,424	26,458	27,981	29,069	31,036	31,507	28,329	29,267	31,613	30,965	2.44
7	Transport, Commu. & Storage	13,995	14,759	15,902	17,186	18,355	19,644	20,860	21,201	22,113	23,273	24,457	5.74
8	Finance & Real Estate	20,534	22,096	23,136	24,494	25,719	27,026	27,491	28,402	29,333	30,275	31,677	4.43
9	Community & Social Services	18,924	20,090	20,817	22,403	23,885	24,833	28,123	28,642	29,529	30,403	31,240	5.14
10	Total GDP at factor cost (Sum of 1 to 9)	209,975	221,930	233,040	240,816	251,757	267,096	280,107	279,169	287,689	298,023	305,244	3.81
11	Imputed value of baking service	5,060	5,616	5,703	6,181	6,610	7,230	7,631	8,064	8,499	8,950	9,435	
12	Total GDP at factor cost (12=10-11)	204,915	216,314	227,337	234,635	245,147	259,866	272,476	271,105	279,190	289,073	295,809	3.74
13	Net indirect taxes	14,261	14,561	15,684	15,537	16,240	17,508	20,710	20,135	21,724	23,194	24,920	
14	GDP at producer's price	219,176	230,875	243,021	250,172	261,387	277,374	293,186	291,240	300,914	312,267	320,729	3.88

Note: *1 Provisional
Source: Economic Survey, MOF

Table 2.4.1-4 Annual Growth Rates of Gross Domestic Product (FY 1994/95 to FY 2004/05) at 1994/95 Prices

Unit: %

No.	Description	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05*1
1	Agriculture, Fisheries & Forestry	-0.92	3.81	4.36	0.85	2.84	4.89	5.48	2.23	2.50	3.86	2.97
2	Mining & Quarrying	3.43	12.98	6.81	1.26	3.74	4.52	4.53	1.55	1.91	0.56	2.48
3	Manufacturing	1.96	9.04	7.05	3.42	5.29	7.20	3.76	-9.97	1.98	1.73	2.60
4	Electricity, Gas & Water	12.10	19.29	1.79	-4.14	5.67	14.35	17.44	10.01	19.88	3.26	4.83
5	Construction	6.11	7.10	6.63	2.20	6.80	9.60	0.87	1.12	1.79	0.18	-0.05
6	Trade, Restaurant & Hotel	6.01	4.51	4.07	5.76	3.89	6.77	1.52	-10.09	3.31	8.02	-2.05
7	Transport, Commu. & Storage	10.61	5.46	7.74	8.07	6.80	7.02	6.19	1.63	4.30	5.25	5.09
8	Finance & Real Estate	4.32	7.61	4.71	5.87	5.00	5.08	1.72	3.31	3.28	3.21	4.63
9	Community & Social Services	4.09	6.16	3.62	7.62	6.62	3.97	13.25	1.85	3.10	2.96	2.75
10	GDP at producer's price	3.30	5.34	5.26	2.94	4.48	6.12	5.70	-0.66	3.32	3.77	2.71

Note: *1 Provisional
Source: Estimated by JICA Team based on Economic Survey, MOF

Table 2.4.1-5 Share of Gross Domestic Product by Source (FY 1994/95 to FY 2004/05)

Unit: %

No.	Description	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05*1
1	Agriculture, Fisheries & Forestry	40.75	40.03	39.78	38.82	38.19	37.76	37.98	38.96	38.75	38.85	39.05
2	Mining & Quarrying	0.53	0.57	0.58	0.57	0.56	0.55	0.55	0.56	0.56	0.54	0.54
3	Manufacturing	9.31	9.61	9.79	9.80	9.87	9.98	9.87	8.92	8.82	8.66	8.68
4	Electricity, Gas & Water	1.36	1.54	1.49	1.38	1.40	1.51	1.69	1.86	2.17	2.16	2.21
5	Construction	11.00	11.14	11.32	11.19	11.43	11.81	11.36	11.53	11.39	11.01	10.75
6	Trade, Restaurant & Hotel	11.59	11.46	11.35	11.62	11.55	11.62	11.25	10.15	10.17	10.61	10.14
7	Transport, Commu. & Storage	6.67	6.65	6.82	7.14	7.29	7.35	7.45	7.59	7.69	7.81	8.01
8	Finance & Real Estate	9.78	9.96	9.93	10.17	10.22	10.12	9.81	10.17	10.20	10.16	10.38
9	Community & Social Services	9.01	9.05	8.93	9.30	9.49	9.30	10.04	10.26	10.26	10.20	10.23
10	Total GDP at factor cost before reduction of imputed value of baking service	100	100	100	100	100	100	100	100	100	100	100

Note: *1 Provisional
Source: Estimated by JICA Team based on Economic Survey, MOF

Table 2.4.1-6 Government Expenditure and Sources of Financing

Unit: Million NRs

No.	Description	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05
1	**Expenditures**	59,579.0	66,272.5	79,835.1	80,072.2	84,006.1	89,442.6	102,560.4
	Recurrent Expenditure	31,944.2	35,579.1	45,837.3	48,863.9	52,090.5	55,552.1	61,686.4
	Capital Expenditure	22,992.1	25,480.7	28,307.2	24,773.4	22,356.1	23,095.6	27,340.7
	Principal Re-payment	4,642.7	5,212.7	5,690.6	6,434.9	9,559.5	10,794.9	13,533.3
2	**Receipts**	41,587.6	48,605.5	55,647.0	57,131.6	67,568.9	73,614.4	84,513.9
	Revenue	37,251.0	42,893.8	48,893.6	50,445.5	56,229.8	62,331.0	70,122.7
	Foreign Grant	4,336.6	5,711.7	6,753.4	6,686.1	11,339.1	11,283.4	14,391.2
3	**Surplus/Deficit (3=2-1)**	-17,991.4	-17,667.0	-24,188.1	-22,940.6	-16,437.2	-15,828.2	-18,046.5
4	**Foreign Loan**	11,852.4	11,812.2	12,044.0	7,698.7	4,546.4	7,629.0	9,266.1
5	**Domestic Loan**	4,710.0	5,500.0	7,000.0	8,000.0	8,880.0	5,607.8	8,938.1
6	**Cash Balance (6=3+4+5)**	-1,429.0	-354.8	-5,144.1	-7,241.9	-3,010.8	-2,591.4	157.7

Source: Economic Survey, MOF

Table 2.4.1-7 National Urban Consumer Price Index (Base Year 1995/96 = 100)

Unit: Million NRs

No.	Description	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06 (First 8 months)
1	**Overall Index**	134.9	138.1	142.1	148.9	154.8	161.8	172.6
			(2.37)	(2.90)	(4.79)	(3.96)	(4.52)	(6.67)
2	**Food and Beverage**	136.1	133.0	137.9	144.0	148.8	154.7	165.3
			(-2.28)	(3.68)	(4.42)	(3.33)	(3.97)	(6.85)
	Grain and Cereal Products	145.0	125.1	127.7	138.2	139.8	145.1	163.2
	Pulses	118.7	121.6	123.9	125.3	126.1	131.6	143.1
	Vegetable and Fruits	120.6	125.6	135.0	135.7	140.3	146.9	154.9
	Spices	141.2	153.0	156.1	142.3	147.0	146.5	146.1
	Meat, Fish and Eggs	134.0	137.8	143.5	148.2	158.3	168.5	171.8
	Milk and Milk Products	136.9	144.7	146.4	147.8	150.4	151.1	157.0
	Oil and Ghee	110.9	105.7	114.5	136.9	153.7	150.8	146.8
	Sugar and Related Products	113.4	126.4	133.8	124.4	123.9	154.6	162.2
	Beverages	141.2	144.0	151.2	161.6	162.1	165.0	179.2
	Restaurant Meals	150.8	162.9	168.2	174.1	183.2	192.6	203.0
3	**Non-Food & Services**	133.4	144.2	147.2	154.6	161.8	170.1	181.1
			(8.10)	(2.08)	(5.03)	(4.66)	(5.13)	(6.47)
	Cloths, Clothing and Sewing Services	127.8	130.6	133.8	135.7	138.1	141.5	145.1
	Footwears	127.1	129.1	131.2	132.7	133.3	133.9	137.1
	Housing Goods and Services	142.5	144.5	153.0	163.1	178.1	174.7	195.6
	Transport & Communication	146.5	158.4	162.4	172.2	185.2	198.2	222.4
	Medical and Personal Care	139.4	147.4	156.5	163.2	169.3	172.1	175.9
	Education, Educational Materials Recreation	141.6	161.4	159.3	174.1	182.1	190.1	199.9
	Tobacco and Related Products	137.4	139.9	146.3	150.5	153.2	156.2	162.5

Note: Figures in a parenthesis show annual growth rate in %.
Source: Economic Survey, MOF

Table 2.4.2-1 Direction of International Trade (FY 1994/95 to FY 2004/05)

Unit: Million NRs

No.	Description	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05
1	**Export (FOB)**	17,639.2	19,881.1	22,636.5	27,513.5	35,676.3	49,822.7	55,654.1	46,944.8	49,930.6	53,910.7	58,705.7
	India	3,124.3	3,682.6	5,226.2	8,794.4	12,530.7	21,220.7	26,030.2	27,956.2	26,430.0	30,777.1	38,916.9
		(17.7)	(18.5)	(23.1)	(32.0)	(35.1)	(42.6)	(46.8)	(59.6)	(52.9)	(57.1)	(66.3)
	Other Countries	14,514.9	16,198.5	17,410.3	18,719.1	23,145.6	28,602.0	29,623.9	18,988.6	23,500.6	23,133.6	19,788.8
		(82.3)	(81.5)	(76.9)	(68.0)	(64.9)	(57.4)	(53.2)	(40.4)	(47.1)	(42.9)	(33.7)
2	**Import (CIF)**	63,679.5	74,454.5	93,553.4	89,002.0	87,525.3	108,504.9	115,687.2	107,389.0	124,352.1	136,277.1	149,473.6
	India	19,615.9	24,398.6	24,853.3	27,331.0	32,119.7	39,660.1	45,211.0	56,622.1	70,924.2	78,739.5	88,675.5
		(30.8)	(32.8)	(26.6)	(30.7)	(36.7)	(36.6)	(39.1)	(52.7)	(57.0)	(57.8)	(59.3)
	Other Countries	44,063.6	50,055.9	68,700.1	61,671.0	55,405.6	68,844.8	70,476.2	50,766.9	53,427.9	57,537.6	60,798.1
		(69.2)	(67.2)	(73.4)	(69.3)	(63.3)	(63.4)	(60.9)	(47.3)	(43.0)	(42.2)	(40.7)
3	**Trade Balance**	-46,040.3	-54,573.4	-70,916.9	-61,488.5	-51,849.0	-58,682.2	-60,033.1	-60,444.2	-74,421.5	-82,366.4	-90,767.9
	India	-16,491.6	-20,716.0	-19,627.1	-18,536.6	-19,589.0	-18,439.4	-19,180.8	-28,665.9	-44,494.2	-47,962.4	-49,758.6
		(35.8)	(38.0)	(27.7)	(30.1)	(37.8)	(31.4)	(32.0)	(47.4)	(59.8)	(58.2)	(54.8)
	Other Countries	-29,548.7	-33,857.4	-51,289.8	-42,951.9	-32,260.0	-40,242.8	-40,852.3	-31,778.3	-29,927.3	-34,404.0	-41,009.3
		(64.2)	(62.0)	(72.3)	(69.9)	(62.2)	(68.6)	(68.0)	(52.6)	(40.2)	(41.8)	(45.2)
4	**Total Volume of Trade**	81,318.7	94,335.6	116,189.9	116,515.5	123,201.6	158,327.6	171,341.3	154,333.8	174,282.7	190,187.8	208,179.3
	India	22,740.2	28,081.2	30,079.5	36,125.4	44,650.4	60,880.8	71,241.2	84,578.3	97,354.2	109,516.6	127,592.4
		(28.0)	(29.8)	(25.9)	(31.0)	(36.2)	(38.5)	(41.6)	(54.8)	(55.9)	(57.6)	(61.3)
	Other Countries	58,578.5	66,254.4	86,110.4	80,390.1	78,551.2	97,446.8	100,100.1	69,755.5	76,928.5	80,671.2	80,586.9
		(72.0)	(70.2)	(74.1)	(69.0)	(63.8)	(61.5)	(58.4)	(45.2)	(44.1)	(42.4)	(38.7)

Note: Figures in a parenthesis show share in %.
Source: Economic Survey, MOF

Table 2.4.2-2 Balance of Payments

Unit: Million NRs

No.	Description	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05
A	**Current Account**	17,084.4	20,148.5	18,161.1	11,614.7	14,598.0	11,544.6
1	Export of Goods (FOB)	58,494.7	69,788.5	57,983.5	50,760.7	55,228.3	59,956.1
2	Import of Goods (FOB)	110,750.2	126,238.0	111,342.0	121,053.0	132,909.9	145,718.2
3	**Balance on Goods**	-52,255.5	-56,449.5	-53,358.5	-70,292.3	-77,681.6	-85,762.1
4	Credit of Services	30,819.9	29,821.7	23,508.2	26,518.9	34,315.9	26,001.9
	Travel	12,073.9	11,717.0	8,654.3	11,747.7	18,147.4	10,463.8
5	Debit of Services	18,895.0	20,519.4	19,569.8	19,469.2	25,241.0	28,036.1
6	**Balance on Services**	11,924.9	9,302.3	3,938.4	7,049.7	9,074.9	-2,034.2
7	**Balance on Goods and Services**	-40,330.6	-47,147.2	-49,420.1	-63,242.6	-68,606.7	-87,796.3
8	**Income Net**	2,361.3	1,700.7	-604.9	-675.7	-1,683.9	1,636.5
9	Credit of Current Transfer	56,952.8	67,027.7	70,157.3	77,765.1	89,161.8	101,310.1
	Grants	1,284.8	12,046.4	12,650.5	13,842.2	19,557.8	21,071.9
	Worker's Remittance	36,818.1	47,216.1	47,536.3	54,203.3	58,587.6	65,541.2
10	Debit of Current Transfer	1,899.1	1,432.7	1,971.2	2,232.1	4,273.2	3,605.7
11	**Current Transfer Net**	55,053.7	65,595.0	68,186.1	75,533.0	84,888.6	97,704.4
B	**Capital Account**	7,899.6	6,173.1	5,694.0	5,393.9	1,452.2	1,573.6
C	**Financial Account**	6,205.4	-28,522.2	-37,333.4	-17,198.9	-21,540.1	-25,536.9
	Loan	8,878.4	6,693.4	2,899.6	-52.4	3,325.2	744.4
D	**Net Errors and Omissions**	-14,582.8	11,749.5	10,600.6	4,176.2	25,587.2	18,098.1
E	**Balance**	16,606.6	9,548.9	-2,877.7	3,985.9	20,097.3	5,679.4
F	**Foreign Exchange Reserve**	93,858	105,173	105,901	109,229	130,201	130,330

Source: Economic Survey, MOF

Table 2.4.2-3 Foreign Aid Commitment by Major Sources

Unit: Million NRs

No.	Description	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05
1	**Bilateral**	19,361.9	11,293.4	17,495.9	18,438.7	15,312.4	8,223.6	21,225.4
	Grant	13,299.1	11,293.4	14,046.0	17,292.2	15,183.1	8,223.6	21,225.4
	Loan	6,062.8	0.0	3,449.9	1,146.5	129.3	0.0	0.0
2	**Multilateral**	4,565.0	9,154.6	13,791.0	14,789.0	27,890.3	15,514.4	16,926.9
	Grant	5.0	1,566.8	243.0	6,048.0	12,174.5	733.4	4,167.3
	Loan	4,560.0	7,587.8	13,548.0	8,741.0	15,715.8	14,781.0	12,759.6
3	**Total**	23,927.0	20,448.1	31,287.0	33,227.8	43,202.8	23,738.1	38,152.4
	Grant	13,304.2	12,860.3	14,289.1	23,340.3	27,357.7	8,957.1	25,392.8
	Loan	10,622.8	7,587.8	16,997.9	9,887.5	15,845.1	14,781.0	12,759.6

Source: Economic Survey, MOF

Table 2.4.2-4 Foreign Loan and Debt Servicing

Unit: Million NRs

No.	Description	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05
1	Outstanding up to Last Year	161,822.9	182,009.9	193,800.7	214,827.5	222,738.3	228,949.0	217,852.7
2	Borrowing	10,839.5	12,362.4	11,104.3	10,049.5	6,192.4	9,597.4	7,743.7
3	Repayments	3,196.5	3,681.1	4,500.6	4,751.4	5,497.5	5,757.1	5,954.5
4	Interest Payments	1,549.0	1,640.3	1,700.8	1,816.1	2,021.7	2,141.8	2,146.8
5	Net Outstanding	169,465.9	190,691.2	200,404.4	220,125.6	223,433.2	232,779.3	219,641.9

Note: Outstanding may differ due to exchange rate fluctuation.
Source: Economic Survey, MOF

2.5 Tenth Plan

The Government of Nepal has completed nine 5-year development plans since the First Plan (FY 1956/57 to 1960/61) was commenced, and the Tenth Plan was started on July 16, 2002. The Tenth Plan is also known as the Poverty Reduction Strategy Paper (PRSP) and aims to reduce the percentage of the population below the poverty line from 38% as of the end of FY 2001/02 (July 2002) to 30% in 2006/07. The major pillars of the Tenth Plan are described below:

- High, broad-based and sustainable economic growth
- Improvement in the access and quality of infrastructure, and social and economic services in the rural areas
- Targeted programs for the social and economic inclusion of the poor and marginalized communities
- Good governance to improve service delivery, efficiency, transparency and accountability

The Plan aims to comprehensively confront the social inclusion of vulnerable groups and sound governance in parallel with economic development and the fair allocation of its fruitions for poverty reduction.

Although the annual growth rate of GDP is targeted at 6.2% in the Tenth Plan, this target has not been achieved, as described in **Section 2.4.1**. The percentage of the population below the poverty line, however, reached 30.8% according to the National Living Standard Survey in FY 2003/04, and this target is considered to be achieved during the Tenth Plan period.

In the Tenth Plan, the following are taken as strategies for the power sector:

- To promote the private sector participation in the power sector
- To improve the financial viability of NEA
- To integrate rural electrification alongside economic development
- To promote cooperative-based rural electrification
- To expand and reinforce the power infrastructure

Regarding hydropower development, the major activities to be taken are described as below:

a. The promotion of private sector participation

b. The development of small- and medium-scale and storage projects

c. The development of export-oriented generation projects

CHAPTER 3 EXISTING STUDY ON SELECTION OF STORAGE HYDROELECTRIC PROJECT

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CHAPTER 3 EXISTING STUDY ON SELECTION OF STORAGE HYDROELECTRIC PROJECT

3.1 Energy Resources

Water resources are the only energy resource in Nepal, due to the lack of any nationwide fossil energy reserves, such as oil, coal and natural gas. Exploitable hydropower potential is estimated to be 42,000 MW. The existing hydropower facilities, however, could generate 556.4 MW as of July 2006, corresponding to 1.3% of the exploitable hydropower potential.

3.2 Power Facilities for Peak Demand

Although hydropower generation has a share of around 90% in terms of the installed capacity of existing power facilities, there are only two storage hydropower plants capable of regulating river discharge on a seasonal basis, namely Kulekhani I and II (with total installed capacity of 92 MW), as mentioned in **Chapter 4**. Because the annual maximum peak demand is recorded in December or January during the dry season, NEA has coped with the peak demand in the dry season by using the electricity generated in thermal power plants and imported from India to cover certain portions of the peak demand.

The annual growth rate in power demand has been recorded at around 8% for the last decade, and is forecast to continue increasing at the same growth rate according to NEA (refer to **Chapter 4**).

Oil-fired/gas-fired thermal power plants and storage type hydropower plants are generally considered as those suitable to meet peak demand. NEA, however, intends to decrease dependence on thermal power plants in Nepal, for the following reasons:

a. The expensive generation cost (refer to **Chapter 4**)
b. The risk associated with fuel procurement and the need for foreign currency for procurement
c. Priority for the utilization of rich national water resources

With the above in mind, thermal power plants are not under consideration as new power facilities to meet peak demand.

3.3 Study on the Selection of Storage Hydroelectric Project

NEA carried out a study termed the Identification and Feasibility Study of Storage Project to identify hydroelectric projects and to select priority project(s), in order to cope with increasing peak demand.

The study is divided into the following two stages:

- Phase I: Coarse Screening and Ranking Study
- Phase II: Fine Screening and Ranking Study

3.3.1 Phase I

The Phase I Study was performed to newly identify storage projects to meet peak demand in the country and was completed in February 2000.

(1) Capacity of the Storage Projects to Be Developed

The installed capacity of the storage projects was considered to be 200 MW to 300 MW, based on NEA's demand forecast for ten years in 1999 when the study was carried out. However, the minimum capacity was decided as 10 MW, with the development of multiple storage projects taken into consideration, and the range for the installed capacity of the new storage projects was therefore selected as 10 MW to 300 MW.

(2) Study Procedure

The procedure for the Phase I Study is shown below:

1) 102 storage projects were identified in a desk study via the use of existing topographic maps at a scale of 1/25,000 or 1/50,000.

2) The following site conditions were confirmed by using existing data, such as topographic maps, hydrological data and regional geological maps, etc:

a. Access road length
b. Transmission line length to be newly constructed
c. Reservoir storage ratio (reservoir storage capacity/annual discharge)
d. Hydrological conditions
e. Geological conditions
f. Environmental and social considerations

Regarding the environmental and social considerations, the number of household, cultivated area, forest area, and infrastructures to be inundated were extracted based on the existing data, to examine affects on physical, biological and social environment in accordance with the National EIA Guidelines (1993), and scoring for each project was carried out according to the number and the area sizes to be affected.

After that, project cost was roughly estimated.

3) Screening

The following conditions were selected for the coarse screening of identified projects;

a. Exceeding 1.2 of the benefit-cost ratio (B/C)
b. Not seriously affecting the environment
c. Access road length of less than 50 km
d. Installed capacity of between 10 and 300 MW, as mentioned in (1)
e. Not located in fault zones
f. Exceeding 3% of reservoir storage ratio

g. Not exceeding 150 m in dam height for projects of 10 to 100 MW and 200 m in dam height for projects of over 100 MW

4) Result

8 projects were selected, based on the screening conditions mentioned above.

Table 3.3.1-1 Result of Screening

Total number of projects	Number of eliminated projects	Number of selected project	Reason of Elimination						
			Economical assessment (a)	Serious affects to environment (b)	Access road length (c)	Installed capacity (d)	Geological conditions (e)	Storage ratio (f)	Dam height (g)
102	94	8	68	27	14	22	6	13	2

The letter in parenthesis corresponds to the screening condition described in 3)

NEA also added two storage projects, which were identified in other previous studies, and the following 10 projects were to be examined in the next stage.

Table 3.3.1-2 Main Features of 10 Selected Projects

No.	Name of project	Region	Dam height (m)	Installed capacity (MW)	Access road length (km)	T/L length (km)	Main affects to environment	Remarks
1	A	East	104	61.4	15	27	Inundating 146 households	
2	B	East	141	53.6	4	25	Inundating important religious facility and national highway	
3	C	East	119	91.2	2.3	29	Inundating many houses and assets	
4	D	Central	151	108.7	2	19	Inundating 94 households	
5	E	Central	115	58.3	10	9	Dewatered river section of 50 km long	
6	F	Central	111	43.3	12	27	Inundating 100 households	
7	Upper Seti	Central	136	122	6	40	Inundating 45 households Restriction of FSL due to village in upstream reservoir area	
8	G	West	150	38	7	50	Inundating 130 households	
9	H	Central	93	218	20	60	Located in a national park	Identified in another study
10	I	West	120	67	5	70	Construction of national highway of 36 km long	Identified in another study

3.3.2 Phase II

The 10 candidate storage projects selected in the Phase I Study were examined in the Phase II Study, which was completed in September 2000.

(1) Study Procedure

The procedure for the Phase II Study is shown below:

a. Preparation of topographic maps necessary to study the layout of each project
b. Grasping the topographic, geological, hydrological and environmental site conditions through site reconnaissance
c. Modification of layouts based on the results obtained in b above
d. Initial environmental assessment
   Affects due to site conditions, during construction stage, and during operation stage were examined for IEE on physical, biological and social environment in accordance with the National EIA Guidelines (1993).
e. Cost estimation
f. Scoring

(2) Scoring

Scoring for the 10 projects was carried out by each item such as access road length, transmission line length, hydrological conditions, geological conditions, environmental and social considerations, sedimentation in a reservoir, and financial risks.

(3) Conclusion

As the result of scoring, in which higher scored project had higher priority, one project had lower scoring, but the other 9 projects did not have outstanding difference in scoring. Hence, ranking among 10 projects was performed from economical viewpoint.

Consequently, the first ranked project was located in a national park. Although Nepalese laws did not prohibit implementation of a project located in a national park, it was considered that it would take a long time to receive consent to conduct a feasibility study on the project from the ministries concerned. The second-ranked Upper Seti project, therefore, was selected as the project to proceed to the feasibility study stage.

3.4 Feasibility Study by NEA

A feasibility study on the Upper Seti project was conducted by NEA and completed in July 2001. Subsequently, NEA completed the upgrading feasibility study on the project in July 2004 and the outlines are described below:

3.4.1 Feasibility Study

NEA conducted a feasibility study from July 2000 to July 2001, during which the following field surveys were performed:

a. Topographic survey and mapping
   Topographic maps at a scale of 1 to 1,000 in structures locations
   Topographic maps at a scale of 1 to 5,000 in the reservoir area
   River section survey
b. Geological investigations
   Geological reconnaissance and geological mapping
   Seismic prospecting of 26 lines of total length 3,335 m
   Drilling of 7 holes of total length 312.8
   27 pit excavation and laboratory tests for construction materials:
c. Hydrological and sedimentological survey
d. Environmental survey

Five alternative layouts were prepared and compared, and the layout in which the underground powerhouse was located in the right dam abutment (similar to Option-II described in **Chapter 10**) was selected as the optimum choice. NEA also selected three alternative FSLs, EL. 420 m, 425 m and 430 m, and selected EL. 425 m as the optimum FSL through an economic comparison study. **Table 3.4.1-1** shows the general features of the selected choice.

Table 3.4.1-1 Salient Feature of the Upper Seti Project

Item	Unit	
Reservoir		
Watershed	km^2	1,502
Average inflow	m^3/s	107.2
FSL	m	425.0
Gross reservoir capacity	Mil m^3	331.7
Available surcharge	m	54.5
Design flood	m^3/s	8,306
Dam		
Type		Concrete gravity
Height × crest length	m	136 × 150
Powerhouse		
Type		Underground
L×W×H	m	55.8 × 18 × 38
Turbine type		Francis
Number of units	unit	2
Generation parameters		
Effective head	m	115.2
Maximum discharge	m^3/s	141.0
Installed capacity	MW	122
Annual generating energy	GWh	558

Item	Unit	
Environmental impact		
Affected householders		45
Affected cultivated land	ha	162
Affected forest	ha	155
Affected people	persons	2,054
Project cost	Mil US$	215.13

Source: Feasibility Study Report, NEA, July 2001

An EIA study on the selected scheme was carried out, while a mitigation plan and monitoring program were prepared, and their costs estimated.

3.4.2 Upgrading Feasibility Study

NEA performed an upgrading feasibility study on the project, which was completed in July 2004. During the study the following field surveys were conducted:

a. Geological investigation
   Drilling of 2 holes of total length 221.05 m
b. Hydrological and sedimentological survey
c. Environmental survey

In the study, the four alternative layouts shown in **Table 3.4.2-1** were examined for comparison, but the optimum one was not selected because a further study was considered necessary.

NEA examined the power evacuation plan and transmission line alignment from the Upper Seti powerhouse and selected the plan to Bharatpur.

Table 3.4.2-1 Comparison of Alternative Layouts

Item	Option A	Option B	Option C	Option D
Outlines	Underground Powerhouse	Tailrace of Option A is shifted downstream of conjunction between Seti and Madi rivers	Powerhouse of Option A is shifted in the dam body.	Tailrace of Option C is shifted to downstream of conjunction between Seti and Madi rivers
Powerhouse Location	Right bank downstream	Right bank downstream	in dam body	in dam body
Intake Location	Right bank upstream	Upstream surface of dam	Right bank upstream	Upstream surface of dam
Turbine Center Elevation	EL. 301.5 m	EL. 281.5 m	EL. 301.5 m	EL. 281.5 m
Tailrace Tunnel Length	156 m	1,610 m	156 m	1,610 m
Installed Capacity	122 MW	144 MW	122 MW	144 MW
Annual Generating Energy	605 GWh	684 GWh	605 GWh	684 GWh
Common Items	Dam: Concrete gravity type, 136 m in height Available surcharge: from EL. 370 m to EL. 425 m Reservoir Storage capacity: Gross-332 MCM, effective-270 MCM Transmission Line: 220 kV, double circuit x 43 km			

Based on the EIA study, the NEA prepared an EIA report in January 2003 and held a public consultation meeting in January 2004 at Damauli, which is located near the project site. The EIA report was subsequently submitted to DOED in July 2004.

3.4.3 Investigations by NEA

NEA conducted the following field investigations during the JICA Study through discussions with the JICA Team. The results of the investigations mentioned in (1) and (2) were then provided to the JICA Team and incorporated into the Study.

(1) Geological Investigation

1) Drilling at the dam site

NEA conducted drilling of 7 holes of total length of 722.5 m from December 2004 to June 2005 as agreed with the JICA S/W mission during discussion of S/W of the Study in October 2004. In addition, NEA carried out drilling of 4 holes (of which the existing one hole was extended) of total length of 200 m up to August 2005, based on the JICA Team's proposal, and has agreed with the JICA S/W mission.

2) Underground powerhouse site

The NEA and JICA Team agreed in March 2006 that NEA would carry out the drilling of 1 hole 100 m long for the underground powerhouse of Options-II and IIIa (refer to **Chapter 10**), and NEA completed the drilling in August 2006.

In addition, NEA agreed, in December 2006, that NEA would conduct drilling for the underground powerhouse of Option IIIb (refer to **Chapter 10**), which was selected to as the optimum layout. NEA is conducting drilling of 3 holes in the vicinity of the underground powerhouse site as of June 2007.

(2) Transmission line route survey

NEA conducted a transmission line route survey under contract with a local consultant, to select a transmission line route from the project site to Bharatpur and decided upon the route. The survey was completed in October 2006.

(3) Environmental survey on the transmission line

NEA commenced an environmental survey on the transmission line from the project site to Bharatpur, upon completion of the above route survey. The IEE study results obtained by the JICA Team will be incorporated into their survey.

CHAPTER 4 POWER SECTOR SURVEY

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CHAPTER 4 POWER SECTOR SURVEY

4.1 Organization

The electric power supply in Nepal was first set up in 1911 at the Pharping small hydropower station. The power supply in the country since expanded, with the construction of other new power stations, transmission and distribution facilities, meaning hydropower development projects such as Devighat, Kulekhani-I, Kulekhani-II and Marsyangdi were implemented to cope with the demand driven by the increasing economic growth.

To date, the bulk of electricity generation, transmission and distribution in Nepal has been managed by the Nepal Electricity Authority (hereinafter referred to as “NEA”), administratively organized under the Ministry of Water Resources (MOWR) since 1985. NEA’s responsibilities include the planning, construction, operation and maintenance of all generation, transmission and distribution facilities within the Integrated Nepal Power System (hereinafter referred to as “INPS”) and principal isolated systems.

Electric power supply in the country has been operated in four power regions, which individually comprise the following areas as shown in **Table 4.1-1**.

Table 4.1-1 Areas for Electric Power Supply Purpose

Power System	Areas covered
ENPS: Eastern Nepal Power System	Sanarmatha, Kosi, Mechi
CNPS: Central Nepal Power System	Narayani, Janakpur, Bagmati
WNPS: Western Nepal Power System	Dhaulagiri, Gandaki, Lumbini
MFWNPS: Mid and Far-Western Nepal Power System	Mahakali, Seti, Karnali, Bheri, Rapti

This Upper Seti project belongs to Gandaki in the West Nepal Power System (WNPS), and Kathmandu to Bagmati in the Central Nepal Power System (CNPS).

Fig. 4.1-2 shows the organization chart of NEA, and **Fig. 4.1-3** shows the locations of small hydropower stations, and isolated solar and diesel power stations in Nepal, while **Fig. 4.1-4** illustrates the national power system.

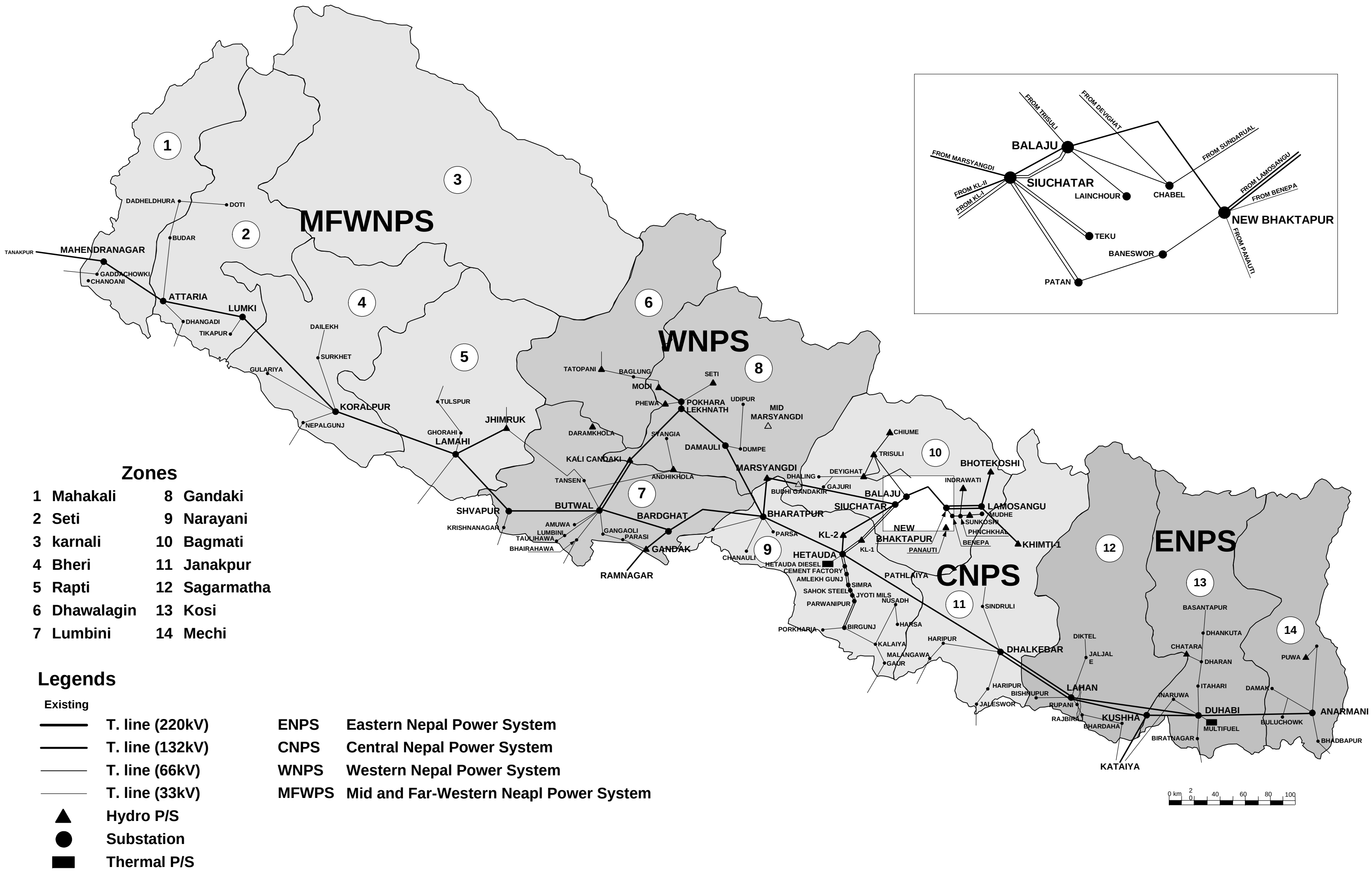

Fig. 4.1-1 Different Power Regions & Administrative Zone

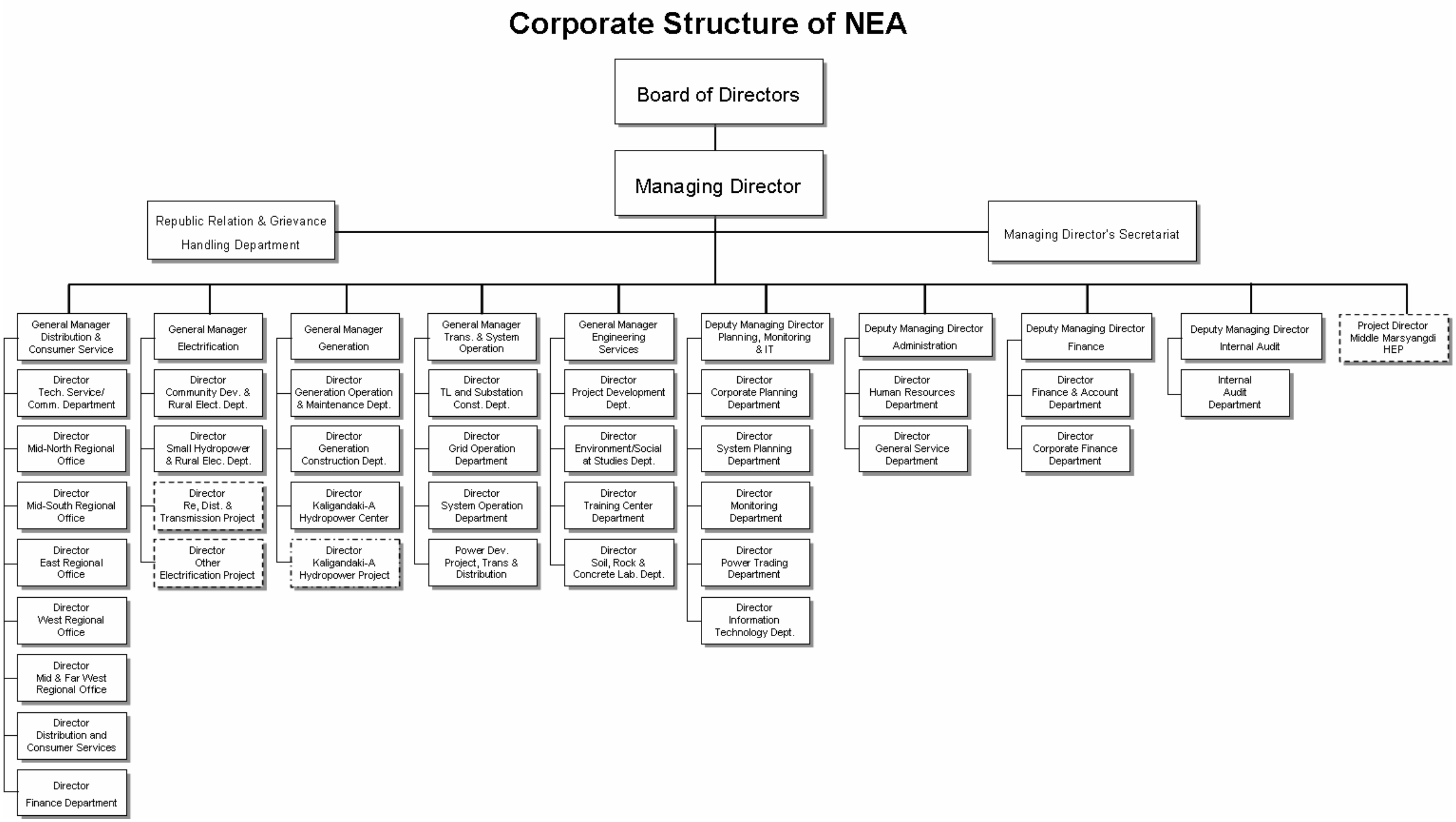

Fig. 4.1-2 Organization Chart of NEA

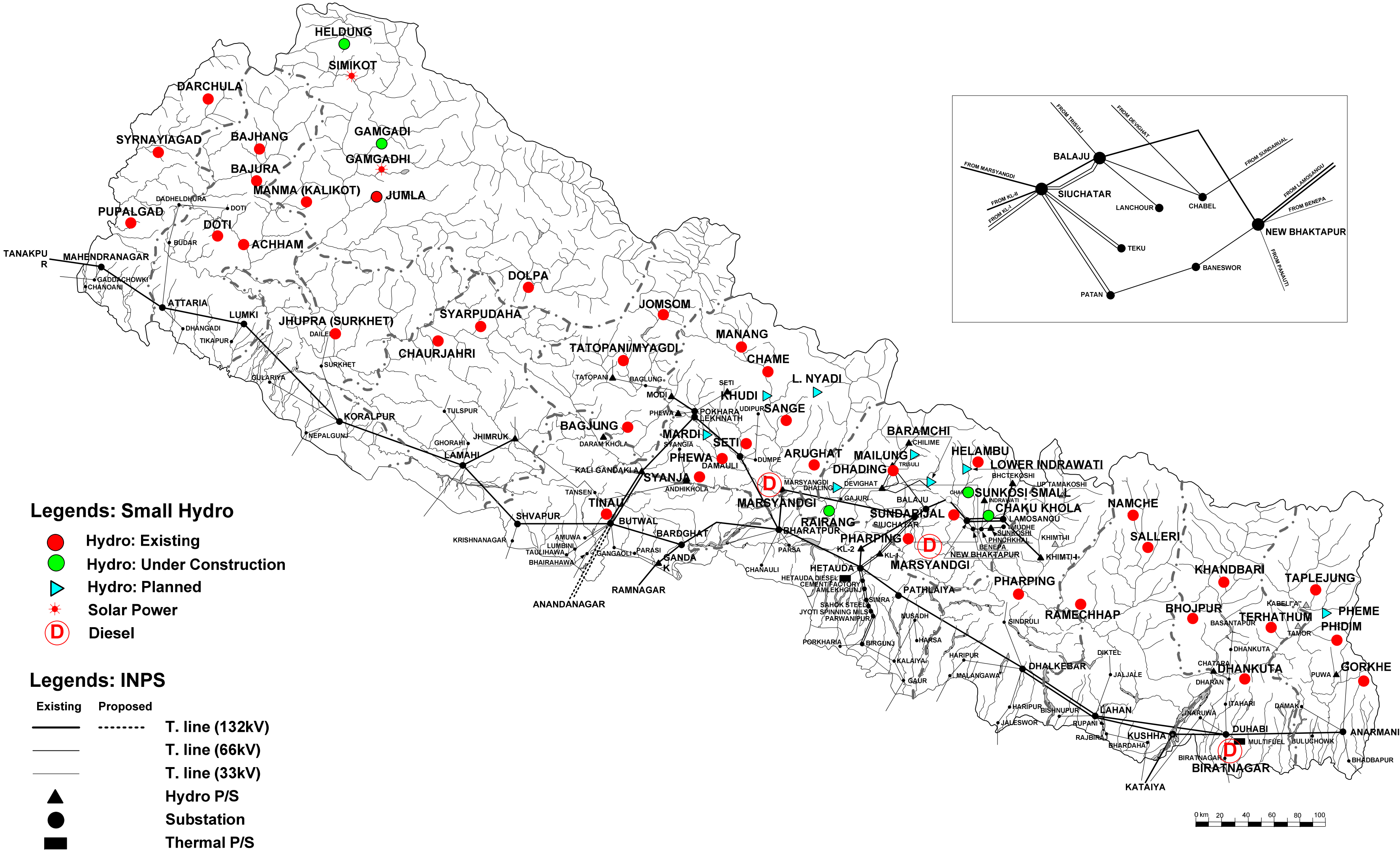

Fig. 4.1-3 Small Hydro Station, Isolated Solar & Diesel Power Station

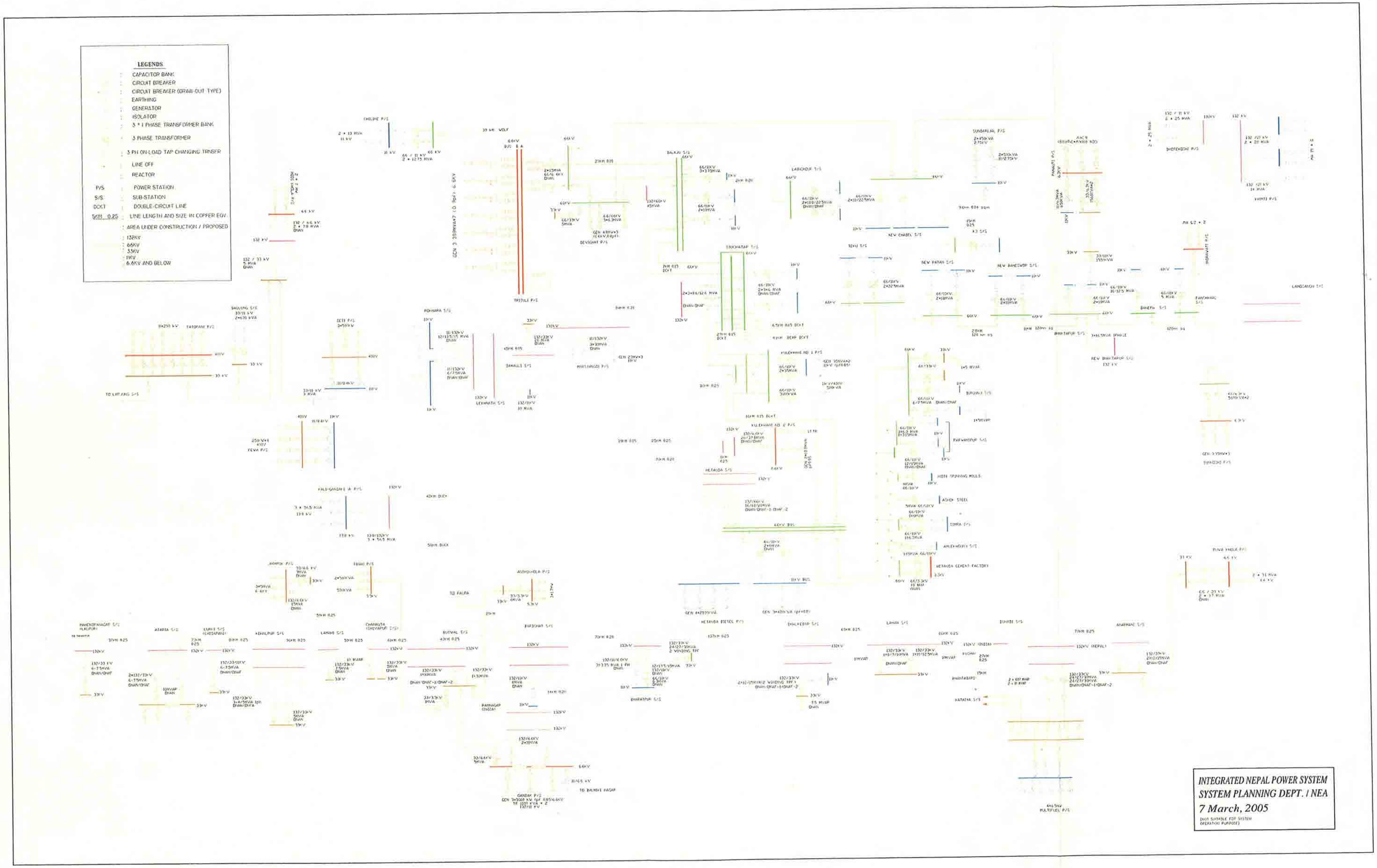

Fig. 4.1-4 Power System Map

4.2 Existing Power Generating Facilities

The installed capacity of the INPS as of July 2006, as shown in **Table 4.2-1**, stands at about 605.253 MW, of which NEA owns 456.97 MW (hydro and thermal). Hydropower plants constitute more than 90% of this capacity, while the remaining is shared by thermal plants (55.058 MW) comprising both multifuel and diesel plants.

NEA purchases power from Independent Power Producers (hereinafter referred to as “IPP”), like Khimti HPL (60 MW), Bhotekoshi BKPC (36 MW), Indrawati-III NHPC (7.5 MW,), Jhimruk and Andhikhola BPC (17.10 MW), and Piluwa AVHDC (3 MW).

The available peaking capacity and the annual available energy in INPS in FY 2005/06 amount to 603.28 MW and 2,777.41 GWh, respectively.

Nepal also imports power from India and exports its surplus power to India during off-peak periods.

The generation facilities in Nepal are summarized in **Table 4.2-1**.

Table 4.2-1 Existing Generation Plants in NEA's Integrated Grid

Power Project Name	Project Type	Commissioned Year	Installed Capacity (MW)
NEA's Hydropower Plants			
Trishuli	ROR	1967 (96)	24.00
Sunkoshi	ROR	1972	10.05
Gandaki	ROR	1979	15.00
Kulekhani-I	ST	1982	60.00
Devighat	ROR	1984 (96)	14.10
Kulekhani-II	ST	1986	32.00
Marsyangdi	PROR	1989	69.00
Puwa Khola	ROR	Dec. 1999	6.20
Modi Khola	ROR	Nov. 2000	14.80
Kali Gandaki-A	PROR	Apr. 2002	144.00
Small Hydro	-	-	12.792
Total			401.942
NEA's Thermal Power Plants			
Biratnagar Diesel			1.028
Hetauda Diesel		1963/83	12.75
Marsyandgi Diesel		1989	2.25
Duhabi Multifuel-I		1992	26.00
Duhabi Multifuel-II		1997	13.00
Total			55.028
IPP's Hydropower Plans			
Andhi Khola (BPC)	ROR	Jun. 1991	5.10
Jhimruk (BPC)	ROR	Aug. 1994	12.00
Khimti Khola (HPL)	ROR	July 2000	60.00
Bhotekoshi (BKPC)	ROR	Nov. 2000	36.00
Sange Khola (SHP)	ROR	Jan. 2002	0.183
Indrawati (NHPC)	ROR	Oct. 2002	7.50
Chilime (CPC)	PROR	Aug. 2003	20.00
Piluwa Khola (AVHP)	ROR	Sept. 2003	3.00
Chaku Khola (APCo)	ROR	Jun. 2005	1.5
Sunkosi Small (SHP)	ROR	Mar. 2005	2.5
Rairang (RHPD)	ROR	Dec. 2004	0.5
Total			148.283
Installed Capacity in Nepal			
Total Hydro (NEA)		401.942	
Total Hydro (IPP)		148.283	
Total Hydro		550.225	
Total Thermal		55.028	
Grand Total		605.253	

ROR: Run of River; PROR: Peaking ROR; ST: Storage

Source: NEA Fiscal Year 2005/06 – A Year in Review

4.3 Existing Transmission Lines and Substations

4.3.1 Existing Transmission Facilities

The present transmission voltages employed in the country are 132 kV, 66 kV and 33 kV. Presently, the INPS is dominated by an east-west 132 kV tie from Anarmani in the east to Mahendranagar in the west. The major part of this tie has single circuit stringing on double circuit towers, except for the Hetauda – Dhalkebar – Lahan section which has double circuits. **Table 4.3.1-1** shows the transmission line data for the 132 kV and 66 kV voltages.

The main features of INPS showing **Table 4.3.1-1** are summarized as follows;

a. The conductor size of the line between Bharatpur and Pokhara, commissioned in 1980, is "Wolf" (150 mm^2), which is considered to have a fairly low transmission capacity, despite being one of the important lines.

b. To evacuate the power generated at Kali Gandaki "A" HEPP, the biggest national power plant, double circuit lines have been constructed from Kali Gandaki "A" to Butwal and a single circuit from Kali Gandaki "A" to Lekhath near Pokhara.

c. Kathmandu Valley is the country's biggest load center, consuming around 35-40% of the peak load, and presently supplied through a combination of 66 and 132 kV. Trisuli, Devighat, Sunkoshi and Kulekhani-I HEPPs supply power with 66 kV, while Kulekhani-II, Marsyangdi, Khimti and Bhotekoshi HEPPs supply power with 132 kV. Siuchatar, Bhaktapur and Balaju Substations are the major grid providers of the valley interconnection system, with a combination of 132 and 66 kV, providing power to the area through 132/66 kV transformers located in these substations.

d. Although the section of line from Attaria to Dipayal was constructed at a voltage level of 66 kV, it has been operated at 33 kV since March 2005.

Table 4.3.1-1 Transmission Line Data

Serial no.	Section From	Section To	Voltage (kV)	CCT	Length (km)	Conductor Kind	Conductor Size (mm^2)	Conductor Cord Word	Commis. Year	Tower Kind	Tower Numbers	SC/DC	Remarks
I. Existing 132 kV Line													
1	Hateuda	Bharatpur	132	1	70	ACSR	200	Panther	1979	Tower	-	SC	
2	Bharatpur	Bardghat	132	1	70	ACSR	200	Panther	1979	Tower	231	SC	
3	Bardghat	Gandak	132	1	14	ACSR	200	Panther	1979	Tower	52	SC	
4	Bharatpur	Pokhara	132	1	85	ACSR	150	Wolf	1980	Tower	251	SC	
5	Modi	Pokhara	u/c	1	40	ACSR	250	Bear	u/c	Tower	109	SC	
6	Hateuda	Dhalkebar	132	1	137	ACSR	250	Bear	1985	Tower	415	DC	
7(i)	Dhalkebar	Lahan	132	1^{st}(a)	56	ACSR	250	Bear	1985	Tower	181	DC	
7(ii)	Kushaha	Dhalkebar	132	2^{nd}(a)	60	ACSR	250	Bear	2000	-	-	-	
8(i)	Lahan	Duhabi	132	1^{st}	90	ACSR	250	Bear	1985	Tower	244	DC	
8(ii)	Duhabi	T758	132	2^{nd}	27	ACSR	250	Bear	1996	-	-	-	
9(i)	T758	Kusaha	132	2^{nd}	1.5	ACSR	250	Bear	1996	Tower	6	DC	
9(ii)	Kusaha	Bhantabari	132	1	13	ACSR	250	Bear	1996	Tower	44	SC	
10	Bardaghat	Butwal	132	1^{st}	36	ACSR	250	Bear	1985	Tower	101	DC	
11	Kulekhani-II	Siuchatar	132	1^{st}	34	ACSR	250	Bear	1986	Tower	108	DC	
12	Kulekhani-II	Hateuda	132	1^{st}	8	ACSR	250	Bear	1986	Tower	-	SC	
13	Duhabi	Anarmani	132	1	76	ACSR	250	Bear	1989	Tower	218	SC	
14(i)	Marsyangdi	Siuchatar T14	132	1	80	ACSR	300	Duck	1989	Tower	209	SC	
14(ii)	Siuchatar T14	Siuchartar	132	1^{st}, 2^{nd}	0.9	ACSR	250	Bear	1997	Tower	5	4C	
14(iii)	Siuchatar T14	Balaju	132	1	4	ACSR	300	Duck	1989	Tower	14	SC	
15	Bhakatpur	Chapali	132&66	2	12	ACSR	250	Bear	1997	Tower	45	DC	
16	Bhakatpur	Katunje	66	2	1.5	ACSR	250	Bear	1996	Tower	8	DC	
17	Siuchatar	Kirtipur T10	66	1^{st}, 2^{nd}	2.5	ACSR	250	Bear	1997	Tower	10	4C	
18	Chapali	Balaju	132&66	2	10	ACSR	250	Bear	1999	Tower	34	DC	
19	Kirtipur T10	Teku	66	2	1.7	ACSR	250	Bear	1997	Tower	7	DC	
20	Bhakatpur	Lamosangu	132	2	48	ACSR	250	Bear	1999	Tower	146	DC	
21	Lamosangu	Khimti	132	1	46	ACSR	250	Bear	1999	Tower	129	DC	
22	Lamosangu	Bhotekoshi	u/c	1	25	ACSR	250	Bear	u/c	Tower	(71)	SC	
23	Marsyangdi	Bharatpur	132	1	25	ACSR	300	Duck	1989	Tower	-	SC	
24	Kaligandaki-A	Lekhnath	u/c	1		ACSR	300	Duck	u/c	Tower	(198)	SC	
25	Kaligandaki-A	Butwal	u/c	2		ACSR	300	Duck	u/c	Tower	(98)	DC	
26	Butwal	Chanauta	132	1^{st}	60.6	ACSR	250	Bear	1988	Tower	171	DC	
27	Chanauta	Lamahi	132	1^{st}	51.1	ACSR	250	Bear	1988	Tower	135	DC	
28	Lamahi	Jhimruk	132	1	40	ACSR	80	Otter	1994	Lattice	101	SC	
29	Lamahi	Koralpur	132	1^{st}	95.7	ACSR	250	Bear	1988	Tower	265	DC	
30	Koralpur	Lamki	132	1	88.4	ACSR	250	Bear	1992	Tower	285	DC	
31	Lamki	Attaria	132	1	64.4	ACSR	250	Bear	1992	Tower	200	DC	
32	Attaria	Mahendra Nagar	132	1	36.6	ACSR	250	Bear	1992	Tower	111	DC	
33	Mahendra Nagar	Gaddachouki	132	1	12	ACSR	250	Bear	1999	Tower	40	SC	
II. Existing 66 kV II. Line													
1	Trishuli	Balaju	66	1	29	ACSR	100	Dog	1964	Tower	119	DC	
2	Balaju	Siuchatar	66	2	4	ACSR	150	Wolf	1966	Tower	16	DC	
3	Sunkosi	Khumaltar	66	1	55	ACSR	120		1972	Tower	202	SC	
4	Baneswar	Khumaltar	66	2	1.8	ACSR	150	Wolf	1986	Tower	9	DC	
5	Khmualtar	New Patan	66	1	0.9	ACSR	120		1972	Tower	4	SC	
6	Hetauda	Amelekhagunj	66	2	16	ACSR	150	Wolf	1966	Tower		DC	
7	Amelekhangunj	Simra	66	2	10	ACSR	150	Wolf	1966	Tower		DC	
8	Simra	Parwanipur	66	2	9	ACSR	150	Wolf	1966	Tower		DC	
9	Parwanipur	Birgunj	66	2	9	ACSR	150	Wolf	1966	Tower		DC	
10	Kulekhani-I	Siuchatar	66	2	29	ACSR	150	Wolf	1966	Tower	92	DC	
11	Kulekhani-I	Hetauda	66	2	16	ACSR	150	Wolf	1966	Tower		DC	
12(i)	Siuchatar	Kirtipur T10	66	3^{nd}, 4^{th}	2.5	ACSR	150	Wolf	1997	Tower	10	4C	
12(ii)	Kirtipur T10	New Patan	66	2	4.5	ACSR	150	Wolf	1982	Tower	13	DC	
13	Devighat	New Chabel	66	2	33	ACSR	100	Dog	1983	Tower	156	DC	
14	Balaju	Lanchour	66	1	2.3	ACSR	200	Panther	1989	H-Pole	24	SC	
15	Trisuli	Devighat	66	1	4.56	ACSR	150	Wolf	2000	Tower	17	SC	
16	Trisuli	Chilime	u/c	1	34.5	ACSR	150	Wolf	u/c	Tower	(108)	SC	
17	Anariya	Dipayal	33	1	103	ACSR	135	Coyote	1995	Tower	308	SC	

Note
a) "1^{st}" means a fisrt circuit, "2^{nd}" means second circuit and so on.
b) Trishuli - Devighat lines have been connected with jumper conductors since 1990.
c) "u/c" meand under constrcution.
d) Lamosangu - Bhotekoshi 132 kV line is owned by IPP Bhotekoshi Power Co. Ltd. (Bhottekoshi Hydel Project).
e) Lamahi - Jhimruk 132 kV line is owned by Butwal Power Company.
f) Scop of work of Modikhola project consists the dismantling the existing 132 kV single circuit towers form the Pokhara Substation towards the Bharatpur and replacing them by constructing five double circuit towers from tower no. 105 to 109

Source: Power System of Nepal (Second Edition), July 6, 2000

4.3.2 Existing Substation Facilities

The substation capacity by each voltage level in 2006 is shown in **Table 4.3.2-1**.

Table 4.3.2-1 Substation Capacity

Voltage (kV)	Capacity (MVA)
132/11	71.00
132/33	385.00
132/66	211.00
66/11	424.00
66/33	25.00

Source: NEA Fiscal Year 2005/06 – A Year in Review

4.3.3 Existing Phase Modifying Facilities

INPS, as illustrated in **Figs. 4.1-3** and **4.1-4**, comprises an irregular grid network, including many single-circuit lines, undeveloped economical hydro-potential in the west region and major areas of electric consumption in the central and east regions. Voltage at peak time in central areas subsides and rises at off-peak times in the east and west regions. In order to improve this unfavorable situation, phase modifying facilities have been installed at each of the relevant substations.

The phase modifying equipment at132 kV voltage level is shown in **Table 4.3.3-1**.

Table 4.3.3-1 Phase Modifying Equipment

Name	Facilities	Capacity (Mvar)
Attaria	Reactor	10
Lamahi	Reactor	10
Laman	Capacitor	20 (2*10)

Source: NEA Transmission Planning Study 2005

4.4 Load Dispatch Facilities

The NEA's power system is monitored/supervised and controlled at the LDC (Load Dispatch Center), installed in the premises of Siuchatar substation in Kathmandu Valley.

4.4.1 Load Dispatch System

The load dispatch system of LDC is constituted based on the SCADA (Supervisory Control And Data Acquisition) concept.

The SCADA system, offered in the form of a duplicated distribution system, was introduced based on assistance of Germany. **Fig. 4.4.1-1** shows the system configuration, and **Fig. 4.4.1-2** shows the block diagram of programmable RTUs (Remote Terminal Units), while the system functions are summarized in **Table 4.4.1-1**.

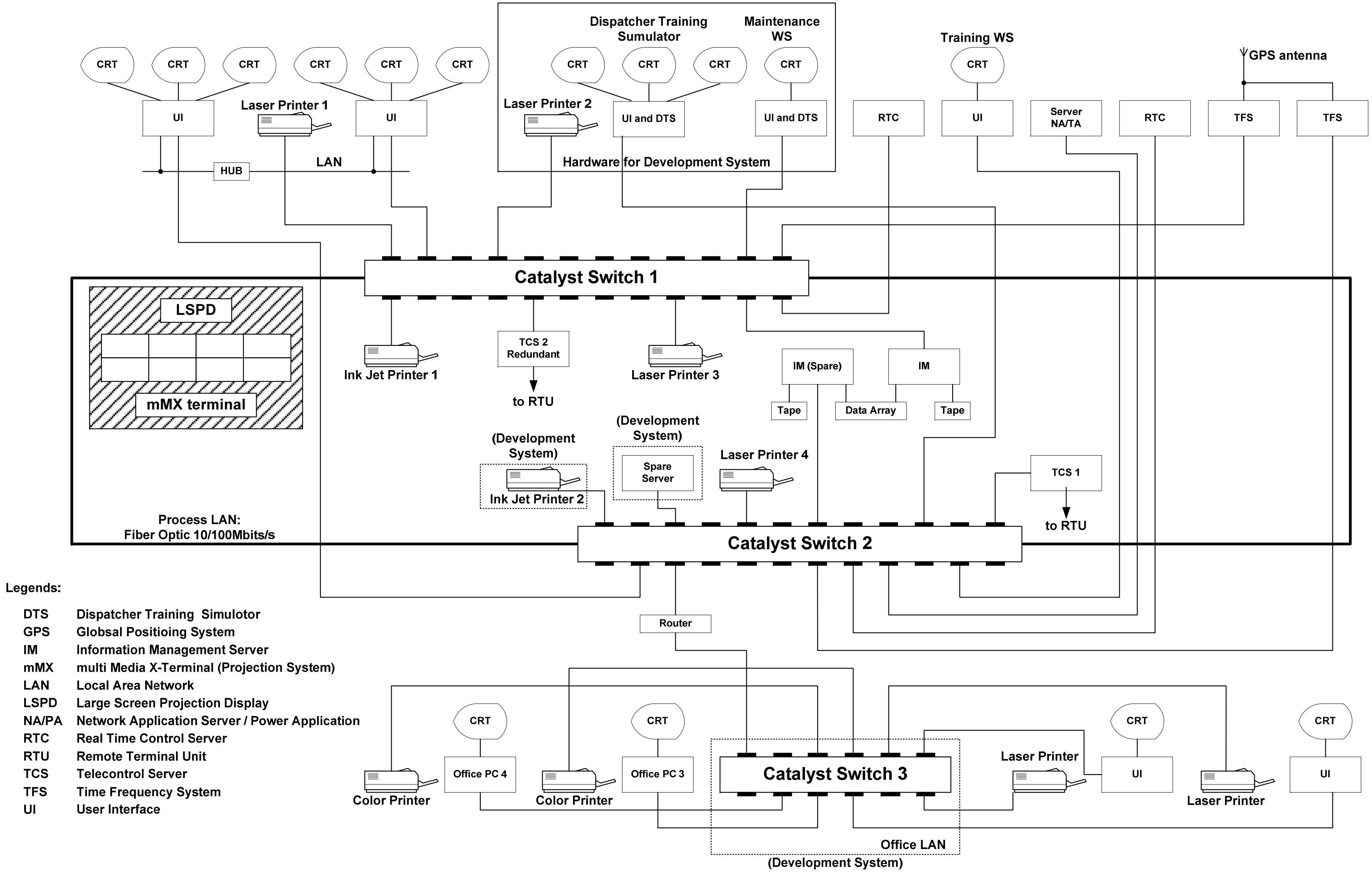

Fig. 4.4.1-1 System Configurations

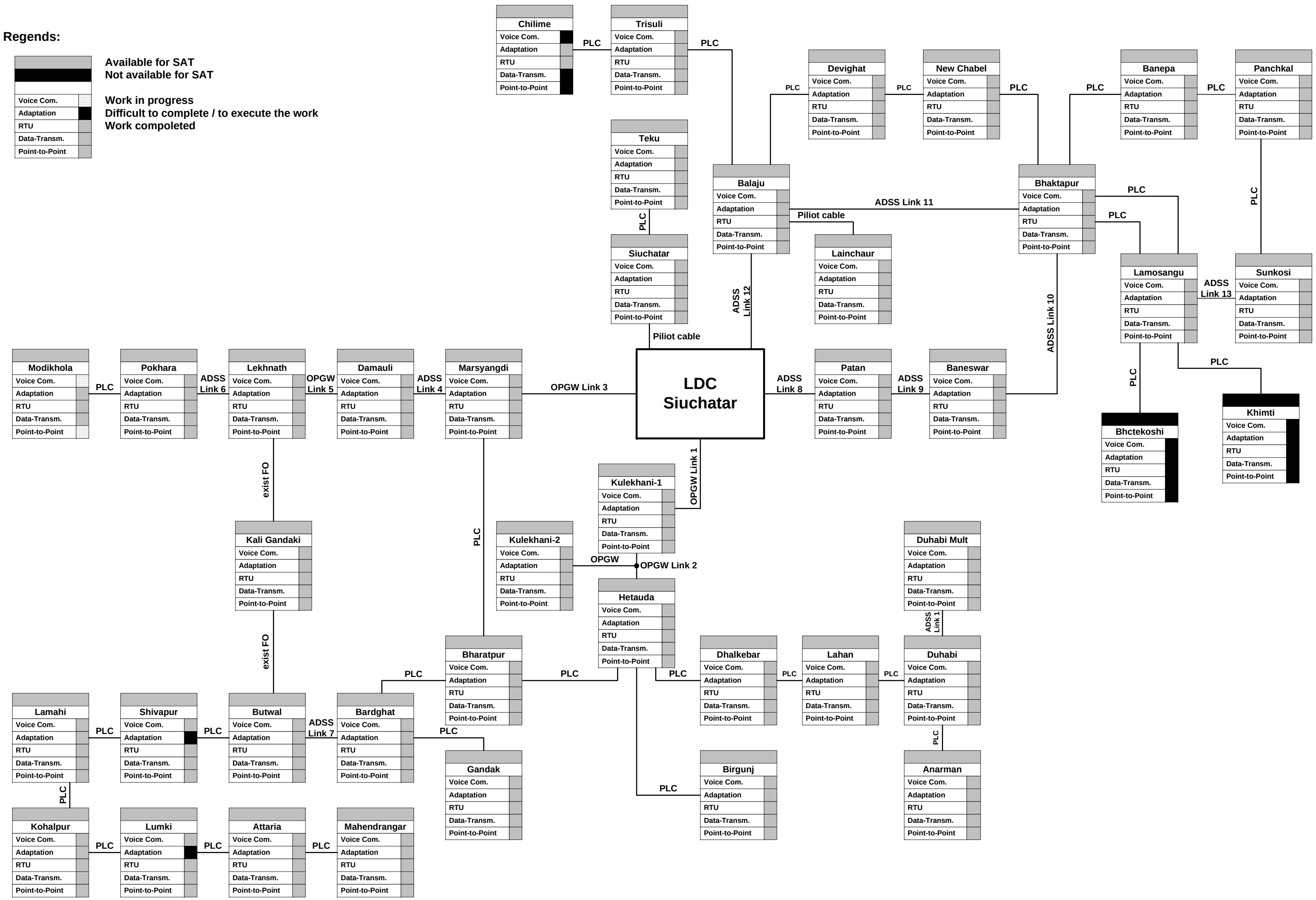

Fig. 4.4.1-2 Block Diagram of Outstation (RTU Stations)

Table 4.4.1-1 Functions of the NEA SCADA System

Computer Configuration	Duplicated Distribution
RTU (Remote Terminal Unit)	Programmable RTU560 (made by ABB)
Communication Data Channel Assignment	Grouping RTUs in a party line configuration
Scanning rate	Status data : Analog data : Pulse data :
Communications system	PLC (Power Line Carrier) and OP (Optical Fiber): ADSS (All Dielectric Self Supporting) and OPGW (Optical Ground Wire)
Individual information items received	- Status of circuit breakers, isolators, transformer tap positions - Measurement of effective power, reactive power, voltage, frequency - Alarms - Pulses for energy accounting
Control items for sending	- On and off control of circuit breakers for 132 kV and 66 kV - Off control of circuit breakers with load shedding purpose for corresponding 11 kV feeders - Transformer tap position - Load increase (raise) and decrease (lower) of the AGC (Automatic Generation Control)
Numerical control for sending	No assignment

The SCADA system is composed of a duplicated distribution system, as described above, while a process-oriented programming language, UNIX, is adopted as an operation system. The issue to be resolved is the insufficient length of the training period, leading to very little understanding of the system being attained, especially concerning the software field aspect. NEA faces a serious problem in managing the SCADA system, especially in terms of raising skilled software engineer(s).

The numbering plan for NEA system telephones is issued by the LDC (Load Dispatch Center), which also handles the frequency allocation for the PLC (Power Line Carrier).

4.4.2 Guide to the Load Dispatch Operation

The following is part of the guide for the NEA load dispatch operation.

(1) Permissible frequency operation range

NEA's regulation governing the permissible fluctuation of the power system frequency is as follows:

Normal operation : 50 Hz+/-1.0 % (49.5 – 50.5 Hz)

Emergency operation	:	50 Hz+/-2.5 % (48.75 – 51.25 Hz)
Activation of load shedding	:	48.5 Hz
Power system shutdown	:	48.0 Hz

(2) Permissible voltage operation range:

	Transmission System	Distribution System
Normal operation	Rated voltage +/- 10%	Rated voltage +/- 5%

(3) Generation Dispatch

NEA's generation dispatch is based on the principle of minimizing cost, in order of preference as follows:

- The cheapest generation is the first to be selected/operated.
- Generation of the run-of-river type newly introduced into the system is next to be selected/operated.
- Reservoir type generation is next selected/operated.
- Imported power is next selected/operated.
- Finally, thermal generation is selected/operated.

4.4.3 Power Trade and Power System Configuration with India

Currently, to facilitate power trade with India, the NEA power system is implementing the launch of various power system operations, one of which is the system operation by INPS (Integrated Nepal Power System), and the other is that involving connection to an India power network. The zones involved with the latter are Mahakari and Seti in the west and Segarmatha, Koshi and Mechi in the east. Those power systems are independently operated as asynchronous power systems.

4.5 Actual Records of Power Supply and Demand

4.5.1 Load Demand

(1) Available Energy and Peak Load

The trend in electricity demand experienced by the NEA power system over the past decade, from both aspects, i.e. available energy (= required energy) at both the generating end and in terms of peak demand, is shown in **Fig. 4.5.1-1** and **Table 4.5.1-1**.

Table 4.5.1-1 Available Energy and Peak Load

	Available Energy		Peak Load	
	Actual (GWh)	Rate of Inc. (%)	Actual (MW)	Rate of Inc. (%)
1996	1,262		275	
1997	1,369	8.5	300	9.1
1998	1,373	0.3	317	5.7
1999	1,475	7.4	326	2.8
2000	1,701	15.3	352	8.0
2001	1,868	9.8	391	11.1
2002	2,066	10.6	426	9.0
2003	2,261	9.4	470	10.3
2004	2,381	5.3	515	9.6
2005	2,643	11.0	558	8.3
2006	2,777	5.1	603	8.1
Ave.		8.3		8.2

Source: NEA Fiscal Year 2005/06 – A Year in Review

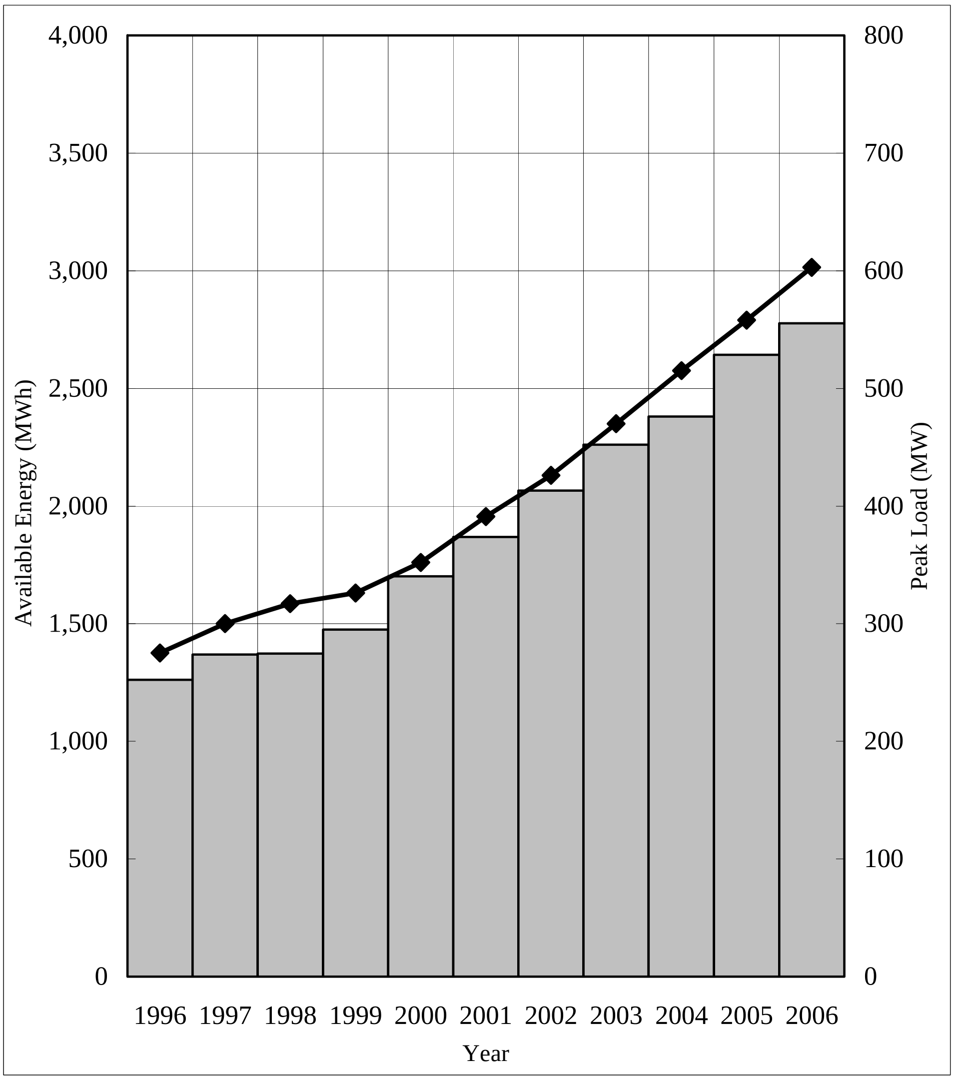

Fig. 4.5.1-1 Energy Demand and Peak Load

The average growth rate of available energy at the generating end within the period FY 1995/96 and FY 2005/06 was 8.3% and that of peak demand 8.2% respectively, demonstrating the remarkable growth of the Nepalese social economy.

(2) Energy Demand by Category

Power consumption in the NEA power system is classified into the following 10 categories:

Category	Category
Domestic	Street light
Industrial	Temporary supply
Water supply and irrigation	Transportations
Non-commercial	Temple
Commercial	Community state

Table 4.5.1-2 shows the actual records of the number of consumers, sales revenue, and electricity demand for the whole of Nepal from FY 19/0596 to FY 2005/06.

Table 4.5.1-2 Number of Consumers, Sales Revenue and Energy Demand

Item	Unit	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Number of Consumers												
Domestic	-	471,599	503,330	548,110	593,468	643,314	713,307	848,540	930,554	1,010,719	1,113,740	1,229,750
Non-commercial	-	6,548	6,338	7,192	7,654	7,815	7,643	8,629	9,722	9,865	9,950	10,010
Commercial	-	2,162	2,441	2,637	2,948	3,096	3,386	3,898	5,317	5,454	6,000	6,170
Industrial	-	12,329	12,928	14,062	14,996	16,179	17,701	18,789	19,833	21,374	22,500	23,020
Water Supply & Irrigation		889	903	981	1,091	1,199	1,319	1,604	2,026	2,909	3,770	6,830
Street Light	-	456	482	683	842	932	1,012	1,048	1,229	1,437	1,500	1,550
Temporay Supply	-	187	155	175	207	144	141	172	138	150	155	
Transport	-	8	8	12	21	47	37	49	48	48	50	50
Temple	-	782	867	992	1,131	1,248	1,441	1,800	1,738	1,959	2,150	
Community Sale	-							1	1	15	35	58
Internal Total	-	494,960	527,452	574,844	622,358	673,974	745,987	884,530	970,606	1,053,930	1,159,850	1,277,438
Bulk Supply (India)	-	5	5	5	5	5	5	5	5	5	5	5
Grand Total	-	494,965	527,457	574,849	622,363	673,979	745,992	884,535	970,611	1,053,935	1,159,855	1,277,443
Sales Revenue												
Domestic	MRs	1,379.46	1,769.84	1,895.85	2,056.05	2,622.03	3,161.38	3,641.43	4,249.81	4,578.99	4,987.04	5,363.46
Non-commercial	MRs	307.25	386.36	405.14	419.58	527.40	835.78	722.12	783.99	816.01	862.37	929.48
Commercial	MRs	349.63	446.96	477.04	515.72	661.58	555.62	818.75	894.91	986.07	1,012.66	1,138.21
Industrial	MRs	1,406.73	1,801.58	1,973.37	2,093.88	2,599.34	3,086.10	3,608.13	4,039.65	4,380.22	4,799.74	5,061.11
Water Supply & Irrigation	MRs	68.40	95.70	100.28	78.14	95.65	120.90	138.68	148.53	154.80	211.57	196.63
Street Light	MRs	53.04	80.11	101.98	111.37	149.95	176.05	200.74	246.79	329.52	314.11	373.06
Temporay Supply	MRs	11.84	7.99	7.17	7.06	13.39	6.77	3.63	4.74	3.46	5.06	9.86
Transport	MRs	4.20	6.09	6.51	9.46	18.31	27.73	27.90	29.29	28.94	30.72	30.50
Temple	MRs	4.56	6.21	6.71	7.42	9.70	11.45	12.16	14.24	20.80	29.17	25.04
Community Sale	MRs								16.59	20.09	24.04	28.47
Internal Sales	MRs	3,585.10	4,600.84	4,974.05	5,298.67	6,697.35	7,981.78	9,173.53	10,428.53	11,318.92	12,276.48	13,155.82
Bulk Supply (India)	MRs	206.72	249.29	199.92	198.15	327.80	396.06	514.12	808.96	673.69	609.51	565.60
Total Sales	MRs	3,791.82	4,850.13	5,173.96	5,496.82	7,025.16	8,377.83	9,687.65	11,237.49	11,992.61	12,885.99	13,721.42
Energy Demand (GWh)												
Domestic	GWh	328.730	355.118	378.778	410.566	467.049	518.360	557.940	617.110	676.365	730.829	810.190
Non-commercial	GWh	53.464	57.991	60.227	62.931	63.592	73.157	78.220	80.736	83.012	91.342	101.030
Commercial	GWh	62.916	67.606	71.471	77.343	81.822	94.166	90.426	92.741	108.122	107.435	123.450
Industrial	GWh	358.672	376.742	413.738	440.996	508.357	520.634	596.677	629.505	689.799	763.771	803.350
Water Supply & Irrigation	GWh	25.091	27.978	29.045	22.831	15.742	28.600	29.283	29.983	31.671	36.115	42.730
Street Light	GWh	16.720	20.929	26.585	29.405	31.741	36.981	39.517	45.803	55.196	57.844	64.880
Temporay Supply	GWh	1.154	0.844	0.711	0.766	0.927	0.826	0.282	0.348	0.251	0.394	0.730
Transport	GWh	1.432	1.483	1.663	2.598	2.678	5.892	5.635	5.530	5.471	5.715	5.980
Temple	GWh	1.503	1.691	1.801	1.982	2.366	2.511	2.476	2.811	4.111	4.204	4.910
Community Sale	GWh							5.717	4.740	5.581	8.172	8.020
Internal Total	GWh	849.682	910.382	984.019	1,049.418	1,174.274	1,281.127	1,406.173	1,509.307	1,659.579	1,805.821	1,965.270
Bulk Supply (India)	GWh	87.014	100.218	67.410	64.158	95.000	126.000	133.857	192.249	141.235	112.529	101.000
Grand Total	GWh	936.696	1,010.600	1,051.429	1,113.576	1,269.274	1,407.127	1,540.030	1,701.556	1,800.814	1,918.350	2,066.270

Source: NEA Fiscal Year – A Year in Review

The actual demand and ratio of each category to total demand are shown in **Table 4.5.1-3.**

As shown in **Table 4.5.1-3** and **Fig. 4.5.1-2**, it is understood that nationwide energy demand in Nepal has been almost totally occupied by two major categories, namely “domestic” and “industry”. The ratio of industry to total demand remains almost constant every year, while that of domestic and street lighting has shown an upward tendency. In particular, the ratio of street lighting has shown remarkable growth, almost doubling within a decade. This energy demand, however, was about 5% relative to the domestic level in the year FY 1995/96 and 8.2% in FY 2005/06 respectively. Conversely, domestic energy demand has been steadily increasing, and was at a level virtually equivalent to industry in FY 2005/06. The growth rates for the two major areas of energy demand are shown in **Table 4.5.1-4**.

Table 4.5.1-3 Energy Demand and Rate of Increase

Energy Demand (GWh)	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Domestic	328.730	355.118	378.778	410.566	467.049	518.360	557.940	617.110	676.365	730.829	810.190
Rate of Increase (%)		8.0	6.7	8.4	13.8	11.0	7.6	10.6	9.6	8.1	10.9
Ratio to Total (%)	38.7	39.0	38.5	39.1	39.8	40.5	39.7	40.9	40.8	40.5	44.9
Non-commercial	53.464	57.991	60.227	62.931	63.592	73.157	78.220	80.736	83.012	91.342	101.030
Rate of Increase (%)		8.5	3.9	4.5	1.1	15.0	6.9	3.2	2.8	10.0	10.6
Ratio to Total (%)	6.3	6.4	6.1	6.0	5.4	5.7	5.6	5.3	5.0	5.1	5.6
Commercial	62.916	67.606	71.471	77.343	81.822	94.166	90.426	92.741	108.122	107.435	123.450
Rate of Increase (%)		7.5	5.7	8.2	5.8	15.1	-4.0	2.6	16.6	-0.6	14.9
Ratio to Total (%)	7.4	7.4	7.3	7.4	7.0	7.4	6.4	6.1	6.5	5.9	6.8
Industrial	358.672	376.742	413.738	440.996	508.357	520.634	596.677	629.505	689.799	763.771	803.350
Rate of Increase (%)		5.0	9.8	6.6	15.3	2.4	14.6	5.5	9.6	10.7	5.2
Ratio to Total (%)	42.2	41.4	42.0	42.0	43.3	40.6	42.4	41.7	41.6	42.3	44.5
Water Supply & Irrigatio	25.091	27.978	29.045	22.831	15.742	28.600	29.283	29.983	31.671	36.115	42.730
Rate of Increase (%)		11.5	3.8	-21.4	-31.0	81.7	2.4	2.4	5.6	14.0	18.3
Ratio to Total (%)	3.0	3.1	3.0	2.2	1.3	2.2	2.1	2.0	1.9	2.0	2.4
Street Light	16.720	20.929	26.585	29.405	31.741	36.981	39.517	45.803	55.196	57.844	64.880
Rate of Increase (%)		25.2	27.0	10.6	7.9	16.5	6.9	15.9	20.5	4.8	12.2
Ratio to Total (%)	2.0	2.3	2.7	2.8	2.7	2.9	2.8	3.0	3.3	3.2	3.6
Temporary Supply	1.154	0.844	0.711	0.766	0.927	0.826	0.282	0.348	0.251	0.394	0.730
Rate of Increase (%)		-26.9	-15.8	7.7	21.0	-10.9	-65.9	23.4	-27.9	57.0	85.3
Ratio to Total (%)	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Transport	1.432	1.483	1.663	2.598	2.678	5.892	5.635	5.530	5.471	5.715	5.980
Rate of Increase (%)		3.5	12.1	56.2	3.1	120.0	-4.4	-1.9	-1.1	4.5	4.6
Ratio to Total (%)	0.2	0.2	0.2	0.2	0.2	0.5	0.4	0.4	0.3	0.3	0.3
Temple	1.503	1.691	1.801	1.982	2.366	2.511	2.476	2.811	4.111	4.204	4.910
Rate of Increase (%)		12.5	6.5	10.0	19.4	6.1	-1.4	13.5	46.2	2.3	16.8
Ratio to Total (%)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Community Sale							5.717	4.740	5.581	8.172	8.020
Rate of Increase (%)								-17.1	17.7	46.4	-1.9
Ratio to Total (%)								0.3	0.3	0.5	0.4
Total of Energy Demand	849.7	910.4	984.0	1,049.4	1,174.3	1,281.1	1,406.2	1,509.3	1,659.6	1,805.8	1,965.3

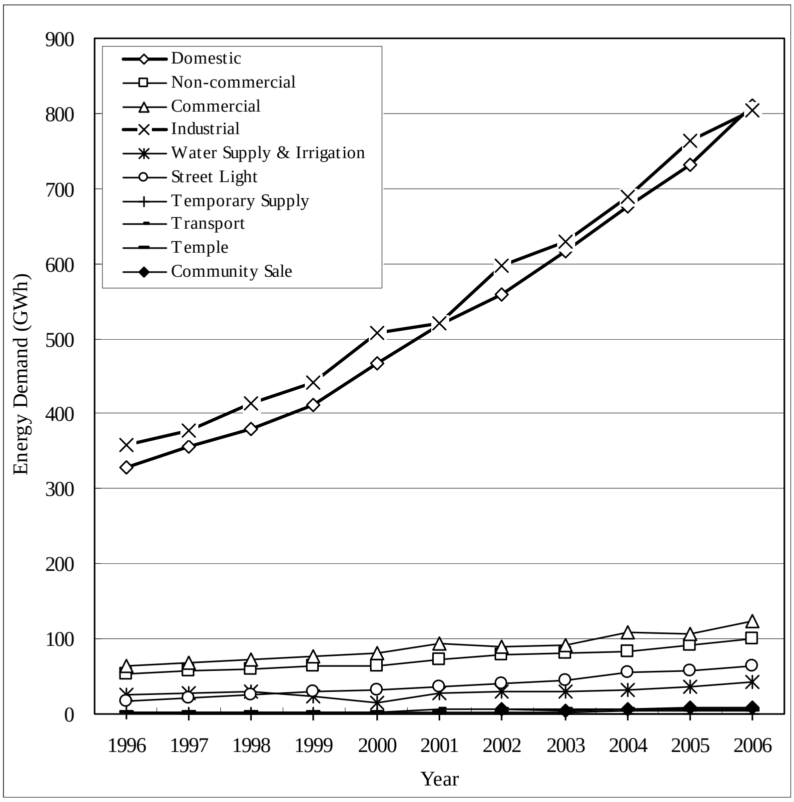

Fig. 4.5.1-2 Energy Demand by Category

Table 4.5.1-4 Growth Rates for Domestic and Industrial Demand

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Domestic (GWh)	328.7	355.1	378.8	410.6	467.0	518.4	557.9	617.1	676.4	730.8	810.2
Growth Rate (%)		8.0	6.7	8.4	13.8	11.0	7.6	10.6	9.6	8.1	10.9
Industrial (GWh)	358.7	376.7	413.7	441.0	508.4	520.6	596.7	629.5	689.8	763.8	803.4
Growth Rate (%)		5.0	9.8	6.6	15.3	2.4	14.6	5.5	9.6	10.7	5.2

(3) Monthly Maximum and Minimum Peak Loads

Figs. 4.5.1-3 and **-4** illustrate the monthly maximum and minimum peak loads from FY 2004/05 to 2005/06. The dry season in Nepal is from November to April, the wet season from May to October. In general the maximum peak load is recorded during the dry season and the minimum peak load during the early wet season.

Fig. 4.5.1-3 Monthly Maximum Peak Load

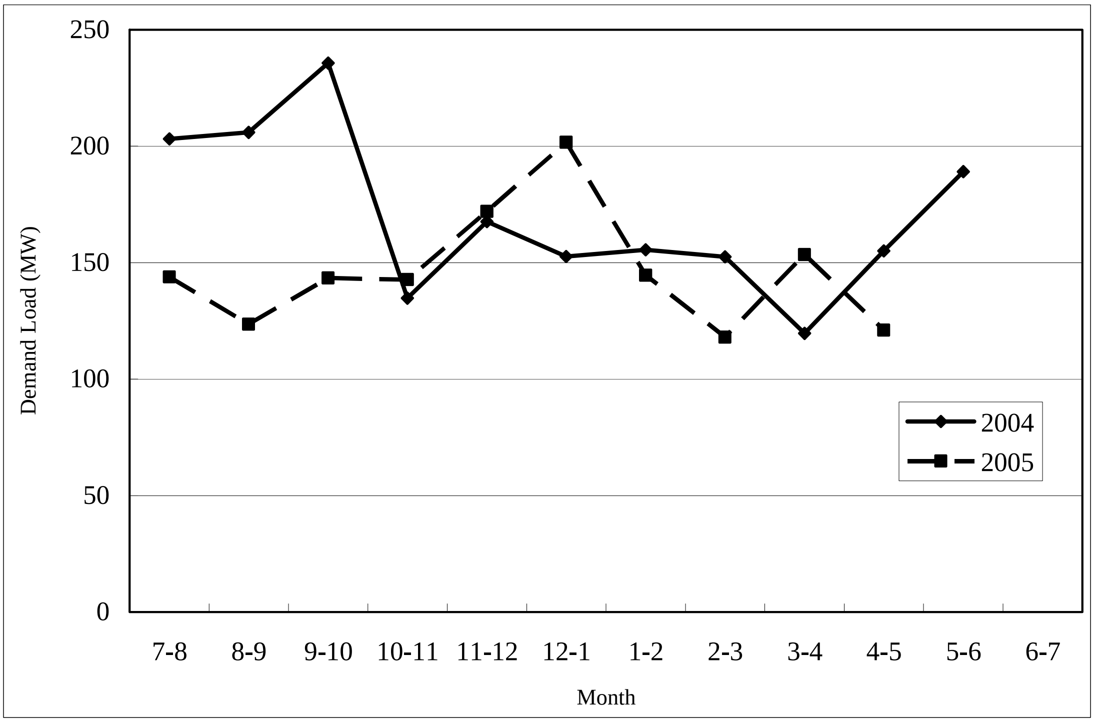

Fig. 4.5.1-4 Monthly Minimum Peak Load

(4) Daily Load

The Peak Load Curve for the period FY 2004/05 to FY 2005/06 is shown in **Fig. 4.5.1-5**. Peak load in Nepal is recorded in terms of morning and evening peaks and illustrates the general tendency for typical domestic demand.

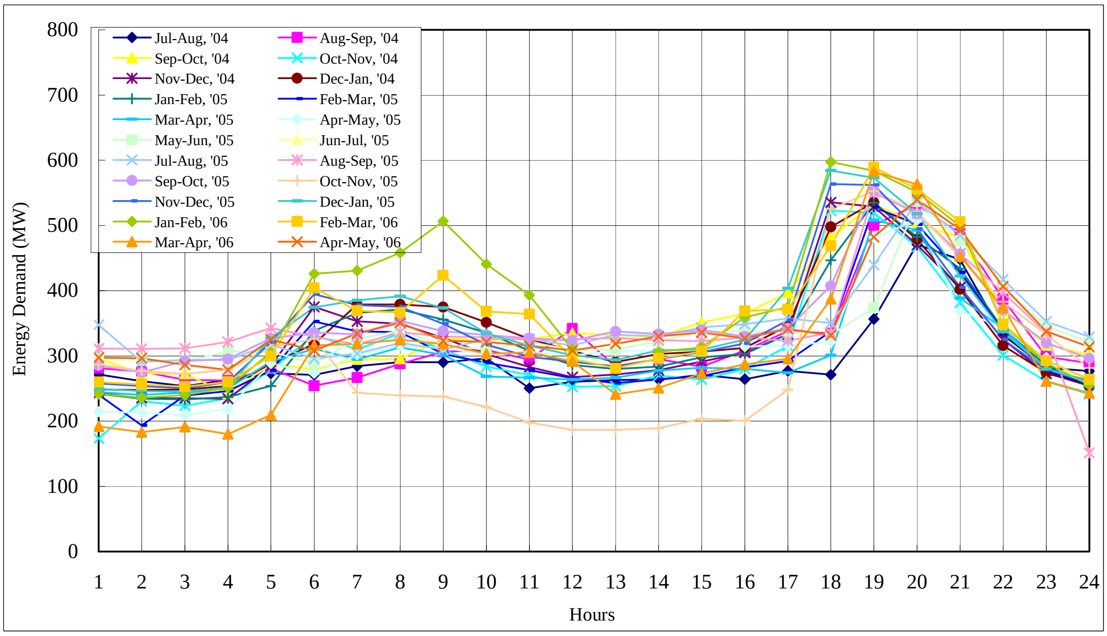

Fig. 4.5.1-5 Daily Load Curve recorded in terms of Monthly Maximum Figure (FY2004/05 – 2005/06)

(5) Daily Load Curve Recorded as an Annual Maximum Peak Load

The daily load curves for December 3, 2003, December 5, 2004, and January 12, 2006, when the maximum load in FY 2003/04 to 2005/06 was recorded, are shown in **Figs. 4.5.1-6, -7** and **-8** respectively.

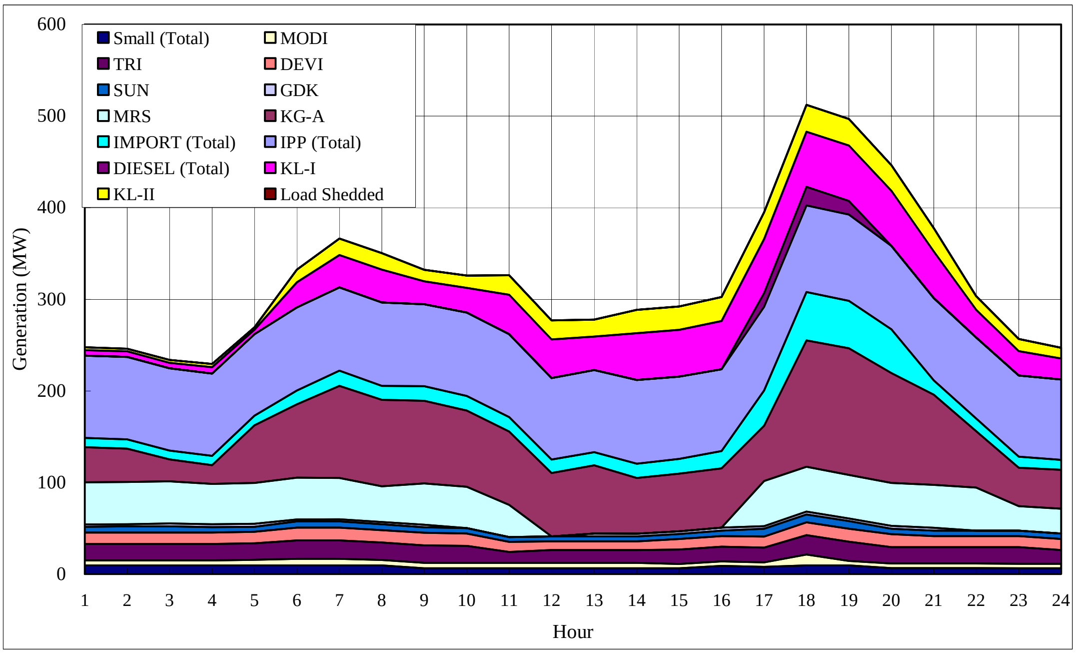

Fig. 4.5.1-6 Daily Load Curve on 3 Dec. 2003

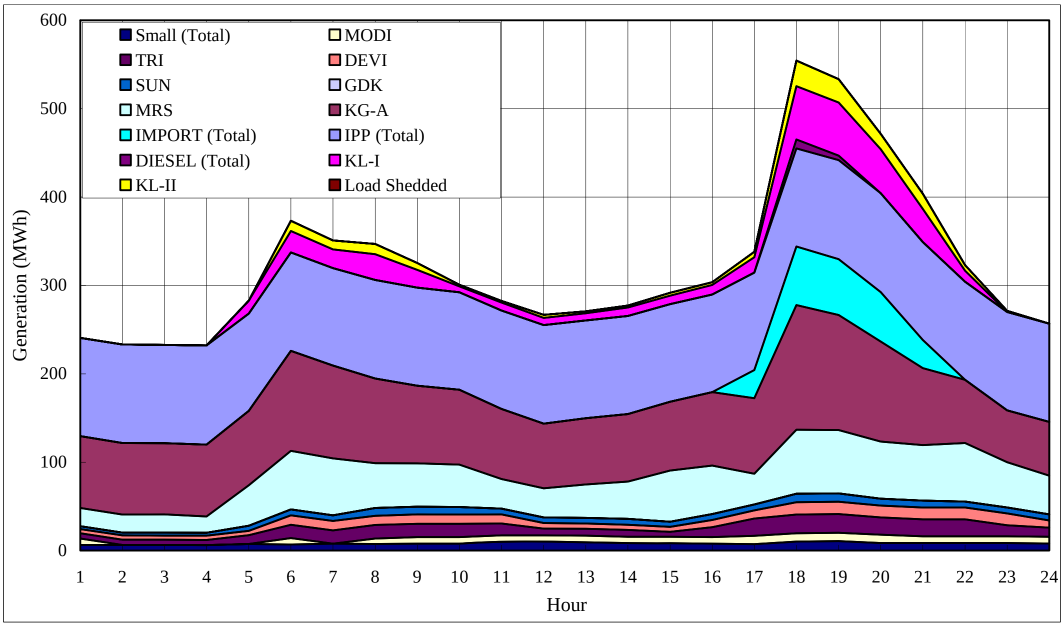

Fig. 4.5.1-7 Daily Load Curve on 8 Dec. 2004

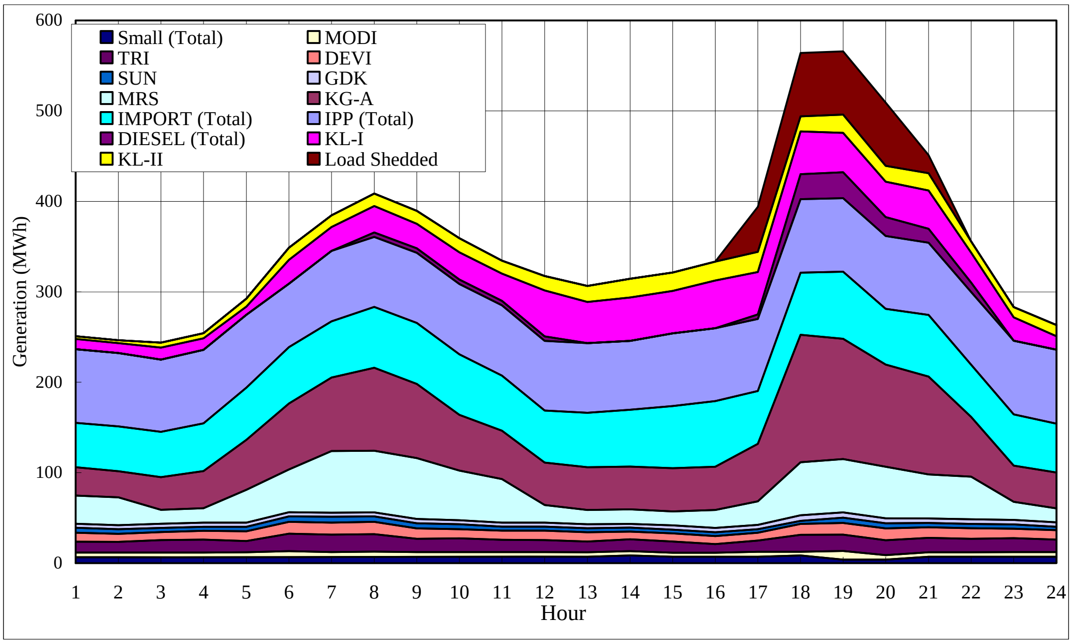

Fig. 4.5.1-8 Maximum Daily Load Curve on 12 Jan. 2006

The composition of the power supply in the NEA power system, mainly comprising hydropower stations, is classified into the following:

1) Base load

Base load is supplied by run-of-the river type hydropower plants owned by both NEA and IPPs.

2) Intermediate load

Kali Gandaki "A" is a typical plant supplied with intermediate load.

3) Peak load

Peak load is mainly controlled by the reservoir type hydropower plants, such as Kulekhani-I and Kulekhani-II, and thermal power plants. In addition, the roles of Kali Gandaki "A" and Masyangdi are also important to respond to rapid load fluctuation within a short period. In the case of December 8, 2004 when the maximum peak of the fiscal year was recorded, it is easily understood that generation had to increase supply by around 200 MW in one hour from around 17:00 to 18:00 to cope with demand and absorb the fluctuation of frequencies during the same period, and this tendency is supposed to persist for future power system operation.

Imported power has an important role in isolated power system operations, i.e. one is the system in the west region, connected to the Indian system at Tanakpur, and the other is that in the east region, where the Duhabi and Anamani substations are located.

(6) Actual Records of Reservoir Operation

Fig. 4.5.1-9 shows the actual records of the Kulekhani-I hydropower plant reservoir operation. The following are summarized as observed from the figure:

- It is easily understood that FY 2001/02 was a dry one, FY 2002/03 a wet one, and FY 2003/04 midway between two.
- Virtually all run-of-river type hydropower plants must lower the output below the rated level during the dry season due to the decreased water inflow. For this reason, reservoir type power plants are expected to operate on a large scale for about 4 months, starting from around the second half of December up to around the second half of April.
- From around the second half of December to the second half of April, namely the dry season in Nepal, the generation of reservoir type hydropower plants increases the operation hours and thus contributes to response in terms of both peak and partial base loads.

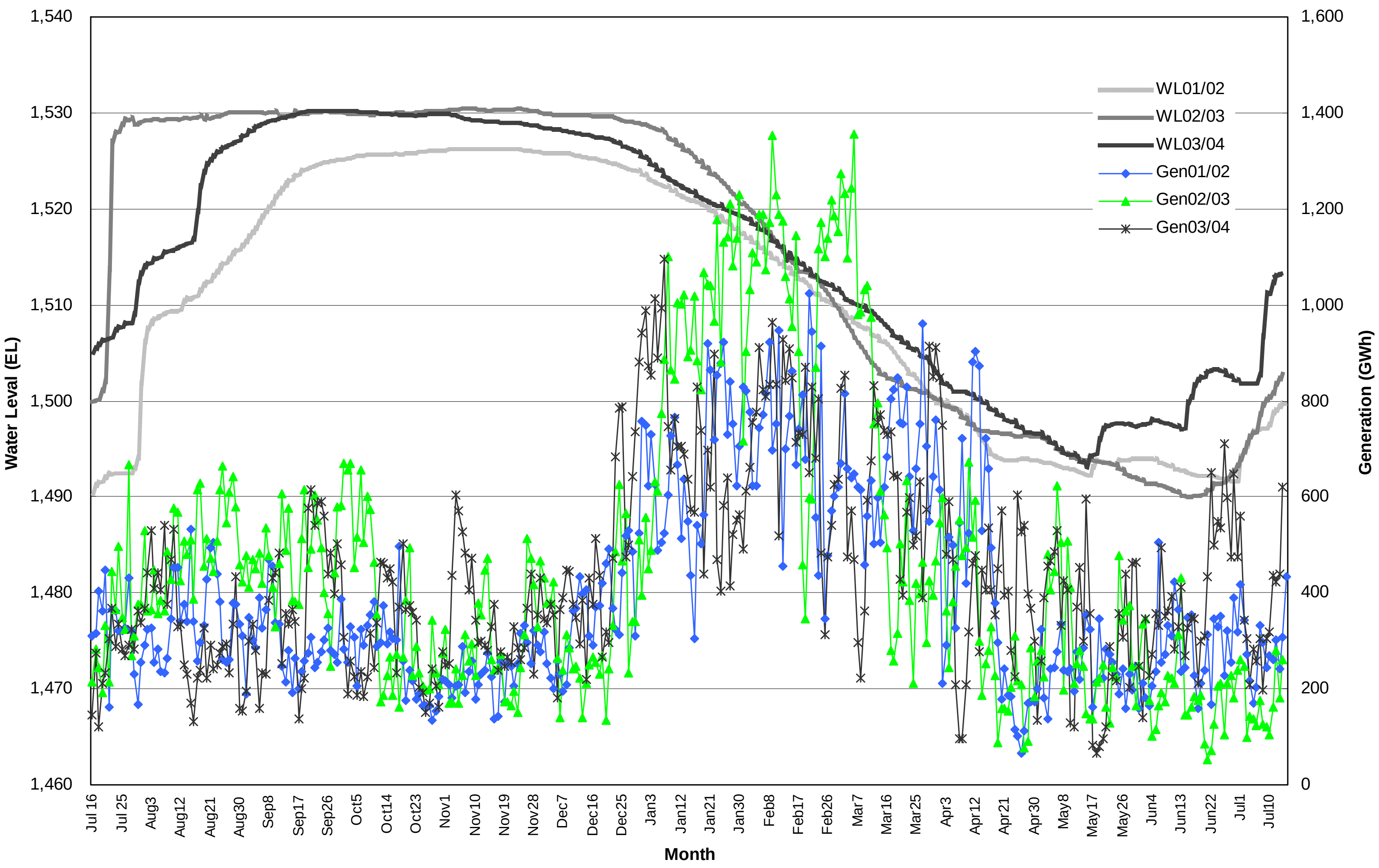

Fig. 4.5.1-9 Reservoir Operation of Kulekani I

4.5.2 Power Supply

(1) Energy Generation

Energy generation data from the commissioning of each power plant to FY 2005/06 is shown in **Table 4.5.2-1** and **Fig. 4.5.2-1**, while the individual share of each plant of the overall total can be seen in **Fig. 4.5.2-2.**

Table 4.5.2-1 Generation Data

S.No.	Power Stations	Type	Commercial Operation	Generation (MWh)						
				Up to 2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	Total
1	Kali Gandaki A	Hydro	April, 2002	0.00	117,253.00	512,625.00	542,538.61	551,652.00	621,348.00	2,345,416.61
2	Marsyangdi	Hydro	Unit-1 27 Dec, 1989 Unit-2 07 Dec, 1989 Unit-3 05 Nov, 1989	5,029,760.00	386,133.20	333,921.00	244,651.80	335,717.80	369,416.30	6,699,600.10
3	Kulekhani I	Hydro	1982	4,568,298.00	145,418.00	170,026.00	160,609.00	173,785.00	114,700.00	5,332,836.00
4	Kulekhani II	Hydro	1986	1,078,299.60	61,999.20	72,065.00	66,676.00	72,092.20	47,329.18	1,398,461.18
5	Trishuli	Hydro	1967	3,170,993.05	128,238.10	117,646.30	96,900.10	122,944.60	134,463.45	3,771,185.60
6	Gandak	Hydro	1978-79	740,161.19	19,026.60	4,566.10	8,365.40	20,717.40	27,072.30	819,908.99
7	Modi Khola	Hydro	Cct. 2000	41,446.50	51,174.00	54,375.00	45,003.70	42,180.60	46,453.30	280,633.10
8	Devighat	Hydro	1984	1,318,142.20	91,525.65	84,318.52	69,481.36	84,008.35	95,071.15	1,742,547.23
9	Sunkoshi	Hydro	1972	1,417,685.60	50,820.48	52,795.20	50,181.60	50,234.78	51,328.66	1,673,046.32
10	Ilam Puwakhola	Hydro	April, 2000	21,327.02	24,158.60	25,765.20	31,984.45	29,377.86	28,930.86	161,543.99
11	Chatara	Hydro	Jul, 1996	8,766.60	209.25	978.50	4,504.25	4,115.00	4,563.25	23,136.85
12	Panauti	Hydro	1965	90,078.68	4,653.00	1,421.46	3,925.26	3,684.42	3,074.94	106,837.76
13	Seti	Hydro	1987	147,048.42	1,111.81	9,325.69	8,580.15	9,152.46	9,659.25	184,877.78
14	Phewa	Hydro	1967	55,912.18	8,037.70	1,249.18	527.27	1,352.41	2,383.58	69,462.32
15	Sundarijal	Hydro	1936	56,320.37	4,205.96	3,974.29	4,203.29	4,211.62	2,612.39	75,527.92
16	Multifuel	Diesel	1992	472,945.19	19,310.28	13,661.54	8,742.88	11,142.48	12,588.02	538,390.39
17	Hetauda Diesel	Diesel	1963-Unit 1,2,3 1980-Unit 4,5,6,7	105,522.06	5,196.75	3,039.65	1,117.12	2,192.82	3,520.76	120,589.16
	Total			18,322,706.66	1,118,471.58	1,461,753.63	1,347,992.24	1,518,561.80	1,574,515.39	25,344,001.30

Source: NEA Generation (August 2006)

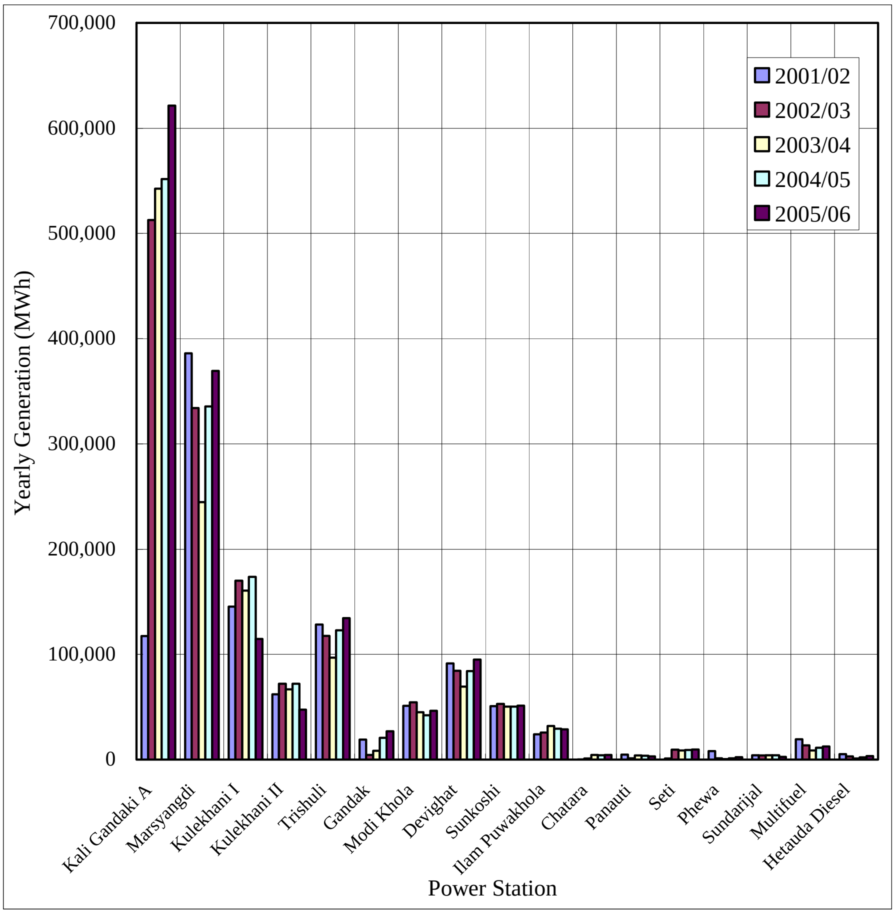

Fig. 4.5.2-1 Yearly Generation (2001/02-2005/06)

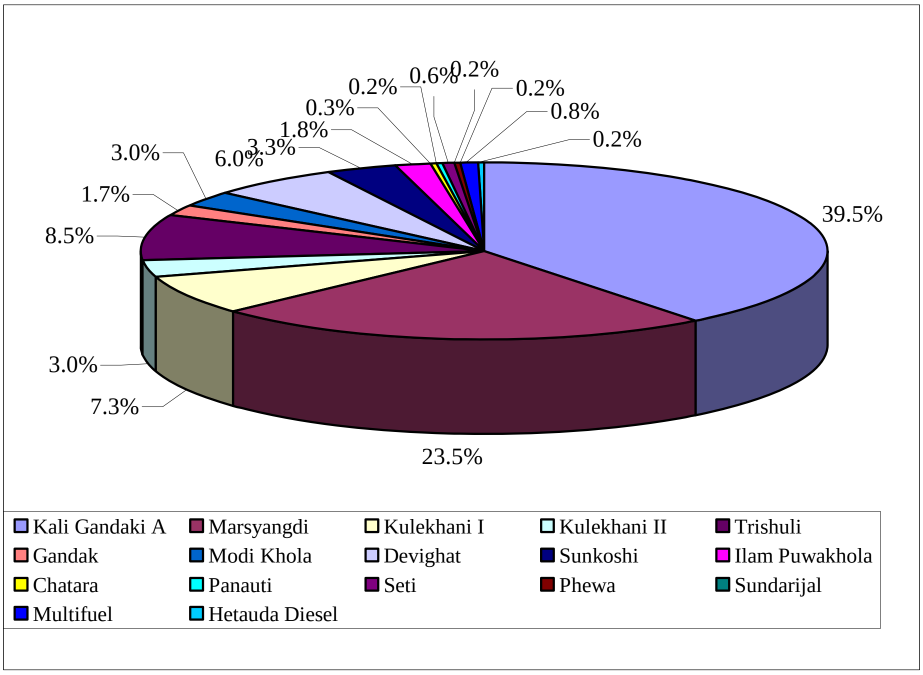

Fig. 4.5.2-2 Ratio of Generation at 2005/06

(2) Operation and Generation Cost

The operation and generation costs for FY 2003/04 are shown in **Table 4.5.2-2.** Both costs are defined as follows:

1) Operation cost

Operation cost = Operation and maintenance expenditure / total generating energy

2) Generation cost

Generation cost = (Operation and maintenance expenditure + royalties + depreciation + interest + deferred + overheads) / total generating energy

The generation cost of both thermal power stations “Multifuel Power Plant” and Hetauda Diesel Power Plant were as follows in 2004:

a) Multifuel Power Plant

Fuel consumption (g/kWh)	:	265
Fuel type	:	Furnace oil (heavy oil)
		Specific gravity 1.010 (3.8 kWh/ltr)
Cost of fuel and lubricant (US cents/kWh)	:	9.27

b) Hetauda Diesel Power Plant

Fuel Consumption (g/kWh)	:	237.14
Fuel type	:	LDO (Light Diesel Oil)
		Specific gravity 0.83 (3.5 kWh/ltr)
Cost of fuel and lubricant (US cents/kWh)	:	18.27

Table 4.5.2-2 Operation and Generation Costs

Type	Installed Capacity MW	Generation MWh	Assets	Budgt alloted	O&M expenditure	Royalty	Depreciation	Inerest	Deferred	Overhead		Total Cost	Operation Cost, Rs/kWh	Generation Cost Rs/Unit	Transfer Cost Rs/Unit
										Generation	Head Office				
Hydro	144	621,348.00	22,400,112.23	138,978.00	111,940.00	96,763.69	498,887.08	1,704,094.96	75,134.76	16,154.41	135,536.97	2,638,511.86	0.18	4.25	4.67
Hydro	69	369,416.30	5,773,870.87	66,998.00	51,030.29	313,657.99	150,200.00	366,218.93	0.00	9,604.44	80,582.16	971,293.81	0.14	2.63	2.89
Hydro	60	114,700.00	2,695,658.29	39,263.00	36,610.20	135,790.96	57,499.14	34,809.24	0.00	2,982.08	25,019.94	292,711.56	0.32	2.55	2.81
Hydro	32	47,329.18	830,925.67	25,681.00	25,987.67	63,322.41	17,622.01	11,603.08	0.00	1,230.51	10,324.09	130,089.77	0.55	2.75	3.02
Hydro	24	134,463.45	1,850,617.97	5,212,900.00	48,604.00	110,093.04	21,981.21	0.00	0.00	3,495.91	29,331.02	213,505.18	0.36	1.59	1.75
Hydro	15	27,042.30	198,377.67	22,171.00	22,776.96	324,723.43	6,019.46	0.00	0.00	703.07	5,898.84	678,700.76	0.64	2.51	2.76
Hydro	14.8	46,453.30	2,037,508.32	27,847.00	19,467.26	7,561.03	55,036.78	87,309.70	502.80	1,207.74	10,133.03	181,218.34	0.42	3.90	4.29
Hydro	14.1	95,071.15	388,746.59	29,468.00	28,637.34	77,111.09	14,317.00	0.00	0.00	2,471.75	20,738.23	143,275.41	0.30	1.51	1.66
Hydro	10.05	51,328.66	136,274.00	4,281.00	51,891.77	43,879.16	3,242.44	0.00	0.00	1,037.60	11,196.51	110,947.48	1.01	2.16	2.38
Hydro	6.2	28,930.86	1,053,471.47	24,938.00	23,112.08	4,466.08	23,307.00	0.00	0.00	752.17	6,310.80	57,948.13	0.79	2.00	2.20
Hydro	3.2	4,563.25	142,404.57	9,604.00	5,893.30	0.00	271.14	0.00	0.00	118.64	995.40	7,278.47	1.29	1.60	1.75
Hydro	2.4	3,074.94	21,296.17	6,786.00	9,265.27	4,411.85	248.00	0.00	0.00	79.95	670.75	14,675.81	3.01	4.77	5.25
Hydro	1.5	9,659.25	15,108.67	12,750.00	7,257.00	7,916.80	429.00	0.00	0.00	392.81	3,295.71	19,291.32	0.78	1.28	2.20
Hydro	1	2,383.58	7,554.33		5,731.00	2,662.06	429.00	0.00	0.00	196.40	1,647.85	10,666.32	2.40	1.41	4.92
Hydro	0.64	2,612.39	0.00		5,420.27	0.00	0.00	0.00	0.00	67.92	569.85	6,058.04	2.07	2.32	2.55
Diesel	39	12,588.02	1,672,716.62	147,998.00	162,864.00	0.00	42,216.00	86,493.42	0.00	327.28	2,745.87	294,646.57	12.93	23.41	25.75
Diesel	14.41	3,520.76	57,015.84	65,885.00	71,658.00	0.00	1,155.00	0.00	0.00	91.54	768.00	73,672.53	20.35	20.93	23.02
		1,574,485.39	39,281,659.28	5,835,548.00	688,146.41	1,192,359.59	892,860.26	2,290,529.33	75,637.56	40,914.22	345,765.02	5,844,491.36	47.54	81.57	93.87

M Expenditure / Total Generation

&M Expenditure + Royalty + Depreciation + Interest + Deferred + Overhead) / Total Generation

I Expenditure + Royalty + Depreciation + Interest + Deferred + Overhead of generation only) / Total Generation

Source: NEA Generation (August 2006)

(3) Generation Availability

The generation availability in FY 2003/04 is shown in **Table 4.5.2-3**, while generation availability is defined as below:

Generation availability = Wi x Ai

Where,

Wi: Weight of the center = installed capacity of the plant / total installed capacity

Ai: (1 – (Scheduled outage / Yearly hours (8760))) * 100

From **Table 4.5.2-3**, it is easily understood that Kali Gandaki "A", Marsyangdi, Kulekhani- I, Kulekhani-II and Multifuel play major roles in the NEA power system operation, and in the Kali Gandaki "A" power plant, special mention is made of a generation availability of about 30%.

Table 4.5.2-3 Generation Availability in 2005/06

S.No.	Name of Powerstation	Type	Unit Capacity MW	No. of Units	Installed Capacity MW (P)	Weightage of the Center (Wi)	Running Hours	Idle Hours	Planned Outage	Total Hours of this Year	Plant Abailability (Ai)	Genration Availability (Wi * Ai)
1	Kali Gandaki A	Hydro	48	3	144	0.319	17454.24	8566.19	331.57	26352.00	98.74	31.506
2	Marsyangdi	Hydro	23	3	69	0.153	20436.24	5845.30	175.46	26352.00	99.33	15.187
3	Kulekhani I	Hydro	30	2	60	0.133	6152.27	11287.42	128.31	17568.00	99.27	13.198
4	Kulekhani II	Hydro	16	2	32	0.071	5403.41	12045.05	119.54	17568.00	99.32	7.042
5	Trishuli	Hydro	3.5 & 3	6 + 1	24	0.047	48695.00	12575.00	218.00	61488.00	99.65	4.637
6	Gandak	Hydro	5	3	15	0.033	9558.25	17045.69	1148.06	26352.00	95.64	3.179
7	Modi Khola	Hydro	7.4	2	14.8	0.033	7979.17	9496.24	92.59	17568.00	99.47	3.262
8	Devighat	Hydro	4.7	3	14.1	0.031	23011.31	23972.78	170.22	26352.00	99.35	3.104
9	Sunkoshi	Hydro	3.35	3	10.05	0.022	17384.34	6796.14	171.52	26352.00	99.35	2.212
10	Ilam Puwakhola	Hydro	3.1	2	6.2	0.014	11242.12	6323.41	2.47	17568.00	99.99	1.374
11	Chatara	Hydro	1.6	3	3.2	0.007	8373.00	7954.00	1241.00	17568.00	92.94	0.659
12	Panauti	Hydro	0.8	3	2.4	0.005	6717.00	19503.79	731.21	26352.00	97.23	0.517
13	Seti	Hydro	0.5	3	1.5	0.003	20948.00	5122.00	296.00	26352.00	98.88	0.329
14	Phewa	Hydro	0.25	4	1	0.002	22413.00	20396.00	1537.00	35136.00	95.63	0.212
15	Sundarijal	Hydro	0.32	2	0.64	0.001	7890.00	8784.00	894.00	17568.00	94.91	0.135
16	Multifuel	Diesel	6.5	6	39	0.086	2601.67	43404.00	8520.00	52704.00	83.83	7.245
17	Hetauda Diesel	Diesel	2.5&1.47	4+3	14.41	0.032	2939.65	50622.65	10520.00	61488.00	82.89	2.647
	Total					1.0	239198.67	269739.66	26296.95	500688.00	96.26	96.45

Source: NEA Generation (August 2006)

(4) Generation Load Factor and Plant Factor

The load and plant factors of each plant owned by NEA in FY 2005/06 are shown in **Table 4.5.2-4.**

Table 4.5.2-4 Load and Plant Factors in 2005/06

S.No.	Name of Powerstation	Type	Installed Capacity MW	No. of Units	Unit Capacity MW	Generation MWh	Running Hours	Load Factor %	Plant Factor %
1	Kali Gandaki A	Hydro	144	3	48	621,348.00	17454.24	74.16	49.26
2	Marsyangdi	Hydro	69	3	23	369,416.30	20436.24	78.59	61.12
3	Kulekhani I	Hydro	60	2	30	114,700.00	6152.27	62.15	21.82
4	Kulekhani II	Hydro	32	2	16	47,329.18	5403.41	54.74	16.88
5	Trishuli	Hydro	24	6 + 1	3.5 & 3	134,463.45	48695.00	78.90	63.96
6	Gandak	Hydro	15	3	5	27,042.30	9558.25	56.58	20.58
7	Modi Khola	Hydro	14.8	2	7.4	46,453.30	7979.17	78.67	35.83
8	Devighat	Hydro	14.1	3	4.7	95,071.15	23011.31	87.90	76.97
9	Sunkoshi	Hydro	10.05	3	3.35	51,328.66	17384.34	88.14	58.30
10	Ilam Puwakhola	Hydro	6.2	2	3.1	28,930.86	11242.12	83.01	53.27
11	Chatara	Hydro	3.2	3	1.6	4,563.25	8373.00	34.06	16.28
12	Panauti	Hydro	2.4	3	0.8	3,074.94	6717.00	57.22	14.63
13	Seti	Hydro	1.5	3	0.5	9,659.25	20948.00	92.22	73.51
14	Phewa	Hydro	1	4	0.25	2,383.58	22413.00	42.54	27.21
15	Sundarijal	Hydro	0.64	2	0.32	2,612.39	7890.00	99.92	46.60
16	Multifuel	Diesel	39	6	6.5	12,588.02	2601.67	74.44	3.68
17	Hetauda Diesel	Diesel	14.41	4+3	2.5&1.47	3,520.76	2939.65	58.18	2.79
	Total		451.30			1,574,485.39	239198.67	83.04	39.83

Source: NEA Generation (August 2006)

The load factor of reservoir type hydropower stations, i.e. Kulekhani-I and Kulekhani-II, is relatively lower, because the operational objectives of these power plants are the absorption of frequency fluctuation as a priority, followed by the ability to respond to peak load.

Moreover, the water inflows of the run-of-river type hydropower plants are significantly affected through the entire year, and their load factors lowered accordingly.

Based on **Table 4.5.2-4** above, the generation availability of Kali Ganadaki "A" shows a low level situation, with fairly long full tripping hours, despite the fact that this power plant has been assigned an important role in terms of intermediate generation and response to peak generation.

The cause(s) to be highlighted can be mainly attributed to the influence of suspended solids in river water, which represented a very serious situation. Following commissioning in 2002, the guide vane and other turbine parts were subject to fatal wear and tear, consequently hampering the mechanism for opening and closing the inlet valve. Immediate remedial action in the shape of a major overhaul was required.

Fundamentally resolving this situation involves reducing the size of the suspended solid particles flowing into the water turbine. However, it remains very difficult to implement such fundamental countermeasures once the plant construction is completed.

Repair work for the inlet valve, guide vane and turbine were commenced in 2005 under a JBIC loan, and this will serve to improve the generation reliability once complete.

At reservoir type hydropower installations like that in this project, the influence of suspended solids is modest when using reservoir water for generation purposes during the dry season, but during the wet season, when using the water having flowed into the reservoir for generation purposes when the water level is full, the situation becomes relatively similar to that facing the run-off-river type hydro plants, meaning the impact suspended solids is inevitable. This matter is examined at the feasibility design stage, but there is the potential for the annual plant operation to be restricted in some ways.

4.6 Electricity Tariff

(1) Electricity Tariff in Nepal

The electricity tariff in Nepal has long been decided politically and as is usual in developing countries, did not cover the cost of electricity, which caused considerable internal financial problems in the NEA, which requires investment to cover rural electrification and the increase in power demand. However, with the assistance of donors, including the Asian Development Bank, NEA implemented the following tariff revisions during the 1990s as detailed below. The main reasons for repeated tariff increment were to generate sufficient internal cash flow to finance the capital cost of power system expansion, to achieve a reasonable rate of return on capital, and to remain a financially sound organization.

December 1991	60%
March 1992	25%
March 1993	38%
May 1996	20%
November 1999	28%
October 2001	22%.

Although the tariff had previously long been decided by the government, the decision making has now been assigned to the Electricity Tariff Fixation Committee. In addition, a provision for semi-automatic adjustment to the existing tariff not exceeding 5 % a year was introduced. However, no revision has been made for the five consecutive years since 2001, leading to deterioration in the financial circumstances of NEA.

The average tariff rate between 1996 and 2006 is shown in **Table 4.6-1**. There has been an increase of 10% since 2001, which is due to factors unrelated to the tariff revision.

Table 4.6-1 Tariff Rate

(unit: N.Rp.kWh)

Year	Tariff	Year	Tariff
1996	4.1	2002	6.3
1997	4.8	2003	6.6
1998	4.9	2004	6.7
1999	4.9	2005	6.7
2000	5.5	2006	6.6
2001	6.0		

The actual electricity tariff applicable since 2001 is shown in **Table 4.6-2**.

Table 4.6-2 Electricity Tariff Rates

(Billing effective since September 17, 2001)

1:	**DOMESTIC CONSUMERS**		
	A Minimum Monthly Charge: METER CAPACITY	**Minimum Charge (NRs.)**	**Exempt (kWh)**
	Up to 5 Ampere	80.00	20
	15 Ampere	299.00	50
	30 Ampere	664.00	100
	60 Ampere	1394.00	200
	Three phase supply	3244.00	400
	B Energy Charge:		
	Up to 20 units	Rs. 4.00 per unit	
	21 - 250 units	Rs. 7.30 per unit	
	Over 250 units	Rs. 9.90 per unit	
2:	**TEMPLES**		
	Energy Charge	Rs. 5.10 per unit	
3:	**STREET LIGHTS**		
	A With Energy Meter	Rs. 5.10 per unit	
	B Without Energy Meter	Rs. 1860.00 per kVA	
4:	**TEMPORARY SUPPLY**		
	Energy Charge	Rs. 13.50 per unit	
5:	**COMMUNITY WHOLESALE CONSUMER**		
	Energy Charge	Rs.3.50 per unit	
6:	**INDUSTRIAL**	**Monthly Demand Charge (Rs./kVA)**	**Energy Charge (Rs./unit)**
	A Low Voltage (400/230 Volt)		
	(a) Rural and Cottage	45.00	5.45
	(b) Small Industry	90.00	6.60
	B Medium Voltage (11kV)	190.00	5.90
	C Medium Voltage (33kV)	190.00	5.80
	D High Voltage (66kV and above)	175.00	4.60
7:	**COMMERCIAL**		
	A Low Voltage (400/230 Volt)	225.00	7.70
	B Medium Voltage (11kV)	216.00	7.60
	C Medium Voltage (33kV)	216.00	7.40
8:	**NON-COMMERCIAL**		
	A Low Voltage (400/230 Volt)	160.00	8.25
	B Medium Voltage (11kV)	180.00	7.90
	C Medium Voltage (33kV)	180.00	7.80
9:	**IRRIGATION**		
	A Low Voltage (400/230 Volt)	-	3.60
	B Medium Voltage (11kV)	47.00	3.50
	C Medium Voltage (33kV)	47.00	3.45
10:	**WATER SUPPLY**		
	A Low Voltage (400/230 Volt)	140.00	4.30
	B Medium Voltage (11kV)	150.00	4.15
	C Medium Voltage (33kV)	150.00	4.00
11:	**TRANSPORTATION**		
	A Medium Voltage (11kV)	180.00	4.30
	B Medium Voltage (33kV)	180.00	4.24

TIME OF DAY (TOD) TARIFF RATES

	Consumer Category & Supply Level	Monthly Demand Charge (Rs./kVA)	Energy Charge (Rs./unit)		
			Peak Time 18:00-23:00	Off-Peak 23:00-06:00	Normal 06:00-18:00
A:	**High Voltage (66kV and Above)**				
	1 Industrial	175.00	5.20	3.15	4.55
B:	**Medium Voltage (33kV)**				
	1 Industrial	190.00	6.55	4.00	5.75
	2 Commercial	216.00	8.50	5.15	7.35
	3 non-Commercial	180.00	8.85	5.35	7.70
	4 Irrigation	47.00	3.85	2.35	3.40
	5 Water Supply	150.00	4.55	2.75	3.95
	6 Transportation	180.00	4.70	2.95	4.15
	7 Street Light	52.00	5.70	1.90	2.85
C:	**Medium Voltage (11kV)**				
	1 Industrial	190.00	6.70	4.10	5.85
	2 Commercial	216.00	8.65	5.25	7.55
	3 non-Commercial	180.00	9.00	5.45	7.85
	4 Irrigation	47.00	3.95	2.40	3.45
	5 Water Supply	150.00	4.60	2.80	4.10
	6 Transportation	180.00	4.80	3.00	4.25
	7 Street Light	52.00	6.00	2.00	3.00

Note:

a) If demand meter reads kilowatts (kW) then kVA = kW/0.8.

b) 10% discount in the total bill amount will be given to the Government of Nepal approved Industrial District

c) 25% discount in the total bill amount will be given to the Nepal Government Hospital and Health Centers (except residential complex).

(2) Tariff Structure

The tariff is structured according to the voltage level and consumer category. This structure is adopted in order to differentiate tariff and give cost signals as well as taking the consumer ability to pay into consideration. The NEA tariff structure is outlined below (**Table 4.6-3**), with customers divided into three categories according to voltage consumption:

Table 4.6-3 Classification of Electricity Tariff

Category	Voltage class
High voltage customer	66 kV and above
Medium voltage customer	between 11 kV and 33 kV
Low voltage customer	Below 11 kV
Customer categories:	Domestic, Temple, Industrial, Commercial, Non commercial, Irrigation, Water supply, Transportation, Street light, Temporary supply, Bulk community

Under the NEA system, peak demand is recorded for a few hours overnight and to cope with this peak demand, a generation expansion plan has been formulated. The considerable expense incurred in expanding capacity is one of the main reasons for the relatively high cost of supply. In order to deal with this problem, a Time-of-Day (TOD) tariff (peak, off-peak and normal, according to the time of day) was introduced for Medium and High voltage customers via an incentive and disincentive mechanism. A two-part tariff (capacity charge and energy charge) as well as a TOD tariff is applied and introduced on a compulsory basis to encourage load management on the part of customers.

(3) Procedure for Tariff Revision

Formerly, NEA was given the authority to fix the tariff subject to Government approval. However, the amendment of the NEA Act in 1992, meant the right was given to NEA to fix the tariff without Government approval. Instead, the Government constituted the Electricity Tariff Fixation Commission (ETFC) as an independent regulatory authority to determine the selling price of electricity in 1993. The Government appoints the chairperson of the Commission from the non-governmental sector and the Commission has the following six members:

- One representative from the Ministry of Water Resources
- One private economist appointed by the Government
- One representative from utilities, involved in the generation, transmission and distribution of electricity

- One representative from the Federation of the Nepal Chamber of Commerce and Industry
- One individual from among consumers appointed by the Government
- The Executive Director of the Department of Electricity Development as a Member Secretary.

Following the establishment of ETFC, procedures for tariff revision have been revised as follows:

1. The utility shall apply to ETFC concerning any proposed change in the existing tariff, providing social, economical, financial and legal justifications.
2. The ETFC shall approve or reject the application within sixty days of receipt, with any necessary adjustment made to the proposal following detailed discussion by the board.
3. The ETFC may opt for a public hearing, if desired.
4. The revised tariff approved by the ETFC must be notified to the public before its implementation.

In addition, the provision of semi-automatic tariff adjustment has been introduced in ETFC rules. This allows adjustments to the existing tariff of up to 5% without having to undergo a cumbersome process of tariff application and ETFC approval. However, this shall only be applicable following ETFC approval of a formula for such increase. NEA has submitted a proposal on the formula to ETFC for their review and approval, but approval remained pending as of 2006.

4.7 Financial Performance of NEA

As part of the Power Sector Reform in Nepal, international financing institutions such as the Asian Development Bank requested that NEA improve its financial circumstances as a prerequisite for fresh financial funding. NEA has thus agreed on several financial targets with donor agencies; the main purpose being to generate internal cash flow for investment and debt servicing and operating expenses, as well as working capital. The financial targets are as follows: Debt Service Ratio (not less than 1.2), Self Financing Ratio (minimum 20-23%), Level of Receivables (not to exceed the equivalent of NEA's sales revenue for three months), Rate of Return (not less than 6%), Level of Inventory (no more than 1% of revalued gross fixed assets). Several revisions of the electricity tariff during the 1990's contributed significantly to attaining such improved financial performance of NEA in 2000. Due mainly to the lack of any tariff revision after 2001, the financial condition of NEA has been clearly deteriorating since 2003.

Table 4.7-1 shows NEA's financial performance over the last 5 years. According to the Balance Sheet, an increase in the fixed assets account and secured long-term loan account stand out. NEA's major business is hydropower generation, and its fixed assets include many hydropower plants. At the same time NEA predominantly makes use of international donor agencies, such as the Asian Development Bank and the World Bank, as its main sources of the funding required. Loan accounts are guaranteed and on-lent by the Government. Given recent increases in the amounts of the two accounts, the repayment will become an important topic of future discussion.

On the other hand, Profit and Loss Statements for the past 5 years reveal that electricity sales have increased for the last three years due to growth in both customers and energy sales. Conversely however, since FY2004, the operation profit has been in decline compared to previous years. Due to the considerable interest expenses, pretax profit has been negative for the last five consecutive years, and the amount has increased annually since FY2001.

Table 4.7-1 Financial Condition of NEA for the Last 5 Years

BALANCE SHEET					（Unit：Million NRs.）
Capital and Liabilities	FY2006*	FY2005	FY2004	FY 2003	FY 2002
Capital	21,273	20,162	18,216	16,977	16,601
Reserve	4,731	4,826	4,551	5,584	8,152
Loan	51,956	48,686	45,252	43,786	41,475
Grand Total	**77,959**	**73,674**	**68,019**	**66,347**	**66,228**
Assets					
Fixed asset	62,423	61,287	58,963	56,949	58,538
Work in Progress	19,379	16,060	10,620	8,655	4,838
Investment	777	777	713	613	553
Current Assets					
Inventory	1,345	1,373	1,048	1,017	1,058
Receivables	4,065	3,698	3,736	3,380	2,285
Cash	1,296	1,323	1,036	1,076	665
Prepaid & others	2,121	2,099	2,603	2,217	3,314
Total Current Assets	8,827	8,492	7,883	7,691	7,322
Payables	12,933	12,620	9,708	7,445	4,704
Provisions	833	698	682	753	1,244
	13,666	13,318	10,389	8,198	5,948
Net Current Assets	- 4,839	- 4,826	- 2,506	- 508	1,374
Deferred expense	71	128	250	507	916
Related A/C	150	249	- 21.7	131	10
Grand Total	**77,959**	**73,674**	**68,019**	**66,347**	**66,229**

PROFIT AND LOSS STATEMENT					(Unit：Million NRs.)
	FY2006*	FY2005	FY2004	FY2003	FY2002
Sales	13,416	12,605	11,8715	11,013	9,476
Cost of sales	8,607	7,462	6,765	5,409	5,887
Gross profit	**4,809**	**5,143**	**5,109**	**5,665**	**3,589**
Other income	597	618	671	513	460
Distribution cost	1,653	1,484	1,376	1,309	1,174
General admin. expense	654	622	489	536	447
Operation profit	**3,099**	**3,654**	**3,916**	**4,332**	**2,427**
Interest	3,282	3,080	2,992	2,973	1,396
Depreciation	1,751	1,734	1,686	1,657	1,420
Exchange loss	49	- 230	59	0	272
Disposal	80	40	0	192	37
Amortization	85	123	320	411	513
Sub-total	**5,246**	**4,747**	**5,057**	**5,233**	**3,637**
Op. profit incl. interest/depreciation	-2,148	-1,093	-1,141	-900	-1,209
Prior adjustment	325	220	345	444	492
Pretax profit	- 2,473	- 1,313	- 1,486	- 456	- 717
Tax provision	0	0	-274	1,498	143
Net profit	**-2,473**	**-1,313**	**-1,760**	**-1,954**	**-861**
Prior reserve	-4,808	-3,475	-1,695	279	1,160
Profit for dividend	-7,281	-4,788	-3,455	-1,675	299
Insurance fund	20	20	20	20	20
YE reserve	-7,301	-4,808	-3,475	-1,695	279

* Figures in FY2006 are provisional, subject to final audit.

Source: NEA's Audit Reports and A Year in Review 2005/06

4.8 Actual Situation of Power Sector Reform

HMG/N has established the following key strategies for the power sector to implement the Tenth Plan targets (2002-2007):

- To promote private sector participation in power generation and distribution
- To streamline NEA activities and improve its financial viability
- To strengthen the power infrastructure
- To accelerate rural electrification in order to promote economic growth, to improve living standards in rural areas, and to integrate RE with rural economic development programs
- To develop hydropower as an important export item.

Power Sector Reform has been implemented based on this strategy. **Table 4.8-1** summarizes the strategies, activities and intermediate indicators in the power sector of the Tenth Plan, as well as the present status of activity.

As for NEA, organizational reform has been implemented. The National Water Resources Strategy (2002) contains a roadmap for restructuring NEA, with the main points as follows:

(1) Make NEA commercially viable through corporatization, improved management, and the separation of rural electrification operations that require a government subsidy.

(2) Streamline NEA by creating a separate transmission/load dispatch centre that will be responsible for buying and selling power and for system planning.

- Generation operations will be the responsibility of a separate corporation that will compete on a level playing field with the private sector.
- Distribution operations will be sold or contracted out to municipal or private operators.
- NEA will operate as a holding company and will gradually divest its shares to the public: the necessary amendments to the NEA Act will be made.

As a first step toward organizational restructuring, “Generation”, “Transmission and System Operation”, “Engineering Services” and “Distribution and Consumer Services” shall be internally unbundled as core NEA business groups. These core businesses will be accorded increased operational independence, authority and accountability with an integrated performance-related bonus and punishment system. “Distribution and Consumer Services”, for example, introduced a performance contract in all 34 Distribution Centers by 2005, which led to positive performance in reducing system loss.

Additionally, the Electrification Business Group was established to manage distribution expansion, including rural electrification activities, which will provide some relief to NEA in terms of avoiding investment to be made in rural electrification, for which financial viability is difficult to achieve.

Table 4.8-1 Tenth Plan: Power Sector Strategies, Activities and Indicator

Strategies	Activities	Intermediate Indicators	Responsible Agency	Present Status
Promote private sector participation in the power sector	Establish the Power Development Fund	A power development Fund established	MOWR	PDF funding approved by the World Bank, the Nepal Bangladesh Bank appointed.
	Establish an independent regulatory body	A regulatory body established	MOWR	IRG/USAID Draft roadmap to establish independent regulator under review
Improve the NEA financial viability	Develop profit-making centers within NEA	Reduce system losses by 1% a year, starting from 23% at the beginning of the tenth plan	NEA	24.7% in 2006 and 2% reduction in 2007. Performance contracts for 34 distribution centers in place in January 2005
	Internal unbundling of NEA into transmission, generation and distribution units	Complete the internal unbundling of NEA by FY 2004	NEA	NEA reorganized into separate business units, and work for a subsidy policy in place
	Initiate an explicit subsidy policy for grid-based rural electrification	Adopt a subsidy policy for grid-based rural electrification in FY2004	MOWR MoF	For community based RE, 176 proposals approved among 391 applications.
Integrate rural electrification with rural economic development	Promote productive end uses (continued)	Adopt a framework for cooperative–based rural electrification	NEA	Technical and financial maturity assessed by NEA
Promote cooperative based grid-based rural electrification	Capacity building of cooperatives (continued)	Training programs to cooperatives	MOWR	Technical Assistance for Community
Expand and reinforce infrastructure	Expand and reinforce generation, transmission and distribution (ongoing)	Increase the installed capacity from 527 MW to 830 MW	NEA	605MW as of July 2006. Several projects under preparation.
		Increase the length of transmission lines (66/132/220 kV) from 1962 km to 2392 km	NEA	ADB 8th Power Project ongoing. Khimti-Dhaklebar 220kV line (75km) on going..
	Promote small-, medium and storage hydropower projects (ongoing)	Initiate the construction of a storage project	MOWR WECS	Upper Tamakoshi, Upper Seti, Kulekhani III under preparation.

Source: JBIC Nepal Power Sector Study Report and NEA

CHAPTER 5 POWER DEVELOPMENT PLAN

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5.1 Load Demand Forecast

The following are the load demand forecasts conducted by NEA and the JICA Study Team respectively for review purposes, and a comparison of both.

5.1.1 Load Demand Forecast by NEA

In this section, a demand model, economic development forecast, and the results of the load demand forecast study for the INPS (Integrated Nepal Power System) by NEA are described:

(1) Demand Model

Demand modeling by NEA was performed based on the load forecast study in 1997 by Norconsult. The demand model is discussed by classifying into three categories, as shown below:

- Domestic sector
- Industrial, Commercial and Other sectors
- Irrigation

The model for each sector is as follows:

1) Domestic Sector

$D_t = D_{t-1}\ (l+a_t*b)(\Delta P_t/\Delta PI_t + 0.5*\Delta N_{t-1}*d_{t-1}(l+a_t*b)(\Delta P_t/\Delta CPI_t +0.5*\Delta N_t*d_t$

where:

D_t = Electricity consumption during a period t

ΔP_t = Fluctuation in the electricity price during a period t

ΔCPI_t = Fluctuation in the CPI (Consumer Price Index) during a period t

ΔN_t = New consumers connected during a period t

a_t = Real income growth rate during a period t

b = Income elasticity for electricity

c = Price elasticity for household electricity

d_t = Average consumption for new consumers during a period t

2) Industrial, Commercial and Other Sectors

$D_{t,i} = D_{t-1,i}(1 +a_{t,i}*b_i)\ (\Delta P_{t,i}/\Delta PI_t)^{ci} +\Delta L_{t,i}$

where,

Dt,i = Electricity consumption by sector i during a period t

ΔPt,i = Fluctuation in the price of electricity for sector i during a period t

ΔPIt = Fluctuation in the CPI (Consumer Price Index) during a period t

at,i = GDP growth rate for sector i during a period t

bi = Propensity to increase electricity consumption in relation to GDP fluctuation in sector i

ci = Price elasticity for electricity in sector i

$\Delta Lt,i$ = New large-scale projects in sector i during a period t

3) Irrigation

$$Dt = Dt,i(l+a) + \Delta At*b$$

where,

Dt = Electricity consumption in the existing schemes during a period t

a = Fluctuation in electricity requirements of the existing schemes (annual growth rate,%)

ΔAt = Large incremental increases in irrigated land area (by specific projects in hectares) during a period t

b = Average electricity consumption of irrigated land per hectare

(2) Forecast Result

The results of demand forecast by NEA in FY 2005/06 are shown in **Table 5.1.1-1**.

Table 5.1.1-1 Demand Load Forecast and Peak Load by NEA

F.Y.	Energy (GWh)	Growth (%)	Peak Load (MW)	Growth (%)
2006*1	2,777.40		603.28	
2007	2,897.1	4.3	642.2	6.5
2008	3,136.6	8.3	695.3	8.3
2009	3,428.1	9.3	759.9	9.3
2010	3,698.4	7.9	819.8	7.9
2011	4,057.1	9.7	890.6	8.6
2012	4,423.3	9.0	971.0	9.0
2013	4,815.0	8.9	1,057.0	8.9
2014	5,231.2	8.6	1,148.0	8.6
2015	5,673.8	8.5	1,245.6	8.5
2016	6,144.7	8.3	1,336.1	7.3
2017	6,645.9	8.2	1,445.1	8.2
2018	7,179.6	8.0	1,561.1	8.0
2019	7,719.4	7.5	1,678.5	7.5
2020	8,296.7	7.5	1,804.0	7.5
Average Growth		8.14		8.14

*1: Actual

Source: Fiscal Year 2005/06 – A Year in Review

The required annual energy is forecast to be 2,897 GWh in FY 2006/07 and 8,296 GWh in FY 2019/20, with an annual average growth rate of 8.1%, and peak load forecast as 642 MW in FY 2006/07 and 1,804 MW in FY 2019/20 respectively.

5.1.2 Load Demand Forecast by the JICA Team

There are two major concepts involved when forecasting national load demand. One is a macro approach covering the nationwide area using an explanatory parameter such as GDP, selling price, the number of consumers, etc. The other is a micro concept, in which an attempt is made to forecast load demand by stacking the demands of each category in each zone as NEA applies in 5.1.1 above. In the Study, the former "macro approach" concept was used with the intention to confirm the load demand forecast conducted by NEA in mind.

(1) Load Factor

Load factor is estimated based on actual energy at the generating end and the forecast peak load.

1) Available Energy

The correlation of available energy at the generating end was estimated based on actual data concerning the available energy for the period from FY 1991/92 to 2005/06. The appropriate formulae are shown, as follows:

Quadratic regression: $910.58 + 27.573 \times N + 6.6946 \times N^2$ (R2=0.99)

Where,

N: 1, 2, 3 …, N indicates “N” years after 1992

2) Peak Load

The correlation of peak load was estimated based on the actual data of peak load for the period FY 1991/92 to 2005/06. The appropriate formulae are shown as follows:

Quadratic regression: $209.08 + 3.5777 \times N + 1.5101 \times N^2$ (R^2=0.99)

3) Load Factor

Load factor is estimated based on the forecast results of available energy and peak load above. **Table 5.1.2-1** shows the result of load factor estimation.

Table 5.1.2-1 Load Factor

SNo	Year	Avarable Energy		Peak Load		Load Factor	
		Actual (GWh)	Forecast (GWh)	Actual (MW)	Forecast (MW)	Actual (%)	Forecast (%)
1	1992	981		216		51.9	
2	1993	963		214		51.4	
3	1994	1,031		231		50.9	
4	1995	1,117		244		52.3	
5	1996	1,262		275		52.4	
6	1997	1,369		300		52.1	
7	1998	1,373		317		49.4	
8	1999	1,475		326		51.6	
9	2000	1,701		352		55.2	
10	2001	1,868		391		54.5	
11	2002	2,066		426		55.4	
12	2003	2,261		470		54.9	
13	2004	2,381		515		52.8	
14	2005	2,643		558		54.1	
15	2006	2,777		603		52.6	
16	2007		3,066		653		53.6
17	2008		3,314		706		53.6
18	2009		3,576		763		53.5
19	2010		3,851		822		53.5
20	2011		4,140		885		53.4
21	2012		4,442		950		53.4
22	2013		4,757		1,019		53.3
23	2014		5,086		1,090		53.3

The load factor of the NEA power system will decline gradually, due to the future growth tendency for domestic demand. The effect of lowering the peak load by improving the load factor is one of the foreseeable priority areas for the NEA.

(2) Loss Rate

The loss rate incurred by the NEA power system is significant, due to unfavorable non-technical losses such as through theft.

NEA targets a reduction in the loss rate of 1 percentage point per annum during the period FY 2005 – FY 2009 and to limit the overall loss rate to 17% for the period FY 2010 – FY 2020, based on the agreement with ADB. The annual loss rate for the demand forecast is assumed to be in accordance with the target and shown in **Table 5.1.2-2.**

Table 5.1.2-2 Loss Rate

F.Y.	Loss Rate (%)	F.Y.	Loss Rate (%)	F.Y.	Loss Rate (%)
1992	24.8	2000	25.4	2008	19.8
1993	26.3	2001	24.7	2009	18.8
1994	26.6	2002	25.5	2010	17.0
1995	26.2	2003	25.0	2011	17.0
1996	25.8	2004	23.8	2012	17.0
1997	26.2	2005	22.8	2013	17.0
1998	23.4	2006	21.8	2014	17.0
1999	24.5	2007	20.8		

Improvement in the loss rate has a significant impact in terms of saving on project investment costs, meaning further efforts have been requested in this area to further reduce the loss rate, after reaching the target of 17% in the ADB agreement.

(3) Demand Forecast

1) Selection of Explanatory Parameters

In order to decide the explanatory parameter to be used for the demand forecast study, GDP, the average electricity selling price and the total number of consumers are chosen for examination, and the correlation between load demand and each individual parameter is calculated.

a) GDP

Table 2.4.1-4 shows the statistic data of GDP, based on the "Economic Survey 2005/06" published by MOF/Nepal. As judged from the table, it is easily understood that the sudden change in the GDP decrease in FY 2001/02 was caused by manufacturing and trade. These two sectors aside, GDP growth rates show a steadily rising tendency.

The actual records for energy demand and GDP are shown in **Table 5.1.2-3.**

Table 5.1.2-3 Energy Demand and GDP

	Energy Demand (MWh)	GDP (MNRs)
1996	937	221,930
1997	1,011	233,040
1998	1,051	240,816
1999	1,114	251,757
2000	1,269	267,096
2001	1,407	280,107
2002	1,540	279,169
2003	1,702	287,689
2004	1,801	298,023
2005	1,918	305,244
Average Rate	7.4	3.2
Elasticity	2.3	

Energy demand increased at a fairly high ratio to the growth rate of increase of GDP (elasticity; 2.3), despite the fact that the sudden change occurred in FY 2001/02. The formula of correlation between energy demand and GDP during FY 1995/96 – FY 2006/05 is shown as follows:

$$\text{Energy demand} = 5361.6 - 43.167*10^{-3} \times \text{GDP} + 0.1048 \times 10^{3} \times \text{GDP}^{2} \quad (R^{2}=0.98)$$

GDP incorporating sudden change is not considered to have reflected demand with steady growth. In addition, the global economy has experienced fluctuation due to various elements. For this reason, GDP is unsuitable as an explanatory parameter for the long term 10 year demand forecast in Nepal.

b) Average selling price

The actual data for energy demand and average selling price are shown in **Table 5.1.2-4.**

Table 5.1.2-4 Energy Demand and Available Selling Price

	Energy Demand (MWh)	Average Selling Price (NRs)	CPI at 1996 = 100	Selling Price at 1996
1996	937	3.97	100.0	3.97
1997	1,011	4.05	108.1	3.75
1998	1,051	4.80	117.2	4.10
1999	1,114	4.94	130.5	3.78
2000	1,269	5.53	134.9	4.10
2001	1,407	5.95	138.1	4.31
2002	1,540	6.29	142.1	4.43
2003	1,702	6.60	148.9	4.43
2004	1,801	6.66	154.8	4.30
2005	1,918	6.70	161.8	4.14
2006	2,066	6.64	172.6	3.85
Average Rate	7.5	4.8		-0.3
Elasticity				-26.1

Although the average selling price showed a growth tendency up to FY 2003/04, it was subsequently seen to decline. It is understood that no correlation between energy consumption and selling price was found.

The selling price, therefore, is unsuitable for the explanatory parameter.

c) Number of consumers

The actual data for energy demand and the number of consumers are shown in **Table 5.1.2-5.**

Table 5.1.2-5 Energy Demand and Number of Consumers

	Energy Demand (MWh)	Number of Consumers
1996	937	494,965
1997	1,011	527,286
1998	1,051	574,849
1999	1,114	622,363
2000	1,269	673,979
2001	1,407	745,992
2002	1,540	884,535
2003	1,702	970,611
2004	1,801	1,053,935
2005	1,918	1,159,855
2006	2,066	1,277,447
Average Rate	7.5	9.0
Elasticity		0.8

Energy demand increased at a rate of 0.9 times the ratio of increase in the number of consumers. The number of consumers shows a positive correlation to energy consumption, which has shown an upward tendency for the effective period of FY 1995/96 – FY 2005/06, as follows:

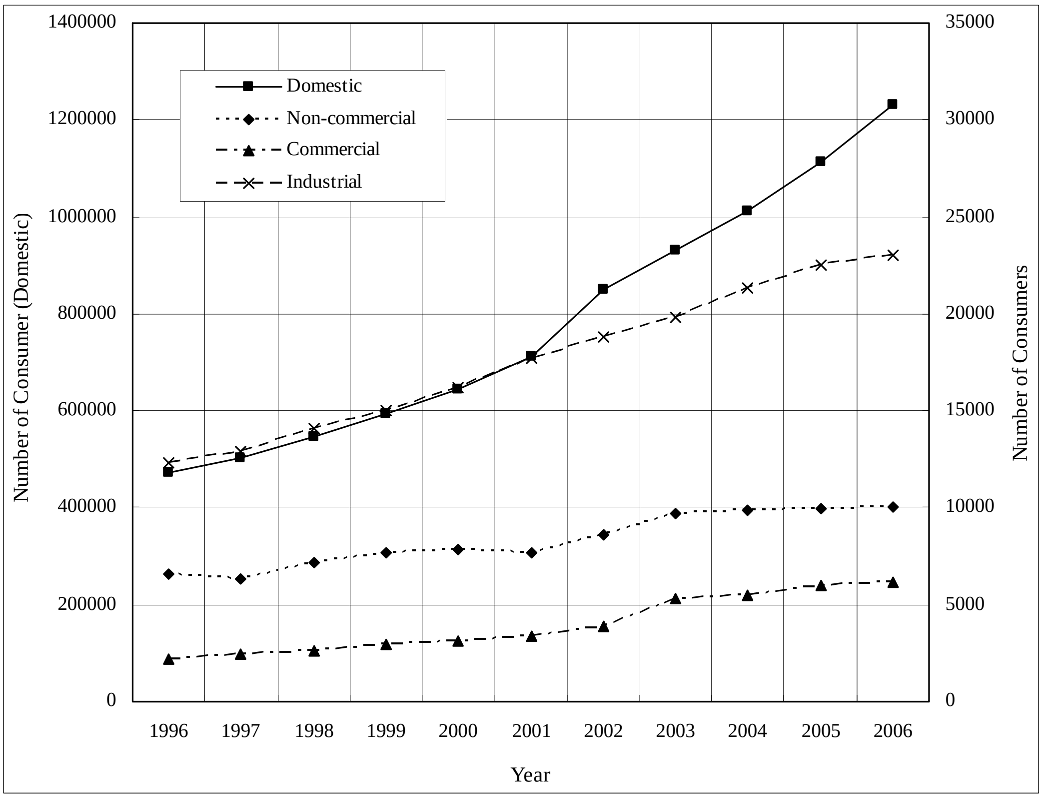
$$\text{Energy demand} = 245.9 + 1.4591 \times 10^{-3} \times \text{number of consumers} \qquad (R^2=0.99)$$

Fig. 5.1.2-1 shows the trend of increase in consumers in each of the categories of demand. The number of consumers in each category, except for temporary supply and bulk supply, which remains almost constant, has shown a growth tendency every year. Consequently, the number of consumers is selected as the explanatory parameter for the demand forecast study by the JICA Study Team.

As a countermeasure to increase the number of consumers, NEA is currently promoting the following:

a. The action required to connect new consumers to the existing distribution system is promptly taken by NEA, based on the assumption that the access is within the existing grid domains, assuming it to be in the relative vicinity of the existing system.

b. In order to enhance the electrification ratio of Nepal, which was recorded at a fairly low level of about 21% in 2003, NEA cites rural electrification in the power sector as its second priority (the first being to develop generation, and the third being to reinforce the overall power system).



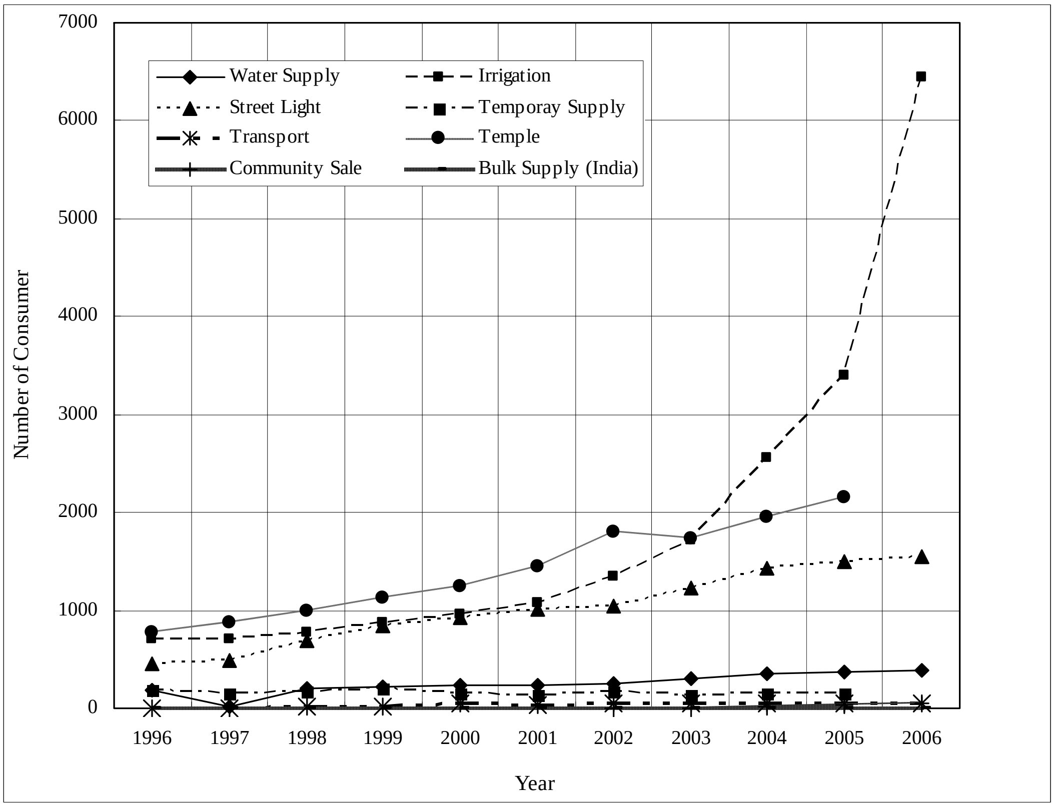


Fig. 5.1.2-1 Consumers by Categories

2) Energy Demand and Number of Consumers

Fig. 5.1.2-2 shows a correlation between energy demand and the number of consumers as the results of the above forecast study. Energy demand during FY 1995/96 – FY 2005/06 was forecast using the following formula:

Energy demand = -245.9 + 1.4591 x 10^{-3} x the number of consumers (R^2=0.99)

Number of consumers = 459900 + 23436 x N + 4703.8 x N^2 (R^2=0.99)

Where, N: 1, 2, 3 …, it shows after "N" year from 1988

Table 5.1.2-6 shows the result of energy demand forecast at the receiving end.

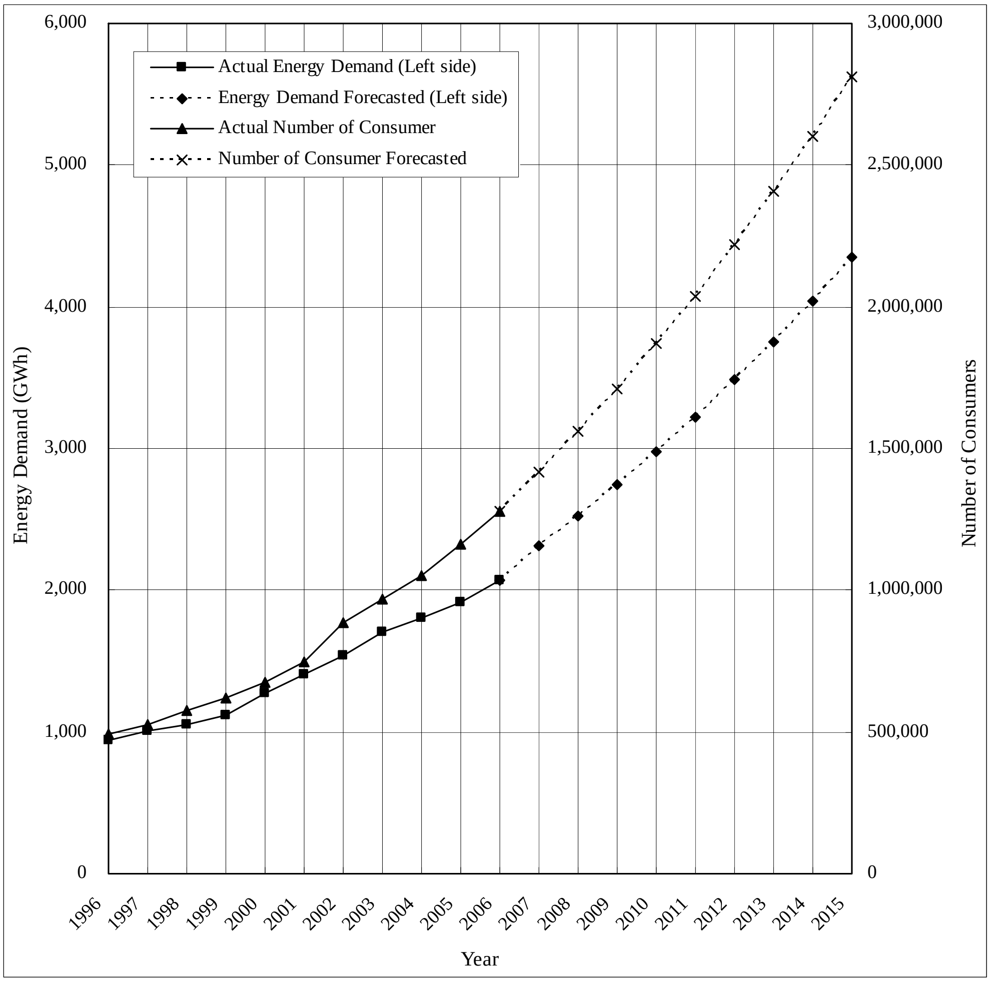


Fig. 5.1.2-2 Energy Demand and the Number of Consumers

Table 5.1.2-6 Load Demand and Forecast

S.No	Year	Energy Demand		Number of Consumers	
		Actual (GWh)	Forecas (GWh)	Actual	Forecast
1	1996	937		494,965	
2	1997	1,011		527,286	
3	1998	1,051		574,849	
4	1999	1,114		622,363	
5	2000	1,269		673,979	
6	2001	1,407		745,992	
7	2002	1,540		884,535	
8	2003	1,702		970,611	
9	2004	1,801		1,053,935	
10	2005	1,918		1,159,855	
11	2006	2,066		1,277,447	
12	2007		2,316		1,418,479
13	2008		2,521		1,559,510
14	2009		2,741		1,709,949
15	2010		2,974		1,869,795
16	2011		3,221		2,039,049
17	2012		3,482		2,217,710
18	2013		3,756		2,405,779
19	2014		4,044		2,603,256
20	2015		4,346		2,810,140

The energy demand projected up to 2015 will see the growth rate of 7.5% maintained. It is important that energy demand be reviewed every year, based on the actual level of recorded energy demand.

(4) Available Energy and Peak Load

1) Available Energy

Table 5.1.2-7 shows the results for the forecast of available energy at the generating end, based on the study results of the loss rate as described above.

Table 5.1.2-7 Available Energy

Year	Energy Demand (GWh)	Loss Rate (%)	Available Energy (GWh)	Growth Rate (%)
2007	2,316	20.8	2,924	-
2008	2,521	19.8	3,144	7.5
2009	2,741	18.8	3,375	7.4
2010	2,974	17.0	3,583	6.2
2011	3,221	17.0	3,881	8.3
2012	3,482	17.0	4,195	8.1
2013	3,756	17.0	4,526	7.9
2014	4,044	17.0	4,873	7.7
2015	4,346	17.0	5,236	7.5
Average Growth Rate (%)				7.6

The available energy during the projected period up to 2015 is forecast to maintain a growth rate of 6.7%.

2) Peak Load

Table 5.1.2-8 shows the results estimating the peak load; based on the study results of the load factor described above.

Table 5.1.2-8 Peak Load

Year	Available Energy (GWh)	Load Factor (%)	Peak Load (MW)	Growth Rate (%)
2007	2,924	53.6	623	-
2008	3,144	53.6	670	7.6
2009	3,375	53.5	720	7.5
2010	3,583	53.5	765	6.3
2011	3,881	53.4	829	8.4
2012	4,195	53.4	897	8.2
2013	4,526	53.3	969	8.0
2014	4,873	53.3	1,044	7.8
2015	5,236	53.2	1,124	7.6
Average Growth Rate (%)				7.7

The peak load during the projected period up to FY 2015 is forecast to increase with a growth rate of 6.8%.

Fig. 5.1.2-3 shows the result of the forecast period up to FY 2014/15, in terms of the available energy and peak load.

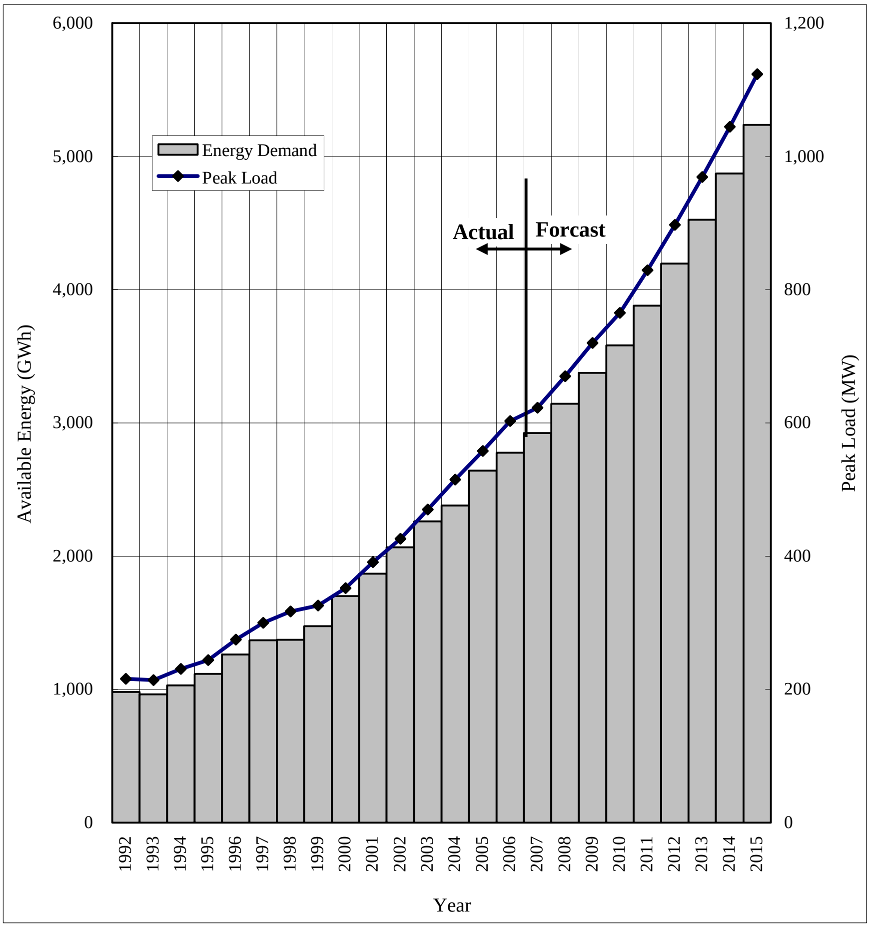


Fig. 5.1.2-3 Available Energy and Peak Load

5.1.3 Load Demand Forecast by the NEA and JICA Study Team

The results of a study taken by both NEA and the Study Team are shown in **Table 5.1.3-1. Fig. 5.1.3-1** shows the result of the load demand forecast, with a comparison made between the NEA and the JICA Study Team.

Table 5.1.3-1 Comparison between NEA and JICA

F.Y.	Energy (GWh)		Peak Load (MW)	
	NEA	JICA	NEA	JICA
2006*[1]	2,777.40		603.28	
2007	2,897.1	2,924	642.2	622.7
2008	3,136.6	3,144	695.3	670.0
2009	3,428.1	3,375	759.9	720.0
2010	3,698.4	3,583	819.8	765.0
2011	4,057.1	3,881	890.6	829.3
2012	4,423.3	4,195	971.0	897.3
2013	4,815.0	4,526	1,057.0	969.0
2014	5,231.2	4,873	1,148.0	1,044.4
2015	5,673.8	5,236	1,245.6	1,123.6

*1 Actual

The results of the NEA load demand forecast reveals a figure slightly larger than that obtained by the JICA Study Team. However, the difference in available energy is around 8%, and a figure of up to 10% for the peak load in FY2015. Therefore, NEA's load demand forecast can be judged as reasonable. In this report, the NEA load demand forecast is used for the Study.

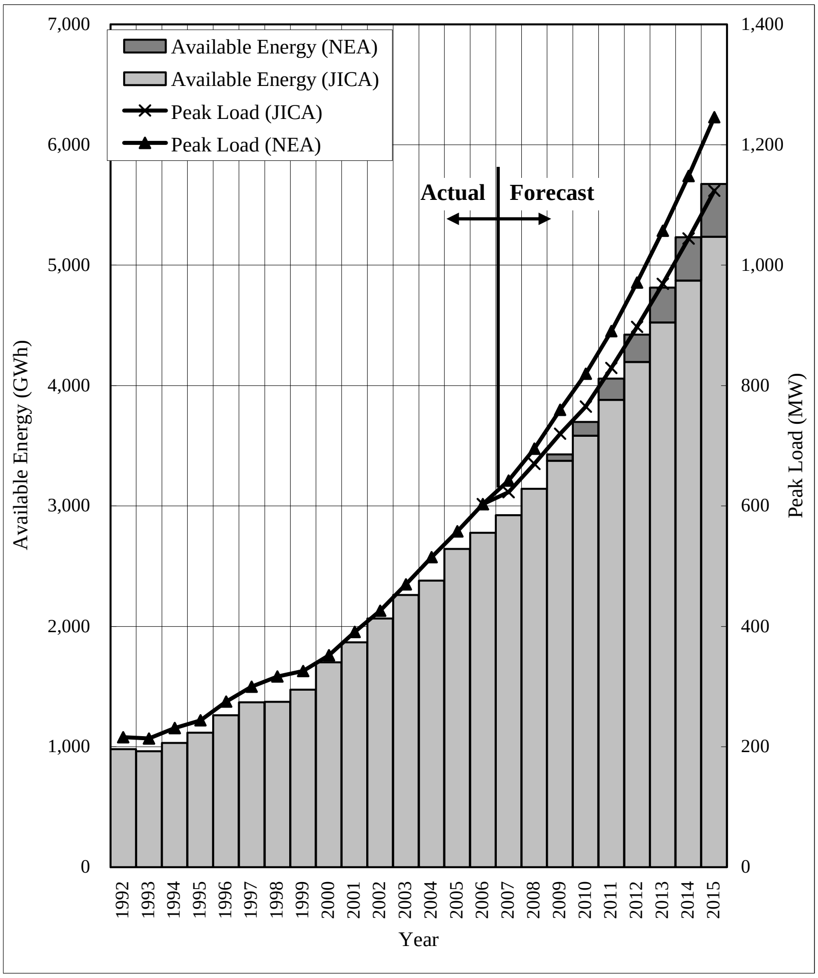


Fig. 5.1.3-1 Comparison of Energy Demand Forecast between NEA and JICA

5.2 Development Plan

5.2.1 Generator Expansion Plan by NEA

To meet the requirements of an increase in peak load and required energy, as per the load forecast, a power development plan for the period FY 2005/06 to FY 2019/20 has been established as part of the generation expansion study.

NEA's generation expansion plan in FY 2005/06 is shown in **Table 5.2.1-1.**

Table 5.2.1-1 Generation Expansion Plan

FY	Project	Installed Capacity (MW)	Type*1	Developer
2006/07	Khudi	3.5	ROR	IPP, Under Construction
	Sinsne Khola	0.75	ROR	IPP, Under Construction
	Sali Nadi	0.232	ROR	IPP, Request for PPA
	Baramchi	0.98	ROR	IPP, Under Construction
2007/08	Middle Marsyangdi	70	PROR	NEA, Under Construction
	Pheme	0.995	ROR	IPP, Under Construction
	Tadi Khola	0.97	ROR	IPP, PPA concluded
	Toppal khola	1.4	ROR	IPP, Under Construction
2008/09	Lower Indrawati	4.5	ROR	IPP, Under Construction
	Lower Nyadi	4.5	ROR	IPP, Under Construction
	Mardi	3.1	ROR	IPP, PPA concluded
2009/10	Kulekhani-III	14.0	ROR	NEA, Under Construction
	Mailung	5.0	ROR	IPP, PPA concluded
	Upper Mai Khola	3.0	ROR	IPP, PPA concluded
	Daram Khola	5.0	ROR	IPP, PPA concluded
	Upper Modi	14.0	ROR	IPP, Under Construction
	Madi-I	10.0	ROR	IPP, Under Construction
2010/11	Chameliya	30.0	PROR	NEA, Under Construction
	Mewa	18.0	ROR	NEA, Planned
	Hewa	10.0	ROR	NEA, Planned
	Lower Modi	19.0	ROR	Private
	Sanjen	-	-	-
2011/12	Upper Trihuli	44.0	ROR	NEA, Planned
2012/13	Upper Tomakoshi	309.0	ROR	NEA-Private JV
2013/14	Tamor	83.0	ROR	NEA, Planned
	Upper Seti	122.0	ST	NEA, Planned
	Kankai	60.0	ST	NEA, Planned
	Upper Karnali *2	75.0	PROR	NEA-Private JV
2014/15	West Seti *3	75.0	ST	Private
2015/16	-	-	-	-
2016/17	-	-	-	-
2017/18	-	-	-	-
2018/19	Kebeli-A	30.0	PROR	Private
	Upper Marsyandgi “A”	121.0	PROR	NEA, Planned
	Likhu-4	40.0	PROR	NEA, Planned
	Upper Modi A	42.0	ROR	NEA, Planned
2019/20	Dudhi Koshi	300.0	ST	NEA, Planned

*1: ROR: Run of River, PROR: Peaking Run of River, ST: Storage
*2: Export Project (NEA 75 MW = 25% of installed capacity 300 MW)
*3: Export Project (NEA 75 MW = 10% of installed capacity 750 MW)

Table 5.2.1-2 and **Fig. 5.2.1-1** show the demand – supply balance, calculated with the load demand forecast and the above generation expansion plan. At the column of “Plan” in **Table 5.2.1-2**, the available output of each power plant from December to January in the dry season is summarized up to FY2009/10. However, the installed capacity is summarized for power plants commissioned after FY2010/11.

Table 5.2.1-2 Power Development Plan

Unit: MW

FY	Existing*1	On going	Plan	Total	NEA	
					Forecast	Difference
2005/06	532.7	0.0	0.0	532.7	603.3	-70.5
2006/07	532.7	3.6	0.2	536.6	642.2	-105.6
2007/08	532.7	75.5	1.2	609.4	695.3	-85.9
2008/09	532.7	81.6	4.2	618.5	759.9	-141.4
2009/10	532.7	113.6	16.5	662.8	819.8	-157.0
2010/11	532.7	143.6	46.9	723.2	890.6	-167.4
2011/12	532.7	143.6	90.9	767.2	971.0	-203.8
2012/13	532.7	143.6	399.9	1,076.2	1,057.0	19.2
2013/14	532.7	143.6	739.9	1,416.2	1,148.0	268.2
2014/15	532.7	143.6	814.9	1,491.2	1,245.6	245.6
2015/16	532.7	143.6	814.9	1,491.2	1,336.1	155.1
2016/17	532.7	143.6	814.9	1,491.2	1,445.1	46.1
2017/18	532.7	143.6	814.9	1,491.2	1,561.1	-69.9
2018/19	532.7	143.6	987.9	1,664.2	1,678.5	-14.3
2019/20	532.7	143.6	1,287.9	1,964.2	1,804.0	160.2

*1: Excluding Import from India 50 MW

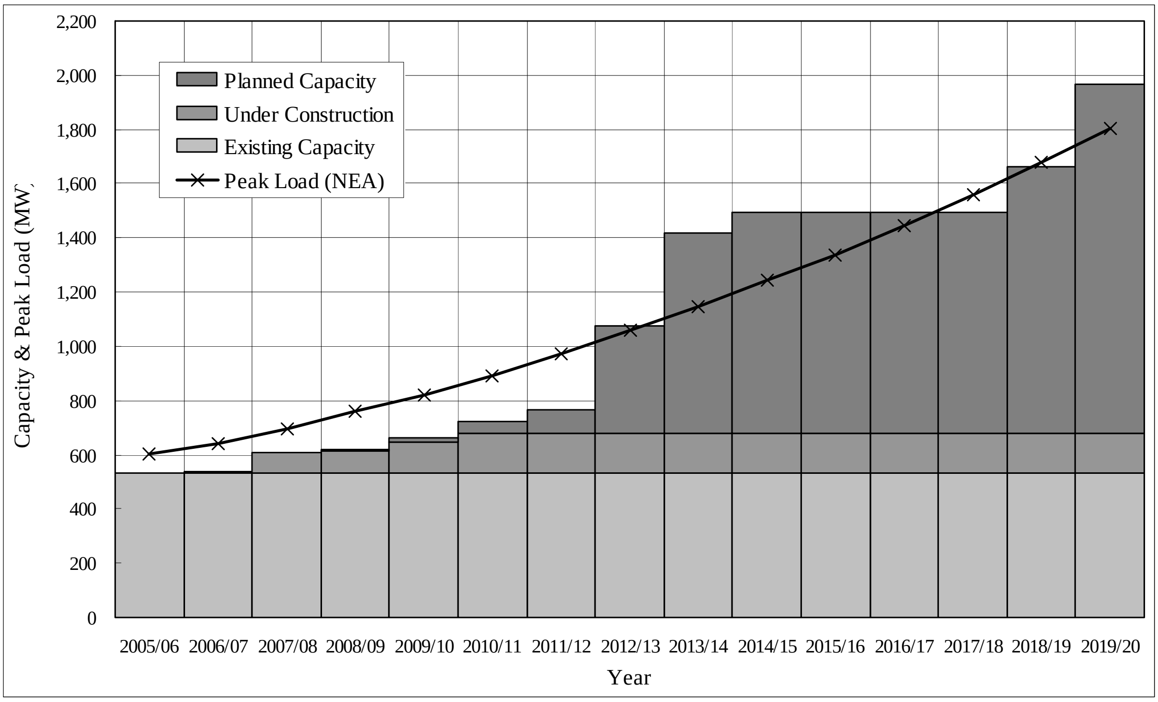


Fig. 5.2.1-1 Capacity of Generation and Peak Load

In the above plan, the situation regarding the demand and supply balance remains tight up to FY 2011/12, when Upper Tamakoshi will be commissioned and the NEA will have to take countermeasures to remedy power shortages through imports from India and/or load shedding.

5.2.2 Transmission Plan by NEA

(1) Generation Expansion

Table 5.2.2-1 shows the transmission line projects prepared in 2005, featuring more than 33kV of power evacuation from power plants.

Table 5.2.2-1 Transmission Line Projects for Power Evacuation

Name	Connection	Voltage (kV)	No. of Circuits	Word Code	Distance (km)
Khudi	Khudi Bazaar	33	s/c		7
Sisne Khola	Jhumsa (Dobhan VDC)	33	s/c		
Pheme	-	33			3
Lower Nyadi	Nyadi Bazar	33			18
Lower Indrawati	Indrawati	66			0.2
Mailung	Chilime – Trishuli	66			3.2
Mardi	Baskot	33			5.5
Thoppal Khola	Jare Substation	33			10
Kulekhani III	Hetauda s/s	132	s/c		4
Upper Modi	Modi Khola – Pokhara	132	s/c		4
Daran Khloa	Tamghas	33			21
Lower Modi	Modi	132	s/c	Bear	4.5
Madi-1	Lekhnath (New Pokhara)	132	s/c	Bear	7.2
Hewa	Kabeli-A	132	s/c	Bear	8.8
Mewa	Tamor Power House	132	s/c	Bear	9
Rahughat	Pokhara	132	s/c		66
Upper Marsyangdi A	Middle Marsyandgi	132	s/c		20
Kabeli-A	Duhabi	132	d/c		129
Tamor	Kabeli	132	d/c	Bear	19
Likhu-4	Khimti 1	132	d/c		25
Chameliya	Ataria	132	s/c	Bear	127
Upper Modi A	Modi	132	s/c	Bear	7.5
Budhiganga	Ataria	132	s/c	Bear	47
Upper Seti	New Bharatpur	220	d/c		43
Upper Tomakoshi	Khimti	220	d/c		47
300MW Dudhkosi-1	Dhalkebar	220	d/c		93
180MW Andhi Khola	Butwal	132	d/c		64

Source: Report on Transmission Planning Study 2005

(2) Reinforcement of the Transmission System

The reinforcement of the transmission system is one of the most important issues, which should be given the first priority.

The transmission lines required for system reinforcement established in 2005 are shown in **Table 5.2.2-2**.

Table 5.2.2-2 Transmission Plan for System Reinforcement

No.	Voltage (kV)	From	To	Notes
1	132	Butwal	Sunauli	New line
2	132	Birgunj corridor		
3	132	Thankot	Bhaktapur	New line
4	220	Khimti	Dhalkebar	New line
5	132	Kohalpur	Lamahi	Second circuit
		Lamahi	Shivapur	Second circuit
		Shivapur	Butwal	Second circuit
6	220	Bardghat	Hetauda	New line
7	220	Bardghat	Butwal	Second circuit
8	132	Tamor	Mewa	New line
		Mewa	Kabeli	New line
		Kabeli	Hewa	New line
		Hewa	Duhabi	New line
9		KL-3	Thankot	Second circuit add.
10	220	New Bharatpur	Hetauda	
11	132	Siuchatar	Thankot	Second circuit add.
12	220	Thankot	Hetauda	New line
13	220	Thankot	Hetauda	Second circuit

Source: Report on Transmission Planning Study 2005

Fig. 5.2.2-1 shows the transmission system with system reinforcement in FY 2018/19, when the Upper Seti project will have been connected via the transmission line from the Upper Seti Plant to the new 220 kV Bharatpur substation.

However, even after the above transmission system reinforcement is completed, some bottlenecks will still remain in the system.

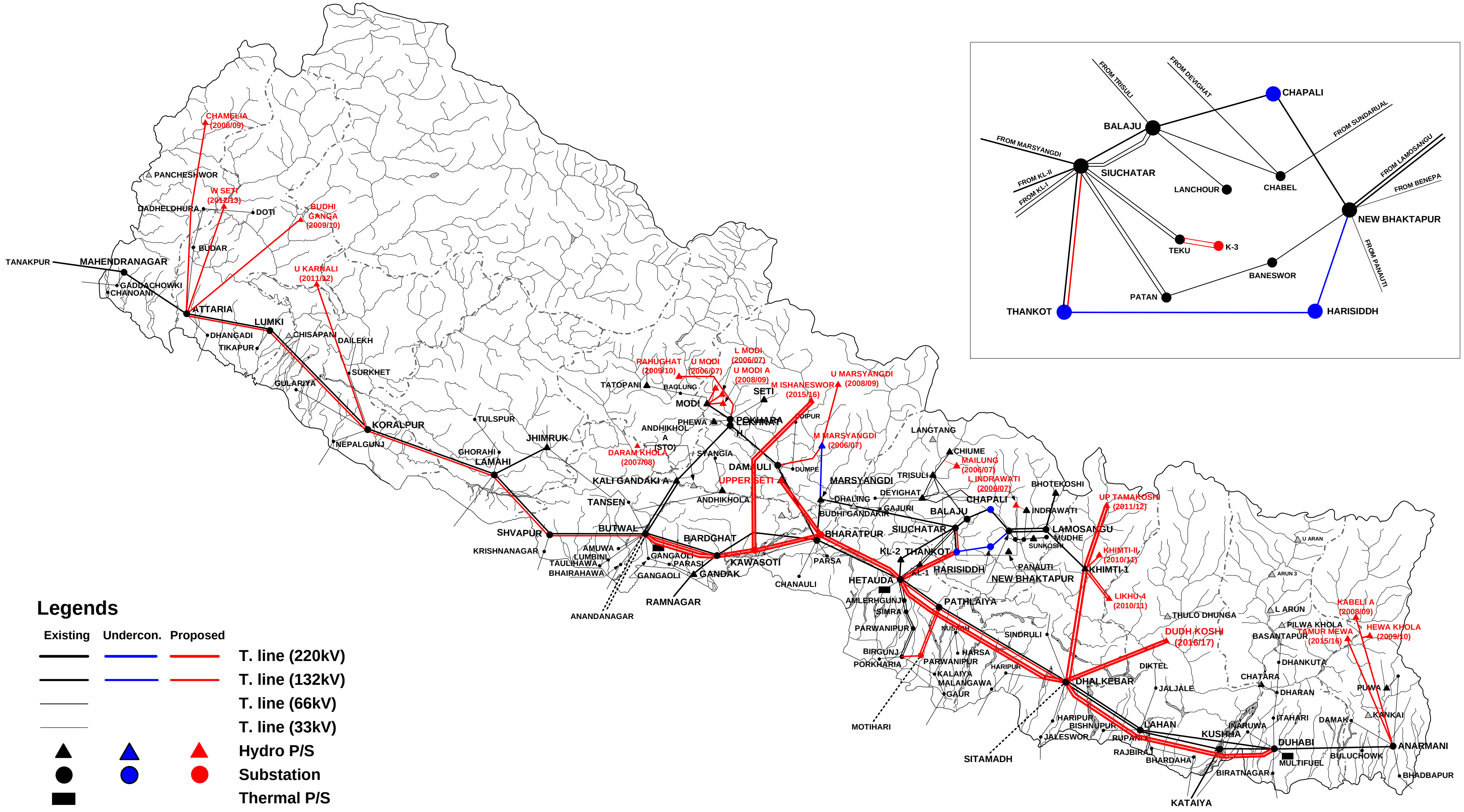


Fig. 5.2.2-1 Transmission System: End of Year 2018/19

5.2.3 Peak Duration Hours

Generation facilities in Nepal mainly consist of run-off-river type power plants which cannot generate the power for peak demand. However, the Upper Seti hydropower project will cope with the increased peak load in Nepal. In this section, the peak duration hours required for the Upper Seti hydropower project are examined.

The peak duration hours are examined in terms of the peak load in each month, the load curve shape and the load duration curve as follows:

(1) Peak Load

Peak load in Nepal is recorded from December to March in the dry season, as shown in **Fig. 4.5.1-3**, while the maximum peak load in FY 2005/06 was recorded as 603.28 MW at 18:30 on 12 January 2006. **Fig. 5.2.3-1** shows the daily load curve on the day when the annual maximum peak load was recorded in the period FY 2003/04 to 2005/06.

(2) Load Curve Shape

The load curve shape in Nepal indicates typical domestic demand, for which peak load occurring in the evening is dominant, as shown in **Figs. 4.5.1-5** and **5.2.3-1.** According to the results of the power survey conducted by the Study Team, there are no plans to construct new factories with significant demand, meaning the current load curve shape, showing typical domestic demand, will be retained.

(3) Load Duration Curve

1) Daily load duration curve

Fig. 5.2.3-2 shows the daily load duration curves on 12 January 2006, on 3 December 2003, and on 8 December 2004, when the annual maximum loads were recorded respectively.

2) Yearly load duration curve

Fig. 5.2.3-3 shows the yearly load duration curve in FY2004/05 and 2005/06.

Fig. 5.2.3-4 shows the daily load curve and daily load duration curve in FY2013/14 when this project will be commissioned, based on the load demand and forecast by NEA in the country, as mentioned in 5.1.

The duration of the evening peak load period has increased year on year over the past three (3) years, as shown in **Fig. 5.2.3-1**. This tendency can also be confirmed in the load duration curve. Therefore, the period of load duration hours is considered to be at least five (5) hours long, and a six (6) hour period is reasonable, taking consideration of a peak load increase in the morning and an increased peak load duration in the evening.

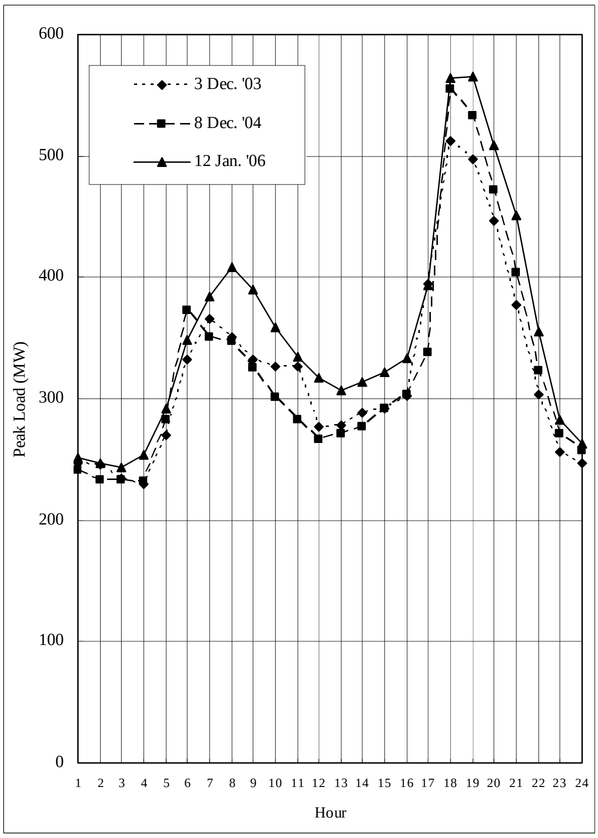


Fig. 5.2.3-1 Daily Load Curve (12 Jan. 2006)

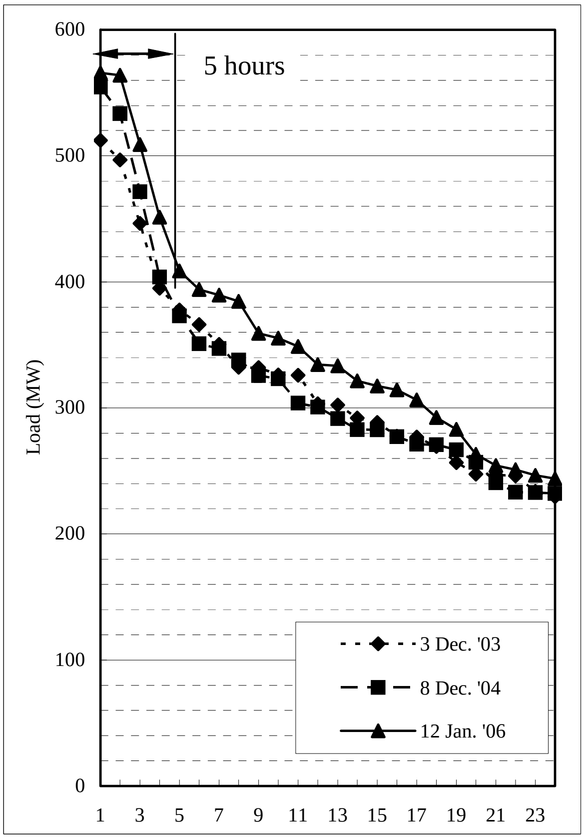


Fig. 5.2.3-2 Load Duration Curve (12 Jan. 2006)

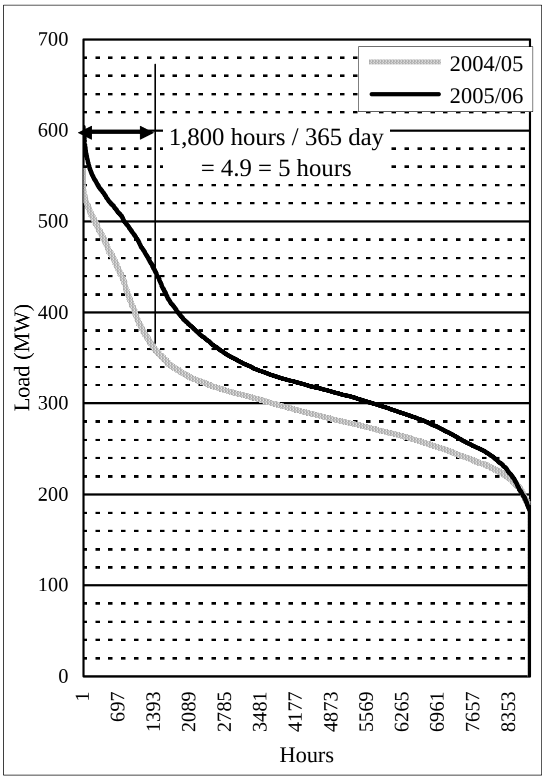


Fig. 5.2.3-3 Yearly Load Duration Curve (2004/05 and 2005/06)

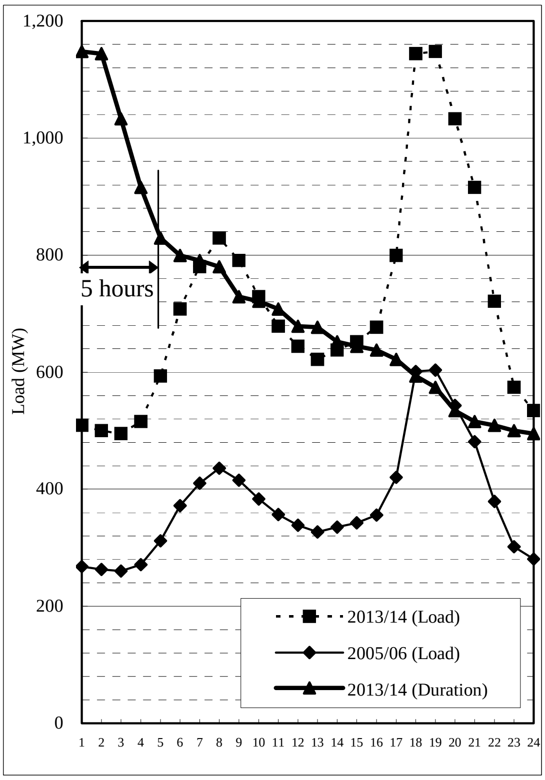


Fig. 5.2.3-4 Daily Load and Duration Curve on 2013/14

5.2.4 Review of Transmission Plan

(1) Outlines of Transmission System

The NEA power system at the end of FY2004/05 is shown in **Fig. 5.2.4-1**, and the power system map is presented in **Fig. 4.1-4** in **Section 4.1** "Organization".

The NEA power system is facing a serious situation, as described in **Section 5.3.4** "Examination observed from the Aspect of Development Scheme for Truck Transmission Line". The system has poor reliability and suffers from numerous power system disruptions each year. Improving the power system reliability is one of the priority issues for implementing reliable load dispatch operation.

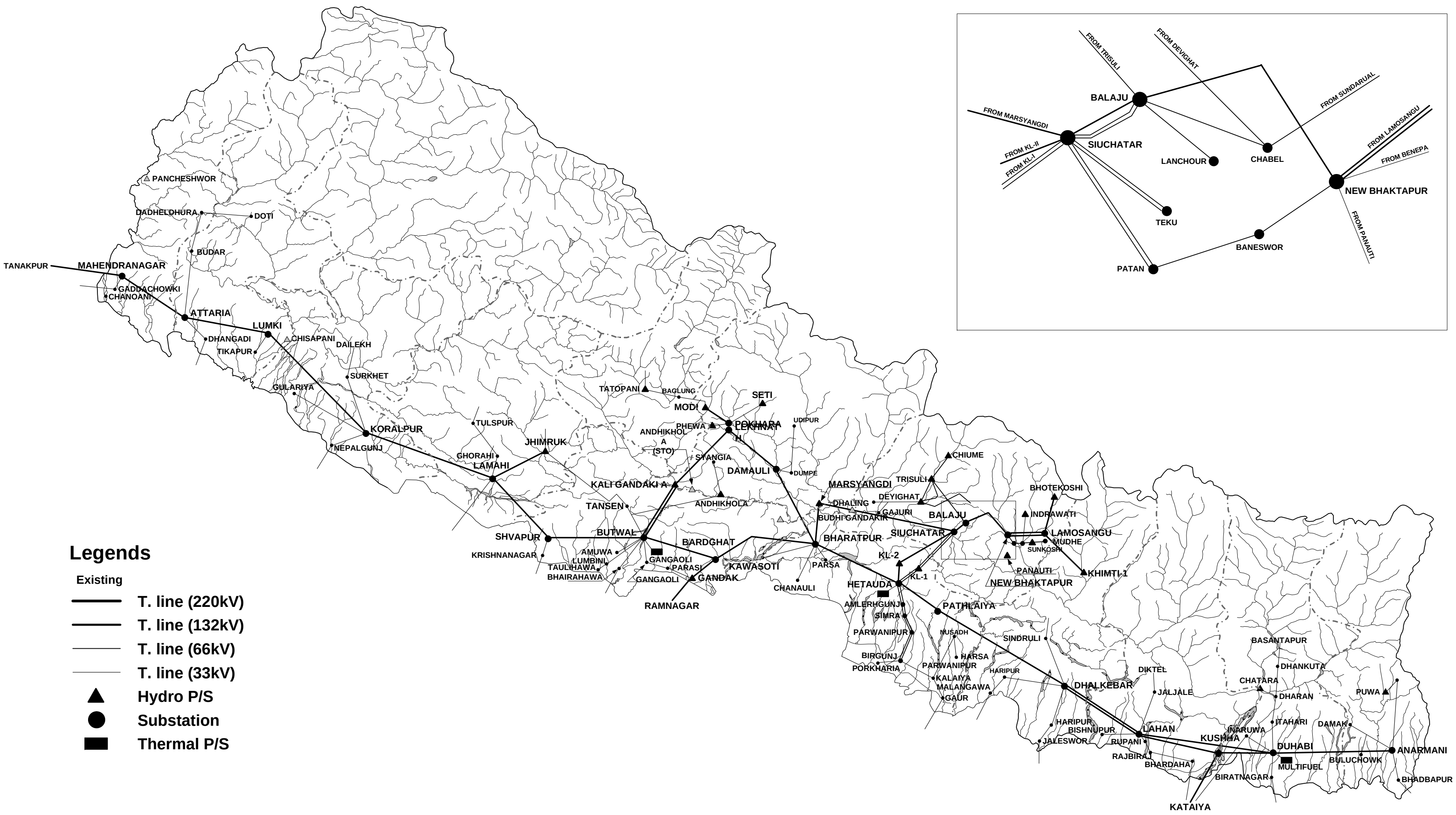


Fig. 5.2.4-1 Existing Transmission System

(2) JICA Study Team's Review of NEA's Study

1) NEA's Study

The basic power evacuation study and transmission line route alignment are reported in "Volume V Power Evacuation Study and Transmission Line Route Alignment, Upgrading Feasibility Study Upper Seti Storage Hydroelectric Project", prepared by NEA in July 2004.

In the transmission plan of this project, as shown in **Table 5.2.4-1** and **Fig. 5.2.4-2**, four (4) alternatives were proposed, as follows:

Table 5.2.4-1 Transmission Scheme of the Upper Seti Project

No.	From	To	Voltage (kV)	Distance (km)
1	Upper Seti Storage Hydroelectric Plant	Bharatpur Substation	220	43
2	Upper Seti Storage Hydroelectric Plant	Kawasoti Substation	220	47
3	Upper Seti Storage Hydroelectric Plant	Thankot Substation	220	120
4	Upper Seti Storage Hydroelectric Plant	Hetauda Substation	220	112

The evacuation study, including the formulation of the schemes, was conducted via a combination of two different planning methods.

- Method 1: Direct spreadsheet calculation to determine the optimum conductor size and voltage level. It is based on the capitalized cost per km of transmission line.
- Method 2: A system study using the planning software, PSS/E. The optimization is based on overall system-wide costs and benefits, with substation-wise load forecast and generation projects as per NEA's LCGEP (Least Cost Generation Expansion Projects).

The result of NEA's transmission study of this project judged the optimum scheme to be a transmission line to connect the Upper Seti Hydroelectric Plant and the Bharatpur Substation.

2) Review of the JICA Study Team

The following elements are part of the review by the JICA Study Team.

a) Location of substation

The power generated by the Upper Seti hydroelectric plant will be transmitted to demand centers, such as the industrial belt in eastern Nepal and the Kathmandu valley. Regarding the substation location, it is reasonable that a substation east of the Upper Seti hydroelectric project site, such as Bharatpur, Thankot and Hetauda, should be used for power evacuation.

b) Transmission line plan by NEA

NEA already has plans to construct 220kV double circuit lines from Bharatpur to Hetauda, as shown in **Table 5.2.2-2**, before the completion of the Upper Seti hydroelectric plant.

c) Distance of transmission line

In the case of a transmission line with equivalent specifications, the longer the transmission line, the greater the transmission loss and construction cost. Moreover, a longer line is also unstable from a power system perspective.

Regarding the number of circuits, the following is taken into consideration:

a) In the case of a single circuit line, the INPS will suffer from serious power supply disruption until the transmission line is repaired, if the line fault continues. Hence a double circuit line is recommended.

b) Typically, around 90% of all faults affecting double circuit lines affect just one circuit only. Double circuit lines are therefore very close to two single circuit lines in terms of reliability but less costly and more demanding in terms of ROW (Right Of Way) than two single circuit lines. The NEA’s planning criteria suggests that simultaneous outage of both circuits in double circuit lines should be excluded from the regular types of events which the system should be designed to sustain. The plant should therefore be connected to the grid via two circuits.

With the above in mind, it is suitable to construct 220kV double circuit lines with Bison to Bharatpur substation from this project site. The Study Team judges the verdict of NEA’s Power Evacuation Study and Transmission Line Route Alignment for the Project to be reasonable.

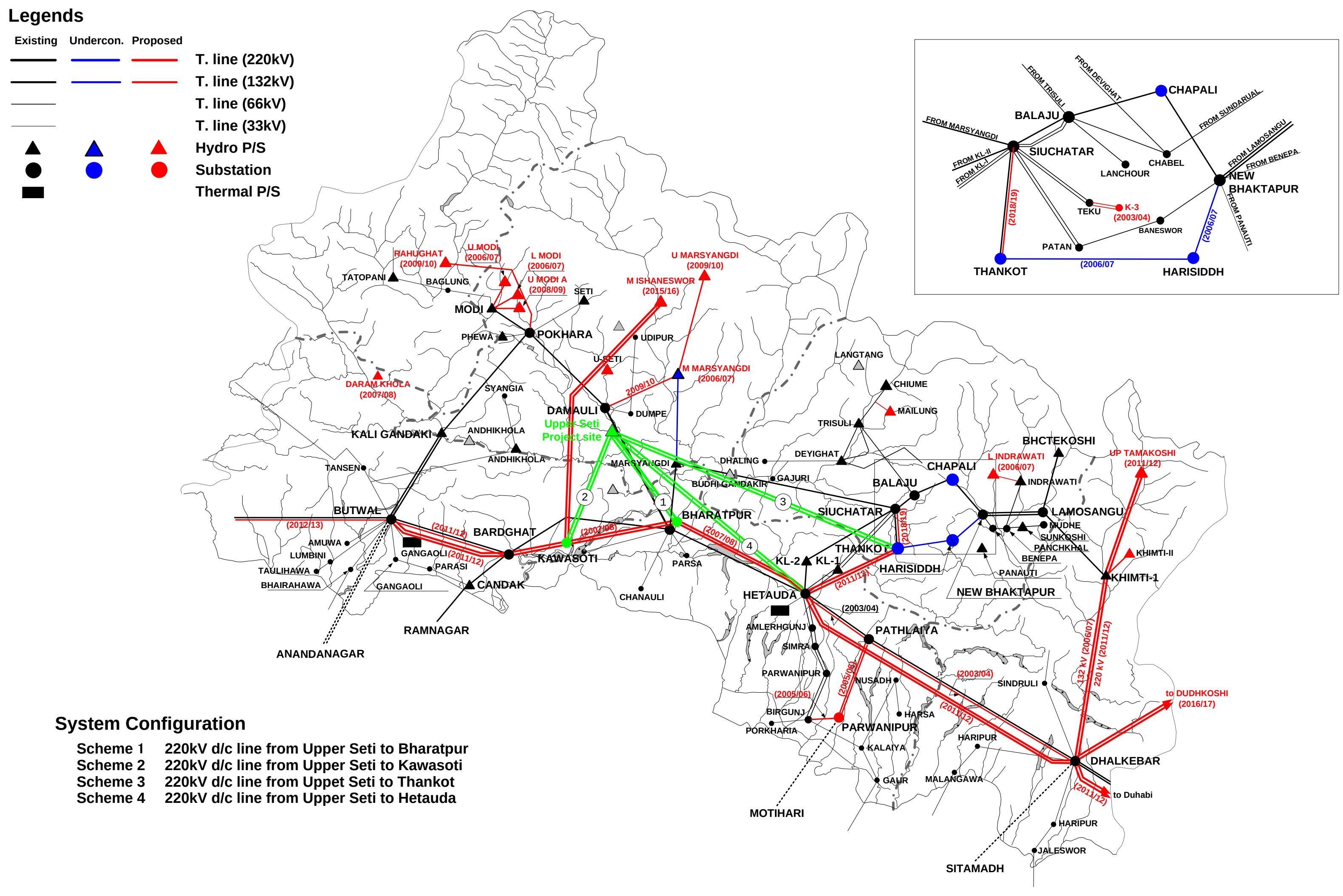


Fig. 5.2.4-2 Transmission Scheme of the Upper Seti Project

5.3 Justification of Project observed from the Power Development Scheme

Justification of this project, as observed from the power development plan, is examined in this section, based on the above study results of the power sector.

Comprehensive examination of the justification of this project will be described in **Chapter 14**.

5.3.1 Examination observed from the Aspects of Demand and Supply

The NEA power system faces an unfavorable situation in terms of the restrictive balance of demand and supply, which is set to continue until FY 2012/13, even in the case that the power plants listed in the power expansion plan are developed as scheduled. Power should be imported from India and/or the scheduled load shedding should be carried out to cope with the power shortage. The demand and supply balance up to FY 2013/14, when the project will be commissioned is shown in **Table 5.3.1-1**.

Table 5.3.1-1 Demand and Supply Balance up to FY 2013/14

(Unit: MW)

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Peak Load	603	642	695	760	820	891	971	1057	1148
Peaking and/or Install Capacity	583	587	659	669	713	762	806	1,115	1,455
Surplus power	-20.5	-56	-36	-91	-107	-128	-165	58	307

However, this demand and supply balance includes the following uncertain factors:

a. The peaking capacity of the supply side up to FY2009/10 shows the total dependable output of each power plant for the period December to January during the dry season, as estimated by NEA, but the total installed capacity of the hydroelectric plants commissioned after FY 2010/11. Hence, it will not be possible to generate the total power output during the dry season from FY 2010/11 onwards.

b. In years of drought[1], the dependable output will fall below that in an average year.

c. In the generation expansion plan shown in **Table 5.2.1-1**, hydroelectric projects with a collective total capacity of around 1,070 MW are to be developed up to FY2013/14. Of this total, projects developed by NEA will generate installed capacity of only about 500 MW, corresponding to 50% of the total. With past progress in mind, IPP projects are prone to delay because the commissioning date is not guaranteed in the Power Purchase Agreement (PPA).

[1] In FY 2005/06, Nepal suffered from a serious drought, which seemed to recur cyclically every 30 years. NEA commenced load shedding for 17 hours a week in late January 2006 and subsequently for 29 hours a week in late March 2006. The generating capacity in late March 2006 was reduced by up to 40% of the total installed capacity.

Therefore, the reserve margin of 307 MW for the period FY2013/14 will not be maintained in the dry season, emphasizing the importance of this project in coping with peak load demand.

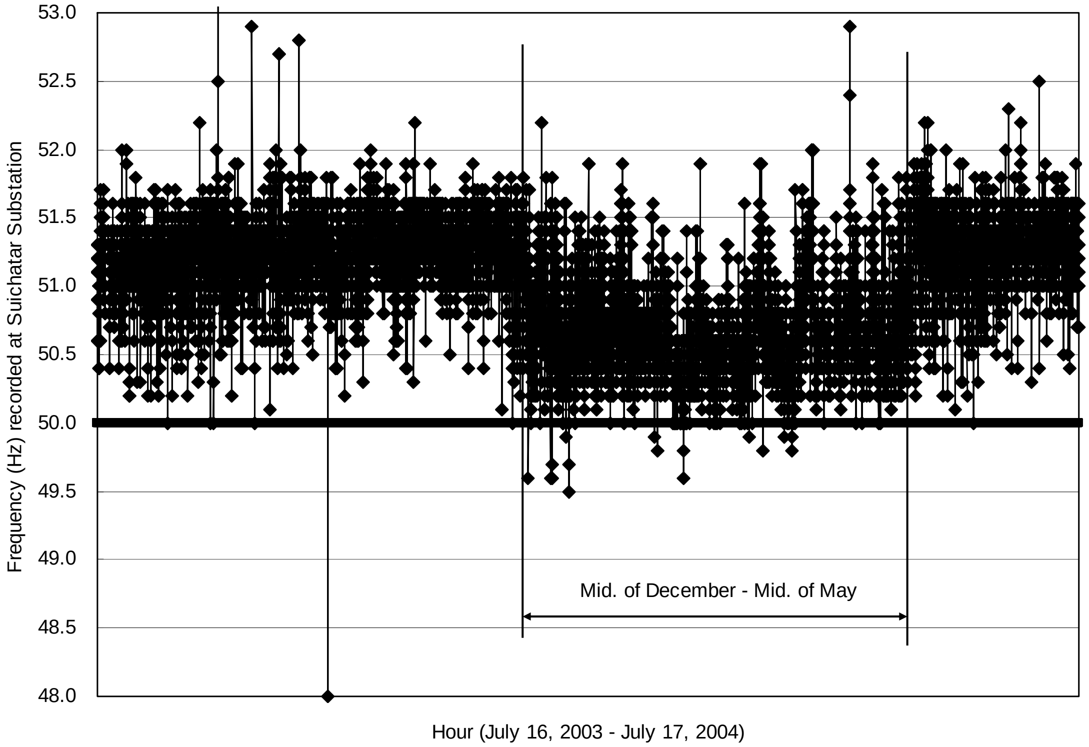
5.3.2 Examination observed based on the Quality of Electricity

The actual details of the quality of electricity are observed and discussed from the following perspectives:

- Power system frequency
- Power system voltage
- Power system-off

5.3.2.1 Power System Frequency

Fig. 5.3.2.1-1 shows actual data from the daily log recorded at Suichatar substation in the Kathmandu valley, covering the period July 16, 2003 to July 17, 2004, as well as the daily maximum and minimum frequencies of the NEA power system, recorded at the LDC (Load Dispatching Center) from the period July 16, 2004 to February 11, 2005. Based on the former daily log, a fairly significant frequency fluctuation from the year 2003 to 2004 is apparent. The power system frequency is maintained, to be high in the rainy season and low in the wet season respectively and also to remain above the rated frequency (50 Hz) throughout the entire year.



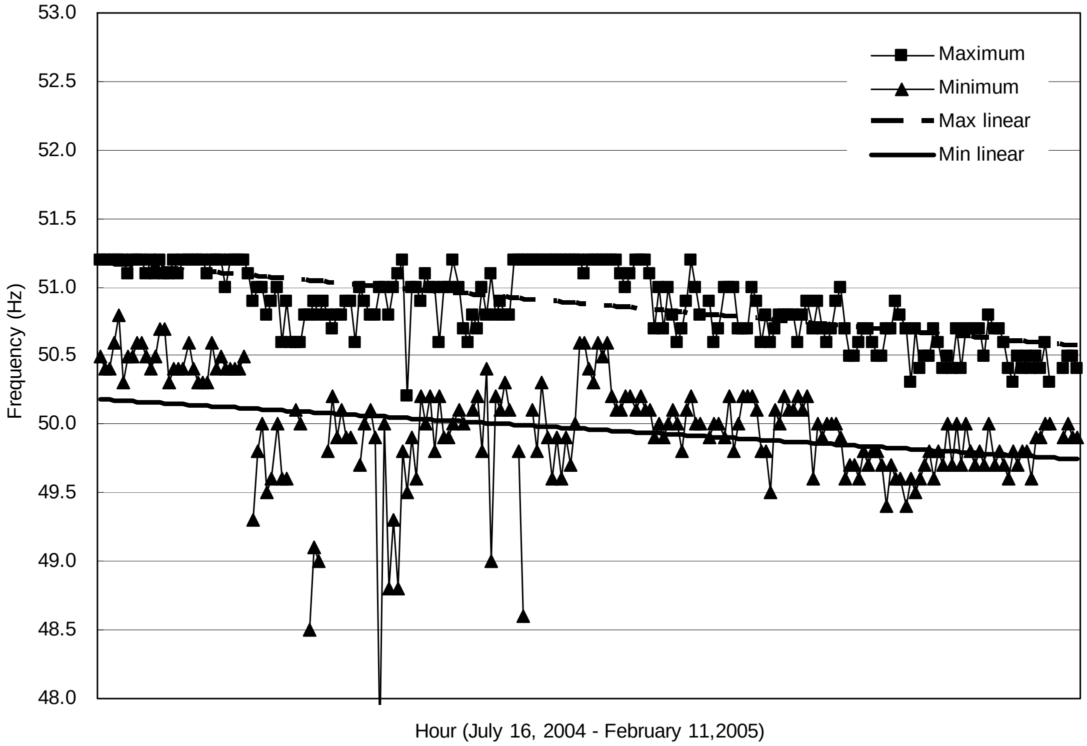


Fig. 5.3.2.1-1 Frequency Variation

The power system frequency of the NEA power system is to be controlled to within 50 Hz +/- 1.0% (49.5 – 50.5 Hz) of the normal operation range. Although the system frequency is maintained within this range in daytime, based on actual records of daily maximum and minimum frequencies, it is difficult to maintain the frequency to within the normal operating range, and it is thus maintained to within 50 Hz +/- 2.5% (48.75 – 51.25 Hz) of the emergency operating range, as prescribed in the "Electricity Regulations, 1993" to cope with steep load increases/decreases during peak loading times. These operational circumstances for the power system frequency have the tendency of seeing the mean frequency gradually fall from July (rainy season) to February (dry season), while maintaining frequency over the rated value (50 Hz).

The power system frequency is controlled year-round in order to maintain positive system time.

The individual major factors taken in consideration when adjusting power system frequency are presently as follows:

(1) Automatic Frequency Control (AFC) Function

The function of AFC is presently facilitated on a year-round basis via the use of an AGC (Automatic Generation Control = governor-free-operation) function at Kulekhani-I, Kulekhani-II (Storage Type) and Marsyangdi (Peaking Run-off-River Type) hydropower stations, with no on-line control function from LDC having been realized to date.

Kulekhani-I (Pelton turbine), Kulekhani-II (Francis turbine) and Marsyangdi (Francis turbine) were commissioned in 1982, 1986 and 1986, respectively. At these times, the governors of each power station equipped with mechanical type units, which were inappropriate for governor-free-operation due to the poor response. NEA therefore, renovated the governors, from mechanical to digital units with superior response characteristics, for both the Kulekhani-II and Marsyangdi power stations, which have recently been put into operation. Speed regulation[2] of AFC has been set at 5% in these power stations.

(2) Power-frequency Constant[3]

The power-frequency constant in the NEA power system is presumed to be 7 – 10%. The former figure of 7% is considered to apply to operations, excluding peak load times, during which time the latter figure of 10% is applicable. Because no actual testing for this constant involving the use of a real power system has been performed, the system values used are experimental, obtained through real global power system operation.

(3) Unit Load

The NEA power system has a relatively modest unit load that triggers fluctuations in the power system frequency. The biggest unit load is estimated to be 5 MW, at a certain cement factory that is irregularly operated, in daytime hours rather than at night.

[2] Speed regulation refers to the ratio of generator speed change, in the case of change of generator output.
[3] Power system frequency constant means a constant indicating the relation between frequency change and an imbalance of generation capacity in the power system to power demand.

(4) System Load Factor

The system load factor from the period FY 1974 to FY 2004 is shown in **Table 5.3.2.1-1**.

The system load factor in FY 2000 shifted from 51.6% to 55.2%, reflecting a steep increase in industry energy demand, although it subsequently fell gradually. This tendency is supposed to persist with a value of around 52% or less, as shown in **Section 5.1.2 (1)** "Load Factor", provided there is no significant fall in the domestic load growth rate. This means that rapid increases in peak load will occur more swiftly in future, and frequency control of the power system, dependent on AGC, will also become more difficult.

Table 5.3.2.1-1 Load Factor

F.Y.	LF(%)	F.Y.	LF(%)	F.Y.	LF(%)	F.Y.	LF(%)	F.Y.	LF(%)
1974	42.4	1981	51.8	1987	51.7	1993	51.4	2000	55.2
1975	45.9	1978	51.8	1985	58.0	1994	50.9	2001	54.5
1976	49.9	1982	53.5	1988	50.9	1995	52.3	2002	55.4
1977	51.6	1983	59.0	1989	51.2	1996	52.4	2003	54.9
1978	51.8	1984	55.4	1990	50.2	1997	52.1	2004	52.8
1979	53.6	1985	58.0	1991	50.7	1998	49.4	2005	54.1
1980	55.1	1986	50.7	1992	51.9	1999	51.6	2006	52.6

(5) Operational Regulation

As shown in **Fig. 5.3.2.1-1**, the system frequency of the NEA power system is controlled with plus system time on a year-round basis, even during peak load periods. The area controlled with plus system time is also supposed to be fairly large, which means that the NEA power system is consuming excess energy. NEA, by improving the power system frequency, will be able to save on fuel expenses for costly thermal power plants and enable effective hydropower generation.

Countermeasures to improve the power system frequency in the NEA power system are considered as follows:

- Securing of AFC resources
- Maintaining power system frequency within the permissible operating range
- Improvement of the active power control system
- Decrease of operation with plus system time

1) Securing of AFC resources

It is important to construct other generation plants as AFC resources for the absorption of frequency fluctuation, in order to cope with peak load with rapid fluctuation over a short period and to maintain a stable frequency.

This project is planned as a reservoir type hydropower plant, meaning this plant is both a useful and worthy means of securing the marginal supply capability for AFC resources, because this station incorporates both functions, namely the ability to respond to peak load featuring rapid increases within a short time and also to absorb frequency fluctuations. The power station is estimated to be capable of adjusting the power system frequency by around 1 Hz during the peak load time in FY 2014.

The said role of the Upper Seti Hydropower Plant will release part of the roles of Kulekhani-I, Kulekhani-II and Marsyangdi hydropower plants as AFC units.

2) Maintaining power system frequency within the permissible operating range

One of the key priority issues for power system operation involves stabilizing the power system frequency, especially at the peak load periods. The current power system frequency control system, dependent on the AGC, has its limits, and NEA is strongly requested to improve the current system in order to avoid unfavorable control failures during peak load periods.

The speed regulation of hydropower stations is also presently set at 5%, as described in the former clause. NEA, however, is requested to alter this figure from 5% to 3%, and to commence trial operation to observe whether the new setting produces will work effectively or not.

This project is very useful for improving the power system frequency, with consideration given to optimally exploit its features, i.e. the large scale installed capacity and reservoir type one.

3) Improvement of an active power control system

The active NEA power control system consists of an off-line system, in which an AGC function incorporated at each power station controls the active power individually. In such cases of individual control at each power station, there is the potential for reciprocal adjustment of active power at mutual power plants to be implemented as part of circulation control. To avoid this unfavorable operation, however, the active power control system function must be improved from the existing off-line system to an on-line system at LDC.

4) Reduction in plus system time

The generation of plus system time can be attributed to the inadequate function of the power system frequency control system, the delayed response by governor action, and the control failure by manual operation, etc. meaning that frequency is to be controlled at the safety side.

NEA, by improving the power system frequency, will be able to save on costly fuel expenses incurred for the operation of the thermal power plants, to partially compensate for the rise in frequency. NEA is presumably very well aware that power system operation with plus system time does not utilize natural resources for hydropower nor fuel for thermal power stations effectively.

This project is useful for avoiding control failures, by constructing, as appropriate, an on-line control system between the LDC control system and that of this power plant.

5.3.2.2 Power System Voltage

Fig. 5.3.2.2-1 shows the power flow map recorded at LDC at 18:26 on December 8, 2004, while **Fig. 5.3.2.2-2** shows a 132 kV bus bar voltage fluctuation, recorded at Suichatar substation in the Kathmandu valley, from July 16, 2003 to July 17, 2004 and that of a 33 kV bus bar voltage fluctuation, recorded at Damauli substation near this project site, during the period September 18, 2003 to September 19, 2004.

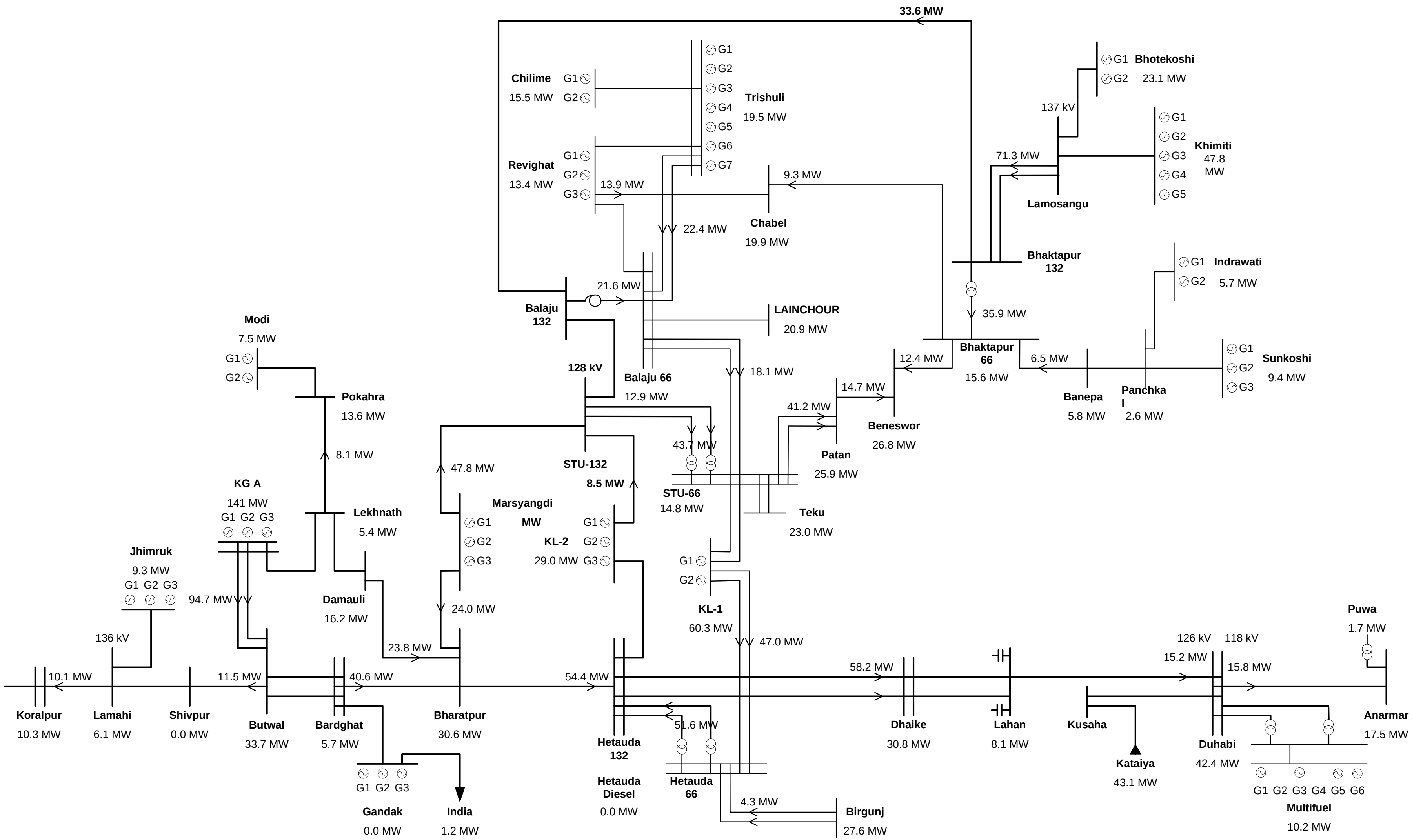


Fig. 5.3.2.2-1 Power Flow Map (8 December 2004, 18:26)

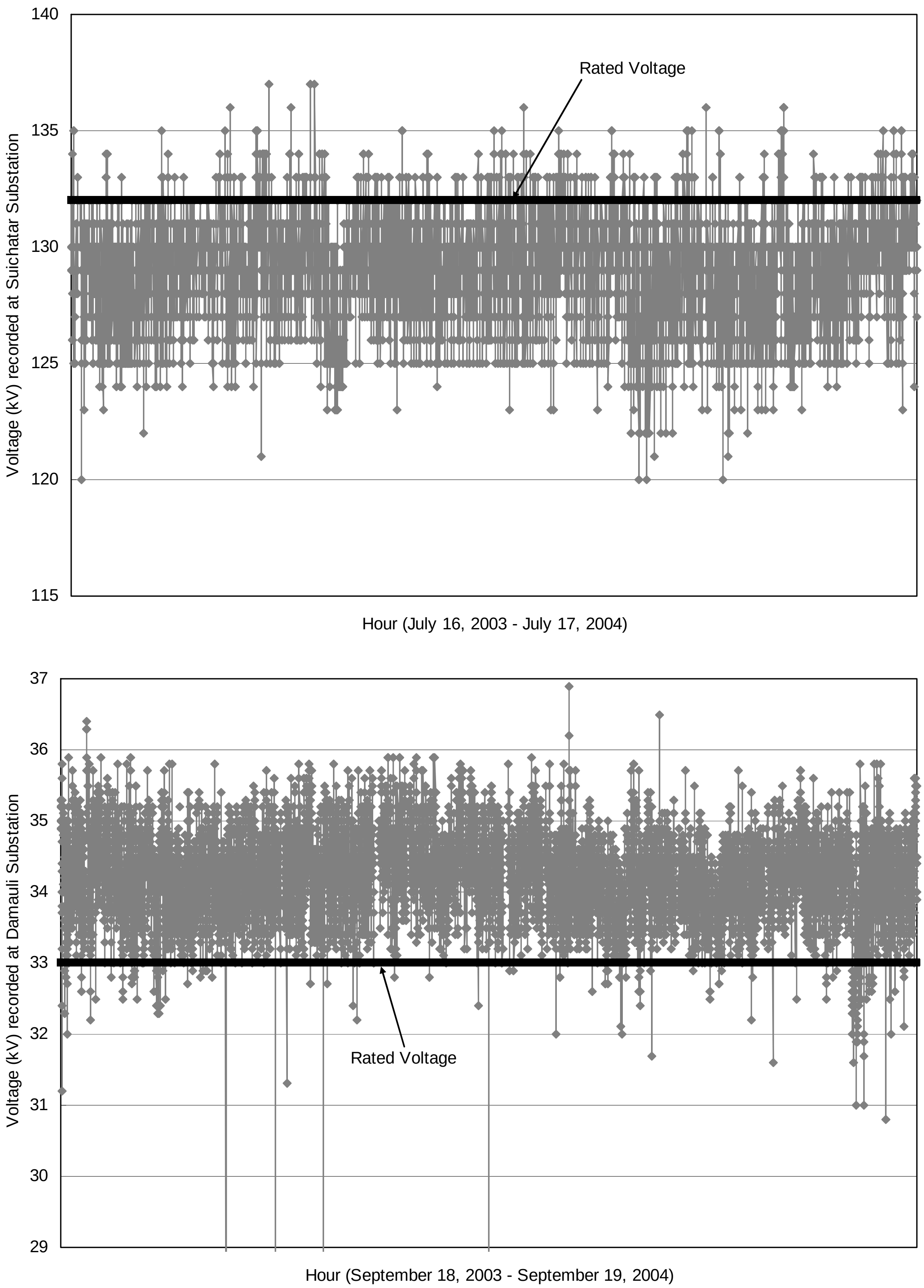


Fig. 5.3.2.2-2 Voltage Fluctuation

The NEA power system, from a power system voltage perspective, and as observed from **Fig. 5.3.2.2-1**, can be summarized as follows:

- The power system voltage for the area of power sources covered by the Kali Gandaki "A" hydropower plant was maintained at a fairly high level over the rated 132 kV. The bus bar voltage at the Kali Gandaki "A" hydropower plant was maintained at 139 kV and that of the Butwal substation at 136 kV respectively.
- The bus bar voltage of the Hetauda substation was maintained at 126 kV, that of the Suichatar substation in the Kathmandu area at 128 kV, and that of the Duhabi substation in the east region at 126 kV.
- There were two operational modes in the Duhabi substation, one being the operation connecting to the INPS (Integrated Nepal Power System) and the other involving connection to the Indian grid system. In the case of the former operation, the bus bar voltage was maintained at 126 kV, but the latter at only 118 kV, which is fairly low level and lower by 10% than the rated output.

In addition, the NEA power system, from a power system voltage perspective and as observed from **Fig. 5.3.2.2-2**, can be summarized as follows:

- In the Kathmandu valley, it is difficult to maintain 132 kV of primary voltage on a year-round basis.
- The bus bar voltage of the Damauli substation, located within the power supply zone, is maintained at level exceeding the rated output.

It is supposed to be difficult to maintain the power system voltage within the permissible operating range on a year-round basis, and the situation is thought to be in danger of deteriorating ever more swiftly, due to the expanding demand load which is not accompanied by the required drastic reinforcement of the power system.

In order to maintain well-controlled power system voltage, the power system voltage must be adjusted with reactive power and sufficient reactive power obtained at peak load periods on a year-round basis. This project will be able to evacuate reactive power at a rated output of around 80 Mvar to the power system, and this evacuation of reactive power will facilitate the power system operation in terms of maintaining the bus bar voltage at an appropriate voltage level at substations, both day and night, and throughout both the dry and wet seasons.

5.3.2.3 Power cuts Caused by Power System

The most common form of power system disruption is that which affects certain power system components, such as transmission lines or equipment such as generators, transformers, etc. whereby a trigger is pulled and the effects are felt system-wide as the "line overload relay" is activated. A typical example would be an incident involving a trip of the 132 kV single circuit transmission line between the Marsyangdi hydropower plant and the Suichatar substation. The transmission line between the Bharatpur substation and the Hetauda substation detects an overload condition and trips the line, following the trip of the line between Marsyangdi and Suichatar. The generation of Zones 7 “Lumbini” and 8 “Gandaki”, that respectively comprise the power source area, then become excessive, causing abnormally increased power system frequency and shutting down generation in the Zones in question. On the other hand, the power system frequency of Zones 9 “Narayani” and 10 "Baginali" falls drastically, causing system operation to stop.

The situation will also be repeated in the event of trips of other lines, between Bharatpur and Hetauda, Hetauda and Kulekhani II, and so on.

Another problem in the NEA power system operation is the operation and maintenance of the protection relay system. The following are pointed out:

- Insufficient maintenance work.

  A lack of any detailed drawings for protection relay circuits with single line and three phase lines, no rules or regulations for maintenance work of protection relays, no list of protection relay settings, and no report for protection relay testing, etc.

- No guidance for network-wide protection relay coordination.

- No appropriate curriculum for a digital type protection relay at the training center.

  This matter is also referred to that of digital governor, digital AVR (Automatic Voltage Regulator), digital control system, etc.

Countermeasures to avoid system disruption of the NEA power system are as shown below:

- To enhance the reliability of the power system
- To establish an appropriate organization for the protection relay system

a. The key subject when considering reliable load dispatch operation is currently the question of how to enhance power system reliability. Particularly pressing aspects at this time include the need to reinforce the lines between Butwal and Bharatpur, Bharatpur and Hetauda, and Bharatpur and Siuchatar respectively.

   The introduction of a higher voltage than 132 kV is necessary and vital for reinforcing the existing power system, which depends on a 132 kV transmission line. The transmission lines designed to evacuate power generated under this project will handle a voltage of 220 kV. However, the introduction of the planned transmission line will not itself help to resolve the overall problem of system reinforcement, although this line will help implement the essential functions for evacuating the generated power by efficiently combining the elements of the power system reinforcement plan.

b. It is necessary to establish an appropriate organization for an early warning type protection system, in order to minimize the frequency of power system disruption as far as possible.

5.3.3 Examination from the Aspect of Power System Operation

The most serious issue, with power system operation in mind, is the rapidly rising rate of increase in peak period loads; a phenomenon which is accelerating every year. This tendency is supported by the results of an analytical study for energy demand in the domestic category showing a high growth rate.

Based on the illustrated daily load curve for January 12, 2006, when the maximum peak load was recorded (refer to **Fig. 4.5.1-8**), the load increases by about 180 MW in one hour from a system load of around 420 MW. In FY 2013/14 the peak load is forecast to be about 1,150 MW, and the rapid load increase of 180 MW in FY 2005/06 is presumed to rise to around 350 MW.

The system load factor of the NEA power system is supposed to gradually decline, especially based on the increase in domestic energy, which equates to a share of total energy demand of around 40%. This means that the load increase recorded on January 12, 2006 will further intensify in the period FY2013/14, as shown in **Fig. 5.3.3-1**.

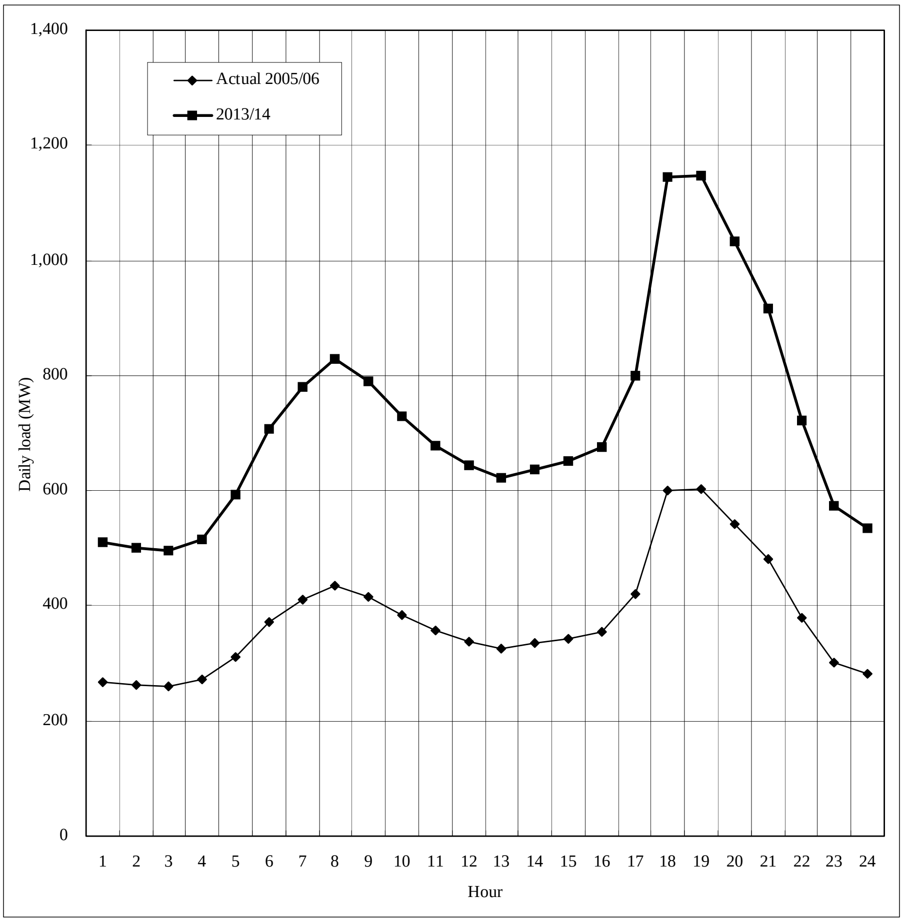


Fig. 5.3.3-1 Daily Load Curve Expected

As can be easily understood from **Fig. 5.3.3-1**, the early development of generation facilities capable of responding to the peak load will be required as well as those capable of absorbing fluctuations of the power system frequency, the latter of which will be vital to maintain the frequency within the permissible operating range on a year-round basis.

This project is one of a few very promising schemes to satisfy the crucial requirements described above and steadfast efforts to implement its construction have been earnestly requested. The peak period load is controlled by increasing the output of the peaking run-off-river type hydropower stations, like Kali Gandaki “A” and Marsyangdi, the reservoir type hydropower stations like Kulekhani-I and Kulekhani-II, and thermal power stations. In particular, the reservoir type hydropower stations play an especially important role in swiftly coping with the load.

The anticipated role to be filled by this project is relatively important in terms of responding to load fluctuation as well as absorbing fluctuations in the power system frequency. As shown in **Fig. 4.5.1-9**, this project is also expected to generate power in the form of a base load source in the dry season, from around mid-December to the end of April, when the run-off-river type hydropower stations lower their outputs.

The anticipated requirements of this project, based on the perspectives of power system operation and with improvements in the quality of electricity in mind, are summarized below:

a. To be a power station with a relatively large capacity, capable of responding to fluctuations in load and absorbing fluctuations in power system frequency during peak times.
b. To be a power station capable of generating the power during the dry season, from mid-December to the end of April, via seasonal reservoir operation, not only during peak times but also non-peak load times as the base load, depending on the demand and supply balance.
c. To be a power station that is capable of continuing to generate a full output of at least five (5) hours during peak periods.
d. To be a power station that is capable of producing sufficient reactive power in order to maintain the bus bar voltage at substations in consideration of the irregular NEA power system.
e. To be a power station with the potential to save on costly fuel expenses incurred by thermal power plants

This project should be developed from the aspect of power system operation because the roles can partially be filled by the PROR (Peaking Run-off-River) type hydropower stations, excluding the above b, but the reservoir type hydropower station is best placed to fully satisfy all the above requirements.

5.3.4 Examination observed from the Aspect of a Development Scheme for Trunk Transmission Lines

The existing NEA power system, which is dependent on 132 kV transmission lines, is facing its limits and incorporates many bottlenecks, as described above.

As described in **Section 5.2.4** “Development Plan for the Generation and Transmission System”, the NEA power system faces the serious situation of poor reliability and considerable annual disruption to the power system. With this in mind, enhancing the power system reliability is one of the most important subjects for implementing reliable load dispatch operation.

Two schemes, i.e. ”transmission line projects for power evacuation” and “transmission lines required for system reinforcement” are under consideration by NEA to satisfy the evacuation of power generated with new projects and to secure reliability up to around 2020. **Fig. 5.3.4-1** shows the projected power system in 2020.

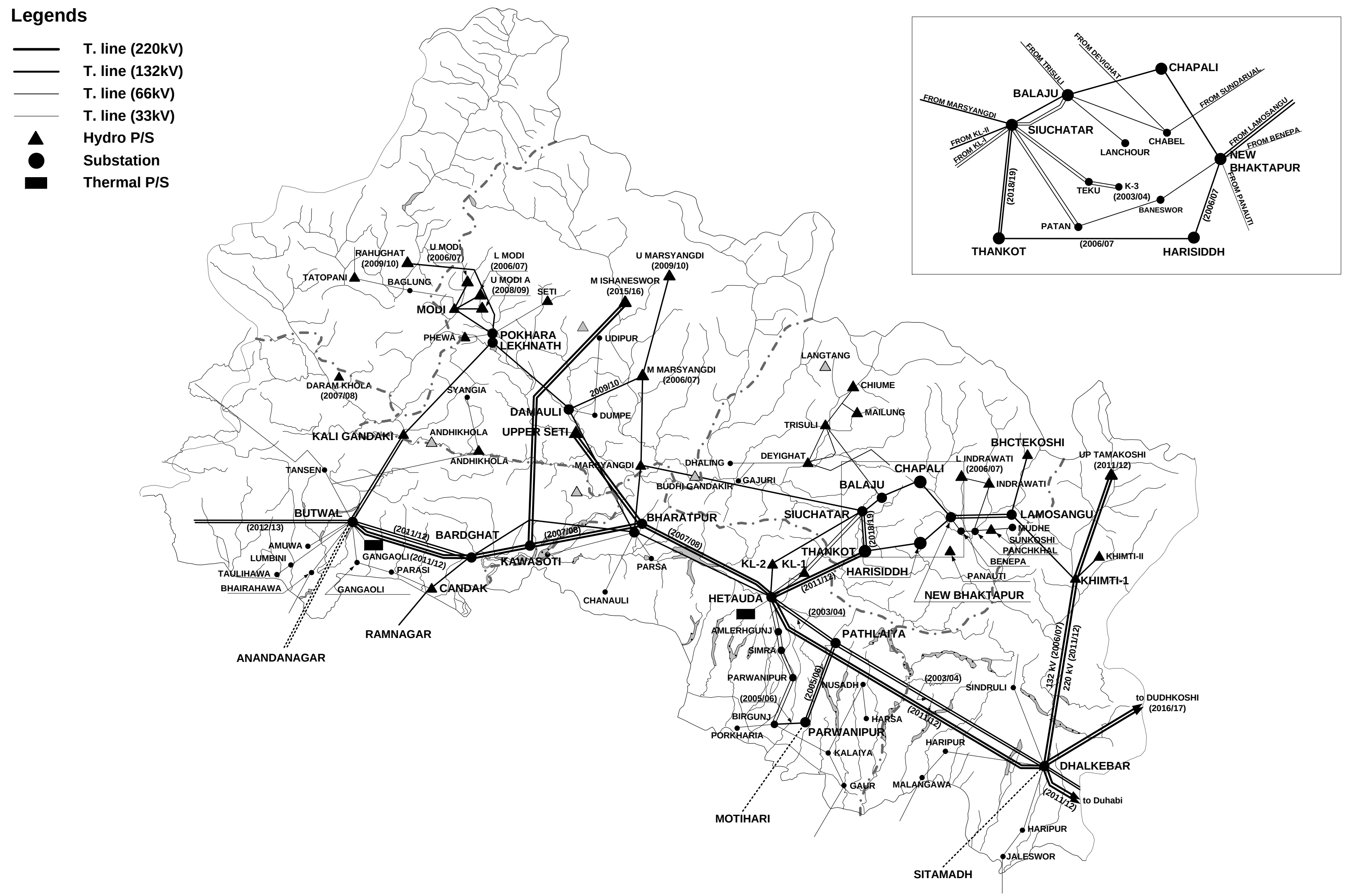


Fig. 5.3.4-1 Transmission System at End of Year 2020

The planned transmission system for this project includes a 220 kV double circuit line to connect to the new 220 kV Bharatpur substation. Completion of the new 220 kV lines between Heteuda and Bardghat, which will represent one of the major line routes for system reinforcement, is vital before the commissioning of this project and the construction of this transmission line will represent one of the crucial steps in forming a strong 220 kV loop to enhance power system reliability, as well as being useful for revising the contents of the master plan for reinforcing the power system.

As shown in **Fig. 5.3.4-1**, certain bottlenecks still remain. The following aspects are highlighted, following the completion of the line between the Upper Seti power station and Bharatpur substation:

- Plan on forming a 220 kV loop, consisting of Upper Seti – Marsyangdi – Thankot – Hetauda – Bharatpur – Upper Seti, and plan for the construction of a new 220 kV line of Upper Seti – Marsyangdi – Thankot to solve the bottleneck of the 132 kV lines of Bharatpur – Marsyangdi - Siuchatar
- Plan for alternation from Madi Ishaneswor - Kawasoti to Madi Ishaneswor - Upper Seti

5.3.5 Summary

Justification for the development of this project, as observed from the power development scheme, is summarized as below:

(1) The following roles are anticipated to be filled by this project development, incorporating aspects of the balance between power demand and supply, power system operation and the quality of electricity.

a. To be a power station with a relatively large capacity, capable of responding to fluctuations in load and absorbing fluctuations in power system frequency during peak times.

b. To be a power station capable of generating the power during the dry season, from mid-December to the end of April, via seasonal reservoir operation, not only during peak times but also non-peak load times as the base load, depending on the demand and supply balance.

c. To be a power station that is capable of continuing to generate a full output of at least five (5) hours during peak periods.

d. To be a power station that is capable of producing sufficient reactive power in order to maintain the bus bar voltage at substations in consideration of the irregular NEA power system.

e. To be a power station with the potential to save on costly fuel expenses incurred by thermal power plants

(2) The new transmission line of the project will represent one of the vital steps for forming a strong 220 kV loop to enhance power system reliability.

NEA's power development plan incorporates two storage type hydropower stations, namely West Seti (750 MW) and Kankai (60 MW), as well as the Upper Seti storage hydropower station.

Regarding West Seti, this hydroelectric project is planned by IPP for the export of power to India and NEA wishes around 10% (75 MW) of the output to be supplied to Nepal. However, power supply conditions of 75 MW have remained unclear, since NEA and the IPP have not concluded any PPA. This project will also be unable to meet the aforementioned roles for the balance of demand and supply and power system operation in Nepal, because it predominantly targets power exports to India.

Less significant roles are also expected of the Kankai hydroelectric project than the Upper Seti project, in terms of power supply and the power system operation, because the output of the former (60 MW) is smaller than that of Upper Seti, and the project site is also located in East Nepal.

NEA is planning certain PROR (Peaking Run-off-River) type projects. However, they cannot guarantee hydropower stations will generate sufficient reactive power, in comparison to the Upper Seti storage hydropower station, in order to maintain the bus bar voltage at substations, because their outputs will be relatively lower then Upper Seti. In addition, PROR type plants will be unable to supply base power during off-peak times, namely the dry season from February to April.

The Upper Tamakoshi hydroelectric project (0.38 MW) is of the PROR type and anticipated to be one of the base power sources.

It is thus concluded that the Upper Seti storage hydropower project should be developed from the aspect of a power development plan.