Nepal Electricity Authority
Nepal

Nationwide Master Plan Study
on
Storage-type Hydroelectric Power Development in Nepal

Final Report

February 2014

Japan International Cooperation Agency

Electric Power Development Co., Ltd.

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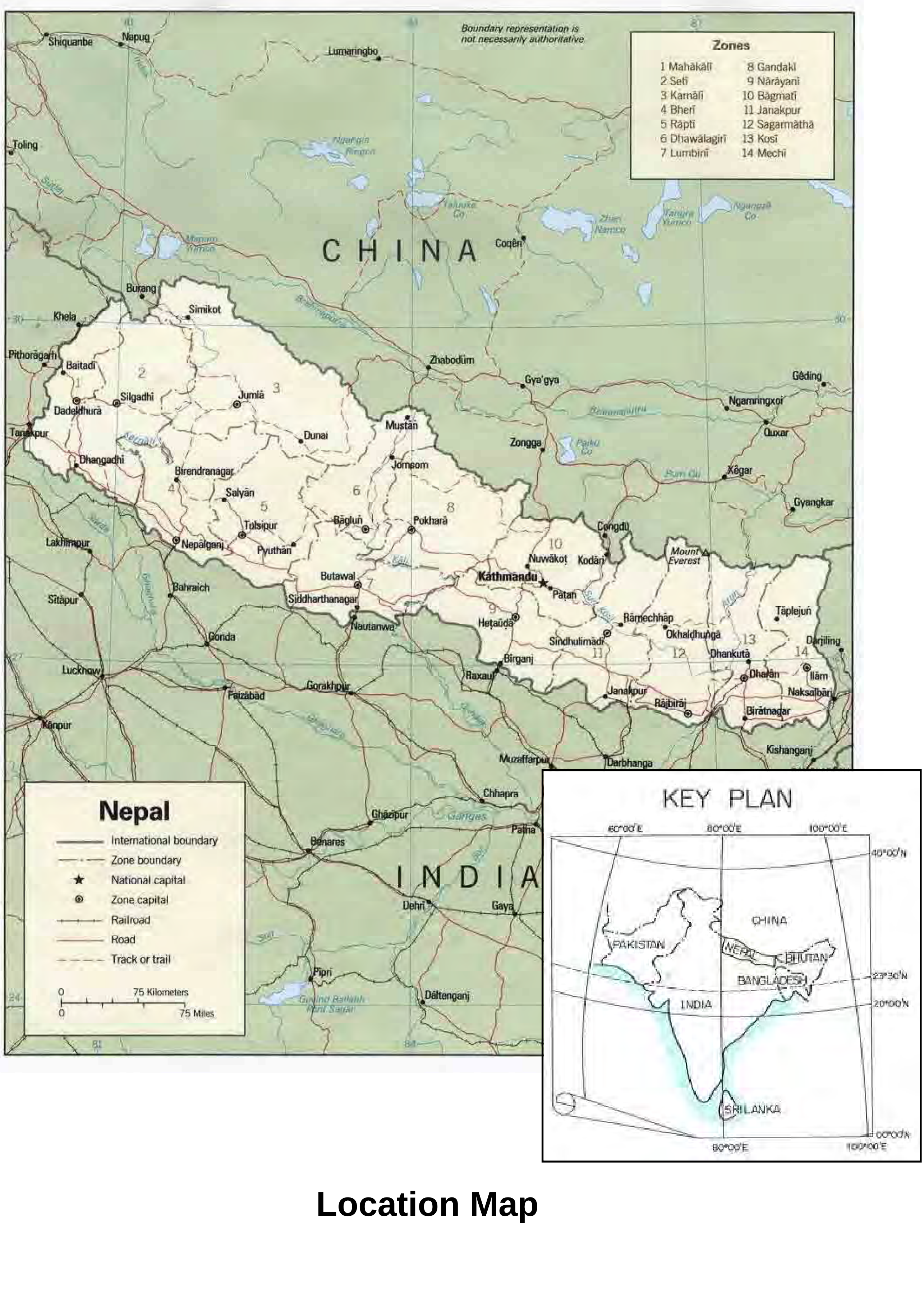

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Joint Coordination Committee Meeting (June 3, 2013)

ABBREVIATION

ADB	Asian Development Bank
AR	Autonomous Region
CA	Conservation Area
CFRD	Concrete Faced Rockfill Dam
CITES	Convention on International Trade in Endangered Species of Wild Fauna and Flora
CIWEC	Canadian International Water and Energy Consultants
CPI	Consumer Price Index
CR	Critically Endangered
DD	Detailed Design
Df/R	Draft Final Report
DHM	Department of Hydrology and Meteorology
DOED	Department of Electricity Development
DP	Dynamic Programming
EDF	Électricité de France
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
EMP	Environmental Management Plan
EN	Endangered
ENS	Energy Not Supplied
ETFC	Electricity Tariff Fixation Committee
F/R	Final Report
FAO	Food & Agriculture Organization of the United Nations
FGD	Focus Group Discussion
FIRR	Financial Internal Rate of Return
FS (F/S, F.S.)	Feasibility Study
FY	Fiscal Year
GDP	Gross Domestic Product
GIS	Geographical Information System
GLOF	Glacial Lake Outburst Flood
GON	Government of Nepal
GS	Gauging Station
HFT	Himalayan Frontal Thrust
HPP	Hydroelectric Power Plant
HR	Hunting Reserve
HSRS	Hydrosuction Sediment Removal System
Ic/R	Inception Report
ICIMOD	International Centre for Integrated Mountain Development
IDA	International Development Association
IDC	Interest during Construction
IEE	Initial Environmental Examination
IMF	International Monetary Fund
INPS	Integrated Nepal Power System

IPP	Independent Power Producer
IPP	Indigenous People Plan
ISC	International Seismological Center
It/R	Interim Report
IUCN	International Union for Conservation of Nature
JCWR	Nepal-India Joint Committee on Water Resources
JICA	Japan International Cooperation Agency
JPY	Japanese Yen
JSTC	Nepal-India Joint Standing Technical Committee
KBA	Key Biodiversity Area
KIS	Key Informant Survey
LA	Loan Agreement
LC	Least Concern
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
Lu	Lugeon value
M	magnitude
Ma	million annum (million years ago)
MBT	Main Boundary Thrust
MCM	Million Cubic Meter
MCT	Main Central Thrust
MFT	Main Frontal Thrust
MHT	Main Himalayan Thrust
MOL	Minimum Operating Level
MOWR	Ministry of Water Resources
MP (M.P.)	Master Plan
MWI	Monsoon Wetness Index
NEA	Nepal Electricity Authority
NEDIN	Nepal Federation of Indigenous Nationalities
NERC	Nepal Electricity Regulatory Commission
NESS	Nepal Environmental and Scientific Services Ltd.
NGO	Nongovernmental organization
NP	National Park
NP BZ	National Park Buffer Zone
NRs	Nepalese Rupee
NSC	National Seismological Centre
NT	Near Threatened
ODA	Official Development Assistance
OJT	On-the-JOB Training
PMF	Probable Maximum Flood
PPA	Power Purchase Agreement
Pr/R	Progress Report
Pre FS (Pre-FS)	Pre Feasibility Study
PROR	Peaking run-of river
PS (P/S)	Power Station
RAP	Resettlement Action Plan

RESCON	Reservoir Conservation
ROR	Run-of-river
RQD	Rock Quality Designation
Rs (Rs.)	Rupee
S/W	Scope of Work
SAARC	South Asian Association for Regional Cooperation
SEA	Strategic Environmental Assessment
SHM	Stakeholder Meeting
SS (S/S)	Substation
STDF	South Tibetan Detachment Fault
STDS	South Tibetan Detachment System
STO	Storage
TAR	Tibet Autonomous Region
TL	Transmission Line
TOD	Time of Day
TOE (toe)	Tonnes of oil equivalent
UNDP	United Nations Development Programme
USAID	United States Agency for International Development
VDC	Village Development Committee
VU	Vulnerable
WASP	Wien Automatic System Planning Package
WB	World Bank
WDPA	World Database on Protected Areas
WECS	Water and Energy Commission Secretariat
WR	Wildlife Reserve
WR BZ	Wildlife Reserve Buffer Zone

Chapter 1

Introduction

Chapter 1 Introduction

1.1 Background

The Federal Democratic Republic of Nepal (hereinafter referred to as “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 km^2 of land, with an average length of 880 km east to west and an average breadth of 190 km from north to south. The country is bordered by India on the East, South, and West, and China on the North, while the elevation of the land ranges from 90 to 8,848 m.

The population of Nepal, as estimated by the Central Bureau of Statistics (CBS), was recorded at 26.49 million in FY 2011/2012. The population growth was recorded at 1.35% per annum. The population distribution is 50.27% in the Terai region, 43% in the Hills and mid-mountain region and 6.73% in the Himalayan region.

The GDP per capita is about US $735 in FY 2011/2012 fiscal year. The GDP growth rate is staying at 3.8% (CBS, FY 2011/2012) due to the influence of rolling blackouts for a long time to a normal state and prolonged political turmoil, while in recent years, major SAARC countries have achieved economic growth of more than 5%.

The main industry is agriculture, accounting for about 33.0 percent of GDP, about 65.7% of the working population (FY2009/2010). Tourism and textile processing industry are core businesses following agriculture. Tourism is a key means of foreign currency acquisition, accounting for more than 20% of the acquisition of foreign currency before 1996 when the national conflict began, however it was reduced to 10% or less since 2002 by the decrease in the amount of tourists. However, the number of tourists mainly from China and India increased with the restoration of civil order, and more than 500,000 tourists visited in 2007, the most ever. Tourism is being revived by governmental policy.

Major exports are industrial products, ready-to-wear items, carpets, and food such as tea and spices. India, the U.S., Bangladesh and Germany are the main export destinations. On the other hand, the main imports are petroleum products, industrial products, gold, silver, food and food processing, etc., and countries such as India, China, the United Arab Emirates and Indonesia are major sources of imports. Every year the import surplus is expanding, and the trade deficit of FY 2009/2010 had reached US$ 5.08 billion (32.0% of the GDP ratio). The mechanism is to cover the deficit in grants and foreign remittances mainly from overseas migrant workers. Since the largest partner is India in terms of both exports and imports, maintaining friendly relations with India has a vital importance.

Nepal is rich in water resources, its potential water power is 83,000 MW and economically exploitable water power is 42,000 MW. As of the end of FY2012/13, however, the total installed capacity of the existing hydroelectric power stations is only about 709 MW. In addition, since most of hydroelectric power plants are run-of-river type, their output decreases seriously in dry seasons. Consequently, rolling blackouts of as long as 14 hours a day are implemented and it poses many problems for living conditions and economic activity.

To cope with these circumstances, the government of Nepal worked out a “National Electricity Crisis Resolution Action Plan” and “10-Year Hydropower Development Task Force” at the end of 2008.

These projects declare that it is absolutely necessary to construct storage-type hydroelectric power plans which are able to supply electricity stably even in dry seasons to solve the current power shortage at an early date.

However, construction of storage-type hydroelectric power plants should be carried out systematically taking into consideration the consistency of overall water development, hydrological and geological characteristics, environmental impact, etc. Therefore, the government of Nepal requested the government of Japan to work out a nationwide master plan for storage-type hydroelectric power development.

1.2 Purpose of the Study

This Study will contribute to solving problems like power shortage and the seasonal change of power output by moving ahead with hydroelectric power development with due consideration for social and natural environment based on the above-mentioned master plan, and it will also contribute to improving the environment of daily life and economic activity in Nepal.

In addition, technology transfer and human resource development on storage-type hydroelectric power development are intended through cooperative work with officials of the Nepalese government.

1.3 Scope of the Study

The scope of the Study is based on the above-mentioned Scope of Work agreed between the Government of Nepal and the Japan International Cooperation Agency (JICA) in June 30, 2011, and the contents and schedule of the Study are mentioned in “2. STUDY SCHEDULE AND STUDY ITEMS” of the Scope of Work.

The Study aims at preparation of a master plan for storage-type hydroelectric power development for domestic demand in Nepal as mentioned below.

- To prepare a power development plan for 20 years from 2013, and clarify the importance of storage-type hydroelectric power development.
- To select promising storage-type hydroelectric power projects from 65 potential projects listed in the long list prepared by the NEA, taking into account technical, environmental, economical and financial issues. The development scale of these promising projects should be about 100 MW to 300 MW. The long list is attached at the end.
- To study the order of development, development scale and timing, methods of funding, etc. of the promising projects and to prepare a master plan for storage-type hydroelectric power development for the next two decades.

Further, the target values in existing power development plans are deemed as conditions not given in this Study. The optimization of the power development plan is to be implemented based on the power demand forecast in consideration of the GDP growth ratio of each sector, the forecasted price increase of electricity and so on.

1.4 Points to consider on the Study and Structure of this Report

As the Economic and Social Indexes of Nepal in 2012, GNI per capita is $700 and the Human Development Index (HDI) is 0.458 which is in the lowest level as compared to other developing countries[1]. Since the load-shedding time per day in recent years has ranged from 14-16 hours, and it is a bottleneck in advancing social and economic development, to ensure the power supply through the development of hydroelectric power is urgent issue[2]. In addition, it is pointed out in the National Water Plan which was formulated by the Government of Nepal in 2005, that the water stored in the rainy season from rainfall should be used in the dry season in order to utilize water and ensure power supply capacity. This is in view of the difference in rainfall during the dry season and the rainy season in the country, which is very large.

However, as described later in this Report, since a storage-type hydroelectric power project accompanies large-scale development, the impact on the natural and social environment is large in general. For this reason, it is required to select a promising site with maximum consideration to the impact on the natural and social environment from an early stage of project formulation through a Strategic Environmental Assessment (SEA). Further, it is also required to note cumulative impact in case that development has progressed in the future.

Based on the considerations described above, this Report is prepared with the following structure. From Chapters 2 through 5, an overview of the natural and social environment in Nepal is given and a description of the general situation of the power sector is given in Chapter 6. In Chapter 7, the power demand forecast up to 2032 is examined, and the power development plan is formulated in Chapter 8. In formulating the power development plan, a mid-and long-term power development plan up to 2032 is developed examining the possibility of alternative power sources other than hydroelectric power in the light of the existing Nepal side development plan. In Chapter 9, an economic financial analysis related to the power development plan is carried out. In Chapter 10, a description will be given regarding the selection process of promising storage-type projects that make up the power development plan. Specifically, based on the concept of SEA, 67 candidate projects are evaluated in a comprehensive manner from technical, economical, natural environmental and social environmental view points to eventually narrow down 10 promising projects. In Chapter 11, the transmission line expansion plan is verified. In Chapter 12, the concept of SEA through the whole Study is again explained as well as the points to consider on environmental and social considerations for the next study stage. Finally, the conclusions and recommendations obtained as a result of this Study is described in Chapter 13.

[1]Other major economic and social indexes are i) Poverty Rate 25.2%, ii)Life Expectancy 68.8 Years and iii)Child Mortality Rate 46 deaths/1000 live births

[2]IMF, Nepal 2012 Article IV Consultation

1.5 Study Schedule

The overall work schedule is shown in the following flow chart:

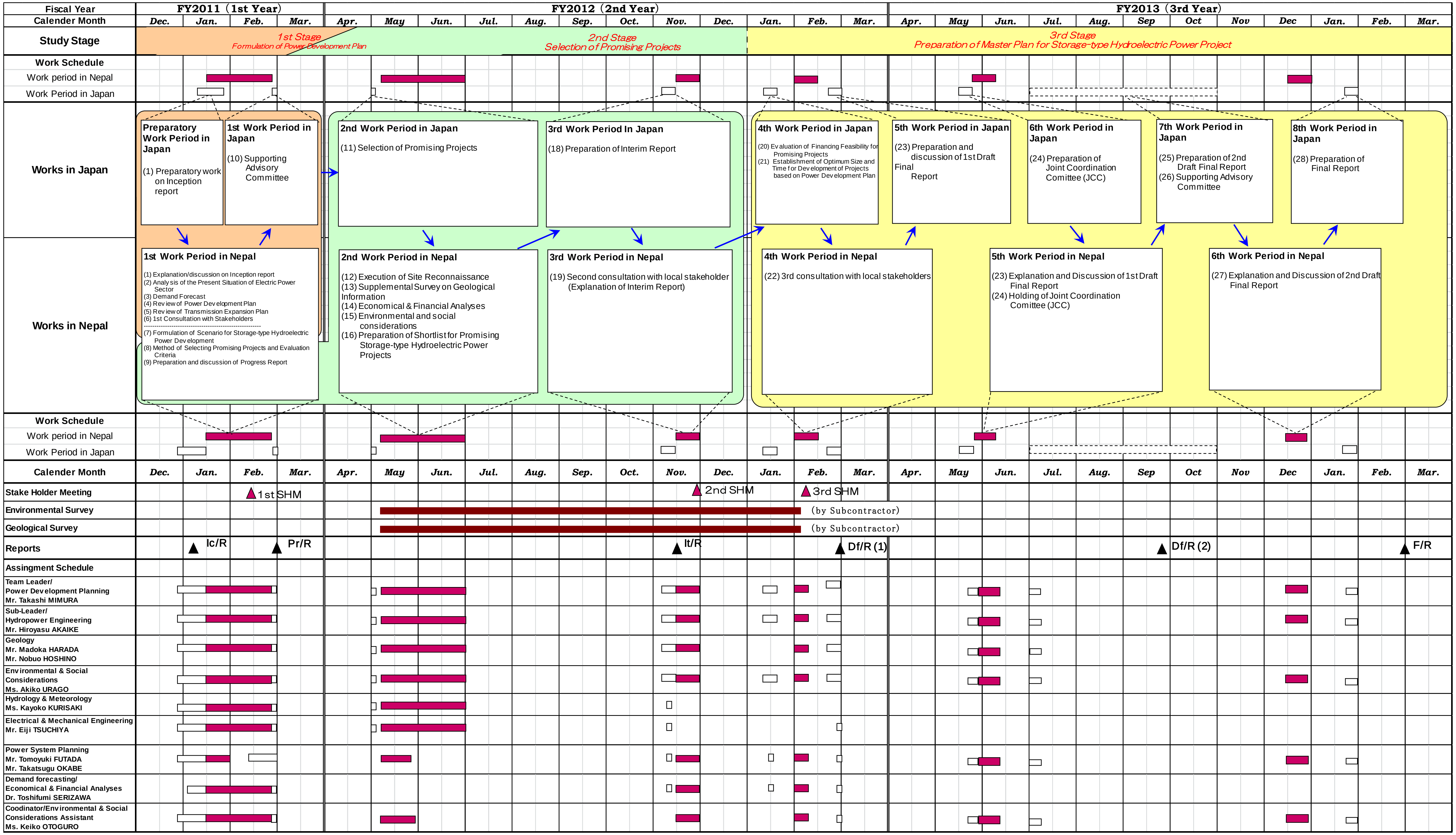


Figure1.5-1 Work Schedule

Work contents and output of each study stage are shown below.

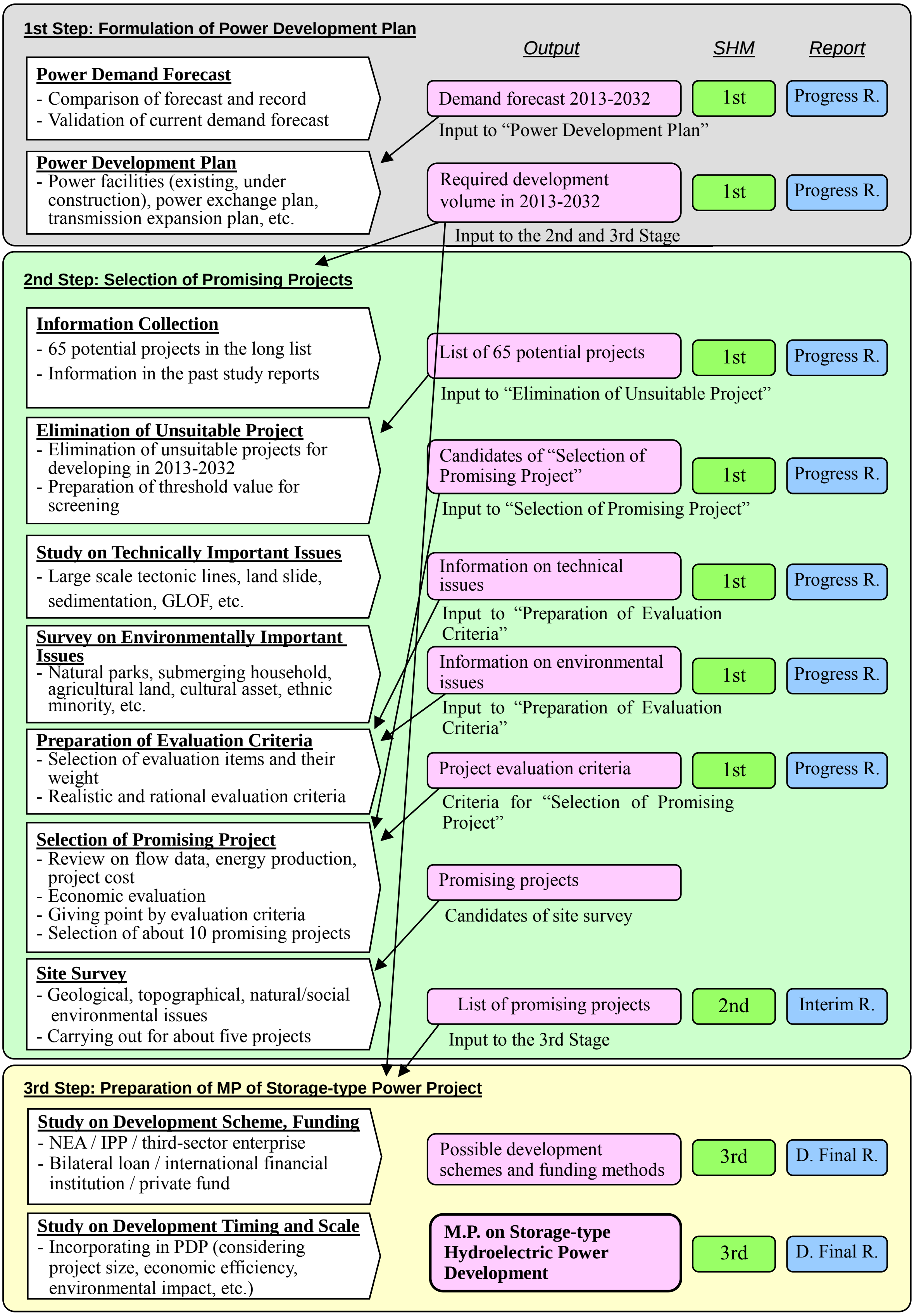


Figure1.5-2 Work Contents and Output

1.6 Record on Dispatch of Study Team

JICA commenced the Study in December 2011, based on S/W, and has dispatched the Study Team to Nepal so far as described below:

- 1st Field Work in Nepal; January 16, 2012 to February 26, 2012
- 2nd Field Work in Nepal; May 8, 2012 to June 30, 2012
- 3rd Field Work in Nepal; November 18, 2012 to December 2, 2012
- 4th Field Work in Nepal; February 3, 2013 to February 17, 2013
- 5th Field Work in Nepal; May 26, 2013 to June 9, 2013
- 6th Field Work in Nepal; December 12, 2013 to December 26, 2013

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

- Inception Report; December 2011
- Progress Report; February 2012
- Interim Report; November 2012
- 1st Draft Final Report; February 2013
- 2nd Draft Final Report; December 2013
- Final Report; February 2014

1.7 NEA Counterpart and Study Team

1.7.1 NEA

The NEA counterpart is listed as below:

No.	Name	Assignment	Title	Organization
1	Mr. Lila Nath Bhattarai	Team Leader (up to Apr. 2012)	Director	Project Development Department(PDD)
2	Mr. Keshab Raj Bhatta	Team Leader (up to Oct. 2012)	Director	Project Development Department(PDD)
3	Mr. Sunil Kumar Dhungel	Team Leader (up to Nov. 2013)	Director	Project Development Department (PDD)
4	Mr. Jagdishwor Man Singh	Deputy Team Leader (up to Apr. 2012)	Director	Engineering Services(ES)
5	Mr. Biswa Dhoj Joshi	Team Leader	Chief	Project Development Department(PDD)
		Deputy Team Leader (up to Nov. 2013)	Manager	Project Development Department(PDD)
6	Mr. Tika Ram Paudel	Geology	Asst. Manager	Soil, Rock and Concrete Laboratory, ES
7	Mrs. Annu Rajbhandari	Social and Natural Environments	Deputy Manager	Environment and Social Development Department, ES
8	Mr. Raju Gyawali	Social and Natural Environments	Environmentalist	Environment and Social Development Department, ES
9	Mr. Damodar Bhakta Shrestha	Hydrology and Meteorology	Manager	PDD,ES
10	Mr. Nahakul Nepal	Electrical and Mechanical Engineering	Asst. Manager	E/M Division, ES

No.	Name	Assignment	Title	Organization
11	Mr. Pradeep Man Shrestha	Electrical and Mechanical Engineering		
12	Mr. Anil Rajbhandari	Power System Planning	Manager	System Planning Department
13	Mr. Sanjib Man Rajbhandari	Demand Forecasting / Economical and Financial Analysis	Manager	PDD,ES
14	Mr. Gopal K. Lohia	Deputy Team Leader /Coordinator	Manager	PDD, ES
		Coordinator (up to Nov. 2013)	Manager	PDD, ES

1.7.2 JICA Study Team

The JICA Study Team members are listed as follows:

	Name	Assignment	Firm	Remarks
1	Takashi MIMURA	Team Leader/ Power Development Planning	Electric Power Development Co., Ltd. (J-POWER)	
2	Hiroyasu AKAIKE	Sub-Leader/ Hydropower Engineering	J-POWER	
3	Madoka HARADA	Geology	J-POWER	(up to Oct. 2012)
4	Nobuo HOSHINO	Geology	OPC Corp.	(from Nov. 2012)
5	Akiko URAGO	Environmental & Social Considerations	IC-Net Co., Ltd.	Raven Corp. (from April 2012)
6	Kayoko KURISAKI	Hydrology & Meteorology	J-POWER	
7	Eiji TSUCHIYA	Electrical & Mechanical Engineering	J-POWER	
8	Tomoyuki FUTADA	Power System Planning	J-POWER	(up to Oct. 2012)
9	Takatsugu OKABE	Power System Planning	J-POWER	(from Nov. 2012)
10	Toshifumi SERIZAWA	Demand forecasting/ Economical & Financial Analyses	JIN Co., Ltd.	
11	Keiko OTOGURO	Coordinator/ Environmental & Social Considerations Assist	Oriental Consultants Co., Ltd.	

Chapter 2

Meteorology and Hydrology

Chapter 2 Meteorology and Hydrology

2.1 Meteorology

Nepal has an area of 147,182 km^2. The east-west length is about 885 km and the north-south width varies between 150 km and 200 km. About 83% of the total area is the mountains and the rest 17% is the plains.

The High Himalaya is located on the northern side. The Mahabharat range and Churia Hills lie south and parallel with it. The Midland is located between the High Himalaya of the north and the Mahabharat range of the south. The Dun is the wide valley between the Mahabharat range and Churia Hills. The Terai belt lies in the south of Churia Hills and the northern border of the Ganges plain.

The Himalaya contains not only the highest peak of the world but also great number of high peaks which have altitudes that go beyond 7,000 m. The highest peak, Sagarmatha (Mt. Everest) is 8,848 m. The elevation of the Midland and Mahabharat range is between 2,000 m and 3,000 m. The lowest elevation of the Terai belt in the southern part of Nepal is 62 m.

The difference of elevation is more than 8,000 m in the land of 200 km in the north and south width. The geography varies widely. The variation of the geography effects the complicate variation of the regional climate.

2.1.1 Distribution of Climate

The climate of Nepal varies along with the altitude and changes from the subtropical climate in the southern part to the alpine climate in the northern part. In Nepal, five characteristic climatic parallel belts are distinguishable from the south to north as follows.

1) Subtropical climate in Terai
2) Warm temperate monsoon climate in the Mahabharat range and beyond up to a height of about 2,000 m with a warm and wet summer and a cool and dry winter.
3) Cool temperate monsoon climate in the Mahabharat range and beyond up to a height of about 3,500 m with a mild wet summer and a cold dry winter.
4) An alpine climate is found in the highest mountain region up to a height of about 5,000 m with low temperature in the summer and extremely frosty conditions in the winter.
5) Tundra climate lies above the snow line where there is perpetual snow and also cold desert conditions.

Inside the belts above, deeply incised valleys of the major rivers which run north and south have a tropical monsoon climate or warm temperate monsoon climate within the Alpine or Tundra belts.

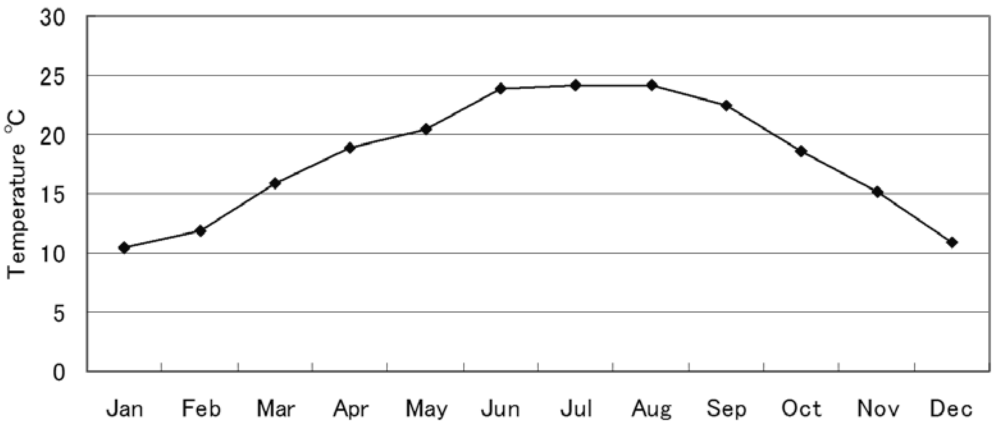
2.1.2 Season

According to the temperature and rainfall, the Nepalese terrain has four seasons in a year. They are spring, summer, rainy and winter. The period of each season is three months. The beginning time of each season has a lag and lead according to the terrain, latitude and longitude of the area.

The year is divided into two seasons, monsoon season and dry season by monsoon. The monsoon season starts in June and ends in October in the mountains. The monsoon season starts July and ends in November in the plains of the south.

2.1.3 Temperature

The capital of Nepal, Kathmandu, is located at an elevation of 1,300 m and the annual mean temperature is 18.1°C. The lowest mean temperature is 10.5°C in January and the highest mean temperature is 24.2°C in July. Figure 2.1.3-1 shows the monthly mean temperature in Kathmandu.



Source: Nepal Atlas & Statistics, Revised edition, 2008

Figure 2.1.3-1 Monthly Mean Temperature in Kathmandu

2.1.4 Humidity

The humidity is high in January and reaches to 75% in the eastern region and 92% in the western region. The humidity is low in April and reaches to 53% in the eastern region and 43% in the western region.

2.1.5 Rainfall

Rainfall is by monsoons and westerlies. About 90% of the annual precipitation is brought by monsoons and the other 10% is by westerlies.

When a monsoon cloud touches eastern Nepal, it first hits the Mahabharat range which has an average height of 2,000 m and starts to precipitate in that part of the Terai. The cloud climbs the Mahabharat range and the southern face is heavily precipitated, whereas the northern face gets less. A part of the clouds reach the High Himalaya and the southern face is heavily precipitated, whereas the northern face gets less. When some streams of clouds touch the Koshi gorge, they follow the river valleys to east Tamur, north Arun and west Sun Koshi. The excess clouds move to the west and the same cycles happen in the Gandaki valley. As there are no wells developed in the Mahabharat range before the Annapurna range, most of the clouds find easy access to reach Pokhara, which is located in the east of the Annapurna range, compared to other regions. As the result, Pokhara experiences maximum rainfall in Nepal which is 4,500 mm.

The precipitation by westerlies happens by the same mechanism in a reverse direction.

Figure 2.1.5-1 shows a map of Nepal as reference.

Source: http://www.nepal-dia.de

Figure 2.1.5-1 Map of Nepal

The 18% of the rainfall becomes snow, 72% becomes surface water and 10% becomes ground water.

2.1.6 Snow

The rainfall in the High Himalaya is around 1,000 mm and is converted to snow. The average thickness is 1.2 m. The snow which falls on the steep slope becomes avalanches and glaciers.

Table 2.1.6-1 shows the snow covered area. The snow covered area of the Arun, the Marsyangdi, the Kali and the Karnali is large. Snow is an important water resource in these rivers. Snow contributes to flow of the rivers with ground water for the period of low flow.

Table 2.1.6-1 Snow Covered Area

Basin Name	River Name	Snow Covered Area
Khoshi	Tamur Arun Dudh Koshi Sun Koshi	750 km^2 4,475 km^2 500 km^2 650 km^2
Gandaki	Trishuli Marsyangdi Kali	1,100 km^2 2,100 km^2 2,100 km^2
Karnali	Bheri Karnali West Seti	1,850 km^2 3,400 km^2 190 km^2
Mahakali	Mahakali	805 km^2
Total		15,820 km^2

Source: Engineering Challenges in Nepal Himalaya

2.1.7 Precipitation

Precipitation monitoring in Nepal is managed by the Department of Hydrology and Meteorology (DHM). Precipitation is gauged at precipitation stations, climatology stations, synoptic stations, agro-meteorology stations and aeronautical stations. There are respectively 170, 69, 9, 22, and 6 of these stations. The total number of the stations is 276.

The location of the precipitation gauging stations is shown in Figure 2.1.7-1. The specifications of precipitation gauging stations are shown in Table 2.1.7-1.

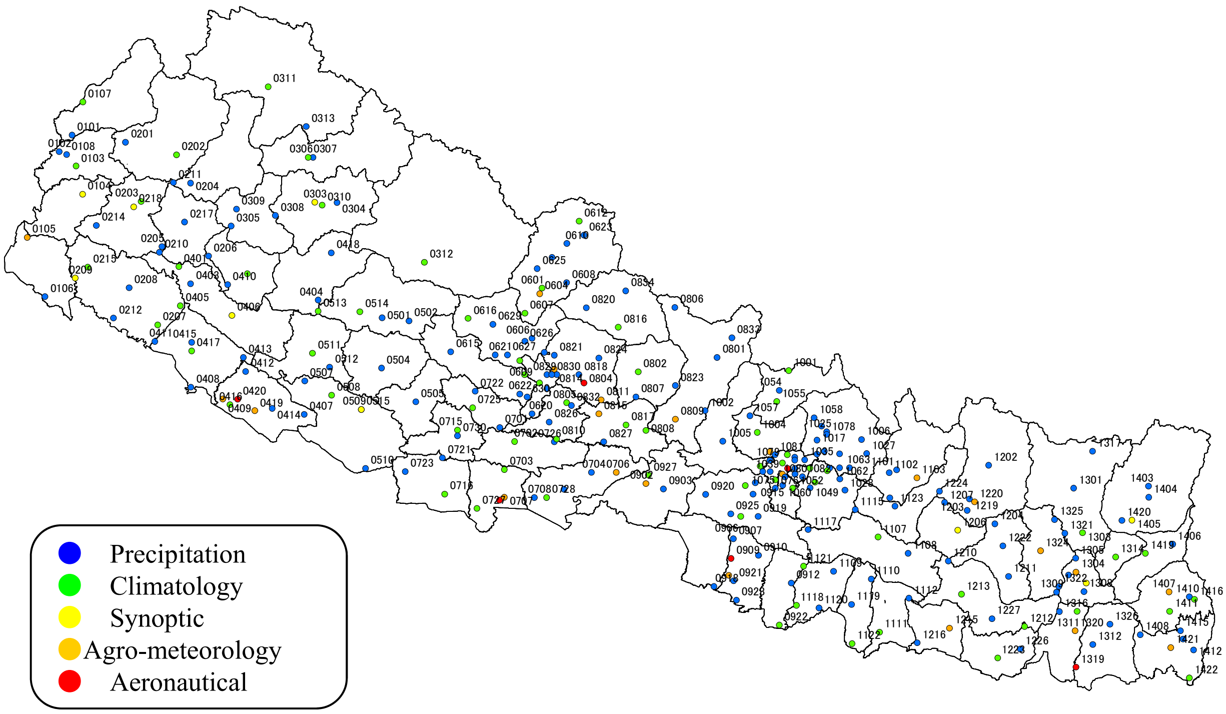


Figure 2.1.7-1 Location of Precipitation Gauging Stations

The oldest record is from 1956. The latest record is from 2010. The longest period of record keeping is 55 years, the shortest period is 9 years and the average period is 40 years.

The gauging period at four precipitation gauging stations, which is 623, 834, 927 and 1326, is less than 10 years. The records of these four precipitation gauging stations are eliminated considering the reliability of data.

Therefore, the records of the other 272 stations are considered in this study.

In Table 2.1.7-1 the monthly precipitation is the average data during the gauging period at each station.

Table 2.1.7-1 Specifications of Precipitation Gauging Stations (1/6)

No.	Name	Index	District	Type of Station	Start to record	Closed to record	Location		Elevation	Precipitation (mm)												
							Latitude	Longitude	(m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1	KAKERPAKHA	0101	Baitadi	PRECIPITATION	Jul, 56		29.65	80.50	842	38.2	44.8	53.7	45.7	98.8	258.3	455.5	406.8	225.7	55.9	7.4	17.1	1,708.0
2	BAITADI	0102	Baltadi	PRECIPITATION	Feb, 73		29.55	80.42	1,635	41.3	57.1	56.5	55.1	128.2	198.4	307.9	260.8	161.1	46.3	7.8	27.4	1,347.8
3	PATAN (WEST)	0103	Baitadi	CLIMATOLOGY	Jun, 56		29.47	80.53	1,266	37.9	41.0	46.8	46.1	100.3	191.5	342.4	307.9	165.7	41.1	8.9	19.6	1,349.1
4	DADELDHURA	0104	Dadeldhura	SYNOPTIC	Jun, 56		29.30	80.58	1,848	45.1	59.4	57.5	48.7	78.5	177.0	336.5	318.6	185.9	56.3	7.8	23.7	1,394.9
5	MAHENDRA NAGAR	0105	Kanchanpur	AGROMETEOROLOGY	Mar, 71		29.03	80.22	176	25.7	38.5	19.4	17.2	51.7	254.4	509.0	524.7	297.3	55.4	6.2	15.5	1,814.9
6	BELAURI SANTIPUR	0106	Kanchanpur	PRECIPITATION	Mar, 71		28.68	80.35	159	22.3	31.5	18.7	17.6	52.1	239.2	487.4	450.6	279.5	55.9	4.3	15.3	1,674.5
7	DARCHULA	0107	Darchula	CLIMATOLOGY	Mar, 74		29.85	80.57	1,097	46.9	64.7	66.4	60.0	121.9	299.3	700.4	652.4	327.4	62.1	9.2	26.0	2,436.7
8	SATBANJH	0108	Baltadi	PRECIPITATION	Jun, 76		29.53	80.47	2,370	40.6	54.5	60.7	63.0	123.4	209.9	376.7	367.5	200.1	39.9	9.8	25.0	1,571.0
9	PIPALKOT	0201	Bajhang	PRECIPITATION	Jan, 57		29.62	80.87	1,456	50.8	53.5	58.4	60.9	114.9	313.7	575.8	548.6	304.0	63.3	11.2	22.9	2,178.0
10	CHAINPUR(WEST)	0202	Bajhang	CLIMATOLOGY	Jan, 57		29.55	81.22	1,304	52.5	61.3	62.9	46.0	60.1	176.8	374.3	388.4	213.1	49.5	8.9	23.7	1,517.4
11	SILGADHI DOTI	0203	Doti	CLIMATOLOGY	Jan, 57		29.27	80.98	1,360	48.6	50.1	49.9	40.4	83.0	194.3	294.3	260.0	180.9	62.3	7.6	21.9	1,293.2
12	BAJURA	0204	Bajura	PRECIPITATION	Jan, 76	Apr, 04	29.38	81.32	1,400	55.8	85.4	66.2	62.7	126.4	289.6	555.9	549.3	226.0	42.0	11.6	31.1	2,101.9
13	KATAI	0205	Doti	PRECIPITATION	Jan, 58		29.00	81.13	1,388	43.0	49.3	44.6	43.9	99.3	307.4	464.8	419.0	251.9	45.4	7.3	17.8	1,793.7
14	ASARA GHAT	0206	Achham	PRECIPITATION	Jan, 64		28.95	81.45	650	40.9	44.5	38.3	33.0	89.6	196.0	302.9	268.1	138.2	37.2	8.4	19.0	1,216.0
15	TIKAPUR	0207	Kailali	CLIMATOLOGY	Apr, 76		28.53	81.12	140	33.6	29.0	19.0	16.7	76.5	227.9	499.7	460.0	268.8	47.8	3.6	15.6	1,698.1
16	SANDEPANI	0208	Kailali	PRECIPITATION	Feb, 62		28.75	80.92	195	26.7	27.0	19.5	18.6	58.5	268.6	559.6	532.3	321.9	48.3	3.6	16.1	1,900.6
17	DHANGADHI(ATARIYA)	0209	Kaliali	SYNOPTIC	Jan, 57		28.80	80.55	187	26.1	26.9	18.1	18.9	62.1	252.9	545.8	465.5	287.9	60.1	3.5	13.1	1,781.0
18	BANGGA CAMP	0210	Achham	PRECIPITATION	Jan, 64		28.97	81.12	340	42.8	50.0	44.7	38.7	88.1	222.6	446.5	366.4	211.1	49.1	7.6	21.4	1,589.0
19	KHAPTAD	0211	Doti	PRECIPITATION	May, 76		29.38	81.20	3,430	46.3	53.0	31.9	59.6	130.3	360.8	810.0	758.7	442.5	55.6	12.6	21.6	2,782.9
20	SITAPUR	0212	Kailali	PRECIPITATION	Mar, 71		28.57	80.82	152	29.3	28.8	13.5	16.2	62.4	231.4	442.5	411.1	241.3	44.4	6.7	12.8	1,540.5
21	KOLA GAUN	0214	Doti	PRECIPITATION	Jan, 76		29.12	80.68	1,304	46.2	62.9	46.4	40.7	111.9	270.6	490.2	465.6	255.0	46.6	12.2	27.6	1,875.9
22	GODAVARI(WEST)	0215	Kailali	CLIMATOLOGY	Jan, 75		28.87	80.63	288	28.8	40.7	22.1	20.2	68.0	297.4	657.0	667.3	397.9	50.2	3.9	14.5	2,268.0
23	MANGALSEN	0217	Achham	PRECIPITATION	Jan, 76		29.15	81.28	1,345	53.5	69.5	58.2	44.5	105.1	199.3	336.3	316.4	180.1	49.1	11.1	26.7	1,449.9
24	DIPAYAL (DOTI)	0218	Doti	SYNOPTIC	Jan, 82		29.23	80.93	720	38.5	51.9	36.4	39.1	86.6	161.3	238.7	225.8	167.1	46.3	5.6	20.3	1,117.7
25	JUMLA	0303	jumla	SYNOPTIC	Jan, 57		29.28	82.17	2,300	31.2	39.4	51.8	39.0	51.2	71.2	181.3	176.4	95.7	34.3	7.5	11.6	790.6
26	GUTHI CHAUR	0304	Jumla	PRECIPITATION	Jan, 57		29.28	82.32	3,080	23.3	30.1	45.1	46.0	74.7	129.4	277.3	264.9	121.8	32.3	12.1	15.0	1,071.8
27	SHERI GHAT	0305	Kalikot	PRECIPITATION	Jan, 67		29.13	81.60	1,210	46.4	52.3	44.0	52.8	121.5	206.2	342.9	350.0	174.6	60.6	8.3	15.3	1,474.8
28	GAM SHREE NAGAR	0306	Mugu	PRECIPITATION	Jan, 71		29.55	82.15	2,133	26.4	30.7	40.6	34.4	47.7	77.4	203.9	204.0	103.7	28.0	7.8	15.7	820.3
29	RARA	0307	Mugu	CLIMATOLOGY	Jan, 71	Dec, 07	29.55	82.12	3,048	31.4	42.7	49.7	43.3	69.5	81.8	192.4	207.6	106.1	30.1	8.5	22.0	884.9
30	NAGMA	0308	Kalikot	PRECIPITATION	Jan, 71		29.20	81.90	1,905	43.8	60.3	59.6	48.7	64.5	79.7	134.4	138.0	85.5	38.3	11.0	18.5	782.2
31	BIJAYAPUR (RASKOT)	0309	Kalikot	PRECIPITATION	Jan, 57		29.23	81.63	1,814	57.0	54.4	60.8	48.8	86.9	122.2	241.9	230.0	148.6	48.1	11.7	17.0	1,127.5
32	DIPAL GAUN	0310	Jumla	CLIMATOLOGY	Jan, 74		29.27	82.22	2,310	31.7	40.9	48.4	44.3	53.4	100.5	222.8	212.1	108.0	32.5	6.0	10.5	911.0
33	SIMIKOT	0311	Humla	CLIMATOLOGY	Jan, 78	Dec, 06	29.97	81.83	2,800	30.0	56.4	68.8	35.4	48.8	77.7	141.3	148.2	110.0	35.0	14.2	18.3	784.0
34	DUNAI	0312	Dolpa	CLIMATOLOGY	Jun, 58		28.93	82.92	2,058	23.0	22.3	33.2	25.0	38.6	49.3	115.8	120.7	66.3	28.7	7.2	12.5	542.6
35	DARMA	0313	Humla	PRECIPITATION	Jun, 79		29.73	82.10	1,950	39.9	46.2	63.9	57.3	69.5	113.7	335.1	300.5	155.8	56.8	22.3	29.3	1,290.3
36	PUSMA CAMP	0401	Surkhet	CLIMATOLOGY	Jan, 63		28.88	81.25	950	37.3	43.0	33.3	30.3	71.3	273.1	442.7	393.8	228.0	42.1	6.0	20.2	1,621.1
37	DAILEKH	0402	Dailekh	CLIMATOLOGY	Jan, 57		28.85	81.72	1,402	36.1	37.0	38.0	33.7	90.3	239.1	482.7	492.0	231.9	45.3	8.5	14.0	1,748.6
38	JAMU (TIKUWA KUNA)	0403	Surkhet	PRECIPITATION	Jan, 63		28.78	81.33	260	28.2	38.7	22.1	22.0	67.6	209.5	382.3	343.4	191.6	35.2	4.9	17.2	1,362.7
39	JAJARKOT	0404	Jajarkot	PRECIPITATION	Jan, 57		28.70	82.20	1,231	30.3	35.4	37.2	35.0	61.9	282.0	478.8	487.0	250.8	68.7	10.4	19.0	1,796.6
40	CHISAPANI(KARNALI)	0405	Bardiya	CLIMATOLOGY	Jan, 63		28.65	81.27	225	34.4	32.1	22.3	24.5	70.5	291.4	690.7	619.8	357.4	50.4	6.5	16.2	2,216.1
41	SURKHET(BIRENDRA NAGAR)	0406	Surkhet	SYNOPTIC	Jan, 57		28.60	81.62	720	37.6	40.2	28.4	31.2	78.9	266.8	517.0	481.6	241.6	51.7	6.1	17.1	1,798.3
42	KUSUM	0407	Banke	PRECIPITATION	Jan, 57		28.02	82.12	235	27.3	21.8	19.4	23.2	65.0	208.9	415.2	352.6	226.9	60.4	5.3	9.8	1,435.7
43	GULARIYA	0408	Bardiya	PRECIPITATION	Jan, 57		28.17	81.35	215	25.2	19.9	16.9	19.4	49.2	187.0	405.9	340.5	234.4	59.5	2.4	11.6	1,371.8
44	KHAJURA (NEPALGANJ)	0409	Banke	AGROMETEOROLOGY	Jan, 68		28.10	81.57	190	20.0	19.4	12.3	17.2	57.2	192.8	427.7	326.8	218.9	58.8	4.2	11.3	1,366.7
45	BALE BUDHA	0410	Dailekh	PRECIPITATION	Jan, 65		28.78	81.58	610	32.0	30.0	24.2	29.2	60.6	167.9	290.9	247.8	123.1	48.1	5.6	12.8	1,072.2
46	RAJAPUR	0411	Bardiya	PRECIPITATION	Jan, 77		28.43	81.10	129	30.3	24.9	14.8	14.5	59.2	189.1	430.9	359.9	213.1	43.5	3.3	17.3	1,400.7
47	NAUBASTA	0412	Banke	PRECIPITATION	Jan, 71		28.27	81.72	135	23.1	19.6	12.3	13.2	42.0	199.6	454.9	357.1	204.7	59.9	5.8	10.7	1,402.8
48	SHYANO SHREE(CHEPANG)	0413	Bardiya	PRECIPITATION	Jan, 71		28.35	81.70	510	31.4	30.1	20.3	20.0	92.6	295.3	622.3	554.3	272.2	58.7	10.9	10.9	2,018.8
49	BAIJAPUR	0414	Banke	PRECIPITATION	Jan, 71		28.05	81.90	226	19.2	27.2	20.5	27.1	46.0	144.7	308.0	274.7	158.3	38.0	14.4	17.2	1,095.4
50	BARGADAHA	0415	Bardiya	PRECIPITATION	Jan, 68		28.43	81.35	200	26.4	20.9	11.9	15.7	58.3	198.2	396.1	377.1	203.8	42.7	4.0	12.7	1,367.8

Table 2.1.7-1 Specifications of Precipitation Gauging Stations (2/6)

No.	Name	Index	District	Type of Station	Start to record	Closed to record	Location		Elevation	Precipitation (mm)												
							Latitude	Longitude	(m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
51	NEPALGUNJ(REG.OFF.)	0416	Banke	CLIMATOLOGY	Jan, 73		28.07	81.62	144	21.2	22.9	14.7	15.6	61.7	185.1	412.5	321.5	210.5	51.6	4.2	11.5	1,333.0
52	RANI JARUWA NURSERY	0417	Bardiya	CLIMATOLOGY	Jan, 76		28.38	81.35	200	20.6	27.5	12.6	11.6	67.5	148.0	399.7	376.4	171.1	38.6	1.9	14.5	1,289.8
53	MAINA GAUN (D.BAS)	0418	Jajarkot	PRECIPITATION	Jan, 75		28.98	82.28	2,000	46.8	40.4	49.8	52.4	83.7	214.7	481.9	436.4	244.2	61.5	15.5	24.8	1,752.1
54	SIKTA	0419	Banke	AGROMETEOROLOGY	Jan, 78		28.03	81.78	195	17.6	21.6	14.8	15.3	71.6	208.7	463.1	392.1	232.8	48.9	5.1	16.0	1,507.5
55	NEPALGUNJ AIRPORT	0420	Banke	AERONATICAL	Jan, 96		28.10	81.67	165	19.3	21.8	14.6	20.0	60.3	213.8	519.6	389.3	212.5	68.8	5.5	3.8	1,549.2
56	RUKUMKOT	0501	Rukum	PRECIPITATION	Jan, 57		28.60	82.63	1,560	37.2	50.9	48.5	66.7	158.0	402.7	653.4	627.2	270.6	78.3	25.4	15.9	2,434.7
57	SHERA GAUN	0502	Rukum	PRECIPITATION	Jan, 76	Aug, 00	28.58	82.82	2,150	27.9	36.5	51.8	59.6	101.5	210.9	368.0	370.0	183.3	41.8	15.6	22.6	1,489.5
58	LIBANG GAUN	0504	Rolpa	PRECIPITATION	Jan, 73		28.30	82.63	1,270	28.1	48.0	39.5	46.9	106.6	293.5	417.3	382.7	264.0	53.6	10.3	17.0	1,707.5
59	BIJUWAR TAR	0505	Pyuthan	PRECIPITATION	Jan, 57		28.10	82.87	823	23.4	27.2	25.5	35.7	78.2	234.5	314.4	265.6	156.0	42.5	6.6	11.0	1,220.4
60	NAYABASTI (DANG)	0507	Dang	PRECIPITATION	Jan, 71		28.22	82.12	698	24.6	26.1	21.9	23.8	85.5	258.7	465.4	420.8	272.1	51.4	13.0	14.3	1,677.5
61	TULSIPUR	0508	Dang	CLIMATOLOGY	Jan, 71		28.13	82.30	725	23.7	22.5	16.7	22.6	85.0	292.7	441.8	399.6	267.6	78.5	9.1	12.0	1,671.8
62	GHORAHI (MASINA)	0509	Dang	PRECIPITATION	Jan, 71		28.05	82.50	725	25.0	22.7	21.5	23.7	83.9	298.4	496.0	440.7	320.5	84.5	9.7	12.4	1,839.0
63	KOILABAS	0510	Dang	PRECIPITATION	Jan, 71		27.70	82.53	320	16.2	22.4	19.2	21.9	65.7	270.5	496.4	401.8	267.8	54.6	9.7	9.8	1,656.1
64	SALYAN BAZAR	0511	Salyan	CLIMATOLOGY	Jan, 57		28.38	82.17	1,457	36.8	32.4	30.7	29.2	60.8	182.4	278.6	230.9	128.6	46.5	7.3	17.4	1,081.7
65	LUWAMJULA BAZAR	0512	Salyan	PRECIPITATION	Jan, 72		28.30	82.28	885	32.0	34.2	30.4	26.5	59.7	156.6	270.7	228.1	145.6	37.4	9.6	19.8	1,050.6
66	CHAUR JHARI TAR	0513	Rukum	CLIMATOLOGY	Jan, 75		28.63	82.20	910	26.2	29.4	25.8	29.4	71.7	171.6	335.4	323.6	159.5	47.4	9.6	12.8	1,242.3
67	MUSIKOT(RUKUMKOT)	0514	Rukum	CLIMATOLOGY	Jan, 73		28.63	82.48	2,100	23.9	35.6	38.5	46.0	120.3	305.0	571.4	549.6	323.1	80.3	14.9	17.0	2,125.6
68	GHORAI (DANG)	0515	Dang	SYNOPTIC	Jan, 89		28.05	82.50	634	20.7	22.5	21.5	26.7	93.6	256.1	413.3	421.7	231.1	57.4	9.9	8.2	1,582.7
69	JOMSOM	0601	Mustang	CLIMATOLOGY	Jan, 57		28.78	83.72	2,744	11.3	13.8	25.7	19.4	15.7	22.1	41.7	40.9	37.2	29.2	5.9	4.3	267.1
70	THAKMARPHA	0604	Mustang	AGROMETEOROLOGY	Jan, 67		28.75	83.70	2,566	7.6	15.9	32.2	28.2	31.2	44.5	69.4	61.9	51.1	36.4	6.3	9.5	394.4
71	BAGLUNG	0605	Baglung	CLIMATOLOGY	Jan, 69		28.27	83.60	984	18.3	25.0	29.8	46.7	139.4	291.7	517.0	443.4	260.1	61.6	16.1	14.3	1,863.5
72	TATOPANI	0606	Myagdi	PRECIPITATION	Jan, 69		28.48	83.65	1,243	17.8	27.8	49.0	78.8	162.8	245.9	367.1	355.7	202.6	62.9	9.2	12.3	1,591.7
73	LETE	0607	Mustang	CLIMATOLOGY	Jan, 69		28.63	83.60	2,384	29.5	55.9	97.6	105.4	120.5	162.4	247.6	240.4	140.9	56.2	15.0	16.5	1,287.9
74	RANIPAUWA (M.NATH)	0608	Mustang	PRECIPITATION	Jan, 69		28.82	83.88	3,609	11.2	12.7	14.3	11.7	9.6	23.7	78.5	82.2	41.3	11.5	4.6	8.3	309.4
75	BENI BAZAR	0609	Myagdi	CLIMATOLOGY	Jan, 56		28.35	83.57	835	24.1	25.3	34.8	47.2	105.3	227.3	395.6	387.7	210.1	57.6	8.1	11.3	1,534.3
76	GHAMI (MUSTANG)	0610	Mustang	PRECIPITATION	Jan, 73		29.05	83.88	3,465	8.3	10.2	10.9	3.2	6.2	8.5	35.3	38.0	12.9	17.8	2.3	9.8	163.4
77	MUSTANG(LOMANGTHANG)	0612	Mustang	CLIMATOLOGY	Jan, 74	Dec, 05	29.18	83.97	3,705	8.2	10.9	4.9	1.5	2.7	6.3	45.1	41.9	8.5	10.5	2.2	8.2	151.0
78	KARKI NETA	0613	Parbat	PRECIPITATION	Jan, 77		28.18	83.75	1,720	24.1	29.7	39.4	76.8	187.5	400.9	677.2	581.0	333.5	67.7	13.3	21.6	2,452.7
79	KUSHMA	0614	Parbat	CLIMATOLOGY	Jan, 69		28.22	83.70	891	22.1	27.2	34.8	71.0	167.6	412.4	677.9	580.7	351.5	84.7	8.7	15.5	2,454.1
80	BOBANG	0615	Baglung	PRECIPITATION	Jan, 78		28.40	83.10	2,273	29.5	30.5	41.1	47.4	105.8	429.7	677.9	675.8	395.9	70.8	8.8	15.9	2,529.1
81	GURJA KHANI	0616	Myagdi	CLIMATOLOGY	Jan, 79		28.60	83.22	2,530	29.9	37.8	33.5	34.2	68.9	244.4	555.1	487.0	287.1	55.5	16.5	13.2	1,863.1
82	GHOREPANI	0619	Myagdi	PRECIPITATION	Jan, 75		28.40	83.73	2,742	23.6	34.3	49.8	100.4	203.3	401.1	775.7	700.2	416.1	83.3	14.2	14.5	2,816.6
83	TRIBENI	0620	Parbat	PRECIPITATION	Jan, 89		28.03	83.65	700	15.7	24.6	24.4	50.9	165.7	412.8	548.2	446.3	234.8	57.7	11.5	8.5	2,000.9
84	DARBANG	0621	Myagdi	PRECIPITATION	Jan, 89		28.38	83.40	1,160	23.3	26.2	44.5	44.9	155.0	366.1	508.2	463.8	253.3	68.1	16.4	11.7	1,981.5
85	RANGKHANI	0622	Baglung	PRECIPITATION	Jan, 89		28.15	83.57	1,740	25.2	50.4	44.0	86.1	229.7	627.7	882.8	740.5	404.2	59.7	13.8	15.1	3,179.2
86	YARA GAUN (DHEE)	0623	Mustang	PRECIPITATION	Jan, 92		29.10	84.00	3,620	–	–	–	–	–	–	–	–	–	–	–	–	–
87	SAMAR GAUN	0624	Mustang	PRECIPITATION	Jan, 92		28.97	83.78	3,570	9.1	10.9	17.2	5.9	3.7	14.4	62.3	71.8	21.8	11.2	2.6	4.9	235.6
88	SANDA	0625	Mustang	PRECIPITATION	Jan, 92		28.90	83.68	3,570	8.6	11.4	20.8	15.1	11.5	16.8	36.2	41.3	25.9	10.5	2.7	2.0	202.6
89	BEGA	0626	Myagdi	PRECIPITATION	Jan, 92		28.47	83.60	1,770	21.2	34.0	58.6	64.3	197.5	419.4	441.9	455.0	253.3	77.8	13.4	13.1	2,049.5
90	KUHUN	0627	Myagdi	PRECIPITATION	Jan, 92		28.38	83.48	1,550	20.2	35.1	31.6	34.7	112.5	261.7	380.0	403.2	216.9	51.2	12.2	14.5	1,573.8
91	BAGHARA	0629	Myagdi	PRECIPITATION	Jan, 92		28.57	83.38	2,330	24.6	33.0	43.6	50.2	117.3	485.5	794.6	786.6	476.4	111.0	20.0	6.4	2,949.3
92	SIRKON	630	Parbat	PRECIPITATION	Jan, 92		28.13	83.62	790	22.9	27.6	34.2	71.8	188.2	488.1	685.2	530.8	296.9	46.7	9.8	10.7	2,413.0
93	RIDI BAZAR	0701	Gulmi	PRECIPITATION	Jan, 56		27.95	83.43	442	24.2	21.7	23.3	38.9	93.6	239.2	391.2	305.3	183.6	45.9	6.8	14.5	1,388.2
94	TANSEN	0702	Palpa	CLIMATOLOGY	Jan, 56		27.87	83.53	1,067	22.6	23.4	23.7	35.5	76.3	237.5	467.4	363.1	195.5	51.0	4.2	14.4	1,514.6
95	BUTWAL	0703	Rupandehi	CLIMATOLOGY	Jan, 57		27.70	83.47	205	16.4	16.7	21.9	22.8	93.5	392.5	704.9	598.8	409.7	110.5	9.6	12.0	2,409.4
96	BELUWA (GIRWARI)	0704	Nawalparasi	PRECIPITATION	Jan, 58		27.68	84.05	150	20.5	16.8	19.1	54.1	155.4	474.3	762.2	607.1	370.4	99.5	7.0	15.7	2,602.0
97	BHAIRAHAWA AIRPORT	0705	Rupandehi	AERONATICAL	Jan, 68		27.52	83.43	109	16.4	16.2	15.9	21.3	74.4	259.5	542.7	380.8	242.9	71.0	6.3	11.2	1,658.5
98	DUMKAULI	0706	Nawalparasi	AGROMETEOROLOGY	Jan, 74		27.68	84.22	154	18.1	15.1	20.1	62.3	181.3	404.8	654.3	521.1	363.1	87.2	8.3	18.9	2,354.7
99	BHAIRAHAWA (AGRIC)	0707	Rupandehi	AGROMETEOROLOGY	Jan, 68		27.53	83.47	120	16.5	17.1	16.4	23.9	82.7	277.1	554.7	404.4	277.5	78.3	5.6	13.4	1,767.7
100	PARASI	0708	Nawalparasi	PRECIPITATION	Jan, 76		27.53	83.67	125	15.8	19.9	20.4	36.0	96.3	328.9	566.6	429.7	280.1	74.0	4.8	17.0	1,889.4

Table 2.1.7-1 Specifications of Precipitation Gauging Stations (3/6)

No.	Name	Index	District	Type of Station	Start to record	Closed to record	Location		Elevation	Precipitation (mm)												
							Latitude	Longitude	(m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
101	DUMKIBAS	0710	Nawalparasi	PRECIPITATION	Jan, 70		27.58	83.87	164	17.0	19.0	14.8	36.2	127.0	387.5	683.4	566.5	376.7	80.7	8.4	14.9	2,332.1
102	KHANCHIKOT	0715	Arghakhanchi	CLIMATOLOGY	Jan, 71		27.93	83.15	1,760	26.9	35.4	30.2	36.6	105.7	280.0	495.1	390.0	269.2	67.2	12.5	23.6	1,772.3
103	TAULIHAWA	0716	Kapilbastu	CLIMATOLOGY	Jan, 71		27.55	83.07	94	16.2	20.4	15.7	22.9	56.5	214.8	509.6	347.4	227.5	44.1	5.9	8.9	1,489.9
104	PATTHARKOT (WEST)	0721	Kapilbastu	PRECIPITATION	Jan, 73		27.77	83.05	200	15.6	18.6	15.5	20.4	88.1	367.7	640.1	566.3	421.6	87.2	10.1	18.1	2,269.1
105	MUSIKOT	0722	Gulmi	PRECIPITATION	Jan, 56		28.17	83.27	1,280	21.3	22.4	33.2	63.0	167.3	410.5	511.1	465.1	262.5	61.9	6.0	16.8	2,041.0
106	BHAGWANPUR	0723	Kapilbastu	PRECIPITATION	Jan, 75		27.68	82.80	80	20.0	21.5	18.4	22.7	71.8	263.9	578.0	428.0	305.3	67.6	7.6	14.8	1,819.4
107	TAMGHAS	0725	Gulmi	CLIMATOLOGY	Jan, 80		28.07	83.25	1,530	25.9	34.2	31.3	55.5	139.5	316.0	496.7	428.6	272.9	49.4	11.4	17.3	1,878.8
108	GARAKOT	0726	Palpa	PRECIPITATION	Jan, 80		27.87	83.80	500	20.1	24.2	32.1	67.4	168.3	360.7	513.7	397.7	260.2	54.1	10.6	19.0	1,928.2
109	LUMBINI MANDIR	0727	Rupandehi	CLIMATOLOGY	Jan, 80		27.47	83.28	95	16.8	16.2	10.5	24.1	80.3	250.7	500.9	327.4	225.9	63.6	5.3	11.4	1,533.0
110	SIMARI	0728	Nawalparasi	CLIMATOLOGY	Jan, 81		27.53	83.75	154	16.4	16.1	16.3	35.3	123.1	266.2	576.4	500.1	257.4	69.6	5.8	18.6	1,901.2
111	SITAPUR(NEPANEY)	0730	Arghakhanchi	PRECIPITATION	Jan, 00		27.90	83.15	1,201	14.3	26.9	30.8	59.0	137.3	314.8	543.4	451.9	310.3	112.5	16.6	9.4	2,027.2
112	JAGAT (SETIBAS)	0801	Gorkha	PRECIPITATION	Jan, 57		28.37	84.90	1,334	29.6	45.5	75.2	68.5	71.4	184.5	328.1	272.3	169.2	53.9	8.7	10.8	1,317.7
113	KHUDI BAZAR	0802	Lamjung	CLIMATOLOGY	Jan, 57		28.28	84.37	823	26.0	44.4	77.2	101.9	208.1	555.0	864.9	829.6	468.3	104.4	15.0	16.0	3,310.8
114	POKHARA AIRPORT	0804	Kaski	AERONATICAL	Jan, 68		28.22	84.00	827	22.3	33.5	58.7	124.2	357.2	655.4	931.1	845.4	620.3	163.1	19.2	18.6	3,848.9
115	SYANGJA	0805	Syangia	CLIMATOLOGY	Jan, 73		28.10	83.88	868	22.1	32.3	43.6	101.5	284.9	545.4	751.0	620.4	383.9	105.3	10.2	16.3	2,917.0
116	LARKE SAMDO	0806	Gorkha	PRECIPITATION	Jan, 78		28.67	84.62	3,650	67.6	83.7	111.4	93.0	62.6	108.5	147.6	155.0	120.0	50.9	20.8	32.7	1,053.9
117	KUNCHHA	0807	Lamiung	PRECIPITATION	Jan, 56		28.13	84.35	855	21.6	32.5	53.7	101.1	252.1	497.3	613.6	520.3	332.0	98.0	13.7	15.3	2,551.1
118	BANDIPUR	0808	Tanahun	CLIMATOLOGY	Jan, 56		27.93	84.42	965	24.5	23.3	35.9	76.7	200.2	333.8	463.0	376.0	201.9	62.9	10.1	15.9	1,824.1
119	GORKHA	0809	Gorkha	AGROMETEOROLOGY	Jan, 56		28.00	84.62	1,097	22.1	17.9	38.8	77.3	166.7	326.0	434.0	364.9	192.1	52.3	9.0	12.8	1,714.1
120	CHAPKOT	0810	Syangja	CLIMATOLOGY	Jan, 57		27.88	83.82	460	23.2	24.4	33.8	57.3	140.7	332.7	520.3	377.7	236.7	68.1	7.2	14.7	1,836.8
121	MALEPATAN (POKHARA)	0811	Kaski	AGROMETEOROLOGY	Jan, 66		28.12	84.12	856	19.1	32.9	61.7	118.4	324.8	618.2	910.6	821.3	599.0	163.6	18.1	15.3	3,702.9
122	BHADAURE DEURALI	0813	Kaski	PRECIPITATION	Jan, 85		28.27	83.82	1,600	20.3	38.3	48.4	95.9	318.7	715.3	1,077.8	1,002.3	584.2	155.7	20.3	23.1	4,100.3
123	LUMLE	0814	Kaski	AGROMETEOROLOGY	Jan, 69		28.30	83.80	1,740	30.3	47.7	61.0	111.2	315.2	875.7	1,454.2	1,401.1	862.2	215.2	26.4	19.1	5,419.3
124	KHAIRINI TAR	0815	Tanahun	AGROMETEOROLOGY	Jan, 72		28.03	84.10	500	18.2	26.8	38.4	104.6	317.9	434.5	536.0	424.0	280.5	70.8	16.4	18.0	2,285.9
125	CHAME	0816	Manang	CLIMATOLOGY	Jan, 74		28.55	84.23	2,680	29.4	49.7	73.0	49.5	60.3	115.3	189.6	169.3	134.5	47.9	13.9	17.2	949.8
126	DAMAULI	0817	Tanahun	CLIMATOLOGY	Jan, 74		27.97	84.28	358	16.6	25.5	36.6	104.0	239.6	337.4	424.3	315.9	206.8	44.9	4.7	18.3	1,774.7
127	LAMACHAUR	0818	Kaski	PRECIPITATION	Jan, 72		28.27	83.97	1,070	26.0	37.0	66.2	122.0	375.9	794.3	1,062.2	992.1	752.5	175.0	20.1	18.1	4,441.5
128	MANANG BHOT	0820	Manang	PRECIPITATION	Jan, 74		28.67	84.02	3,420	23.9	20.9	33.7	22.9	28.5	41.0	58.9	74.6	71.7	33.6	12.4	14.3	436.5
129	GHANDRUK	0821	Kaski	PRECIPITATION	Jan, 75		28.38	83.80	1,960	25.0	57.9	73.2	114.6	203.9	528.2	914.7	916.9	460.1	97.4	17.5	19.9	3,429.2
130	GHAREDHUNGA	0823	Lamjung	PRECIPITATION	Jan, 75		28.20	84.62	1,120	19.1	30.8	58.7	82.5	245.5	512.2	777.9	749.3	411.0	96.1	12.2	19.4	3,014.7
131	SIKLESH	0824	Kaski	PRECIPITATION	Jan, 76		28.37	84.10	1,820	46.3	93.6	144.5	193.6	312.0	548.9	892.4	861.4	495.1	113.0	28.3	28.7	3,757.7
132	WALLING	0826	Syangja	PRECIPITATION	Jan, 89		27.98	83.77	750	18.5	20.1	23.0	51.5	172.0	401.8	554.6	446.7	192.7	26.5	8.3	14.3	1,930.0
133	RUMJAKOT	0827	Tanahun	PRECIPITATION	Jan, 89		27.87	84.13	660	16.1	30.2	36.8	67.8	215.8	319.5	402.3	327.9	180.6	56.7	10.7	16.5	1,681.1
134	SALLYAN	0829	Kaski	PRECIPITATION	Jan, 92		28.27	83.75	1,000	21.7	37.2	48.4	102.3	259.4	686.7	1,030.4	979.8	562.8	109.7	16.5	14.5	3,869.5
135	PAMDUR	0830	Kaski	PRECIPITATION	Jan, 92		28.27	83.78	1,160	158.0	30.6	60.1	124.5	285.4	815.2	1,343.5	1,297.9	811.9	206.9	22.7	17.8	5,174.7
136	DANDASWANRA	0832	Syangja	PRECIPITATION	Jan, 00		28.08	83.92	1,432	27.5	26.6	55.6	130.3	353.5	600.2	814.2	711.9	445.8	114.6	7.5	3.3	3,291.1
137	CHHEKAMPAR	0833	Gorkha	PRECIPITATION	Jan, 00		28.48	85.00	3,300	9.6	17.0	29.0	32.9	40.6	102.3	176.5	170.5	76.5	24.9	15.2	2.3	697.3
138	PHUGAUN	0834	Manang	PRECIPITATION	Jan, 02		28.77	84.28	4,100	—	—	—	—	—	—	—	—	—	—	—	—	—
139	RAMPUR	0902	Chitawan	AGROMETEOROLOGY	Jan, 67		27.62	84.42	256	18.4	15.0	20.9	53.4	153.5	357.2	552.4	440.9	307.7	81.4	7.2	13.2	2,021.2
140	JHAWANI	0903	Chitawan	PRECIPITATION	Jan, 57		27.58	84.53	270	16.6	18.8	19.2	53.1	123.5	310.4	498.2	471.7	289.9	79.2	9.5	11.4	1,901.5
141	CHISAPANI GADHI	0904	Makwanpur	PRECIPITATION	Jan, 57		27.55	85.13	1,706	20.5	21.1	41.2	80.0	160.1	356.6	611.5	488.7	282.6	68.9	7.0	14.1	2,152.2
142	DAMAN	0905	Makwanpur	CLIMATOLOGY	Jan, 67		27.60	85.08	2,314	16.7	26.9	37.2	79.1	162.0	305.2	471.1	350.1	226.2	60.9	9.2	13.1	1,757.8
143	HETAUNDA N.F.I.	0906	Makwanpur	CLIMATOLOGY	Jan, 67		27.42	85.05	474	16.3	18.5	28.4	61.4	176.0	377.3	655.1	553.2	384.4	92.4	10.2	12.6	2,385.6
144	AMLEKHGANJ	0907	Bara	PRECIPITATION	Jan, 57		27.28	85.00	396	14.2	11.5	19.4	50.4	114.2	331.4	600.6	518.2	338.3	87.1	6.8	10.5	2,102.6
145	SIMARA AIRPORT	0909	Bara	AERONATICAL	Jan, 70		27.17	84.98	130	13.9	14.5	17.3	48.5	126.8	274.9	560.2	410.4	277.9	77.6	5.0	10.3	1,837.2
146	NIJGADH	0910	Bara	PRECIPITATION	Jan, 58		27.18	85.17	244	16.7	14.4	21.8	46.8	115.9	298.8	568.1	474.4	355.2	83.0	9.0	8.5	2,012.5
147	PARWANIPUR	0911	Bara	AGROMETEOROLOGY	Jan, 67		27.07	84.97	115	13.3	14.2	15.7	33.7	102.1	262.5	451.6	341.2	229.0	65.7	4.6	9.7	1,543.4
148	RAMOLI BAIRIYA	0912	Routahat	PRECIPITATION	Jan, 56		27.02	85.38	152	17.5	11.4	18.0	42.3	93.5	250.4	499.1	368.9	253.9	72.9	5.1	7.7	1,640.8
149	MARKHU GAUN	0915	Makwanpur	PRECIPITATION	Jan, 72		27.62	85.15	1,530	19.4	27.3	33.6	67.4	131.0	233.3	374.3	291.1	202.8	47.2	8.6	19.4	1,455.3
150	BIRGANJ	0918	Parsa	PRECIPITATION	Jan, 74		27.00	84.87	91	12.0	15.2	16.0	28.5	114.6	237.6	466.0	343.8	230.9	64.8	7.0	10.1	1,546.5

Table 2.1.7-1 Specifications of Precipitation Gauging Stations (4/6)

No.	Name	Index	District	Type of Station	Start to record	Closed to record	Location		Elevation	Precipitation (mm)												
							Latitude	Longitude	(m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
151	MAKWANPUR GADHI	0919	Makwanpur	PRECIPITATION	Jan, 75		27.42	85.17	1,030	17.5	15.5	22.8	50.1	149.6	346.4	666.1	559.4	346.4	93.4	13.5	16.3	2,297.0
152	BELUWA(MANAHARI)	0920	Makwanpur	PRECIPITATION	Jan, 75		27.55	84.82	274	14.7	16.9	19.9	54.2	138.8	287.2	561.8	496.3	322.6	83.1	6.3	11.0	2,012.7
153	KALAIYA	0921	Bara	PRECIPITATION	Jan, 76		27.03	85.00	140	13.1	14.0	12.9	43.0	117.3	237.2	467.7	312.7	225.6	51.0	3.7	12.8	1,511.1
154	GAUR	0922	Routahat	CLIMATOLOGY	Jan, 83		26.77	85.30	90	16.7	13.2	6.5	48.4	129.4	239.7	385.6	327.8	173.7	61.0	2.9	6.5	1,411.4
155	KOLBHI	0923	Bara	PRECIPITATION	Jan, 92		26.92	85.02	109	9.7	11.0	13.0	41.6	105.7	267.3	452.9	368.1	188.6	58.2	6.1	9.1	1,531.3
156	RAJAIYA	0925	Makwanpur	PRECIPITATION	Jan, 92		27.43	84.98	332	15.7	22.9	18.3	58.9	175.4	391.1	605.2	464.6	277.5	72.2	9.1	8.7	2,119.8
157	BHARATPUR	0927	Chitawan	CLIMATOLOGY	Jan, 01		27.67	84.43	205	—	—	—	—	—	—	—	—	—	—	—	—	—
158	TIMURE	1001	Rasuwa	CLIMATOLOGY	Jan, 57		28.28	85.38	1,900	22.3	23.8	50.3	33.8	40.8	105.1	237.1	231.2	138.6	41.8	6.9	11.3	943.1
159	ARU GHAT D.BAZAR	1002	Dhading	PRECIPITATION	Jan, 58		28.05	84.82	518	25.1	29.4	51.4	77.2	172.4	430.9	666.9	637.4	353.4	69.1	13.3	13.3	2,539.7
160	NUWAKOT	1004	Nuwakot	CLIMATOLOGY	Jan, 56		27.92	85.17	1,003	16.9	19.4	31.0	51.0	109.0	306.4	479.1	501.8	263.5	61.3	7.4	10.5	1,857.3
161	DHADING	1005	Dhading	PRECIPITATION	Jan, 56		27.87	84.93	1,420	22.3	24.5	43.0	74.4	175.0	357.3	535.2	520.4	294.7	59.7	8.2	10.4	2,125.0
162	GUMTHANG	1006	Sindhupalchok	PRECIPITATION	Jan, 56		27.87	85.87	2,000	27.4	37.7	61.6	108.9	229.2	589.4	934.2	921.3	613.9	164.9	24.8	15.7	3,729.0
163	KAKANI	1007	Nuwakot	AGROMETEOROLOGY	Jan, 62		27.80	85.25	2,064	16.8	25.6	44.2	66.2	187.3	451.4	703.8	732.9	419.2	81.7	8.8	13.8	2,751.7
164	NAWALPUR	1008	Sindhupalchok	PRECIPITATION	Jan, 59		27.80	85.62	1,592	17.0	23.2	34.6	58.0	134.6	398.6	673.7	686.9	348.4	80.9	10.5	11.8	2,478.2
165	CHAUTARA	1009	Sindhupalchok	PRECIPITATION	Jan, 56		27.78	85.72	1,660	14.9	20.9	36.8	57.8	126.0	333.9	515.7	563.2	305.0	65.6	9.6	12.4	2,061.7
166	THANKOT	1015	Kathmandu	PRECIPITATION	Jan, 67		27.68	85.20	1,630	18.7	26.6	39.5	70.2	144.7	289.6	488.4	430.0	266.4	65.5	9.6	16.6	1,866.0
167	SARMATHANG	1016	Sindhupalchok	PRECIPITATION	Jan, 72		27.95	85.60	2,625	24.8	30.0	47.8	75.2	168.3	560.8	1,039.5	967.0	523.3	115.6	17.4	10.6	3,580.4
168	DUBACHAUR	1017	Sindhupalchok	PRECIPITATION	Jan, 71		27.87	85.57	1,550	17.1	25.5	42.5	71.2	163.4	395.8	644.9	626.2	321.1	72.7	12.1	14.4	2,406.8
169	BAUNEPATI	1018	Sindhupalchok	PRECIPITATION	Jan, 71		27.78	85.57	845	12.0	20.6	31.9	55.8	122.2	292.8	444.6	441.8	250.4	65.0	8.2	11.1	1,756.3
170	MANDAN	1020	Kabhre	PRECIPITATION	Jan, 74		27.70	85.65	1,365	9.3	8.8	15.6	36.7	82.7	169.3	265.2	235.7	126.9	26.9	6.5	6.8	990.6
171	GODAVARI	1022	Lalitpur	CLIMATOLOGY	Jan, 56		27.58	85.40	1,400	22.5	22.9	31.1	57.1	125.4	300.3	488.6	446.7	252.2	66.7	6.8	15.7	1,835.9
172	DOLAL GHAT	1023	Kabhre	PRECIPITATION	Jan, 59		27.63	85.72	710	12.3	15.1	26.3	50.0	93.1	190.9	288.8	264.4	135.2	44.1	6.4	9.2	1,135.9
173	DHULIKHEL	1024	Kabhre	CLIMATOLOGY	Jan, 56		27.62	85.55	1,552	18.6	20.3	28.9	57.7	108.4	256.4	394.0	361.5	189.7	64.8	6.4	10.4	1,517.2
174	DHAP	1025	Sindhupalchok	PRECIPITATION	Jan, 77		27.92	85.63	1,240	13.7	27.6	32.4	53.2	119.1	413.6	761.0	684.5	408.8	55.9	6.3	15.8	2,592.0
175	BAHRABISE	1027	Sindhupalchok	PRECIPITATION	Jan, 66		27.78	85.90	1,220	16.4	26.3	50.2	91.6	189.8	471.9	742.1	743.0	415.6	93.9	10.2	14.3	2,865.4
176	PACHUWAR GHAT	1028	Kabhre	PRECIPITATION	Jan, 66	Dec, 09	27.57	85.75	633	12.6	13.4	20.9	43.1	92.3	167.7	244.3	193.3	135.8	41.6	4.0	14.1	983.1
177	KHUMALTAR	1029	Lalitpur	AGROMETEOROLOGY	Jan, 67		27.67	85.33	1,350	14.9	18.8	28.5	54.5	101.9	195.4	310.5	251.9	156.9	52.4	5.1	13.6	1,204.2
178	KATHMANDU AIRPORT	1030	Kathmandu	AERONATICAL	Jan, 68		27.70	85.37	1,337	14.6	18.4	34.1	57.7	115.6	247.3	365.5	320.7	188.8	56.5	7.4	11.5	1,437.9
179	SANKHU	1035	Kathmandu	PRECIPITATION	Jan, 71		27.75	85.48	1,449	12.4	24.7	30.0	53.4	154.4	303.7	527.6	522.2	278.2	64.2	8.8	10.0	1,989.6
180	PANCHKHAL	1036	Kabhre	CLIMATOLOGY	Jan, 76		27.68	85.63	865	11.8	16.9	21.4	44.2	98.1	202.2	291.3	286.4	165.3	51.0	7.6	13.4	1,209.5
181	DHUNIBESI	1038	Dhading	CLIMATOLOGY	Jan, 71		27.72	85.18	1,085	13.9	17.6	28.7	49.5	126.6	246.0	405.6	369.2	214.3	54.1	7.0	14.2	1,546.7
182	PANIPOKHARI(KATHMANDU)	1039	Kathmandu	CLIMATOLOGY	Jan, 71		27.73	85.33	1,335	11.2	18.6	30.4	70.0	118.2	248.4	386.7	347.8	196.4	55.0	7.5	10.6	1,500.8
183	NAGARKOT	1043	Bhaktapur	CLIMATOLOGY	Jan, 71		27.70	85.52	2,163	16.8	19.5	30.0	58.4	145.2	322.3	475.0	469.1	269.9	70.9	8.4	9.9	1,895.3
184	KHOPASI(PANAUTI)	1049	Kabhre	PRECIPITATION	Jan, 71		27.58	85.52	1,517	16.9	20.0	30.3	56.3	126.2	236.6	350.9	277.2	200.8	62.9	9.4	11.9	1,399.5
185	BHAKTAPUR	1052	Bhaktapur	PRECIPITATION	Jan, 71		27.67	85.42	1,330	13.8	20.5	33.1	56.2	136.0	251.0	374.2	346.5	191.3	52.3	5.3	13.1	1,493.1
186	THAMACHIT	1054	Rasuwa	PRECIPITATION	Jan, 72		28.17	85.32	1,847	15.8	20.0	30.3	24.7	34.7	104.2	188.0	177.7	100.0	32.6	11.7	9.1	748.7
187	DHUNCHE	1055	Rasuwa	CLIMATOLOGY	Jan, 72		28.10	85.30	1,982	43.2	55.7	67.9	85.5	110.7	254.9	438.4	454.8	283.2	94.4	26.1	25.7	1,940.5
188	PANSAYAKHOLA	1057	Nuwakot	PRECIPITATION	Jan, 73		28.02	85.12	1,240	20.9	32.7	43.2	80.7	204.9	481.0	826.9	809.5	470.8	86.3	12.8	14.6	3,084.4
189	TARKE GHYANG	1058	Sindhupalchok	PRECIPITATION	Jan, 74		28.00	85.55	2,480	25.4	31.6	63.0	70.9	150.9	477.6	886.7	865.3	468.7	76.4	17.5	14.4	3,148.4
190	CHANGU HARAYAN	1059	Bhaktapur	PRECIPITATION	Jan, 74		27.70	85.42	1,543	16.0	21.5	32.3	59.3	160.8	258.2	424.8	418.1	228.4	58.5	7.7	13.9	1,699.5
191	CHAPA GAUN	1060	Lalitpur	PRECIPITATION	Jan, 76		27.60	85.33	1,448	16.0	19.4	27.2	49.8	97.0	218.2	376.6	324.8	185.5	44.7	4.4	17.1	1,380.7
192	SANGACHOK	1062	Sindhupalchok	PRECIPITATION	Jan, 81		27.70	85.72	1,327	13.3	17.2	28.4	51.7	141.5	243.5	377.0	359.7	206.2	57.4	7.3	9.7	1,513.0
193	THOKARPA	1063	Sindhupalchok	PRECIPITATION	Jan, 83		27.70	85.78	1,750	18.3	23.7	33.7	63.2	169.3	307.4	536.1	509.9	267.0	73.1	7.1	16.6	2,025.4
194	BUDDHANILAKANTHA	1071	Kathmandu	CLIMATOLOGY	Jan, 87		27.78	85.37	1,350	13.0	20.6	35.6	68.3	195.2	331.7	544.2	492.9	252.8	52.6	6.7	8.3	2,022.0
195	KHOKANA	1073	Lalitpur	CLIMATOLOGY	Jan, 91		27.63	85.28	1,212	18.0	21.8	33.6	60.5	118.2	228.9	346.1	291.4	158.9	41.9	8.2	9.5	1,336.9
196	SUNDARIJAL	1074	Kathmandu	PRECIPITATION	Jan, 94		27.77	85.42	1,490	23.7	20.1	41.0	58.9	190.5	299.3	607.4	593.8	289.4	46.5	9.3	7.2	2,187.1
197	LELE	1075	Lalitpur	PRECIPITATION	Jan, 94		27.58	85.28	1,590	21.9	25.1	30.5	54.3	124.4	285.0	518.4	434.5	259.0	58.3	9.8	14.6	1,835.6
198	NAIKAP	1076	Kathmandu	PRECIPITATION	Jan, 97		27.68	85.25	1,520	13.4	15.4	36.4	53.3	132.0	189.5	359.3	347.9	155.4	38.5	1.4	8.8	1,351.2
199	SUNDARIJAL	1077	Kathmandu	PRECIPITATION	Jan, 97		27.75	85.42	1,360	7.9	19.3	31.5	52.6	165.1	269.5	533.5	523.9	242.3	42.2	2.0	8.7	1,898.5
200	DHAP	1078	Sindhupalchok	PRECIPITATION	Jan, 98		27.90	85.63	1,310	15.6	38.9	38.2	53.6	203.0	453.4	752.1	768.6	419.6	97.5	5.9	4.2	2,850.6

Table 2.1.7-1 Specifications of Precipitation Gauging Stations (5/6)

No.	Name	Index	District	Type of Station	Start to record	Closed to record	Location		Elevation	Precipitation (mm)												
							Latitude	Longitude	(m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
201	NAGARJUN	1079	Kathmandu	PRECIPITATION	Jan, 98		27.75	85.25	1,690	13.6	16.2	36.9	60.0	130.3	219.0	431.6	410.1	234.5	49.1	-	2.3	1,603.7
202	TIKATHALI	1080	Lalitpur	PRECIPITATION	Jan, 00		27.65	85.35	1,341	17.2	16.8	35.9	54.6	123.4	175.6	308.9	307.9	193.5	48.1	4.4	3.3	1,289.7
203	JETPURPHEDHI	1081	Kathmandu	PRECIPITATION	Jan, 00		27.78	85.28	1,320	12.2	25.2	33.8	70.2	139.1	231.7	512.0	478.5	260.8	60.5	4.0	4.3	1,832.3
204	NANGKHEL	1082	Bhaktapur	PRECIPITATION	Jan, 00		27.65	85.47	1,428	6.6	27.7	33.9	63.5	111.5	223.4	323.2	326.4	173.8	24.3	3.0	5.9	1,323.0
205	NAGDAHA	1101	Dolkha	PRECIPITATION	Jan, 77		27.68	86.10	850	7.6	13.7	28.8	71.6	140.2	226.1	359.4	285.7	182.7	41.5	10.3	6.8	1,374.2
206	CHARIKOT	1102	Dolkha	PRECIPITATION	Jan, 59		27.67	86.05	1,940	15.5	24.1	40.7	71.0	151.9	319.3	547.1	535.2	293.7	76.4	12.5	10.8	2,098.4
207	JIRI	1103	Dolkha	AGROMETEOROLOGY	Jan, 62		27.63	86.23	2,003	16.0	24.3	43.5	84.9	167.4	378.2	604.0	593.2	309.5	74.8	13.6	10.6	2,320.2
208	MELUNG	1104	Dolkha	PRECIPITATION	Jan, 59		27.52	86.05	1,536	12.9	14.8	27.7	68.5	122.0	248.5	343.1	338.3	168.7	47.9	7.4	8.7	1,408.5
209	SINDHULI GADHI	1107	Sindhuli	CLIMATOLOGY	Jan, 56		27.28	85.97	1,463	24.8	15.3	38.7	98.0	203.9	437.7	691.2	581.0	423.2	132.8	14.8	10.2	2,671.6
210	BAHUN TILPUNG	1108	Sindhuli	PRECIPITATION	Jan, 73		27.18	86.17	1,417	16.4	20.9	32.8	89.2	175.6	324.9	506.5	356.6	296.4	107.8	11.9	14.7	1,953.8
211	PATTHARKOT(EAST)	1109	Sarlahi	PRECIPITATION	Jan, 56		27.08	85.67	275	13.7	10.3	17.0	47.5	121.1	287.8	565.1	418.5	310.2	100.6	8.8	7.8	1,908.4
212	TULSI	1110	Dhanusa	PRECIPITATION	Jan, 56		27.03	85.92	457	11.7	10.2	16.9	56.5	116.5	257.9	464.6	379.5	261.4	74.5	8.0	5.9	1,663.5
213	JANAKPUR AIRPORT	1111	Dhanusa	CLIMATOLOGY	Jan, 69		26.72	85.97	90	10.8	10.9	12.4	44.9	110.0	233.4	443.4	311.5	187.0	64.6	2.7	7.8	1,439.2
214	CHISAPANI BAZAR	1112	Dhanusa	PRECIPITATION	Jan, 56		26.92	86.17	165	11.3	8.2	15.9	40.8	94.2	243.0	469.2	358.9	244.4	83.7	5.7	6.3	1,581.6
215	NEPALTHOK	1115	Sindhuli	PRECIPITATION	Jan, 56		27.45	85.82	1,098	13.8	13.3	26.4	41.6	77.6	142.9	264.2	178.5	138.5	58.8	4.7	11.3	971.5
216	HARIHARPUR GADHI VALLEY	1117	Sindhuli	PRECIPITATION	Jan, 78		27.33	85.50	250	13.4	14.1	18.1	60.6	174.4	384.6	725.7	569.0	365.5	90.9	7.1	14.6	2,438.0
217	MANUSMARA	1118	Sarlahi	CLIMATOLOGY	Jan, 79		26.88	85.42	100	9.3	12.0	10.1	44.7	88.8	189.0	440.8	356.4	188.4	75.2	4.9	7.5	1,427.0
218	GAUSALA	1119	Mahottari	PRECIPITATION	Jan, 79		26.88	85.78	200	16.5	9.1	9.8	40.2	92.1	188.6	300.4	296.7	175.7	50.7	4.6	8.5	1,192.9
219	MALANGWA	1120	Sarlahi	PRECIPITATION	Jan, 79		26.87	85.57	150	11.1	13.7	14.3	42.9	118.8	205.5	482.5	362.3	205.5	73.9	2.4	7.3	1,540.3
220	KARMAIYA	1121	Sarlahi	CLIMATOLOGY	Jan, 84		27.12	85.47	131	7.4	9.6	14.4	46.6	106.3	231.4	558.2	459.3	291.3	87.7	5.1	10.2	1,827.3
221	JALESORE	1122	Mahottari	CLIMATOLOGY	Jan, 89		26.65	85.78	172	3.1	3.5	9.1	30.6	90.2	183.4	257.2	242.7	158.6	28.1	0.7	5.1	1,012.3
222	MANTHALI	1123	Ramechhap	PRECIPITATION	Jan, 92		27.47	86.08	495	14.3	13.6	24.2	40.5	85.8	143.6	295.7	203.8	123.7	36.1	5.6	7.0	994.0
223	CHAURIKHARK	1202	Solukhumbu	PRECIPITATION	Jan, 56		27.70	86.72	2,619	16.8	26.6	38.7	57.2	106.1	313.0	588.2	569.2	313.5	68.3	13.7	10.6	2,122.0
224	PAKARNAS	1203	Solukhumbu	PRECIPITATION	Jan, 56		27.43	86.57	1,982	15.8	16.2	32.2	45.7	92.2	263.6	493.2	484.4	253.4	70.4	9.6	8.3	1,785.1
225	AISEALUKHARK	1204	Khotang	PRECIPITATION	Jan, 56		27.35	86.75	2,143	18.4	14.3	32.1	75.6	190.1	420.5	592.8	523.4	312.5	111.2	15.7	12.3	2,318.9
226	OKHALDHUNGA	1206	Okhaldhunga	SYNOPTIC	Jan, 56		27.32	86.50	1,720	14.2	14.4	27.9	59.8	145.8	316.2	461.1	402.4	241.1	71.4	10.2	9.9	1,774.4
227	MANE BHANJYANG	1207	Okhaldhunga	PRECIPITATION	Jan, 56		27.48	86.42	1,576	14.8	12.2	23.1	45.9	102.0	197.4	281.0	217.9	131.4	41.2	6.3	7.2	1,080.5
228	KURULE GHAT	1210	Khotang	PRECIPITATION	Jan, 56		27.13	86.43	497	13.0	11.6	22.3	44.0	75.5	145.4	272.3	185.2	131.7	42.9	7.8	9.3	961.1
229	KHOTANG BAZAR	1211	Khotang	PRECIPITATION	Jan, 59		27.03	86.83	1,295	16.6	12.3	29.1	42.6	111.6	201.8	332.2	237.6	159.3	49.4	6.4	9.1	1,208.0
230	PHATEPUR	1212	Saptari	CLIMATOLOGY	Jan, 81		26.73	86.93	100	12.4	10.3	12.5	50.2	131.6	263.2	494.4	373.8	261.8	76.0	7.7	7.8	1,701.6
231	UDAYAPUR GADHI	1213	Udayapur	CLIMATOLOGY	Jan, 56		26.93	86.52	1,175	15.5	14.0	25.0	53.6	153.2	307.5	496.1	387.4	316.1	102.3	11.0	10.9	1,892.6
232	LAHAN	1215	Siraha	AGROMETEOROLOGY	Jan, 56		26.73	86.43	138	14.9	13.1	18.4	40.2	102.5	254.1	393.3	301.2	210.6	78.3	7.8	5.6	1,440.0
233	SIRAHA	1216	Siraha	PRECIPITATION	Jan, 56		26.65	86.22	102	16.8	12.0	13.4	38.1	104.6	223.8	397.0	332.1	198.9	70.7	6.9	6.1	1,420.3
234	SALLERI	1219	Solukhumbu	PRECIPITATION	Jan, 73		27.50	86.58	2,378	12.4	16.9	29.6	51.0	102.5	253.9	453.3	446.3	241.0	59.8	10.5	9.3	1,686.5
235	CHIALSA	1220	Solukhumbu	AGROMETEOROLOGY	Jan, 68	Dec, 98	27.48	86.62	2,770	9.2	11.4	24.2	43.8	98.7	290.9	510.6	482.6	266.9	76.2	9.4	7.7	1,831.7
236	DIKTEL	1222	Khotang	PRECIPITATION	Jan, 73		27.22	86.80	1,623	10.6	14.6	22.6	66.3	162.9	263.7	352.4	296.0	187.7	48.4	9.6	11.9	1,446.8
237	RAJBIRAJ	1223	Saptari	CLIMATOLOGY	Jan, 72		26.55	86.75	91	11.8	11.0	11.4	41.9	115.5	258.7	429.1	283.9	234.4	68.5	6.2	8.4	1,480.9
238	SIRWA	1224	Solukhumbu	PRECIPITATION	Jan, 73		27.55	86.38	1,662	13.0	17.5	34.8	63.7	127.2	287.9	477.7	451.0	267.0	60.3	15.0	9.8	1,824.9
239	BARMAJHIYA	1226	Saptari	PRECIPITATION	Jan, 76		26.60	86.90	85	10.0	14.3	15.5	53.6	158.7	251.7	510.2	352.8	264.7	85.0	8.8	13.2	1,738.5
240	GAIGHAT	1227	Udayapur	PRECIPITATION	Jan, 01		26.78	86.72	152	13.5	10.4	19.0	48.4	95.4	172.0	449.1	227.0	124.7	59.1	0.8	6.7	1,225.9
241	NUM	1301	Sankhuwasabha	PRECIPITATION	Jan, 59		27.55	87.28	1,497	32.2	55.9	103.0	267.4	508.7	824.7	796.5	675.7	554.5	233.3	47.9	20.6	4,120.3
242	CHAINPUR (EAST)	1303	Sankhuwasabha	CLIMATOLOGY	Jan, 56		27.28	87.33	1,329	12.4	14.5	32.2	91.8	180.1	219.9	296.3	270.6	198.2	65.1	15.9	7.0	1,404.0
243	PAKHRIBAS	1304	Dhankuta	AGROMETEOROLOGY	Jan, 76		27.05	87.28	1,680	13.2	15.6	28.1	61.1	151.1	261.5	393.5	344.4	198.7	61.5	11.0	11.4	1,551.1
244	LEGUWA GHAT	1305	Dhankuta	PRECIPITATION	Jan, 57		27.13	87.28	410	6.1	8.7	20.0	69.2	122.7	137.0	183.3	165.1	99.8	36.1	9.1	3.2	860.3
245	MUNGA	1306	Dhankuta	PRECIPITATION	Jan, 56		27.03	87.23	1,317	13.9	12.3	25.2	52.4	102.0	195.1	298.9	250.0	153.9	56.0	8.7	7.4	1,175.8
246	DHANKUTA	1307	Dhankuta	SYNOPTIC	Jan, 56		26.98	87.35	1,210	10.7	15.4	22.5	49.1	95.9	165.4	248.1	158.6	110.9	54.8	9.2	7.1	947.7
247	MUL GHAT	1308	Dhankuta	PRECIPITATION	Jan, 57		26.93	87.33	365	10.5	12.8	24.6	48.3	114.5	178.4	295.2	191.7	137.0	51.2	10.6	6.3	1,081.2
248	TRIBENI	1309	Dhankuta	PRECIPITATION	Jan, 56		26.93	87.15	143	16.1	15.6	21.5	57.8	129.3	299.6	485.1	353.1	284.3	78.3	10.3	5.5	1,756.4
249	DHARAN BAZAR	1311	Sunsari	CLIMATOLOGY	Jan, 56		26.82	87.28	444	14.1	16.0	26.8	66.9	168.7	359.4	615.3	533.5	397.6	148.3	12.7	6.9	2,366.3
250	HARAINCHA	1312	Morang	PRECIPITATION	Jan, 56		26.62	87.38	152	13.7	18.0	18.0	64.0	157.2	330.8	550.1	392.7	288.8	97.8	16.6	14.3	1,962.0

Table 2.1.7-1 Specifications of Precipitation Gauging Stations (6/6)

No.	Name	Index	District	Type of Station	Start to record	Closed to record	Location		Elevation	Precipitation (mm)												
							Latitude	Longitude	(m)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
251	TERHATHUM	1314	Terhathum	CLIMATOLOGY	Jan, 71		27.13	87.55	1,633	11.1	14.5	26.4	87.4	137.5	154.0	215.4	168.4	128.6	42.9	9.7	8.5	1,004.3
252	CHATARA	1316	Sunsari	PRECIPITATION	Jan, 56		26.82	87.17	183	16.8	14.4	25.2	67.6	158.2	353.4	582.9	428.7	357.6	143.9	15.2	7.6	2,171.6
253	CHEPUWA	1317	Sankhuwasabha	PRECIPITATION	Jan, 56		27.77	87.42	2,590	42.8	71.3	131.0	161.3	247.9	411.4	492.3	456.0	358.5	145.5	39.7	20.3	2,578.0
254	BIRATNAGAR AIRPOART	1319	Morang	AERONATICAL	Jan, 69		26.48	87.27	72	11.1	12.2	14.2	51.9	169.4	311.7	518.6	370.7	293.2	90.9	8.2	6.0	1,858.0
255	TARAHARA	1320	Sunsari	AGROMETEOROLOGY	Jan, 69		26.70	87.27	200	15.5	13.7	20.3	63.0	167.9	311.6	528.3	359.5	287.8	92.5	11.9	9.5	1,881.4
256	TUMLINGTAR	1321	Sankhuwasabha	PRECIPITATION	Jan, 77		27.28	87.22	303	6.6	8.7	25.2	88.2	165.5	214.7	246.5	234.8	209.4	60.9	13.4	9.3	1,283.4
257	MACHUWAGHAT	1322	Dhankuta	PRECIPITATION	Jan, 56		26.97	87.17	158	14.1	11.2	19.5	50.2	127.4	265.1	381.9	258.7	189.2	64.4	8.2	6.6	1,396.4
258	BHOJPUR	1324	Bhojpur	AGROMETEOROLOGY	Jan, 56	Dec, 03	27.18	87.05	1,595	20.4	12.3	29.9	70.1	143.1	215.5	277.7	218.3	168.8	79.3	14.7	9.3	1,259.4
259	DINGLA	1325	Bhojpur	PRECIPITATION	Jan, 57		27.37	87.15	1,190	14.7	16.7	34.7	81.5	179.2	304.3	411.1	403.7	339.2	101.2	11.4	9.3	1,906.9
260	LETANG	1326	Morang	PRECIPITATION	Jan, 02		26.73	87.50	250	—	—	—	—	—	—	—	—	—	—	—	—	—
261	LUNGTHUNG	1403	Taplejung	PRECIPITATION	Jan, 56		27.55	87.78	1,780	17.8	34.9	64.7	101.3	146.2	359.2	523.8	522.2	338.5	104.0	17.3	9.4	2,239.6
262	TAPLETHOK	1404		PRECIPITATION	Jan, 56		27.48	87.78	1,383	17.7	27.8	63.1	120.4	215.1	423.6	610.4	607.3	394.2	121.4	27.3	12.4	2,640.7
263	TAPLEJUNG	1405	Taplejung	SYNOPTIC	Jan, 56		27.35	87.67	1,732	19.9	25.6	55.3	134.8	230.9	311.7	421.8	405.4	278.6	87.0	15.5	10.2	1,996.5
264	MEMENG JAGAT	1406	Panchther	PRECIPITATION	Jan, 56		27.20	87.93	1,830	18.9	25.0	51.4	123.6	227.4	330.0	487.0	416.5	289.9	112.3	19.2	13.7	2,114.9
265	ILAM TEA ESTATE	1407	Ilam	AGROMETEOROLOGY	Jan, 56		26.92	87.90	1,300	12.0	13.7	21.8	57.4	138.2	287.2	423.5	321.1	211.5	72.7	10.4	6.9	1,576.3
266	DAMAK	1408	Jhapa	PRECIPITATION	Jan, 63		26.67	87.70	163	13.5	13.6	23.0	66.7	180.2	424.1	688.0	525.0	349.2	133.3	13.9	6.8	2,437.4
267	ANARMANI BIRTA	1409	Jhapa	PRECIPITATION	Jan, 56		26.63	87.98	122	10.1	10.0	21.3	52.1	171.4	450.2	717.2	527.6	330.5	125.1	13.5	6.8	2,435.7
268	HIMALI GAUN	1410	Ilam	PRECIPITATION	Jan, 68		26.88	88.03	1,654	14.2	19.9	31.4	79.3	176.1	444.1	639.7	458.0	340.2	97.0	15.1	11.0	2,325.8
269	SOKTIM TEA ESTATE	1411		CLIMATOLOGY	Jan, 66	Dec, 02	26.80	87.90	530	12.3	15.6	33.7	68.1	187.8	464.9	709.2	536.8	454.9	137.2	23.7	11.1	2,655.3
270	CHANDRA GADHI	1412	Jhapa	PRECIPITATION	Jan, 71		26.57	88.05	120	9.3	11.8	16.9	66.2	182.4	402.7	684.6	427.6	359.4	104.5	10.6	7.2	2,283.2
271	SANISCHARE	1415	Jhapa	PRECIPITATION	Jan, 72		26.68	87.97	168	12.5	15.5	25.2	67.8	205.4	508.1	814.1	556.9	394.7	133.9	19.5	7.0	2,760.6
272	KANYAM TEA ESTATE	1416	Ilam	CLIMATOLOGY	Jan, 72		26.87	88.07	1,678	17.6	24.8	40.1	90.3	238.6	570.6	836.2	622.0	472.7	132.7	21.2	15.7	3,082.6
273	PHIDIM (PANCHTHER)	1419	Panchther	CLIMATOLOGY	Jan, 78		27.15	87.75	1,205	12.9	18.7	35.2	76.5	145.4	181.1	333.5	281.2	173.2	50.4	9.5	11.3	1,329.0
274	DOVAN	1420	Taplejung	PRECIPITATION	Jan, 56		27.35	87.60	763	16.2	18.5	48.6	126.4	207.1	302.3	342.3	294.4	214.9	68.7	10.9	9.7	1,660.1
275	GAIDA (KANKAI)	1421	Jhapa	AGROMETEOROLOGY	Jan, 84		26.58	87.90	143	12.2	14.9	23.6	65.5	211.9	448.5	757.8	592.3	431.5	149.6	16.0	9.3	2,733.0
276	KECHANA	1422	Jhapa	CLIMATOLOGY	Jan, 99		26.40	88.02	60	15.4	8.8	18.9	69.5	225.5	448.9	669.8	485.0	332.4	118.6	2.7	2.6	2,398.0

The monthly average precipitation shows the average data of 272 precipitation gauging stations in Figure 2.1.7-2. The average annual average precipitation is 1,820 mm. The highest monthly average precipitation is 490 mm in July. The lowest monthly average precipitation is 10 mm in November. The precipitation during June and September is 80% of the annual precipitation.

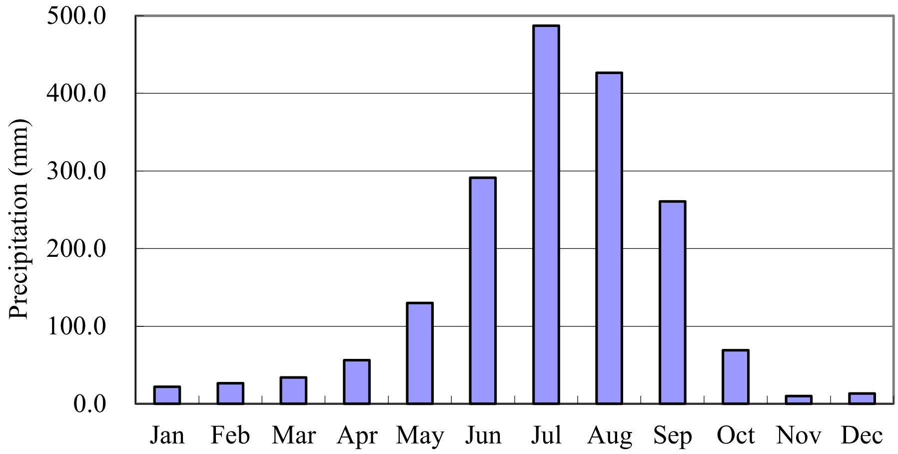


Figure 2.1.7-2 Monthly Average Precipitation

The annual average precipitation at 272 precipitation gauging stations is shown in Figure 2.1.7-3. According to Figure 2.1.7-3, the highest annual average precipitation is 5,419.3 mm at precipitation gauging station 814 Lumle, which is located 20 km northwest from Pokhara.

Figure 2.1.7-4 shows the Isohyetal map of annual average precipitation based on the data of 272 precipitation gauging stations in Figure 2.1.7-3.

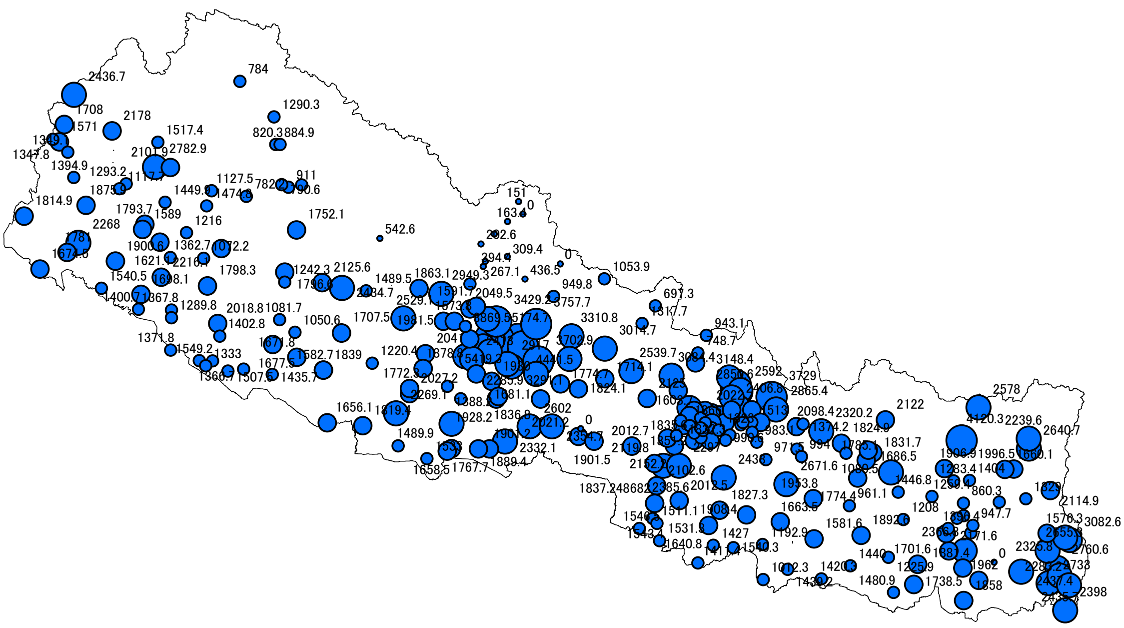


Figure 2.1.7-3 Annual Average Precipitation

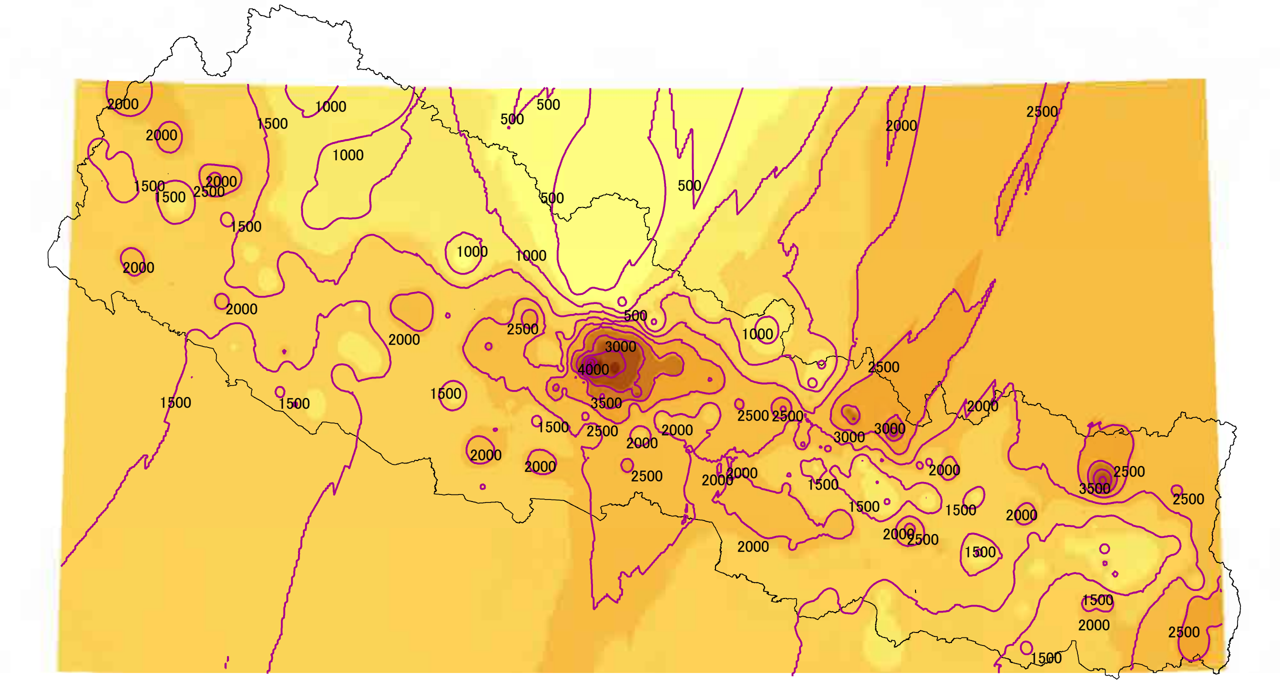


Figure 2.1.7-4 Isohyetal Map of Annual Average Precipitation

2.2 River

2.2.1 General

Most of the rivers in Nepal originate in the Nepal Himalaya and some of rivers originate in the Tibet Autonomous Region of China. The rivers flow to the south and enter India through Nepal. Most of them flow into the Ganges river.

There are more than 6,000 rivers in Nepal, out of which 964 rivers are each longer than 10 km and about 54 rivers are each longer than 150 km. The total length of the rivers runs to 45,000 km.

The following are the laws and regulations concerning river use and fish. Those classified into different sizes of rivers are not defined.

- Water Resources Act 2049 (1992) and Water Resources Rules, 2050 (1993): The license for water use, the priority of the purpose for water use, etc. are stipulated in this law.
- Electricity Rules, 2050 (1993): The license, etc. for water use for the purpose of power generation are stipulated.
- Irrigation Rules, 2056 BS (2000 AD): The license, etc. for water use for the purpose of irrigation are stipulated.
- Aquatic Animals Protection Act 2017 (1960) and Amendment 2055 (1999): Fishing by using electroshock, poison, explosives, etc. are banned in this law.
- National Parks and Wildlife Conservation Act 2029 (1973) and National Parks and Wildlife Conservation Regulation 2030 (1974): National parks and wildlife conservation are stipulated in this law.

In addition, treaties and agreement below are made with India, the country downstream.

- Revised Agreement between His Majesty's Government of Nepal and The Government of India on The Kosi Project (1975)
- Agreement Between His Majesty's Government of Nepal and The Government of India on the Gandak Irrigation and Power Project (1975)
- Treaty Between His Majesty's Government of Nepal And The Government of India Concerning The Integrated Development of the Mahakali Barrage Including Sarada Barrage, Tanakpur Barrage and Pancheshwar Project (1996)
- Indo-Nepal Agreement on setting up a Joint Commission covering "Multiple Use of Water Resources", among others (1987)
- Agreement on the Formation of the Nepal-India Joint Committee on Water Resources (2000)
- Formation of the Nepal-India Committee on Flood Forecasting by the Joint Committee on Water Resources (2000)

2.2.2 Origin of Rivers

The rivers in Nepal are divided into four groups by the different periods governed by different orogenies as follows.

- Antecedent to the Himalaya; old rivers born along or before the Himalaya.
- After the Mahabharat; young rivers originating from the Mahabharat.
- After the Churia; very young rivers originating from the Churia.
- New; new rivers originating from Terai.

(1) Rivers antecedent to the Himalaya

Major rivers which are now called systems like Koshi in the east, Gandaki in the central region and Mahakali in the west were born along or before the Himalaya.

The present mountainous area was occupied by a sea which was called the Tethys Sea. At that time the sea stretched from the Mediterranean to Java. Angara Land, i.e. Eurasia Land, was north of the sea and Gondwana Land was south of the sea. Gondwana Land was divided into some masses and they started to move northward and southward. The masses which moved northward hit Angara Land and joined together. The land is India.

At that time, i.e. fifty million years ago, the Indian plate was thrust under the Eurasian plate, causing pressure and buckling so the mountains were pushed. As the Indian plate continued to be pushed sunder the Eurasian plate, the Himalaya started to rise. In this Himalaya orogeny period, the heavy squeeze had obliterated the Tethys Sea and the ancient main river channels started being widened and deepened along with the development of a monsoon climate.

The major rivers were born as above. The second order tributaries were born from the Oligocene to Miocene, the third order tributaries were born in the Pleistocene and the fourth to fifth order tributaries are recent.

(2) After the Mahabharat

From the Cretaceous to the Miocene, the present river systems were shaped. In other words, by that time the main Himalaya was born and rivers were flowing to the midland area. The midland area was not developed. The area of the present Churia hills were under a shallow sea and the four major river systems were providing the sediment there. When the midland along with Churia hill came into existence, the depression of the Gangetic basin was created. All rivers flow along with the sediments in the depression. Churia formation was deposited from the rocks of the Mahabarat range, hence formations are found only in the vicinity of the channels of these rivers.

Most of the main rivers originating from the Mahabharat range belong to the Oligocene to Miocene. These include the Kankai, the Kamala in eastern Nepal, the Bagmati in central Nepal, and the Tinau, the Rapti and the Babai in western Nepal. Their second order tributaries are from the Pleistocene and the third and the fourth orders tributaries are recent.

After the Mahabharat hills were raised, i.e. in the Miocene Era, the antecedent rivers had to change their courses as the Mahabharat stood as a barrier. As a result, most of the rivers changed their courses either to the east or west.

(3) After the Churia

The rivers originating from the southern face of the Churia hill were born in post Pleistocene.

(4) New rivers originating from Terai

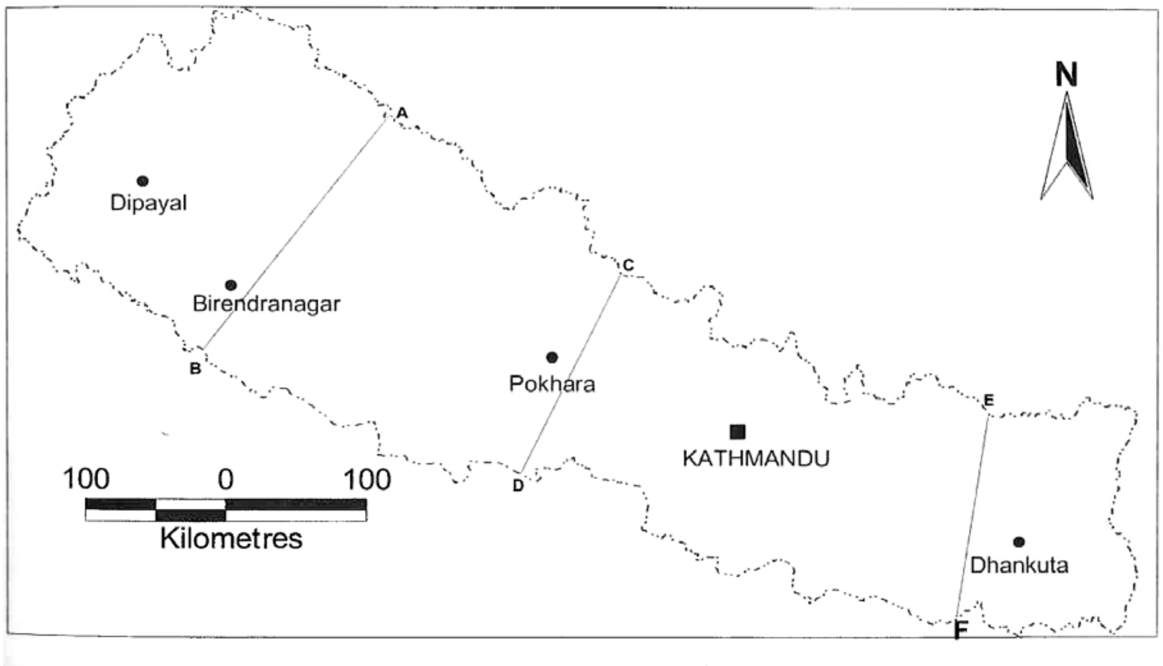
The new rivers are originating from the Terai as well as the fourth or fifth order tributaries.

2.2.3 Hydrological Features of Rivers in Nepal

The hydrological behavior of a river is derived from rainfall and its intensity, the size and shape of the basin, rock type, geomorphology, vegetation, latitude and gradient. These features are reflected to the coefficient of runoff, groundwater percolation, increase of snow cover and sediment load.

The hydrological behavior of rivers in different areas divided by different geographies is as follows.

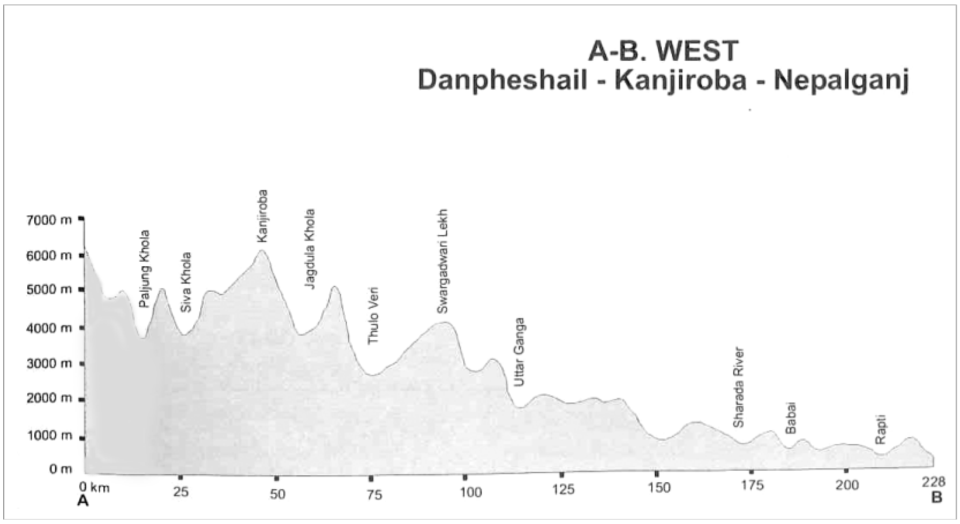
Figure 2.2.3-1 shows the north-south cross sections in the western, central and eastern areas of Nepal.



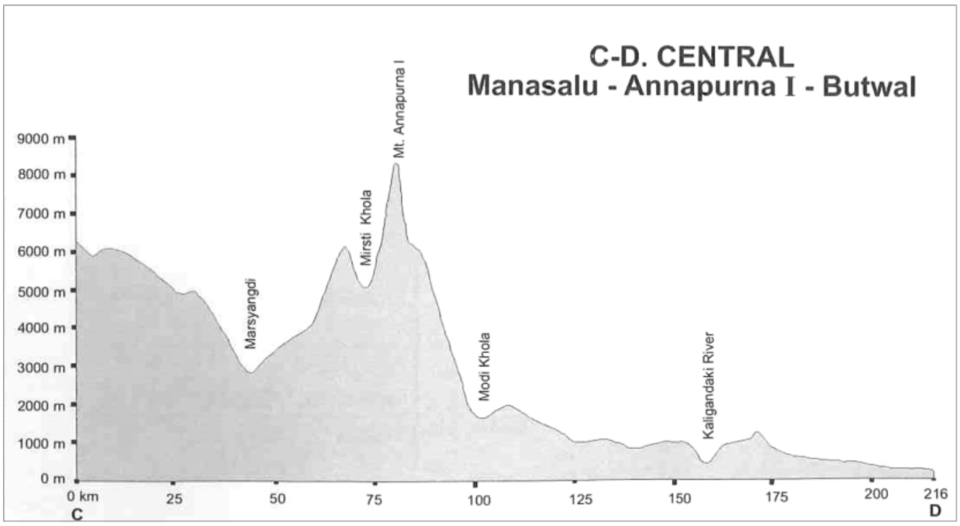
a) Locations of cross sections

Source: Nepal Atlas &Statistics, revised edition, 2008

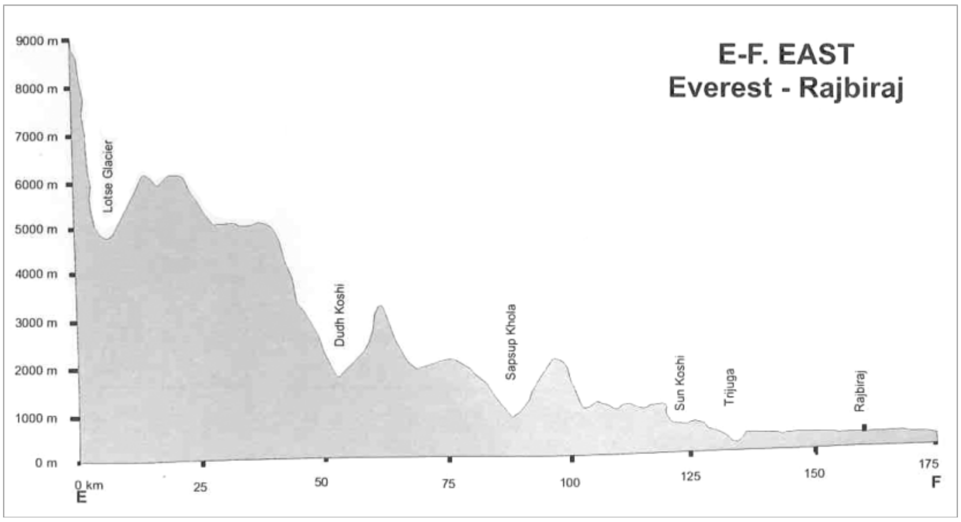
Figure 2.2.3-1 North-South Cross Section (1/2)



b) Western



c) Central



d) Eastern

Source: Nepal Atlas &Statistics, revised edition, 2008

Figure 2.2.3-1   North-South Cross Section (2/2)

Table 2.2.3-1 shows the hydrological futures of six kinds of source areas. These six source areas are the Trans Himalayan, Himalaya, Midland, Mahabharat, Churia, and Terai areas.

Table 2.2.3-1 Hydrological Futures of Rivers in Nepal

Source Area	Nature of Source	Natural Behavior
1) Trans Himalayan	Snow	Diurnal behavior
2) Himalaya	Snow + Monsoon	Low flow and high flow not that different
3) Midland	Monsoon + Groundwater	Reasonable
4) Mahabharat	Monsoon	Extreme
5) Churia	Monsoon	Extreme
6) Terai	Monsoon + Groundwater	Extreme

Source: Engineering Challenges in Nepal Himalaya

(1) Trans Himalayan

Trans Himalayan rivers mostly flow north and south crossing the high Himalaya belt. The rivers are antecedent to the Himalaya. The depth of valley from the nearest peak sometimes ranges to approximately 6,000 m. The river valley works as a wind tunnel or climatic balancing tunnel between the subcontinent and Tibetan plateau. The wind speed is very high and the direction is changed in the morning and evening.

Evaporation is high and the rivers are mostly snow-fed. The hydrological features are governed by diurnal variation of temperature and pressure rather than monsoon influx up to the Midland. Snow melts during the day and the melt water starts rising in the night just below the melting spot.

The valleys of antecedent rivers are narrow and deep in the high Himalaya except in glacial areas. Most of the valleys are oxbow, with waterfalls, cascades, rapids and numerous glacial lakes. The erosive power of the rivers is very strong and it cuts the banks. The meandering of rive is limited.

(2) Himalaya

In the Himalaya, snow starts falling during September, the last month of monsoons, and melting during the summer, from April to June, when the subcontinent is hot. The melt water originates from the Himalaya and flows southward to the Midland by diurnal variation of temperature and pressure. The cold water absorbs heat, debris and other elements on the way to Midland. The melt water is full of clay and fine silt.

The major rivers in the Himalaya, the Koshi, the Gandaki, the Karnali and the Mahakali, are fed by snow. When other rivers dry up from March to May, these rivers are fed by the melt water. Feed by melt water is an advantage. On the other hand, silt transportation with the melt water is a problem.

As the rivers in the Himalaya are fed by snow and monsoons, the high flow is about 25 times as much as the low flow. Snow cover is about 10% of the precipitation in Nepal. The increase of snow cover may help to increase the low flow.

During the monsoons the glaciers are melting and glacial lakes are being formed from place to place. When a glacial lake grows with time, glacial lake outburst floods may occur. GLOF has caused heavy damage downstream due to sudden failure of dams by over-topping and consequently causing flood surge in the past. It would wash out bridges, road trails and caused new landslides, damaging civil and hydropower stations downstream.

(3) Midland

The rivers originating from the Midland are completely influenced by monsoons. Feed by groundwater is limited. The rain runs off immediately. As a result, the high flow is about several thousand times that of the low flow. As these rivers in this area are not fed by melt water, the rate of the high flow to the low flow in this area is about 100 times as much compared to those in the area fed by the melt water.

The catchment area of these rivers is considerably large as compared to rivers in Terai. They carry water throughout the year.

(4) Churia and Terai

The rivers originating from Churia and Terai are dry in summer and winter. They bring flood and silt in the rainy season.

Most of the rivers passing through the Terai plain meander due to heavy sediment load. As a result, there are numerous oxbow lakes in different parts of the Terai.

2.2.4 River Basins

Nepal is divided into four major basins from east to west, the Koshi basin, the Gandaki basin, the Karnali basin and the Mahakali basin. Figure 2.2.4-1 shows a location map of major basins and sub-basins in Nepal. Figure 2.2.4-2 shows east-west cross sections of the Karnali basin, the Gandaki basin and the Koshi basin in northern Nepal.

(1) The Koshi Basin

The Koshi basin lies in eastern Nepal between latitude 26°21’ and 28°13’N, and longitude 85°20’ and 88°13’ E. It has seven major sub-basins, Tamor, Arun, Dudh Koshi, Likhu, Tama Koshi, Sun Koshi, and Indrawati. The Arun, Tama Koshi and Bhote Koshi-Sun Koshi rivers originate in the Tibet Autonomous Region of China, and flow south to the Nepal Himalaya. All other tributaries originate within the territory of Nepal and also flow southwards. The Sun Koshi river generally flows from northwest to southeast. These seven basins flow together in the southeast of the Koshi basin and become the Sapta Koshi river. It flows southwards to India. The Sapta Koshi river is the biggest river of Nepal. The ‘Sapta’ means seven and ‘Koshi’ is taken from the name of Rishi Kaushik who used to live as a hermit on the bank of this river.

The Koshi basin has a lot of glacial lakes upstream. It has about 40% of the total number of glacial lakes. The area of them is about 40% of the total area as well. In particular, there are a lot of potentially critical glacial lakes in this basin.

(2) Gandaki Basin

The Gandaki basin lies in central Nepal between latitude 27°46’ and 28°12’E and longitude 82°44’ and 85°48’E. It has five major sub-basins, Trishuli, Budhi Gandaki, Marsyangdi, Seti and Kali Gandaki. These five basins flow together in the southeast of the Gandaki basin and become the Narayani river. It flows southwards to India.

In the Gandki basin, the sediment yield is larger than in other basins. It has few glacial lakes. The number of glacial lakes is about 10% of the total number. The area is about 10% of the total area.

(3) Karnali Basin

The Karnali Basin lies in western Nepal between latitude 29°04’ and 30°27’ N and longitude 80°33’ and 83°41’ E. It has six major sub-basins, Bheri, Tila, Mugu, Humla, Kawari, and West Seti. Its river network includes the Bheri, Mugu Karnali, Humla Karnali, Kawari, Tila and West Seti. Generally, the rivers flow from north to south. The Humla Karnali river originates in the Tibet Autonomous Region of China.

The number of glacial lakes upstream of the Karnali basin is the most out of the four major basins. The number is about 50% of the total number. The area is about 45% of the total area. However, there are less potentially critical glacial lakes.

(4) Mahakali Basin

The Mahakali basin lies in the far west of Nepal. It flows towards the southwest and forms Nepal’s western border with India. It has two main tributaries in Nepalese territory, the Chamelia river and the Surnagad river. The part of the Mahakali basin lying in Nepal falls between latitude 29°07’ and 30°04’ N and longitude 80°08’ and 81°07’ E. It covers about one-third of the total area of the basin.

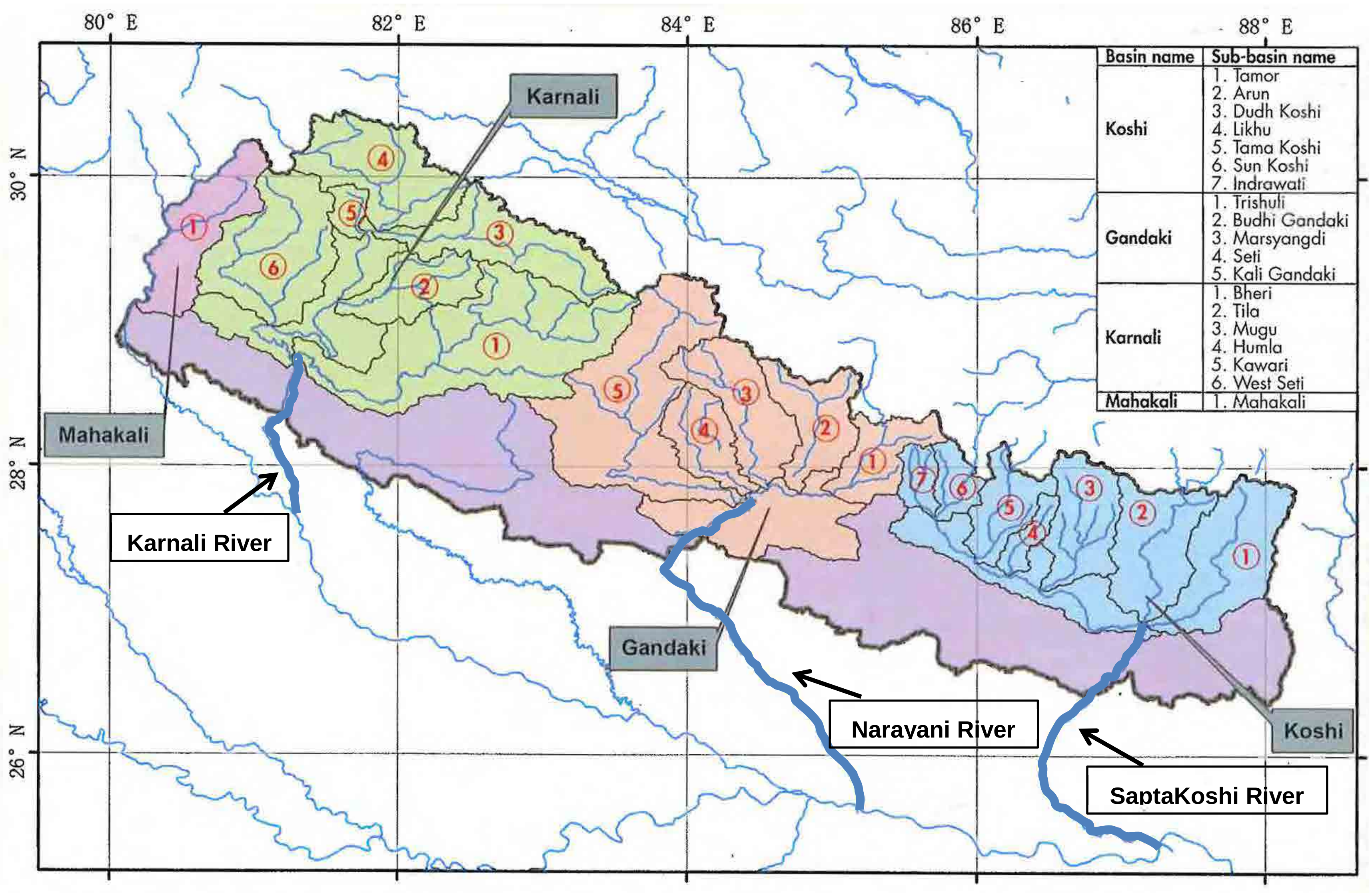
The three drainage basins, namely, the Koshi, the Gandaki and the Karnali basins out of the four mentioned above are related to this Study. The total drainage area of these three basins is 128,090 km^2 which accounts for about 90% of the four major basins. The features of the basins are summarized in the following table.

Table 2.2.4-1 Drainage Area and Annual Discharge of Major Rivers

Major River Basin	Koshi	Gandaki	Karnali
Drainage Area (km^2)	54,100	31,100	42,890
Major Rivers	Tamor Arun Dudh Koshi Likhu Tama Koshi Sun Koshi Indrawati	Trishuli Budhi Gandaki Marsyangdi Seti Kali Gandaki	Bheri Tila Mugu Karnali Humla Karnali Kawari West Seti
Most Downstream River	Sapta Koshi	Narayani	Karnali
Mean Discharge* (m^3/s)	1,620	1,550	1,380
(Gauging Station No.) (Gauging Station)	695 Chatara	450 Natayanghat	280 Chisapani
Specific Sediment Yield ($t/km^{2/}Year$)	3,300	4,400	3,960
Number of Potentially Critical Glacial Lakes	15	5	0

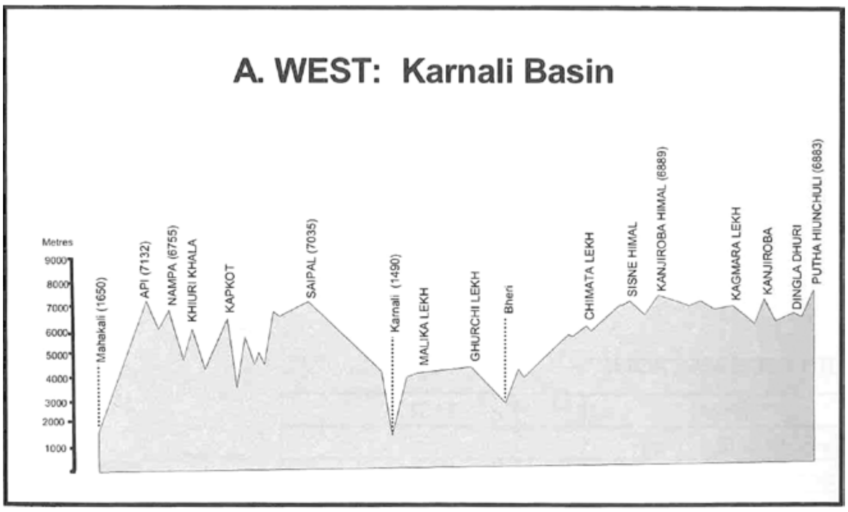
*Source: Stream flow summary (1962-2006), October 2008, DHM.

Figure 2.2.4-3 shows monthly discharges of the Sapta Koshi river, the Narayani river and the Karnali river. Each discharge from June to October accounts for about 80% of the annual total flow volume due to the influence of monsoons. The features of sedimentation and risk of GLOF (Glacial Lake Outburst Flood) are described in the following sub-clauses.

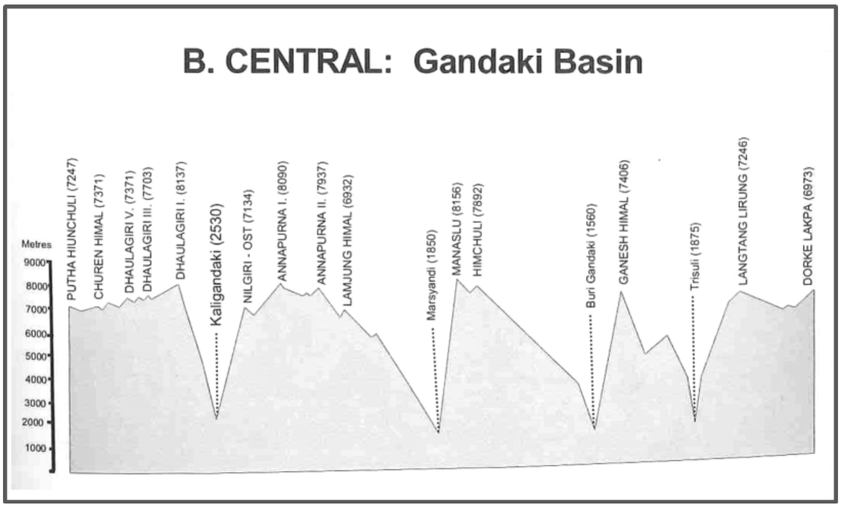


Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD

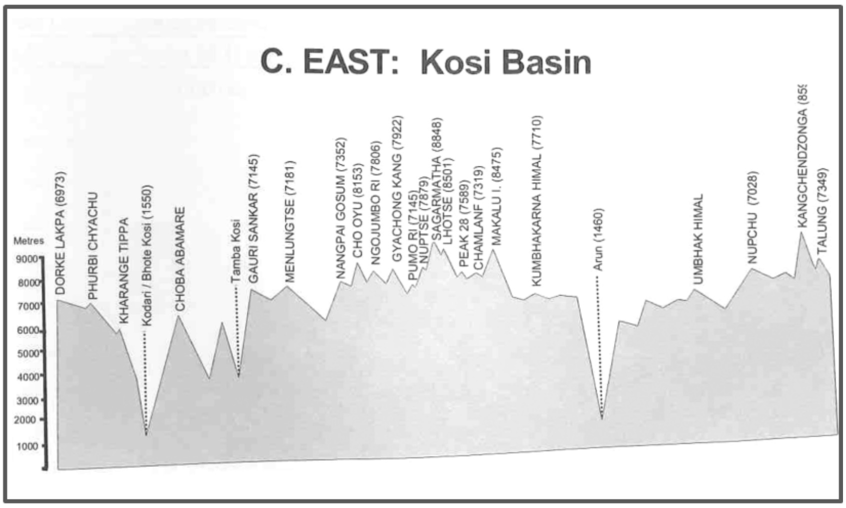
Figure 2.2.4-1 Location Map of Major Basins and Sub-basins in Nepal



a) Karnali Basin



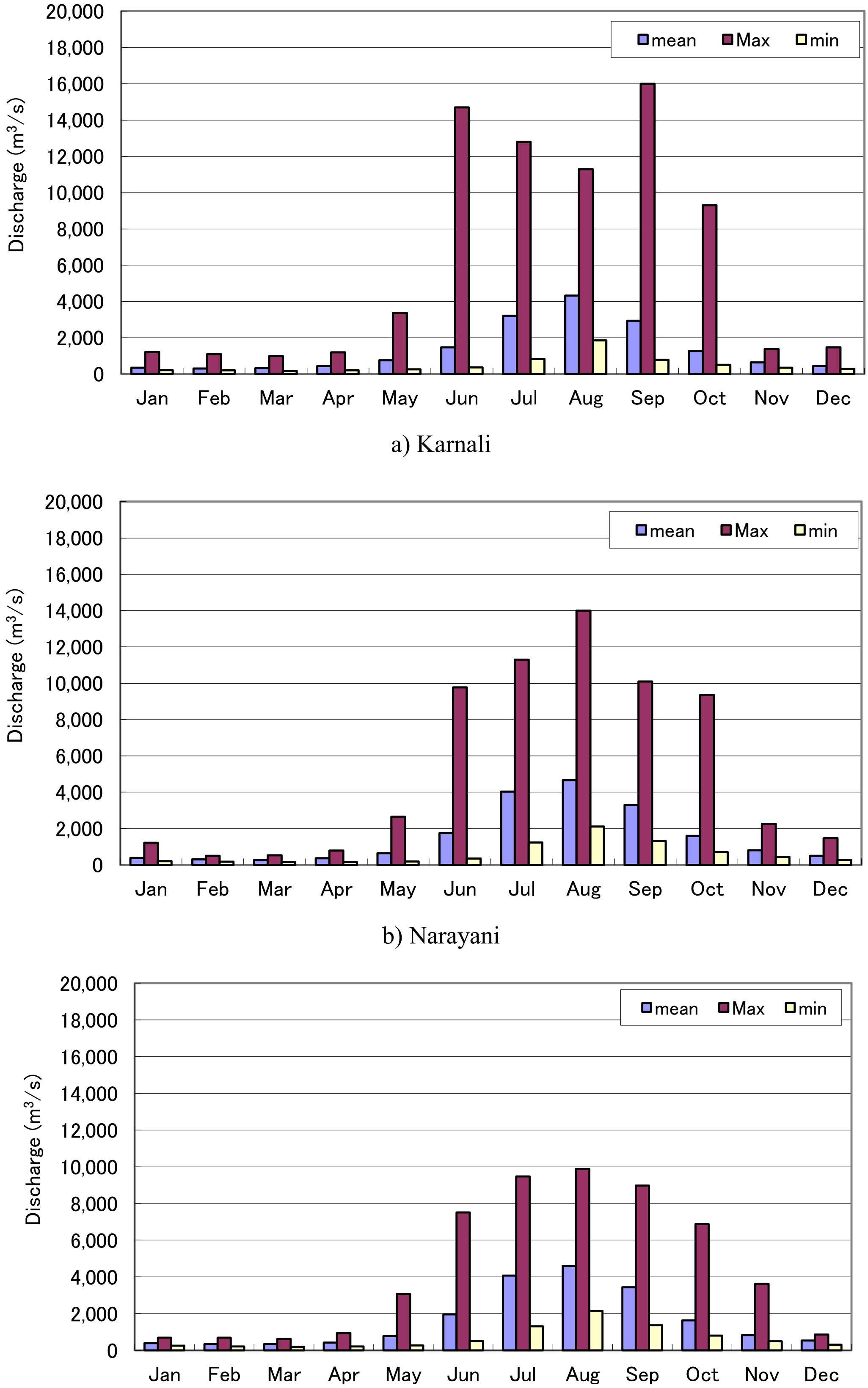
b) Gandaki Basin



c) Koshi Basin

Source: Nepal Atlas & Statistics, revised edition, 2008

Figure 2.2.4-2 East-West Cross Sections of Major Basins



a) Karnali

b) Narayani

c) Sapta Koshi

Source: Stream flow summary (1962-2006), October 2008, DHM

Figure 2.2.4-3 MonthlyAverage Discharge

2.2.5 Flow Gauging

In Nepal the flow gauging is managed by the Department of Hydrology and Meteorology, DHM. The flow is gauged in 99 gauging stations. The flow gauging record from 1962 to 2006 is issued as Streamflow Summary (1962-2006), October 2008.

The location of gauging stations are shown in Figure 2.2.5-1. The specifications of gauging stations are shown in Table 2.2.5-1. There is no record in 2006 at 26 gauging stations. It is assumed that the other 73 gauging stations are operated. The longest gauging period is 45 years. The shortest gauging period is 3 years.

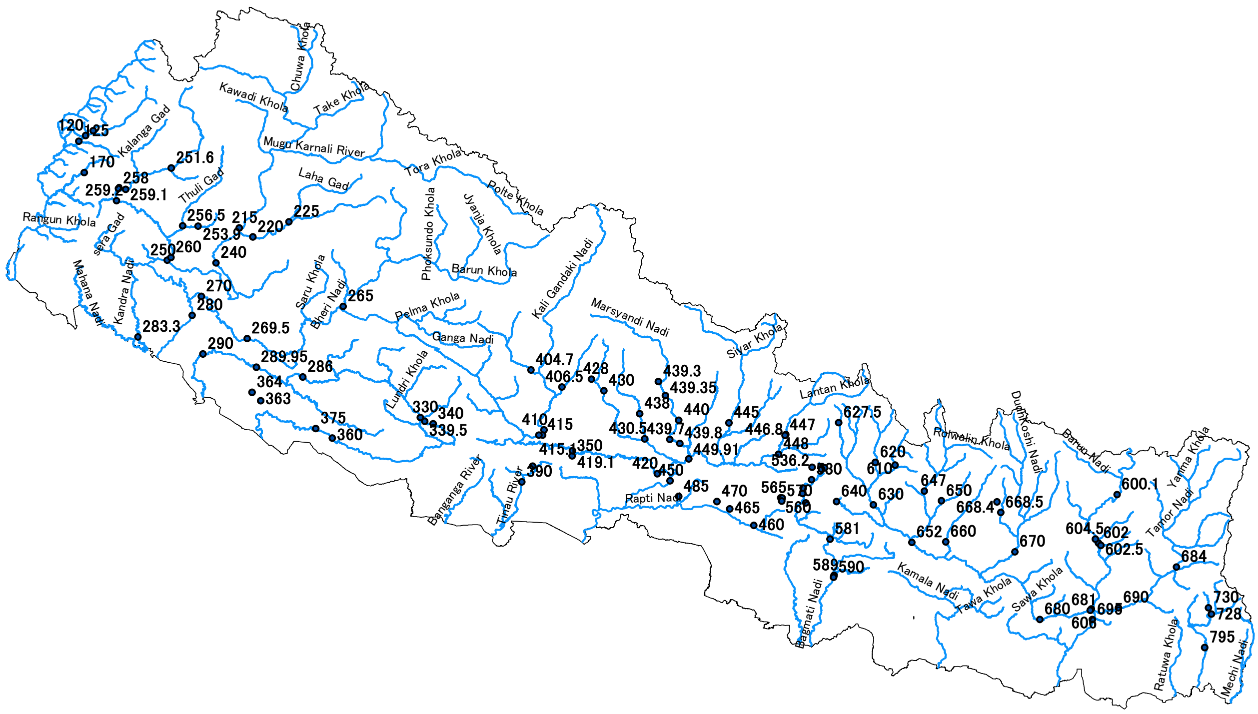


Figure 2.2.5-1 Locations of Gauging Stations

Table 2.2.5-1 Specifications of Gauging Stations (1/2)

No.	GS No.	Name of River	Location	Latitude N	Longitude E	Elevation (m)	Drainage Area (km^2)	Gauging Period		
								From	To	Period
1	115	Naugragad	Harsingbagar	29 42 07	80 36 26	784	203	2000	2006	7
2	120	Chamelia	Nayalbadi	29 40 20	80 33 30	685	1,150	1965	2006	42
3	125	Jamadigad	Panjkonaya	29 38 18	80 30 50	580	228	2001	2006	6
4	170	Sumayagad	Patan	29 27 30	80 33 23	1,110	188	1966	1987	22
5	215	Karnali	Lalighat	29 09 32	81 35 28	590	15,200	1977	2006	30
6	220	Tilanadi	Nagma	29 06 26	81 40 49	1,935	1,870	1973	2006	34
7	225	Sinjhakhola	Diware	29 12 00	81 55 00	1,943	824	1967	2006	40
8	240	Karnali	Asaraghat	28 57 10	81 26 30	629	19,260	1962	2006	45
9	250	Karnali	Benighat	28 57 40	81 07 10	320	21,240	1963	2006	44
10	251.6	Langurkhola	Chhanna	29 29 52	81 07 55	1,158	159	2001	2006	6
11	253.9	Kailashkhola	Mattada	29 09 49	81 19 08	751	196	2001	2006	6
12	256.5	Budhiganga	Chitra	29 09 47	81 12 59	506	1,576	2000	2006	7
13	258	Dhungad	Bhasme	29 22 16	80 47 06	700	135	2000	2006	7
14	259.1	Sailigad	Gautada	29 22 00	80 50 00	770	179	2000	2006	7
15	259.2	Seti	Gopaghat	29 18 00	80 46 30	756	4,420	1986	2006	21
16	260	Seti	Bangga	28 58 40	81 08 40	328	7,460	1963	2006	44
17	265	Thulo Bheri	Rimna	28 42 47	82 17 00	550	6,720	1977	2006	30
18	269.5	Bheri	Sanaijighat	28 31 02	81 39 25	500	12,200	1992	2006	15
19	270	Bheri	Jamu	28 45 20	81 21 00	246	12,290	1963	2006	44
20	280	Karnali	Chisapani	28 38 40	81 17 30	191	42,890	1962	2006	45
21	283.3	Kandra	Pahalmanpur	28 30 41	80 56 24	143	479	2001	2006	6
22	286	Saradakhola	Daradhunga	28 17 58	82 01 30	579	816	1972	2006	35
23	289.95	Babai	Chepang	28 21 04	81 43 14	325	2,557	1990	2006	17
24	290	Babai	Bargadha	28 25 20	81 22 10	192	3,000	1967	1987	21
25	330	Marikhola	Nayagaon	28 04 20	82 48 00	536	1,938	1965	2006	42
26	339.5	Jhimrukkhola	Chernata	28 03 00	82 49 40	762	683	1971	1995	25
27	340	Jhimrukkhola	Kalimatighat	28 02 10	82 53 00	692	696	1965	1970	6
28	350	Rapti	Bagasotigaon	27 51 12	83 47 34	381	3,380	1976	2006	31
29	360	Rapti	Jalkundi	27 56 50	82 13 30	218	5,150	1964	2006	43
30	363	Jhajharikhola	Dhakeri	28 09 22	81 45 13	159	78	2000	2006	7
31	364	Duduwakhola	Masurikhet	28 12 15	81 41 44	162	54	2000	2006	7
32	375	Rapti	Kusum	28 00 02	82 06 58	235	5,200	2003	2006	4
33	387.4	Dumrekhola	Kaimati	27 47 40	83 32 03	595	90	2000	2006	7
34	390	Tinaukhola	Butwal	27 42 10	83 27 50	184	554	1964	1969	6
35	404.7	Mayagdi Khola	Mangalghat	28 21 10	83 31 16	914	1,112	1976	2006	31
36	406.5	Modikhola	Nayapul	28 15 15	83 43 27	701	601	1976	2006	31
37	410	Kali Gandaki	Setibeni	28 00 14	83 36 31	546	6,630	1964	1995	32
38	415	Adhikhola	Andhimuhan	27 58 28	83 35 58	543	476	1964	1991	28
39	415.1	Adhikhola	Bortangpul	27 58 27	83 34 26	749	195	2000	2006	7
40	419.1	Kali Gandaki	Ansing	27 53 05	83 47 42	351	10,020	1996	2006	11
41	420	Kali Gandaki	Kotagaun	27 45 00	84 20 50	198	11,400	1964	2006	43
42	428	Mardikhola	Lahachowk	28 18 02	83 55 06	915	160	1974	1995	22
43	430	Seti	Phoolbari	28 14 00	84 00 00	830	582	1964	1984	21
44	430.5	Seti Gandaki	Damauli	27 57 12	84 15 54	290	1,350	2000	2006	7
45	438	Madi	Shisaghat	28 06 00	84 14 00	457	858	1975	2006	32
46	439.3	Khudikhola	Khudibazar	28 17 12	84 21 27	990	151	1983	1995	13
47	439.35	Marshyandi	Bhakundebesi	28 12 13	84 24 11	610	2,950	2000	2006	7
48	439.7	Marshyandi	Bimalnagar	27 57 00	84 25 48	354	3,774	1987	2006	20
49	439.8	Marshyandi	Goplingghat	27 55 35	84 29 42	320	3,850	1974	1986	13
50	440	Chepekhola	Gharmbesi	28 03 41	84 29 23	442	308	1964	2006	43

Table 2.2.5-1 Specification of Gauging Stations (2/2)

No.	GS No.	Name of River	Location	Latitude N	Longitude E	Elevation (m)	Drainage Area (km^2)	Gauging Period From	To	Period
51	445	Burhi Gandaki	Arughat	28 02 37	84 48 59	485	4,270	1964	2006	43
52	446.8	Phalankhukhola	Brtrawati	27 58 25	85 11 15	630	162	1971	1995	25
53	447	Trishuli	Betrawati	27 58 08	85 11 00	600	4,110	1977	2006	30
54	448	Tadi	Belkot	27 51 35	85 08 18	475	653	1969	2006	38
55	449.91	Trishuli	Kalikhola	27 50 08	84 33 12	220	16,760	1994	2006	13
56	450	Narayani	Devghat	27 42 30	84 25 50	180	31,100	1963	2006	44
57	460	Rapti	Rajaiya	27 26 50	84 58 26	332	579	1963	2006	44
58	465	Manaharikhola	Manahari	27 32 37	84 49 03	305	427	1964	2006	43
59	470	Lotharkhola	Lothar	27 35 14	84 44 07	336	169	1964	2004	41
60	485	Buri Rapti	Chitrasari	27 37 00	84 29 15	189	184	1964	1972	9
61	505	Bagmati	Sundarijal	27 46 49	85 25 36	1,600	17	1963	2006	44
62	507	Nagmati	Sundarijal	27 46 38	85 26 20	1,660	13	1963	1971	9
63	510	Sialmati	Shyamado	27 46 10	85 25 10	1,660	3	1963	1971	9
64	530	Bagmati	Gaurighat	27 42 35	85 21 10	1,300	68	1991	2006	16
65	536.2	Bishnumati	Budhanilkantha	27 46 54	85 21 25	1,454	4	1969	1985	17
66	540	Nakhukhola	Tika Bhairab	27 34 30	85 18 50	1,400	43	1963	1980	18
67	550	Bagmati	Chovar	27 39 40	85 17 50	1,280	585	1963	1980	18
68	550.05	Bagmati	Khokana	27 37 44	85 17 41	1,250	658	1992	2006	15
69	560	Thadokhola	Darkot-Markhu	27 36 20	85 09 00	1,830	14	1964	1976	13
70	565	Kulekhanikhola	Lamichaur	27 36 13	85 09 39	1,515	122	1976	1978	3
71	570	Kulekhanikhola	Kulekhani	27 35 10	85 09 30	1,480	126	1963	1977	15
72	581	Bagmati	Bhorieni	27 21 43	85 28 10	250	1,540	2000	2006	7
73	589	Bagmati	Padharadoven	27 09 06	85 29 30	180	2,700	1979	2006	28
74	590	Bagmati	Karmaiya	27 08 22	85 29 22	177	2,720	1965	1979	15
75	600.1	Arun	Uwagaun	27 35 21	87 20 22	1,294	26,750	1985	2006	22
76	602	Sabayakhola	Tumilingtar	27 18 36	87 12 45	305	375	1974	2006	33
77	602.5	Hinwakhola	Pipaltar	27 17 45	87 13 30	300	110	1974	2006	33
78	604.5	Arun	Turkighat	27 20 00	87 11 30	414	28,200	1975	2006	32
79	606	Arun	Simle	26 55 42	87 09 16	152	30,380	1986	2006	21
80	610	Bhotekosi	Barbise	27 47 18	85 53 55	840	2,410	1965	2006	42
81	620	Balephi	Jalbire	27 48 20	85 46 10	793	629	1964	2006	43
82	627.5	Melamchi	Helambu	28 02 21	85 32 07	2,134	84	1990	2006	17
83	630	Sunkosi	Pachuwarghat	27 33 30	85 45 10	602	4,920	1964	2006	43
84	640	Rosikhola	Panauti	27 34 50	85 30 50	1,480	87	1964	1987	24
85	647	Tamakosi	Busti	27 38 05	86 05 12	849	2,753	1971	2006	36
86	650	Khimtikhola	Rasnalu	27 34 30	86 11 50	1,120	313	1964	2006	43
87	652	Sunkosi	Khurkot	27 20 11	86 00 01	455	10,000	1968	2006	39
88	660	Likhu	Sangutar	27 20 10	86 13 10	543	823	1964	2006	43
89	668.4	Taktorkhola	Benighat	27 33 46	86 33 28	2,400	73	1986	1991	6
90	668.5	Solukhola	Salme	27 30 03	86 34 52	1,800	246	1987	2006	20
91	670	Dudhakosi	Rabuwabazar	27 16 14	86 40 02	460	4,100	1964	2006	43
92	680	Sunkosi	Kampughat	26 52 28	86 49 10	200	17,600	1966	1985	20
93	681	Sunkosi	Hampchuwar	26 55 15	87 08 45	150	18,700	1991	2006	16
94	684	Tamur	Majhitar	27 09 30	87 42 45	533	4,050	1996	2006	11
95	690	Tamur	Mulghat	26 55 50	87 19 45	276	5,640	1965	2006	42
96	695	Saptakosi	Chatara	26 52 00	87 09 30	140	54,100	1977	2006	30
97	728	Maikhola	Rajdwali	26 52 45	87 55 45	609	377	1983	2006	24
98	730	Puwakhola	Sajbote	26 55 00	87 54 40	802	107	1966	1968	3
99	795	Kankai	Mainachuli	26 41 12	87 52 44	125	1,148	1972	2006	35

Source: Stream flow summary (1962-2006), October 2008, DHM

2.2.6 Flow Estimation

In case there is a gauging station near the project site, the flow of the project is estimated by using the gauged flow data. On the other hand, in case there is no gauging station near the project site, the flow of the project is estimated by Regional Analysis. Regional Analysis is how to calculate the flow using the correlation equation, which is derived by the correlation among flow, catchment area and precipitation intensity based on the flow data and precipitation data gauged in all of Nepal.

Regional Analysis is made by the Ministry of Water Resources, MOWR, Water and Energy Commission Secretariat, WECS and DHM in 1990.

NEA has estimated the monthly flow using the following correlation equations, which revised the correlation equations of Regional Analysis.

The monthly average flow from January to May is calculated using the correlation equation, which is derived from the correlation between the flow and the catchment area. The monthly average flow from June to December is calculated using the correlation equation, which is derived from the correlation among the flow, the catchment area and the precipitation from June to December.

In the following equation, Q means the flow at the project site and the unit is m^3/s. A means the catchment area at the project site and the unit is km^2. MWI means Monsoon Wetness Index at the project site from June to December and the unit is mm. The MWI shows the precipitation from June to December at the project site estimated by the Isohyetal map of the precipitation from June to December. Figure 2.2.6-1 shows the Monsoon Wetness Index Isolines made by WECS and DHM in 1990.

The following calculation formula for monthly flow is derived using the flow data before 1990 and the Monsoon Wetness Isolines based on precipitation before 1984.

January:	$Q = 0.03117 \times A^{0.8644}$
February:	$Q = 0.02417 \times A^{0.8752}$
March:	$Q = 0.02053 \times A^{0.8902}$
April:	$Q = 0.01783 \times A^{0.9258}$
May:	$Q = 0.01930 \times A^{0.9657}$
June:	$Q = 0.01135 \times A^{0.9466} \times MWI^{0.2402}$
July:	$Q = 0.01641 \times A^{0.9216} \times MWI^{0.3534}$
August:	$Q = 0.02592 \times A^{0.9095} \times MWI^{0.3242}$
September:	$Q = 0.02206 \times A^{0.8963} \times MWI^{0.3217}$
October:	$Q = 0.01504 \times A^{0.8772} \times MWI^{0.2848}$
November:	$Q = 0.00792 \times A^{0.8804} \times MWI^{0.2707}$
December	$Q = 0.00538 \times A^{0.8890} \times MWI^{0.2580}$

Source: Methodologies for estimating hydrologic characteristics of locations not gauged in Nepal, July 1990, MOWR, WECS, and DHM

Figure 2.2.6-1 Monsoon Wetness Index Isolines

2.3 Sedimentation

2.3.1 General

Sedimentation is soil and sand that occurring through surface erosion, instable slope failure, bank erosion flow down and storage.

Annual sediment yield all over the world is 4.5 billion km^3. The rate of sediment yield to reservoir storage volume is increasing 0.5 - 1.0% every year. It is predicted that the sediment yield will become more than 30% of the reservoir storage volume by the middle of the 21st century.[1]

The Midland located between High Himalaya and Mahabharat range and Lesser Himalaya including the Mahabharat range is one of the most sediment proceeding areas in the world. The main reasons of above are that a large amount of sediment is being supplied from the High Himalaya area to the Lesser Himalaya area and that the rocks have fractured and weathered in there. The sediment also proceeds with the soil and stone collapsed by glacial lake outburst floods. The sediment in the High Himalaya contains a high proportion of boulder and gravel because of the steep gradient of the rivers. Meanwhile, the sediment in Lesser Himalaya contains a high proportion of sand and silt because of the gentle gradient of the rivers formed by rapid uplifting downstream of the Mahabharat range. 90% of annual sediment yield flows during monsoon season (from June to October).

[1] Source: Reservoir sedimentation management: worldwide status and prospects, Session “Challenges to sedimentation management for reservoir sustainability”, The 3rd World Water Forum, 2003, pp. 97-108

2.3.2 Measurement of Sediments

Sediment is of varied forms, for example, rock which has a size of less than 4m, boulder, gravel, sand, silt and clay. The way of movement of sediment is different due to the sediment size. Silt or clay is suspended in flow but it doesn't lie on the bed. Sand is suspended in flow and some pieces lie on the bed. Gravel and boulders move on the bed.

Suspended load is measured using a suspended sediment sampler by attaching a rod with a bottle included to pick sediment. The unit of suspended load is ppm.

Suspended load is measured at a gauging station. In Nepal suspended load is measured at 18 primary gauging stations in the Karnali basin, Narayani basin, Bagmati basin and Sapta Koshi basin. Figure 2.3.2-1 shows the location of these gauging stations. Table 2.3.2-1 shows the specifications of them.

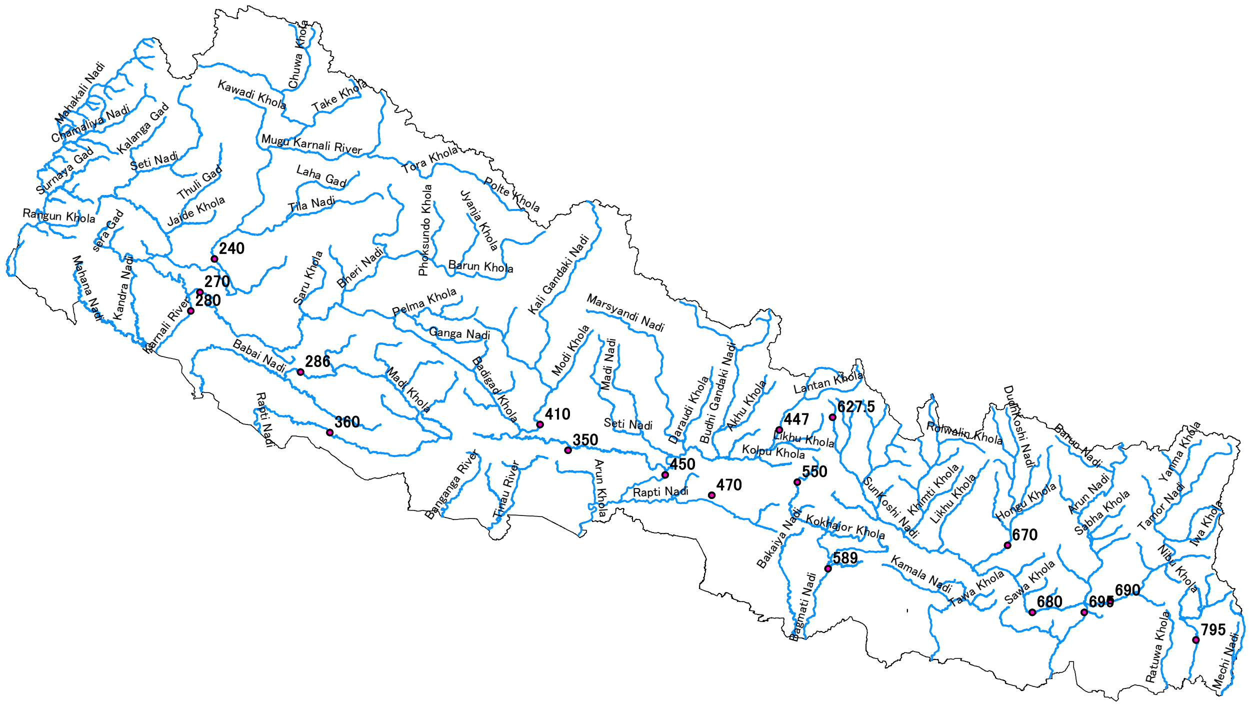


Figure 2.3.2-1 Location of Gauging Stations for Suspended Sediment

Table 2.3.2-1 Specifications of Gauging Stations for Suspended Sediment

No.	GS No.	Name of River	Location	Latitude N	Longitude E	Elevation (m)	Drainage Area (km^2)
1	240	Karnali	Asaraghat	28 57 10	81 26 30	629	19,260
2	270	Bheri	Jamu	28 45 20	81 21 00	246	12,290
3	280	Karnali	Chisapani	28 38 40	81 17 30	191	42,890
4	286	Saradakhola	Daradhunga	28 17 58	82 01 30	579	816
5	350	Rapti	Bagasotigaon	27 51 12	83 47 34	381	3,380
6	360	Rapti	Jalkundi	27 56 50	82 13 30	218	5,150
7	410	Kali Gandaki	Setibeni	28 00 14	83 36 31	546	6,630
8	447	Trishuli	Betrawati	27 58 08	85 11 00	600	4,110
9	450	Narayani	Devghat	27 42 30	84 25 50	180	31,100
10	470	Lotharkhola	Lothar	27 35 14	84 44 07	336	169
11	550	Bagmati	Chovar	27 39 40	85 17 50	1,280	585
12	589	Bagmati	Padharadoven	27 09 06	85 29 30	180	2,700
13	627.5	Melamchi	Helambu	28 02 21	85 32 07	2,134	84
14	670	Dudhakosi	Rabuwabazar	27 16 14	86 40 02	460	4,100
15	680	Sunkosi	Kampughat	26 52 28	86 49 10	200	17,600
16	690	Tamur	Mulghat	26 55 50	87 19 45	276	5,640
17	695	Saptakosi	Chatara	26 52 00	87 09 30	140	54,100
18	795	Kankai	Mainachuli	26 41 12	87 52 44	125	1,148

Source: Stream Flow Summary (1962-2006), October 2008, DHM Suspended Sediment Concentration Records, 2003, DHM

As it is difficult to measure bed load, it is calculated using the rate of bed load to suspended load. Table 2.3.2-2 shows the rate of bed load to suspended load in Nepal. Many of the hydropower project sites are located in the Lower Lesser Himalaya. The rate of bed load to suspended load is between 5% and 15%.

Table 2.3.2-2 Rate of Bed Load to Suspended Load

Type of geology	Bed load / Suspended load
High Himalaya, Upper Lesser Himalaya (steep slopes)	40 – 60%
Lower Lesser Himalaya (along parallel valleys)	5 – 15%
Siwaliks (local steep slopes)	20 – 40%

Source: Himalayan Sediments Issued and Guidelines, January 2003, WECS

2.3.3 Specific Sediment Yield

V. J.Galay, who has studied about sediment yield in Nepal, indicates that specific sediment yield correlates with the Himalayan geological zones based on the sediment yield in Nepal, India and Pakistan.

As shown in Figure 2.3.3-1, the range of Specific sediment yield is provided for five kinds of Himalayan geological zones, the Tibet Plateau, High Himalaya, High Mountain Zone, Middle Mountain Zone and Siwalik Zone.

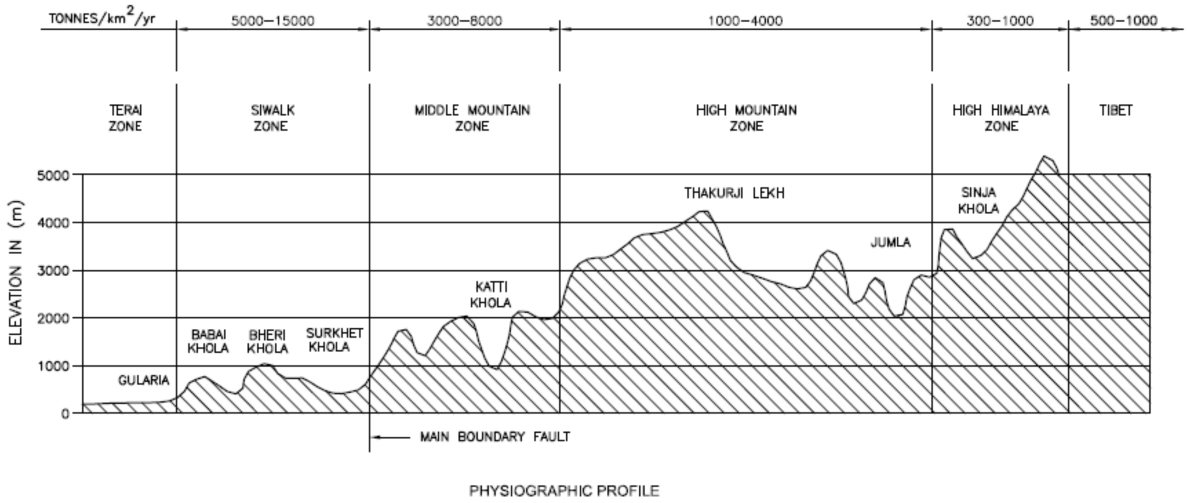


Figure 2.3.3-1 Specific Sediment Yield for Himalayan Geological Zones

Table 2.3.3-1 shows the sediment load and the specific sediment yield in some basins of Lesser Himalaya. River Classes are as follows.

I : Rivers flowing in the High Himalaya

II a : Tributary which originates with the southern High Himalaya and flows in a Class I river

II b : Tributary which originates with the southern High Himalaya except for a Class II a river

Table 2.3.3-1 Specific Sediment Yield in Some Basins of the Lesser Himalaya

Basin	Drainage Area (km^2)	River Class	Sediment load (million t / yr)	Specific Sediment Yield ($t/km^2/yr$)
Marsyangdi	3,100	II a	16.9	5,452
Mahakali	6,930	II a	45.3	6,537
Sapta Gandaki	18,000	I	73.6	4,089
Arun	8,500	I	32.9	3,870
Upper Karnali	8,859	I	14.0	1,580
Trisuli	1,400	II a	5.9	4,214
Sun Koshi	13,830	I	66.5	4,808
Bagmati	585	II b	0.5	855
Gaula (India)	600	II a	2.2	3,667
Sutlej (India)	10,030	I	32.3	3,223
Tamur – GLOF	4,500	II b	38.1	8,467
Tamur – after GLOF	1,200	II b	6.0	1,690

Source: Himalayan Sediments Issued and Guidelines, January 2003, WECS

The table above shows that the specific sediment yield in Class II a rivers is the largest and that in Class I rivers is the next largest. NEA provides the specific sediment yield for three areas of Nepal: the eastern area, central area and western area based on the measurement data of sediment in some basins.

In the case of the eastern area, the specific sediment yield for suspended load is estimated to be 3,000t/km^2/year referring to the sediment yield data of the Arun basin, Dudh Koshi basin and Khimti basin. Assuming that the bed load is 10% of the suspended load, the specific sediment yield in the eastern area is estimated to be 3,300 t/km^2/year.

In the case of the central area, the specific sediment yield for the suspended load is estimated to be 4,000 t/km^2/year referring to the sediment yield data of the Marsyangdi basin and the Narayani basin. Assuming that the bed load is 10% of suspended load, the specific sediment yield in the central area is estimated to be 4,400 t/km^2/year.

In the case of the western area, the specific sediment yield for the suspended load is estimated to be 3,600 t/km^2/year referring to the sediment yield data of the Karnali basin. Assuming that the bed load is 10% of the suspended load, the specific sediment yield in the western area is estimated to be 3,960 t/km^2/year.

According to the above, the specific sediment yield of the central area is the most and the specific sediment yield of the eastern area is the least.

NEA owns and operates the Kulekhani hydropower plant 20 km southwest of Kathmandu, which is the only storage-type hydropower plant in Nepal. Table 2.3.3-2 shows the main features of the Kulekhani Hydropower Plant.

Unit 1 and Unit 2 launched operation, respectively, in December 1982 and May 1987. The measurement of the sediment has been conducted from June 1989.

The sediment yield in 2010 was 25.3 million m^3. Since the catchment area is 126 km^2 and the operation period is 27 years, the specific sediment yield is estimated to be 7,437 m^3/km^2/year (11,156 t/km^2/year). This sediment yield seems rather large compared with those in Table 2.3.3-1. It is presumed that the reason of the large sediment yield could be due to the large-scale floods that occurred in 1984, 1986 and 1993.

Table 2.3.3-2 Main Features of the Kulekhani Hydropower Plant

Structure	Item	Description
Power Station	Capacity	No. 1 Station: 60 MW (30 MW × 2) No. 2 Station: 32 MW (16 MW × 2) Total 92 MW
Reservoir	Catchment Area Reservoir Area Storage Volume	126 km^2 2.2 km^2 85,300,000 m^3
Dam	Dam Type Size	Inclined core rockfill dam Dam Height 114 m Crest Length 406 m Crest Width 10 m

2.3.4 Sediment Management

(1) Actual Example of the Kulekhani Hydropower Plant

As mentioned above, the Kulekhani Hydropower Plant (No.1 Plant: 60 MW, No.2 Plant: 32 MW) is the only storage-type hydropower plant in Nepal at the moment and plays an important role in the stable electric power supply in the situation that the electric power in dry season decreases, since most domestic hydroelectric power plants are of the run-of-river type.

The Kulekhani Hydropower Plant was damaged by floods that occurred due to heavy rain in 1984, 1986 and 1993, hence some disaster prevention projects were implemented with support from the government of Japan. In the projects, the following countermeasures were carried out as sediment management from the aspects of watershed management and dam structure.

1) Construction of a Sediment Control Dam

From the aspect of watershed management, reduction of sediment discharge was promoted by constructing sediment control dams at the upstream of the Kulekhani river and at the river mouth in the reservoir in order to mitigate sedimentation in the reservoir.

2) Improvement of Intake Structure against Clogging

Since the Kulekhani dam had no way to remove sediment and water and to recover operation in case that the intake was clogged by sediment, a structural countermeasure was taken to ensure taking water if sedimentation proceeds in the reservoir and to reduce the risk mentioned above risk. As a specific countermeasure, a sloping intake which enables prevention of clogging by sediment and to take water even if the sedimentation level rises was constructed to promote prolonging the life of the reservoir.

In addition to the measures mentioned above, the application of a Hydrosuction Sediment Removal System (HSRS) is examined as a future measure for sediment management.[2] HSRS is a sediment removal system which sucks sediment with water from the bottom of the reservoir by using a water head between the upstream and downstream of a dam and discharges them downstream through a pipeline.

(2) Sediment Management Plan for the Tanahu Hydropower Project

The Tanahu Hydroelectric 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 Annapurna (at an elevation of 7,555 m above sea level) of the Himalaya and joins the Madi river 2 km downstream from the Dam site after flowing roughly from north to south. The length of the Seti river from the origin to the Dam site is about 120 km, and the catchment area at the Dam site is 1,502 km^2.

The Seti river basin belongs to a high mountain and a humid subtropical climatic zone. The NEA's report states that the average annual precipitation in the project basin is 2,973 mm, of

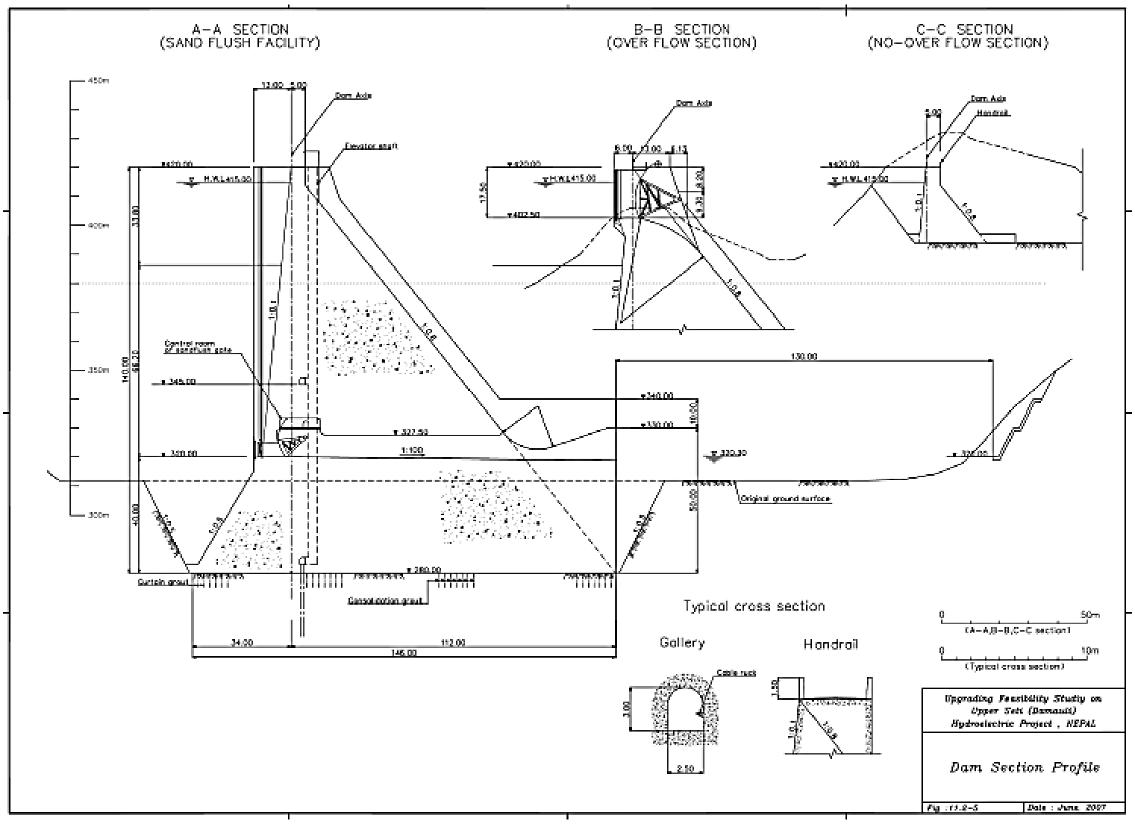
[2] Source: "Sediment Management for Sustainability of Storage Projects in the Himalaya – A case study of the Kulekhani Reservoir in Nepal", by Durga Prasad Sangroula, International Conference on Small Hydropower-Hydro Sri Lanka, 22-24 October 2007

which about 80% falls between June and September due to the influence of the southwest monsoon according to "Upgrading Feasibility Study on Upper Seti (Damauli) Storage Hydroelectric Project in Nepal Final Report, JICA, 2007".

The above-mentioned report also concluded that it would be indispensable for the Tanahu Project to install a sand flushing facility in order to maintain the storage function of the reservoir due to the expected large amount of sedimentation in the reservoir, by the flushing method where that the tractive force of flowing water is increased to more than a critical value by lowering the reservoir water level, and sediment deposited in a reservoir downstream of a dam is carried through a flushing facility installed in dam body with such tractive force.

1) Sand Flush Facility

The feasibility study[3] concluded that the sediment flushing facilities are indispensable for the Tanahu hydropower project to maintain effective reservoir capacity because the project has a lot of sediment inflow to the reservoir. It is better to install sediment flushing facilities in the Dam body from an economic point of view and to install sediment flushing facilities at the lowest possible elevation considering the topography of the Dam site, the riverbed elevation and the positional relation between the facilities and the spillway. The outline of the proposed sand flush facility in FS is shown below.



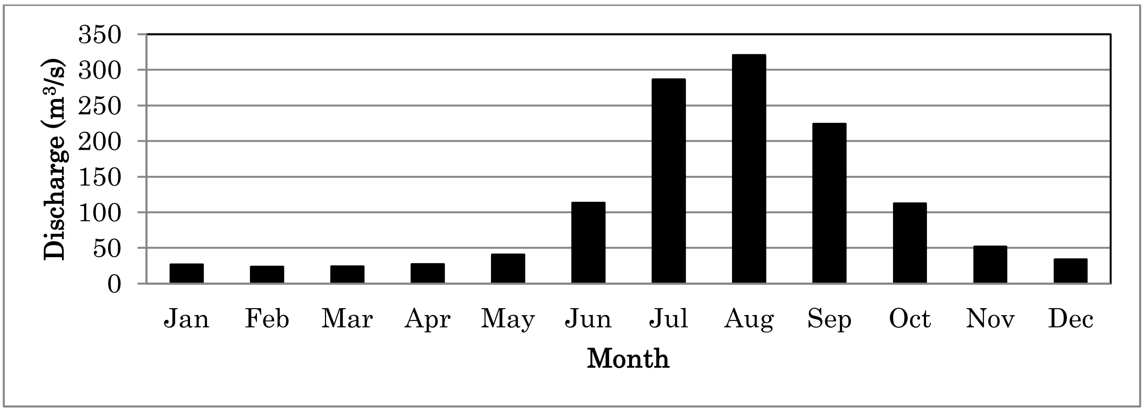
Source: "Upgrading Feasibility Study on the Upper Seti Storage Hydroelectric Project in Nepal, 2007, JICA"

Figure 2.3.4-1 Sand Flush Facility

[3] "Upgrading Feasibility Study on the Upper Seti Storage Hydroelectric Project in Nepal, 2007, JICA"

2) Sediment Flushing Operation

The following graph shows average monthly river discharge at dam site of the Tanahu Hydroelectric Project estimated in the feasibility study. The sediment flushing operation is planned during the rainy season from June to October when the river discharges are large.



Source: Upgrading Feasibility Study on the Upper Seti Storage Hydroelectric Project in Nepal, 2007, JICA

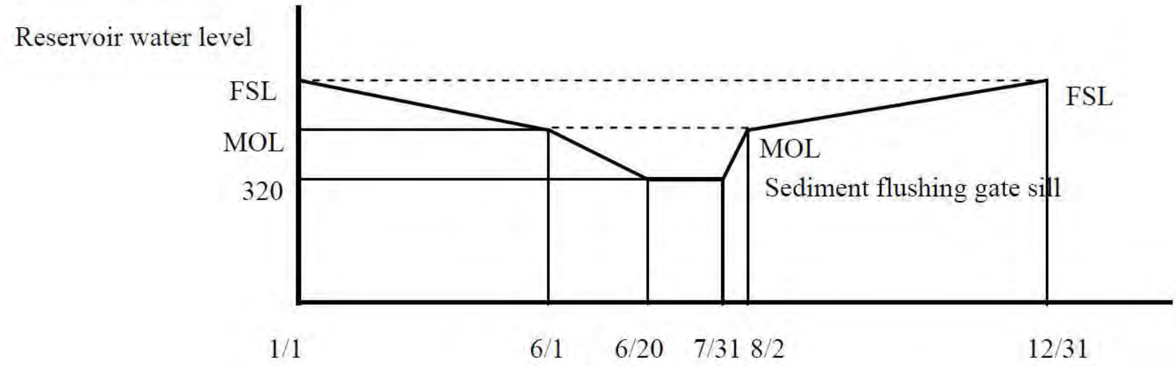
Figure 2.3.4-2 Average Monthly Discharge at the Tanahu Dam Site

The Reservoir water level is lowered less than MOL during the sediment flushing operation which is carried out in the rainy season, so power generation is suspended during the operation. It is estimated that suspension of power generation of the Project in the rainy season does not affect the electricity supply because other run-of-river type hydropower plants supply sufficient electricity during the suspension. Considering the effect of flushing, the Reservoir water level shall be lowered for as long as possible.

The sediment flushing operation is to be carried out in the former half of the rainy season for the following reasons;

- The sediment flushing operation may not be completed within the rainy season if the operation is planned in the last period of the season in which the inflow of river water decreases;
- According to the average daily river discharge record from 1964 to 1999, the average monthly river discharge gets to the maximum level in August. Therefore it is not desirable that the sediment flushing operation is carried out in August so that river water flows through sediment flushing facilities of the least possible total sectional area in an open channel condition from an economical view point;
- It is desirable that the sediment flushing operation is completed in July to restore the Reservoir water level to MOL and higher in the shortest possible period of time after the operation; and
- It is not desirable that the sediment flushing operation is carried out in August so that secondary electricity generation decreases due to flushing operation as little as possible.

It is planned that the sediment flushing operation should be carried out for about a month from the end of June to the end of July every year, and lowering the reservoir water level to the sill elevation of sediment flushing facilities is as shown below.



Source: "Upgrading Feasibility Study on the Upper Seti Storage Hydroelectric Project in Nepal, 2007, JICA"

Figure 2.3.4-3 Reservoir Operation Curve

2.4 Glacial Lake Outburst Flood

2.4.1 Glacier and Glacial Lake

A glacier is a large persistent body of snow and ice that forms from precipitation flowing downstream by gravity. A large persistent body of ice forms where the accumulation of snow exceeds its ablation over many years. When the body of ice becomes thick enough, it flows downstream by its own weight. The above is a mechanism of glacial formation.

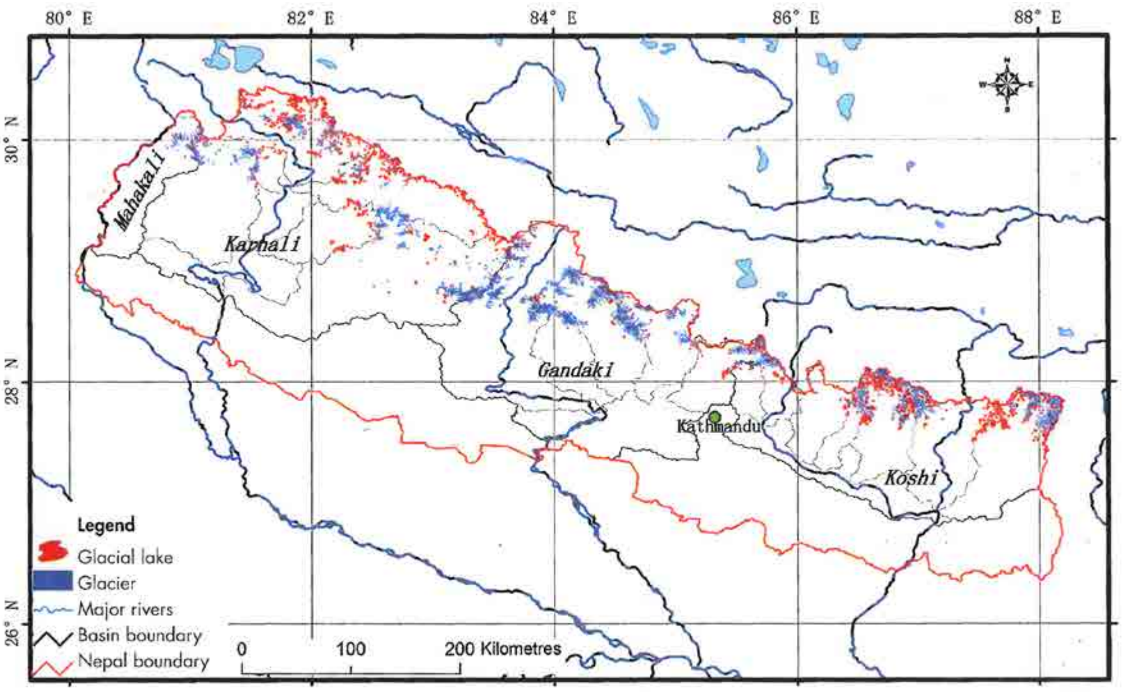
The glacier increased its mass by precipitation and avalanches. On the other hand, the glacier decreased its mass by melting and flowing out. The increase of glacier mass is called cultivation. The decrease of glacier mass is called ablation.

When the monsoon cloud touches eastern Nepal from Bay of Bengal, it hits the Himalaya and starts precipitation on the southern slope of the Himalaya. As 80% of annual precipitation occurs during the monsoon season, from June to September, the glacier cultivation occurs by precipitation. The precipitation is rainfall below 5,200 m and becomes snow above 5,200 m. As the temperature is the highest during the monsoon season, the glacier ablation occurs during the monsoon season. The glaciers of Nepal are cultivated and ablated at the same time.

While a glacier flows downstream, debris is carried downstream and deposited at the end of glacier. A pile of debris which is deposited and surrounded at the end of glacier is called a moraine. During the so-called Little Ice Age (from the 16th century to the 20th century) glaciers thickened and advanced, and moraines with heights from 10m to 150 m were formed at the end of glacier.

As glacier tongues thinned and retreated after Little Ice Age, melt water became trapped in the trough between the glacier terminus and its end moraine, and a glacial lake was formed.

Figure 2.4.1-1 shows the location of glaciers and glacial lakes in Nepal.



Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD

Figure 2.4.1-1 Location of Glaciers and Glacial Lake in Nepal

Table 2.4.1-1 shows the distribution of glaciers in the river basins of Nepal. The 2001 inventory identified 3,252 glaciers covering an area of 5,324 km^2. The 2010 inventory identified 3,808 glaciers covering an area of 4,121 km^2. From 2001 to 2010 the number of glaciers was increasing, but the area of glaciers was decreasing. The number of glaciers is the highest in the Karnali basin. The area of glaciers is the biggest in the Gandaki basin.

Table 2.4.1-1 Distribution of Glaciers in River Basins of Nepal

	2001 glacier inventory			2010 glacier inventory			
Basin	No. of glaciers	Total area (sq.km)	Mean area (sq.km)	No. of glaciers	Total area (sq.km)	Highest elevation (masl)	Lowest elevation (masl)
Koshi	779	1,410	1.81	843	1,180	8,437	3,962
Gandaki	1,025	2,030	1.98	1,337	1,800	8,093	3,273
Karnali	1,361	1,741	1.27	1,461	1,120	7,515	3,631
Mahakali	87	143	1.65	167	112	6,850	3,695
Total	**3,252**	**5,324**	**1.64**	**3,808**	**4,212**		

Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD

Table 2.4.1-2 shows the distribution of glacial lakes and their area in the river basins and sub-basins of Nepal. For the inventory, glacial lakes ware defined as all lakes in a river basin that lie above 3,500m, are greater than 1,000 m^2 in area, and are fed by glacial melts.

The inventory identified a total of 1,466 glacial lakes with a total area of 64.78 km^2 in Nepal. The largest number and greatest lake area of glacier lakes is in the Karnali basin. The second largest number and second greatest lake area of glacier lakes is in Koshi basin. The rate of the total lake area is the most in the Dudh Koshi basin and is 20.39%.

Table 2.4.1-2 Glacial Lakes and their Area in River Basins and Sub-basins of Nepal

Basin	Sub-basin	Glacial lakes				Mean area (sq.km)	Max area (sq.km)	Min area (sq.km)
		Number	% of total	Area (sq.km)	% of total			
Koshi	Tamor	209	14.26	6.584	10.16	0.032	0.615	0.001
	Arun	81	5.53	3.284	5.07	0.041	1.122	0.002
	Dudh Koshi	243	16.58	13.207	20.39	0.054	0.943	0.002
	Likhu	13	0.89	0.312	0.48	0.024	0.082	0.003
	Tama Koshi	24	1.64	2.156	3.33	0.090	1.452	0.003
	Sun Koshi	17	1.16	0.306	0.47	0.018	0.061	0.004
	Indrawati	12	0.82	0.109	0.17	0.009	0.024	0.003
	Basin total	**599**	**40.86**	**25.958**	**40.07**	**0.043**	**1.452**	**0.001**
Gandaki	Trishuli	50	3.41	1.678	2.59	0.034	0.181	0.003
	Budhi Gandaki	12	0.82	0.709	1.09	0.059	0.250	0.002
	Marsyangdi	22	1.50	5.158	7.96	0.234	3.322	0.003
	Seti	6	0.41	0.113	0.17	0.019	0.033	0.013
	Kali Gandaki	26	1.77	1.880	2.90	0.072	0.670	0.003
	Basin total	**116**	**7.91**	**9.538**	**14.72**	**0.082**	**3.322**	**0.002**
Karnali	Bheri	56	3.82	6.936	10.70	0.124	4.814	0.002
	Tila	73	4.98	3.576	5.52	0.049	0.434	0.003
	Mugu	218	14.87	5.020	7.75	0.023	0.382	0.002
	Humla	346	23.60	12.189	18.82	0.035	0.619	0.001
	Kawari	24	1.64	0.774	1.19	0.032	0.160	0.003
	West Seti	25	1.71	0.652	1.00	0.026	0.298	0.002
	Basin total	**742**	**50.61**	**29.147**	**45.00**	**0.039**	**4.814**	**0.001**
Mahakali	Mahakali	9	0.61	0.137	0.21	0.015	0.049	0.003
	Basin total	**9**	**0.61**	**0.137**	**0.21**	**0.015**	**0.049**	**0.003**
	Total	**1466**	**100**	**64.780**	**100**	**0.044**	**4.814**	**0.001**

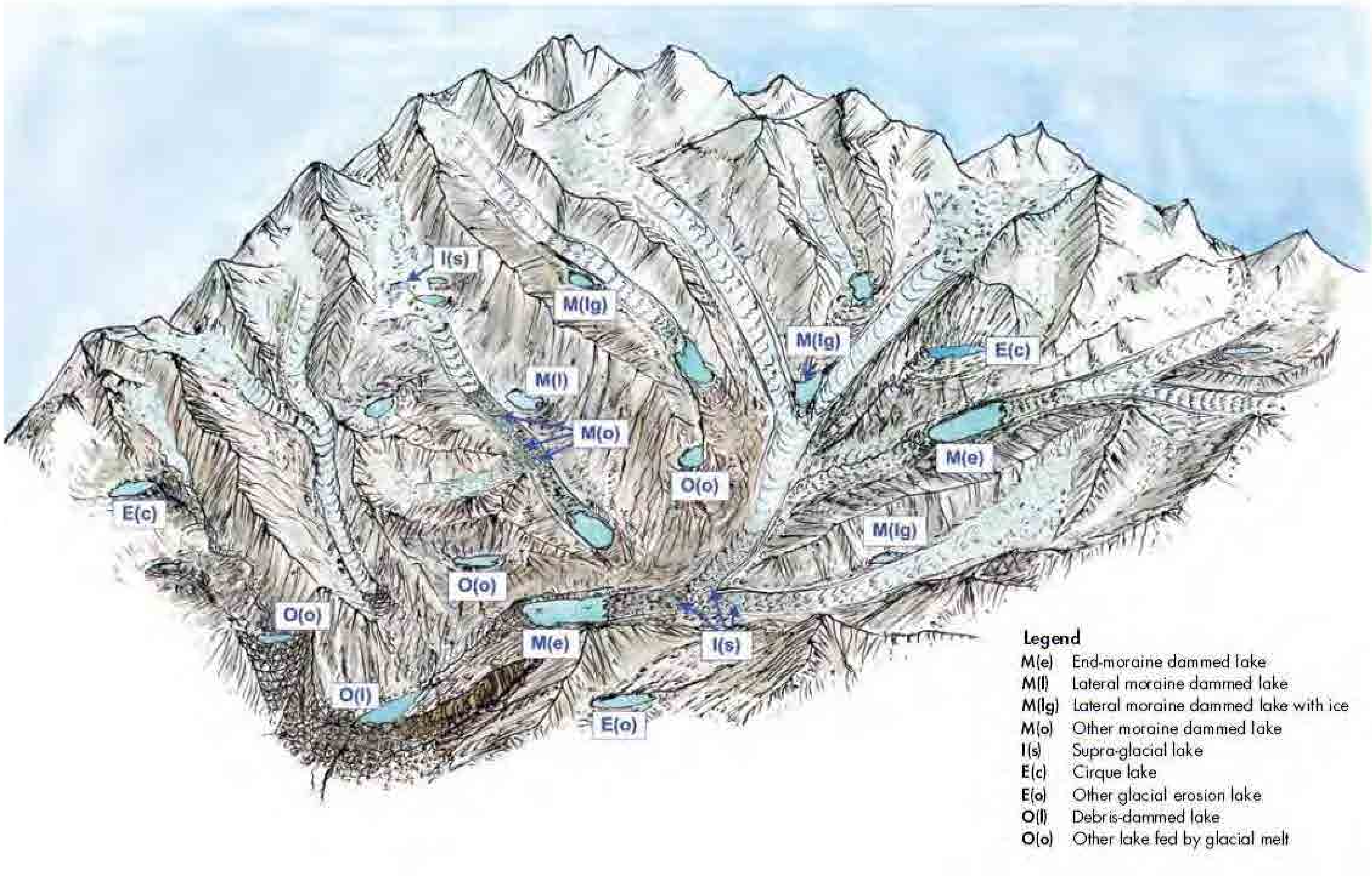
Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD

The glacial lakes were classified into four types, 1) Moraine-dammed lakes, 2) Ice-dammed lakes, 3) Erosion lakes, 4) Other glacial lakes by process of formation. The moraine-dammed lakes were classified into four types. The supra-glacial lakes were classified into two types. The erosion lakes were classified into three types. The other glacial lakes were classified into three types. The classification of glacial lakes is shown in Table 2.4.1-3 and Figure 2.4.1-2.

Table 2.4.1-3 Classification of Glacial Lakes

Glacial lake type	Glacial lake sub-type	Code	Definition
1) Moraine-dammed lake	End-moraine dammed lake	M(e)	Lake dammed by end moraines
	Lateral moraine dammed lake (ice free)	M(l)	Lake dammed by lateral moraine not in contact with a glacial lake
	Lateral moraine dammed lake (with ice)	M(lg)	Lake dammed by lateral moraine in contact with glacial ice
	Other moraine dammed lake	M(o)	Lake dammed by other moraines
2) Ice-dammed lake	Supra-glacial lake	I(s)	Pond or lake on the surface of a glacier
	Glacier ice-dammed lake	I(d)	Lake dammed by glacier ice with no lateral moraines
3) Glacier erosion lake	Cirque lake	E(c)	A small pond occupying a cirque
	Glacier trough valley lake	E(v)	Lakes formed in the flakier trough as a result of the glacier erosion process
	Other glacier erosion lake	E(o)	Bodies of water occupying depressions formed by the glacial erosion process
4) Other glacial lakes	Debris-dammed lake	O(l)	Lakes dammed by debris
	Artificial lake	O(a)	Artificial lake
	Other lakes fed by glacial melt	O(o)	Other lakes fed by glacial melt

Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD



Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD

Figure 2.4.1-2 Classification of Glacial Lakes

Table 2.4.1-4 shows the number and area of different types of glacial lakes in Nepal. The majority of lakes are moraine-dammed occupying 72% of the total lake area. In particular, the area of end-moraine dammed lakes is the greatest, occupying 42.5% of the total lake area. The supra-glacial lakes represent only 1.5% of the total glacial lake area. The erosion lakes represent 16.8% of the total lake area. The other glacial lakes represent 9.5% of the total lake area.

Table 2.4.1-4 Number and Area of Different Types of Glacial Lakes in Nepal

Main type	Sub type	Total number		Total area		Mean area (sq.km)	Max area (sq.km)	Min area (sq.km)
		Number	%	Area	%			
Moraine dammed lake	End-moraine dammed lake	227	15.5	27.526	42.5	0.122	3.322	0.003
	Lake dammed by lateral moraine not in contact with glacial ice	15	1.0	2.358	3.6	0.157	0.670	0.001
	Lake dammed by lateral moraine in contact with glacial ice	33	2.3	3.611	5.6	0.109	0.570	0.004
	Other moraine- dammed lake	700	47.8	13.269	20.5	0.019	0.271	0.001
	Total	**975**	**66.6**	**46.764**	**72.2**	**0.407**	**4.833**	**0.009**
Ice dammed lake	Supra-glacial lake	107	7.3	0.985	1.5	0.009	0.100	0.002
Glacier erosion lake	Cirque lake	121	8.3	6.915	10.7	0.057	0.434	0.003
	Trough valley lake	5	0.3	0.500	0.8	0.100	0.235	0.014
	Other glacial erosion lake	242	16.5	3.450	5.3	0.014	0.168	0.001
	Total	**368**	**25.1**	**10.865**	**16.8**	**0.171**	**0.837**	**0.018**
Other glacial lake		16	1.1	6.166	9.5	0.385	4.814	0.011
	Total	**1,466**	**100**	**64.780**	**100**			

Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD

Recent climate changes have had a significant impact on the high-mountain glacial environment. Rapid melting of glaciers had resulted in the formation and expansion of moraine-dammed lakes, creating a potential danger from glacial lake outburst floods. Most lakes have formed during the second half of the 20th century.

Glaciers in the Mount Everest region, Nepal, are retreating at an average rate of 10 – 59 m per year. During the past decade, Himalayan glaciers have generally been shrinking and retreating faster while moraine-dammed lakes have been proliferating. Although the number of glacial lakes above 3,500 m has decreased, the overall area of moraine-damned lakes is increasing.

2.4.2 Glacial Lake Outburst Flood (GLOF)

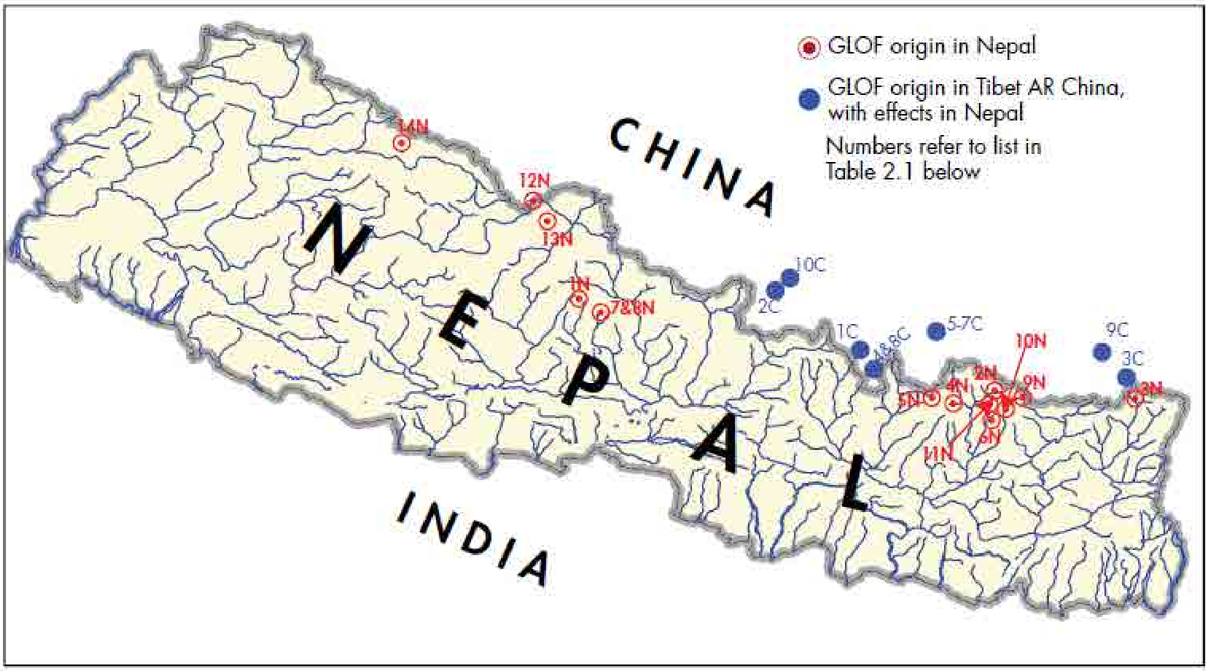
A glacial lake outburst flood is a type of outburst flood that occurs when the dam containing a glacial lake fails. It is often abbreviated as GLOF.

There are two distinctly different forms of glacial lake outbursts. There are those that result from the collapse or overtopping of ice dams formed by the glacier itself, and those that occur when water drains rapidly from lakes formed either on the lower surface of glaciers (supra-glacial) or between the end moraine and the terminus of a retreating glacier (moraine-dammed).

At present, supra-glacial and moraine-dammed lakes are far more common in the Hindu Kush-Himalayan region than glacier-dammed lakes as their development is favored by overall atmospheric warming and glacier wastage.

Nepal has experienced at least 24 GLOF events in the past. Among them, 14 are believed to have occurred in Nepal, and 10 were the result of flood overspills across the China (Tibet AR) –Nepal border. Figure 2.4.2-1 shows the location of GLOF events recorded in Nepal and China (Tibet AR) that caused damage in Nepal. Table 2.4.2-1 shows GLOF events recorded in Nepal.

According to Figure 2.4.2-1 and Table 2.4.2-1, most of the GLOF events caused damage in the eastern Nepal. In particular, a lot of GLOF events occurred in the Dudh Koshi basin, the Arun basin, and the Sun Koshi basin. 12 of the 14 GLOF events within Nepal occurred by moraine collapse. Regarding the 10 GLOF events that originated in TAR and caused damage in Nepal, the cause of 5 GLOF events were not known, one of the 3 GLOF events in the Sun Koshi basin was caused by piping and ice avalanches and one of the 2 GLOF events in the Arun basin was caused by a glacier surge.



Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD.

Figure 2.4.2-1 Location of GLOF Events recorded in Nepal, and in the Tibet Autonomous Region (TAR), China that caused Damage in Nepal

Table 2.4.2-1 GLOF Events Recorded in Nepal

	Date	River basin	Lake	Cause	Losses
Entirely within Nepal					
1N	450 years ago	Seti Khola	Machhapuchchhre	Moraine collapse	Pokhara valley covered by 50–60m deep debris
2N	3 Sep 77	Dudh Koshi	Nare	Moraine collapse	Human lives, bridges, others
3N	23 Jun 80	Tamor	Nagma Pokhari	Moraine collapse	Villages destroyed 71 km from source
4N	4 Aug 85	Dudh Koshi	Dig Tsho	Ice avalanche	Human lives, hydropower station, 14 bridges, etc
5N	12 Jul 91	Tama Koshi	Chubung	Moraine collapse	Houses, farmland, etc.
6N	3 Sep 98	Dudh Koshi	Tam Pokhari	Ice avalanche	Human lives and more than NRs 156 million
7N	15 Aug 03	Madi River	Kabache Lake	Moraine collapse	Not known
8N	8 Aug 04	Madi River	Kabache Lake	Moraine collapse	Not known
9N	Unknown	Arun	Barun Khola	Moraine collapse	Not known
10N	Unknown	Arun	Barun Khola	Moraine collapse	Not known
11N	Unknown	Dudh Koshi	Chokarma Cho	Moraine collapse	Not known
12N	Unknown	Kali Gandaki	Unnamed (Mustang)	Moraine collapse	Not known
13N	Unknown	Kali Gandaki	Unnamed (Mustang)	Moraine collapse	Not known
14N	Unknown	Mugu Karnali	Unnamed (Mugu Karnali)	Moraine collapse	Not known
Originated in TAR/China and caused damage in Nepal					
1C	Aug 1935	Sun Koshi	Tara-Cho	Piping	66,700 sq.m of wheat fields, livestock, etc
2C	25 Aug 64	Trishuli	Longda	Not known	Not known
3C	21 Sep 64	Arun	Gelhaipuco	Glacier surge	Highway and 12 trucks
4C	1964	Sun Koshi	Zhangzangbo	Piping	No remarkable damage
5C	1968	Arun	Ayaco	Not known	Road, bridges, etc
6C	1969	Arun	Ayaco	Not known	Not known
7C	1970	Arun	Ayaco	Not known	Not known
8C	11 Jul 81	Sun Koshi	Zhangzangbo	Ice Avalanche	Hydropower station
9C	27 Aug 82	Arun	Jinco	Glacier surge	Livestock, farmland
10C	6 Jun 95	Trishuli	Zanaco	Not known	Not known

Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD.

International Centre for Integrated Mountain Development, ICIMOD, identified the list of potentially critical glacial lakes in Nepal and their priority category. The potentially critical glacial lakes were ranked in order of their apparent level of instability. This process has two aspects, 1) evaluation of the current degree of lake instability from a purely geophysical point of view, and 2) determination of the potential for downstream damage and loss of life in the event of actual lake outburst.

As mentioned in Chapter 2.4.1, there are 1,466 glacial lakes which are larger than 1,000 m^2 in area in Nepal. 559 glacial lakes more than 2,000 m^2 in area were considered large enough to cause damage downstream if they burst out. Next, this potential would be heightened if they are associated with a glacier. A total of 49 glacial lakes were identified in this manner.

Evaluation of the possibility of catastrophic damage is based on the characteristics of a lake, its dam, associated glaciers and other topographic features. The factors taken into account include the size, rate at which the lake is expanding, position with respect to the associated glacier, height of the moraine dam, overtopping height, origin of the lake, physical condition of the surroundings, and the volume of water that could drain out. Based on these criteria, 21 lakes were identified as significant.

The socioeconomic and physical parameters were considered together and the 21 critical lakes were categorized into I, II, III. Category I is high priority lakes, Category II is medium priority lakes and Category III is low priority lakes. Figure 2.4.2-2 shows the location of 21 potentially critical glacial lakes in Nepal. Table 2.4.2-2 shows the list of potentially critical glacial lakes in Nepal. Of the 21 lakes, six were classed as Category I, four as Category II, and 11 as Category III.

Of the 21 lakes, 16 lakes are located in the Koshi basin and five lakes in the Gandaki basin. Of the 16 lakes in the Koshi basin, nine lakes are located in the Dudh Koshi basin. All of the 21 lakes are moraine-dammed lakes. In particular, most of them are end-moraine dammed lakes.

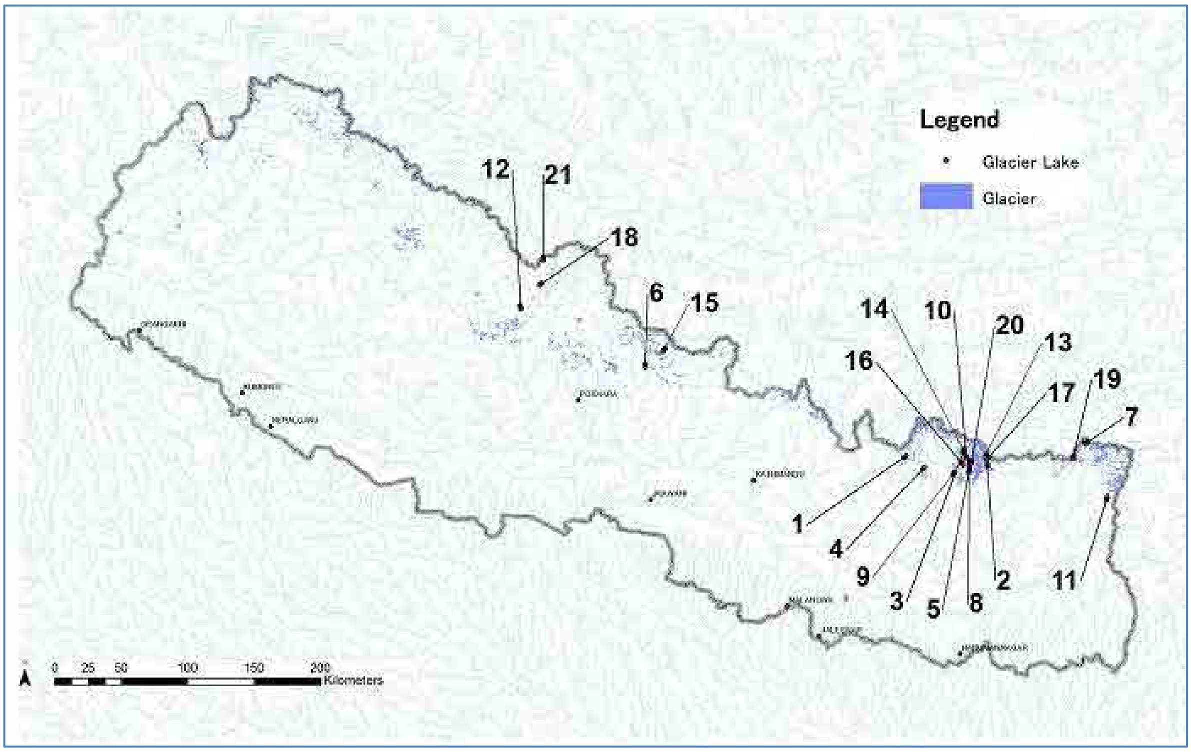


Figure 2.4.2-2 Location of Potentially Critical Glacial Lakes in Nepal

Table 2.4.2-2 List of Potentially Critical Glacial Lakes in Nepal

No.	Basin	Sub Basin	Glacial Lake Name	Category	Longitude	Latitude	Elevation (m)	Area (km^2)	Length (m)	Orientation	Type of Glacial Lake
1	Koshi	Tama Koshi	Tsho Rolpa	I	86° 28.5655'	27° 51.6863'	4,550	1.452	3.327	SE	M(e)
2	Koshi	Arun	Lower Barun	I	87° 5.8021'	27° 47.8810'	4,542	1.122	1.788	E	M(e)
3	Koshi	Dudh Koshi	Imja Cho	I	86° 55.3102'	27° 53.9198'	5,012	0.873	1.879	NW	M(e)
4	Koshi	Dudh Koshi	Lumding Cho	I	86° 36.8792'	27° 46.7344'	4,833	0.943	2.357	SE	M(e)
5	Koshi	Dudh Koshi	Chamlang Cho	I	86° 57.5321'	27° 45.3010'	4,958	0.791	1.695	SW	M(e)
6	Gandaki	Marsyangdi	Thulagi (Dona)	I	84° 29.1270'	28° 29.3204'	4,050	0.915	2.417	NW	M(e)
7	Koshi	Tamor	Nagma	II	87° 50.9725'	27° 54.7227'	5,458	0.016	0.198	SE	M(o)
8	Koshi	Dudh Koshi	Hongu2	II	86° 57.4409'	27° 46.9912'	5,204	0.743	1.982	SW	M(e)
9	Koshi	Dudh Koshi	Tam Pokhari	II	86° 50.6821'	27° 44.5713'	4,423	0.229	0.827	SW	M(e)
10	Koshi	Dudh Koshi	Hongu1	II	86° 56.1550'	27° 50.2717'	5,206	0.224	1.075	SW	M(e)
11	Koshi	Tamor		III	88° 0.2087'	27° 32.8334'	4,653	0.023	0.232	SW	M(o)
12	Gandaki	Kali Gandaki		III	83° 31.6675'	28° 53.1988'	5,583	0.247	0.816	NE	M(e)
13	Koshi	Arun	Barun Pokhari	III	87° 4.9179'	27° 50.7086'	4,842	0.309	1.035	SW	M(e)
14	Koshi	Dudh Koshi	East Hongu 1	III	86° 57.9895'	27° 47.9575'	5,410	0.227	0.996	NW	M(lg)
15	Gandaki	Budhi Gandaki		III	84° 37.7091'	28° 35.7757'	3,632	0.250	1.082	NE	M(e)
16	Koshi	Dudh Koshi	Mera	III	86° 54.6675'	27° 47.6672'	5,274	0.171	1.009	SE	M(lg)
17	Koshi	Arun		III	87° 5.7162'	27° 49.7558'	5,222	0.105	0.534	SW	M(e)
18	Gandaki	Kali Gandaki		III	83° 40.4061'	29° 2.7265'	5,439	0.122	0.487	NE	M(e)
19	Koshi	Tamor		III	87° 44.9685'	27° 48.9727'	4,907	0.146	0.955	SW	M(e)
20	Koshi	Dudh Koshi	East Hongu 2	III	86° 58.4511'	27° 48.3344'	5,511	0.162	0.491	SW	M(e)
21	Gandaki	Kali Gandaki	Kaligandaki	III	83° 41.9066'	29° 12.9371'	5,429	0.670	2.518	NE	M(l)

Source: Glacial Lakes and Glacial Lake Outburst Floods in Nepal, March 2011, ICIMOD

Chapter 3

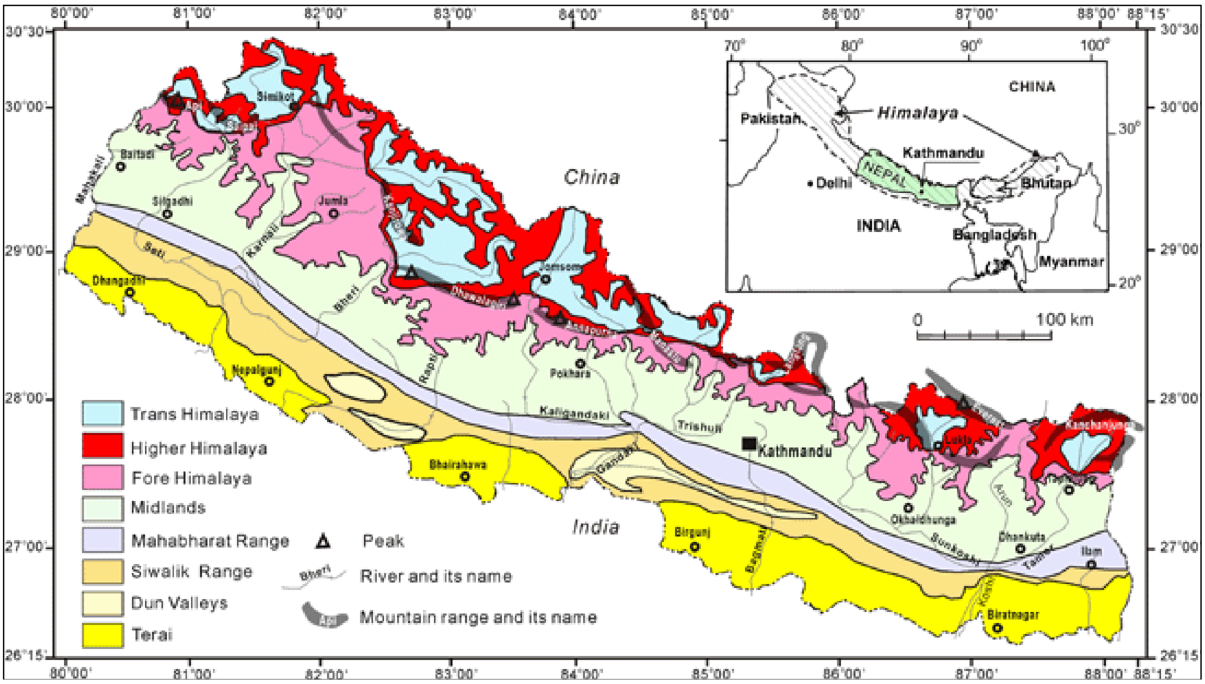
Physiography and Geology

Chapter 3 Physiography and Geology

3.1 Physiography

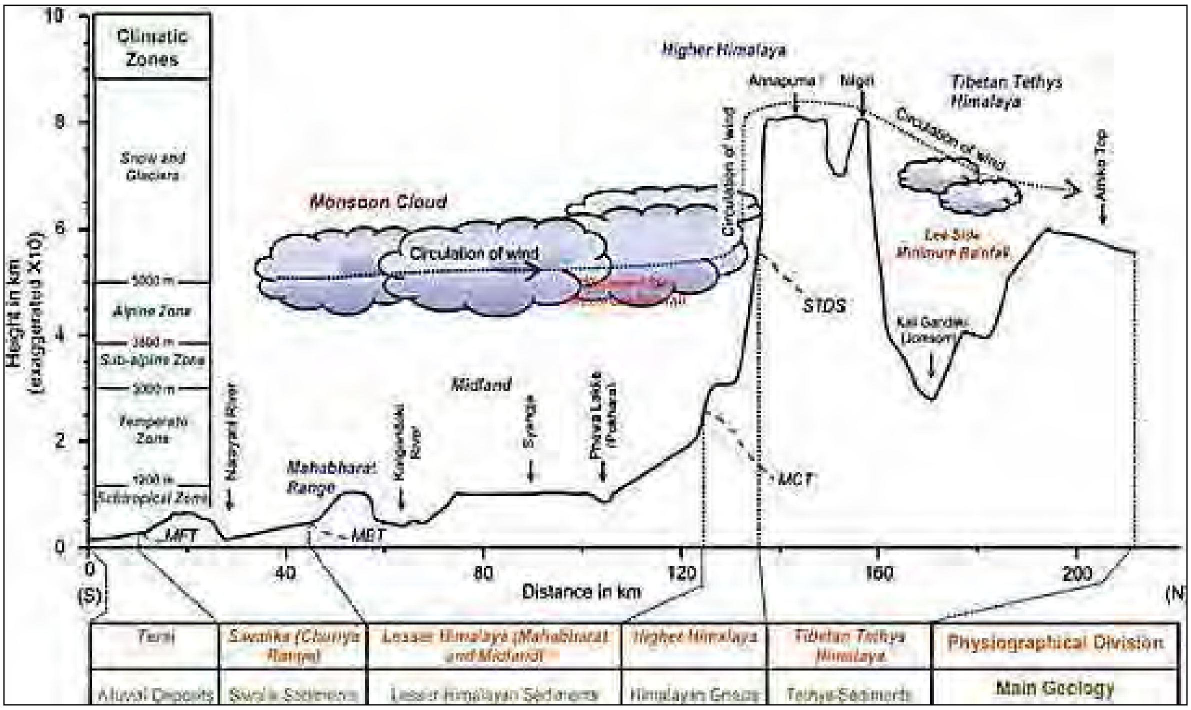
Nepal makes itself well-known to the world for harnessing the Himalaya Mountains. Due to steep geography, weak geology affected by the tectonic crustal movement and seasonal heavy rainfall from monsoons, Nepal has been suffering from repeated floods, landslides, or heavy debris flows.

Figure 3.1-1 and Figure 3.1-2 show the physiographic map and the generalized geographic section of Nepal. Table 3.1-1 explains the features of each geomorphic region. Nepal in general embraces three large parallel extending mountain ranges from east to west, namely the Himalaya, the Mahabharat Range and the Siwaliks. They are all considered to have been developed by a collision of the Indian subcontinent into the Eurasian continent, inducing large tectonic thrusts with low angles such as the Himalayan Frontal Thrust (hereinafter referred as HFT, or it may be called Main Frontal Thrust (MFT)), Main Boundary Thrust (MBT), and Main Central Thrust (MCT) in east-west directions, just in front of or in between these mountain ranges. Parts of these thrusts are tectonically "active faults." To the north, there lies the South Tibetan Detachment System (STDS) which is interpreted as one of the normal faults along the Himalayan range.



Source: Dahal and Hasegawa, 2008

Figure 3.1-1 Physiography of Nepal, Himalaya



Source: Modified after Dahal, 2006

Figure 3.1-2 Generalized Geographic Section of Nepal, Himalaya

Table 3.1-1 Physiographical Division of Nepal, Himalaya

Geomorphic Unit	Width (km)	Altitudes (m)	Main Rock Type	Main Processes for Landform Development
Terai (Northern edge of the Gangetic Plain)	20-50	100-200	Alluvium: coarse gravels in the north near the foot of the mountains, gradually becoming finer southward	River deposition, erosion and tectonic upliftment
Churia Range (Siwaliks)	10-50	200-1300	Sandstone, mudstone, shale and conglomerate.	Tectonic upliftment, erosion, and slope failure
Dun Valleys	5-30	200-300	Valleys within the Churia Hills filled up by coarse to fine alluvial sediments	River deposition, erosion and tectonic upliftment
Mahabharat Range	10-35	1000-3000	Schist, phyllite, gneiss, quartzite, granite and limestone belonging to the Lesser Himalayan Zone	Tectonic upliftment, Weathering, erosion, and slope failure
Midlands	40-60	300-2000	Schist, phyllite, gneiss, quartzite, granite, limestone geologically belonging to the Lesser Himalayan Zone	Tectonic upliftment, Weathering, erosion, and slope failure
Fore Himalaya	20-70	2000-5000	Gneisses, schists, phyllites and marbles mostly belonging to the northern edge of the Lesser Himalayan Zone	Tectonic upliftment, Weathering, erosion, and slope failure
Higher Himalaya	10-60	>5000	Gneisses, schists, migmatites and marbles belonging to the Higher Himalayan Zone	Tectonic upliftment, Weathering, erosion (rivers and glaciers), and slope failure
Inner and Trans Himalaya	5-50	2500-4500	Gneisses, schists and marbles of the Higher Himalayan Zone and Tethyan sediments (limestones, shale, sandstone etc.) belonging to the Tibetan-Tethys Zone	Tectonic upliftment, wind and glacial erosion, and slope degradation by rock disintegrations

Source: modified after Upreti, 1999

The Himalaya (or the Great Himalaya, Higher Himalaya) extends from northern mountains in Myanmar in the east to Chitral, Pakistan in the west, forming an arc 2,500 km long. The Himalaya soar above other Lesser Himalaya mountains at elevations of 7,000-8,000 m high with MCT as a clear transition boundary. The Himalaya form Nepal's national boundaries with China.

The Mahabharat Range has mountains with elevations as high as 2,000-3,000 m, and they lie north of MBT. The area of the plateaus and mountains with elevations of 1,000-2,000 m between MCT and MBT is called "Lesser Himalaya" or "the Midlands."

The Siwaliks are hilly mountain chains with elevations of 150-2,000 m, with a maximum north-south width of about 90 km. The Siwaliks have resulted from accumulating fluvial deposits on the southern front of the evolving Himalaya, thus are quite young, such as 16 Ma or even younger. They are delineated by the HFT (or MFT) and MBT in south and north respectively, both of which are the large tectonic thrusts induced from the collision of the Indian subcontinental plate with the Eurasian continental plate.

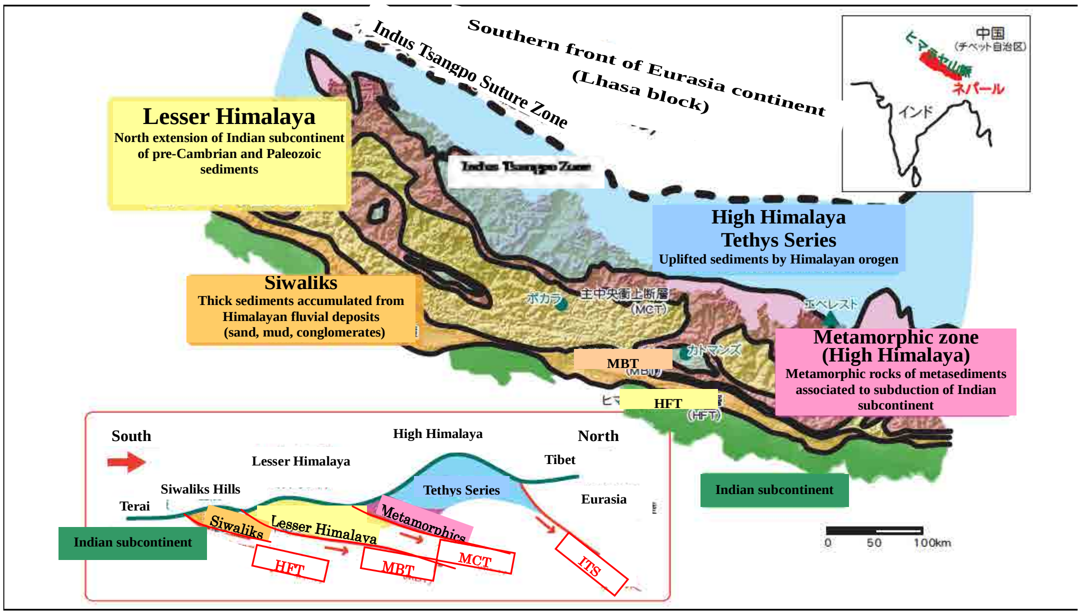
The plain located in the south of Siwaliks is called "the Terai plain." The Terai plain is low in elevation, flat, and fertile, being a northern extension of the Gangetic plain.

These mountain ranges have been raising their heights as the Himalayan orogeny along with the collision of the Indian subcontinent and Eurasian continent that still continues. Some topography surveys have shown lateral displacement north-south of Nepal of 10-20 mm/year, uplifting displacement as 2-10 mm/year. Such rapid tectonic movement caused by the collision of the Indian subcontinent naturally has been inducing "frequent earthquakes" or "large scale sedimentation discharge" from the evolving mass crust. For instance, the Mahabharat Range being placed in "active" movement sandwiched by MCT and MBT, accelerating weathering of rock formations, has been repeating landslides or debris outflows, and the Siwaliks form a hazardous debris flow zone composed of Tertiary-Quarternary weak and unconsolidated deposits. Statistics show 1/6 of the whole world's river sedimentation comes from the Ganges, Indus and Brahmaputra river basins outsourced from the Himalayas, which shows that the Himalaya has been eroded constantly by 3 mm/year. It is reported that the thickness of the sediments accumulated in the Bengal Bay ranges as thick as 9,000m, thus a study has been started for the supply of sediments, indicating that the altitude of the Uimalayan mountain ranges was even higher in the past than the present.

3.2 Geology

3.2.1 Tectonostratigraphic Unit

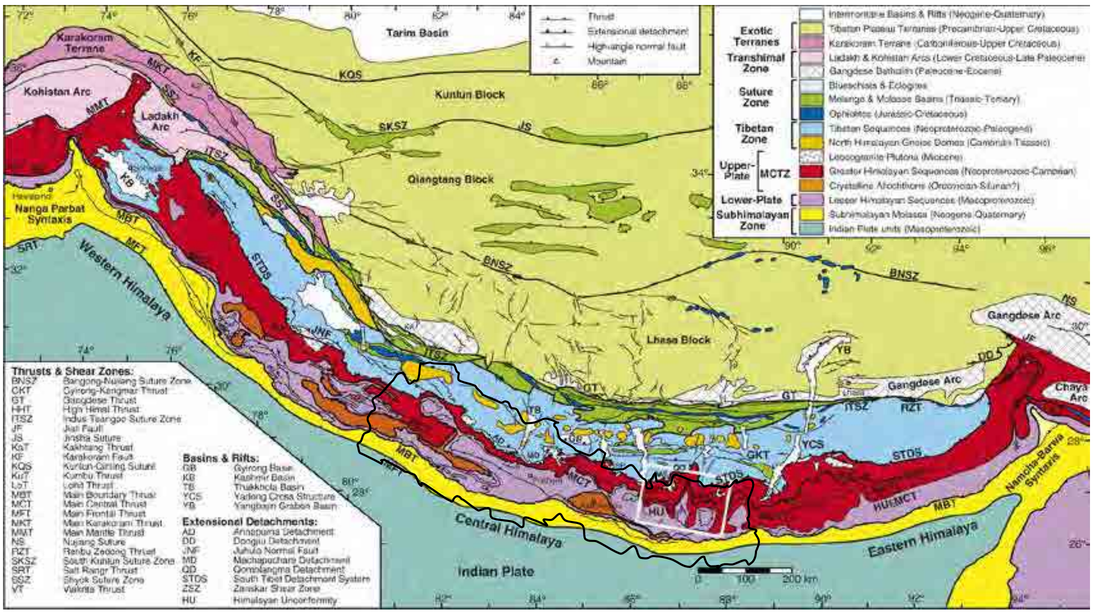
The schematic geologic feature of Nepal is presented in Figure 3.2.1-1.



Source: Geology of Nepal, Saeko Ishihama, Kanagawa Prefectural Museum of Natural History, December, 2008

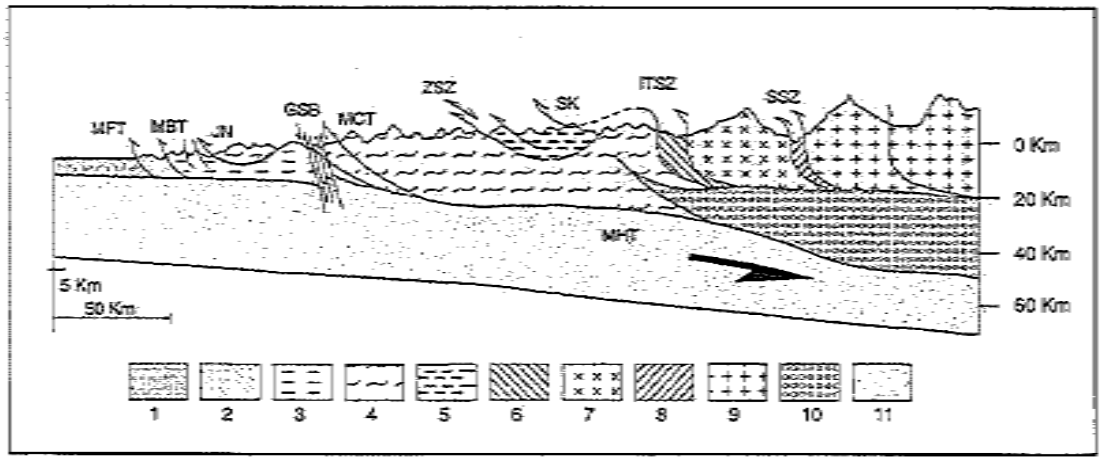
Figure 3.2.1-1 Schematic Geologic Feature of Nepal

The whole Himalayan geology showing tectonostratigraphic units and major structures is presented in Figure 3.2.1-2.



Source: Modified from Crustal architecture of the Himalayan metamorphic front in eastern Nepal, Goscombe et al, 2006, with the approximate outline of Nepal borderline by JICA Study Team.

Figure 3.2.1-2 Geology of the Himalayan Orogen showing Main Tectonostratigraphic Units and Major Structures



1; Indo-Gangetic Plains, 2; Sub-Himalayan Sedimentary Cenozoic Foreland Basin, 3; Lesser Himalayan Jutogh Nappe JN, 4; Higher Himalayan Crystalline Zone Belt & Tso Morar Crystalline, 5; Tethys Sedimentary Zone, Subduction Related Zone, 6; Indus-Tsangpo Suture Zone &Spongtang Klippe, 7; Ladakh Batholith Complex, 8; Shyok Suture Zone, 9; Karakoram Batholith Complex, 10; Partially molten crust, 11; Subducting Indian Crust,
MFT; Main Frontal Thrust, MBT; Main Boundary Thrust, MCT; Main Central Thrust, GSB; Garhwal Seismic Belt, ZSZ; Zanskar Shear Zone (Trans-Himadi Shear Zone), MHT; Main Himalayan Thrust

Source: Jain et al., 2002

Figure 3.2.1-3 Geodynamics of Himalayan Tectonic Movement

The evolution of the Himalaya can be described in a simple way (to be noted that the description hereafter covers the typical conception but does not reject any particular hypothesis or theory regarding the Himalaya). For example, Figure 3.2.1-3 (Jain et al., 2002) explains the evolution of Himalaya in the following way from the collision and the subduction of the Indian subcontinental plate to the Eurasian continental plate.

The movement of the Indian subcontinent started to the north after breaking from the African continent in the Cretaceous, along with the Deccan Trap volcanism collided with Eurasian continent forcing deformation, metamorphism, and leuco-granite intrusions on the Himalayan orgenic area. The collision resulted in initiation and development of major crustal thrusts such as MCT and MBT as well as the evolution of the Siwaliks basin, etc. led by the development of river basins and terraces over the supplies of sediment at the forefront of the Himalaya. In addition, the sea named the Tethys evolved to the north of the Indian Shield, with its withdrawal induced by the movement of the subcontinent, and it formed and marked the base of the Tethys Himalayan Zone. Thus the orgon and evolution of the Himalayan tectonic framework has been explained in the following units.

- The Trans-Himalayan Zone (Tethys Sedimentary Zone) is the shelf sediment unit of the Late Precambrian to Cretaceous from the Tethys Sea being mostly fossilferous. It was evolved by the shrinkage through the accretion and uplift of the Tethys Sea sediment. The zone experienced the various stages of sedimentation, deformation, intrusion, or metamorphism. It is divided from the southern Higher Himalaya Zone by the large fracture STDF (South Tibetan Detachment Fault, or Trans-Himadri shear zone) which is one of the normal faults. The fault, part of it also being observed beneath of Mt. Everest summit, is considered to make the Tethys Sedimentary rock on the Himalaya range slide northwards along it.
- The Higher Himalaya is the zone with Precambrian Crystalline exhumed along the uplifted

terrain. It has intruded granite, some of which is of Tertiary origin from the molten crust. The MCT was considered to have developed some 20 Ma ago, and this separates this zone from the southern lying Lesser Himalaya zone. MCT is one of the E-W trending tectonic large thrusts induced by the collision - subduction of the Indian subcontinent (noted: this zone also called after "Greater Himalayan Sequence" in Figure 3.2.1-2 and "Higher Himalayan Crystalline Zone Belt" in Figure 3.2.1-3).

- The Lesser Himalaya is the 60-80 km wide zone having Riphean (2,000 Ma) to Paleozoic platform sediment with the characteristics of the Peninsular Shield of Precambrian crystalline and metamorphics. MCT separates the zone with the northern Higher Himalaya but some of the zone is also overlain by thrust sheets and crystalline nappes directed from north to south along rapid tectonic transport. (Please note that this zone is named after the "Crystalline Allochthons" in Figure 3.2.1-2). This zone is separated at its southern boundary by MBT, another large tectonic thrust developed after MCT.
- The Sub-Himalayan Zone is a 10-50 km wide zone immediately north of Indo-Ganga alluvial plain of the Miocene to Recent eras. It is a belt of a sedimentary (Mollasse) zone widely supplied from the uplifted Himalayan region. HFT (or MFT) was initiated some 10 Ma ago and limits the organic margin of the zone against Ganga alluviums of a more recent age.
- The Indo-Ganga Plains (Terai Plain) is the most recent quaternary sediment along Ganga Plains as far as the Bengal Bay (Please note that this is also named after "India Plate Units" in Figure 3.2.1-2 or "Indo-Gangetic Plains" in Figure 3.2.1-3).

The tectonic features of Nepal are also concordant with the entire Himalayan tectonics. It is commonly divided into following five tectonostratigraphic zones from the north (Table 3.2.1-1, noting various different names in describing each sequence in literature) that are in principle characterized by distinctive features of geology and lateral continuity extending in an E-W direction. Each zone is explained to be bounded by the large tectonic thrust(s) mentioned above.

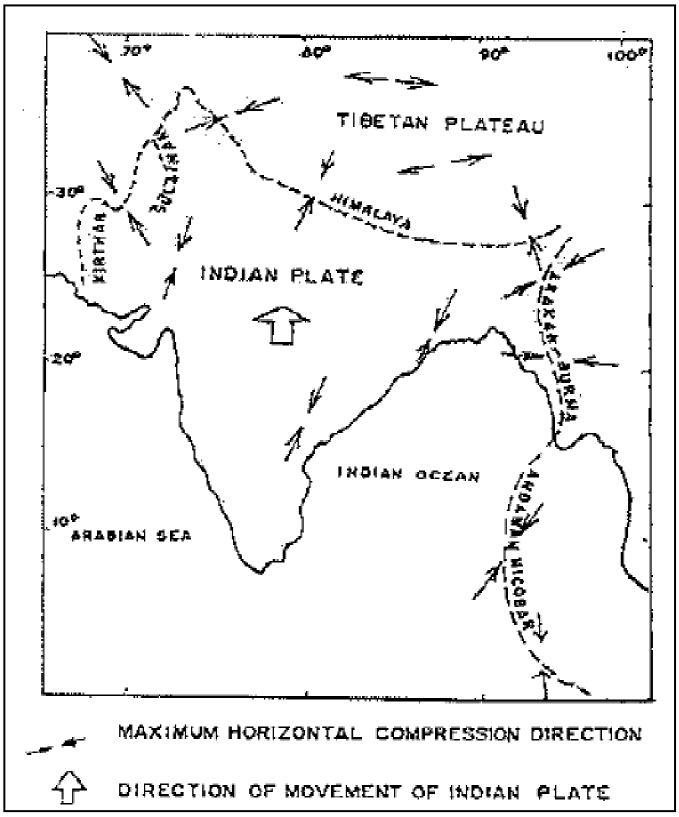
Nepal is situated in a large tectonic zone symbolized by Himalayan orogen which was formed by the collision of the Indian subcontinent, at the age of 50 Ma onwards, along with naturally requiring needs about geological risks as important elements when the development of large scale hydropower stations is considered.

Table 3.2.1-1 Tectonic Subdivisions of Nepal

Higher Himalaya (or Tibetan-Tethys Zone)	Marine sedimentary succession (Tibetan Tethys Series) considered deposited in a part of Indian subcontinent and uplifted by a collision with Eurasia. 500 Ma-50 Ma, width around 40 km. Comprising of Paleozoic-Tertiary shale, limestone, sandstone or other sedimentary rocks. Mt.Everest, Manaslu, and Annapurna are parts of this zone.
Metamorphic zone (Higher Himalayan Crystalline)	Metamorphic sequence of metasedimentary rocks, associated with subduction of the Indian subcontinent, with various metamorphic rocks of low temperature-high pressure type (phyllite-crystalline schist) to high temperature-low pressure type (gneiss) metamorphic belt, with further intrusion of granite. Stronger metamorphism nearing to MCT (Main Central Thrust). Tectonic movement of MCT has been active up to 5Ma, and the movement at present has shifted to MBT and HFT.
Lesser Himalaya	Bounded by MBT (Main Boundary Thrust) and MCT, made up mostly by sedimentary and metasedimentary rocks of the Paleozoic and Mesozoic eras, as a northern extension of Indian subcontinent. Forms complex structures by faulting, width around 60-80 km. PreCambrian to Tertiary sedimentary rocks or metamorphic rocks as slate, phyllite, schist, quartzite also with dolomite or limestone. Thrusts and nappe structures have developed.
Siwaliks (Sub-Himalaya)	Dominated by thick Cenozoic sediments resulting from fluvial deposits from the evolving Himalaya. The youngest and least compressed sedimentary rocks. Width around 10-25 km. Weak and unconsolidated. Typically comprising Neogene sediments dipping north, from the top are conglomerates, med-fine sandstone, and underlain by siltstone, sandstone or mudstone.
Terai Zone	Composes the southernmost part of Nepal. Formed by alluvial sediments and comprises unconsolidated sediments.

3.2.2 Tectonic Stress along the Himalayan Region

The study of the tectonic stress based on the focal mechanism of earthquakes indicates directions in areas of stress fields (maximum and minimum horizontal compressions) in the Himalayan region (Figure 3.2.2-1). In the Himalaya the maximum compression direction trends NNE-SSW, where most of the Indian Peninsula region shows the same direction. It turns N-S to NNW-SSE in the Afghanistan area to the west, and NE-SW in the Assam region. It is considered indicating the ongoing compression and its direction by the collision of the Indian subcontinent against the Eurasian continent.



Source: Rajendran et al., 1992

Figure 3.2.2-1 Tectonic Stress Map of the Indian Subcontinent

3.3 Earthquakes[1]

Earthquakes can possibly cause collapses in slopes and glaciers as well as the failure of dams. It is one of several important items to be evaluated for design of hydropower structures, especially for dams. The Chichi Earthquake in Taiwan in September 1999 is one example that caused a slope collapse. The earthquake in New Zealand in February 2011 caused the collapse of a part of Tasman Glacier. The Tohoku-Pacific Ocean Earthquake in March 2011 is a quite limited example that caused failure of a dam[2] which was an 18.5m high earth fill type dam.

3.3.1 Seismicity

The microseismicity map of Nepal is presented in Figure 3.3.1-1.

Nepal is characterized by a very intense microseismic activity. In only two and a half years since the commencement of systematic telemetry, some 11,000 local and regional events were recorded in the National Network. The intensity made it obvious that lateral narrow variations are significant. This feature of the narrow belt of seismicity in the majority range of M2 to 4 (the Seismic Belt) follows approximately the topographic front of the Higher Himalaya, crossing Nepal from the eastern to the western region.

The belt is relatively narrow and straight for about 550 km between 81.5°E (latitude) and 87°E, and east of 87°E the belt becomes diffuse and is offset by 50 km to the north, continuing farther east at least 150 km. In the west the belt gets more diffuse and complex but two parallel bands about 60 km apart can be distinguished between 81.5°E and 82.5°E, and the seismicity becomes more diffuse to the west of 81.5°E. From these trends, two major discontinuities associated with the seismic cluster are identified.

The mechanism of the microearthquakes is considered to be associated with the subduction movement along the collision of the subcontinents. The seismic events occur at depths between 10 km and 30 km all along the linear seismic belt, which are induced from the activity along the Main Himalayan Thrust (MHT) underneath of the Himalaya as far as up to Tibet. This MHT is a form of a low angle Detachement fault, or Decollement associated with the slip of the subducted Indian subcontinental plate which initiates large major earthquakes (shown in Figure 3.2.1-3).

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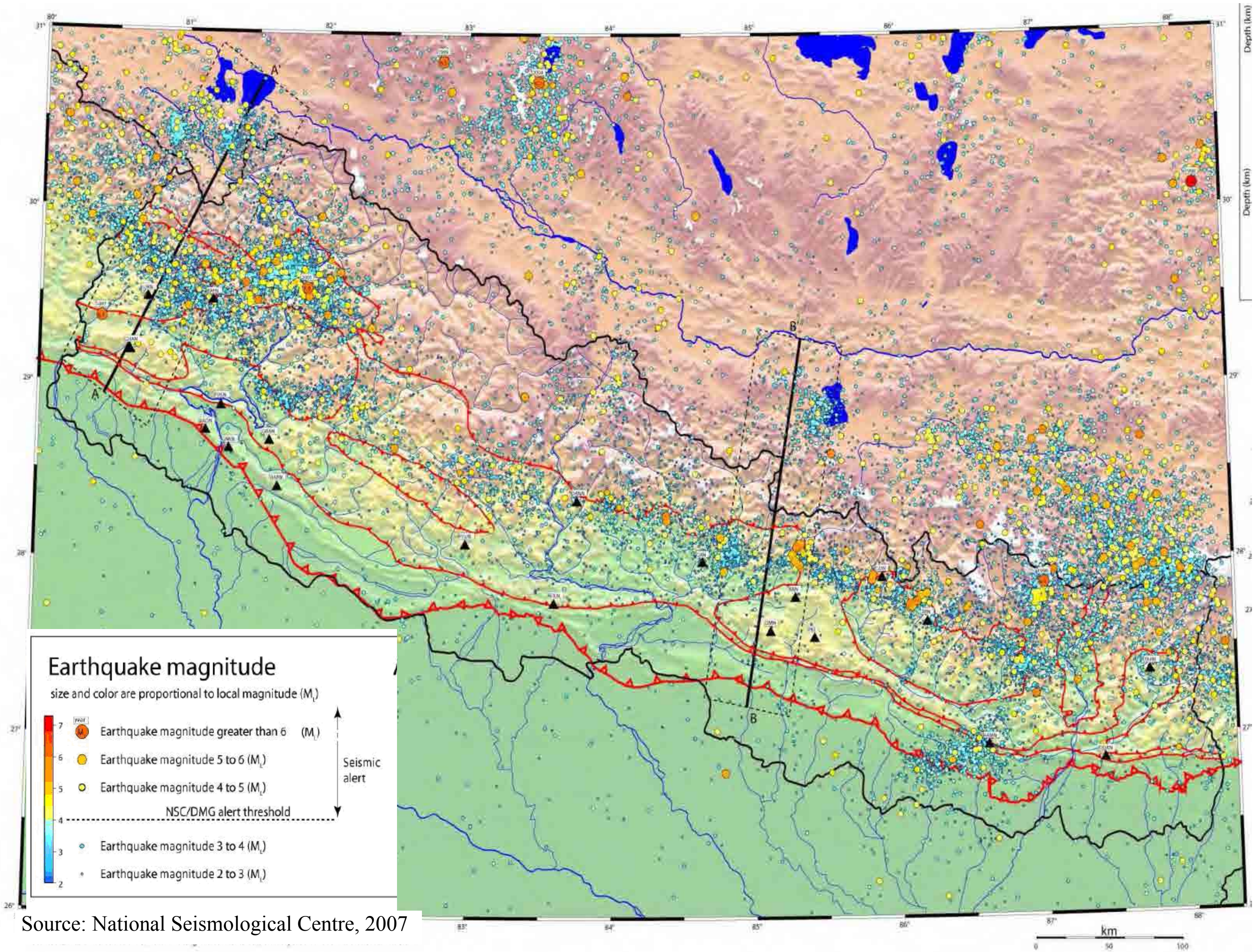
1 This section is referred from Seismotectonics of the Nepal Himalaya from Local seismic network (1999), Seismic Hazard Map of Nepal (2002), National Seismological Network & its Contribution in Seismological Research in the Nepal Himalaya (2007), and the relevant documents.

2 Fujinuma Dam, in the Abukuma River basin in Fukushima Prefecture, Japan.Dam volume 99,000m^3. Total storage volume 1,504,000m^3. Lower 6 on the seismic intensity scale of the Japan Meteorological Agency was measured near the dam site. Analyzed maximum acceleration at the dam crest was 442 gal.



Source: National Seismological Centre, 2007

Figure 3.3.1-1 Microseismicity Map of Nepal (1994-2005)

3.3.2 Active Faults and Large Major Earthquakes

The most active major fault along the Himalaya is the HFT (MFT) that marks the southern edge of the Himalayan foothills. The motion of the HFT is derived from the deformation of the Quaternary sediments, or Holocene fluvials implying a slip rate on the HFT as 21.5 plus/minus 2 mm/yr. Although it is not clear that this fault ruptured during the largest Himalayan earthquakes in the past, the slip rate suggests the crustal ongoing movement shortening across the Himalaya is accommodated by this fault or localized faults along HFT. The HFT continues beneath the Lesser Himalaya as the low angle thrust as MHT. There are other active faults identified in Nepal, but they are in essence secondary associated with MCT, MBT, HFT (MFT) or MHT.

The large major earthquakes in regional areas around Nepal are shown in Table 3.3.2-1, Table 3.3.2-2 and Figure 3.3.2-1.

The relatively large number of events larger than M6.0 occurred near Nepal just in the last 100 years. The historical records of large earthquakes in Nepal only start from 1255 A.D., and instrumental records of earthquakes only started in the last 100 years.

The Himalayan region from Assam to Uttarkhand has experienced four large major earthquakes larger than M8.0 in the last 100 years (if the Tibetan earthquake in 1955 included, five events). Among these, the 1934 event occurred in Nepal, and the area west of Kathmandu and east of Uttarkhand has not been hit for at least last 300 years by the same grade of earthquake standing as the potential area for next “great Himalayan earthquake.”

The seismic slip induced during the 1905 Kangra earthquake indicated 3-5 m, whereas that of the 1934 Bihar Nepal earthquake ranged around 4.7 m. With the slip rate assumption of MHT of 21.5 plus minus 2 mm/yr, the earthquake segment can be thought to rupture about every 130 to 260 years for M>8 earthquakes.[3]

[3] Source: Seismotectonics of the Nepal Himalaya from a Local Seismic Network, 1999.

Table 3.3.2-1 Major Earthquakes in Regional Areas including Nepal (M > 7.5)

Date	Latitude (deg N)	Longtitude (deg E)	Location	Magnitude (Richter's Scale:	Note (Fatalities (Mankind) etc.)
1255			near Kathmandu Valley?	unknown	Deaths: 1/3-1/4 of Kathmandu Valley, historical record
1408			near Kathmandu Valley?	unknown	historical record
1681			unknown	unknown	historical record
1810			unknown	unknown	historical record
1833			50-70km north of Kathmandu Valley	7.8*1)	historical record
12th June, 1897	**25.90**	**91.80**	**Assam, India**	**8.7**	**1,600**
4th April, 1905	**33.00**	**76.00**	**Himachal Pradesh (Kangra Valley),**	**8.6**	**19,000**
12th Dec., 1908	26.50	97.00	Myanmar	7.5	not specified
28th Aug., 1916	30.00	81.00	Far Western Nepal	7.5	not specified
8th July, 1918	24.50	91.00	Assam, India	7.6	not specified
27th Jan., 1931	25.60	96.80	Myanmar	7.5*2)	not specified
15th Jan., 1934	**26.50**	**86.50**	**Bihar-Nepal**	**8.4**	**11,000**
30th May, 1935	29.50	66.70	Quetta, Pakistan	7.6	30,000
29th July, 1947	28.50	94.00	NE Assam, India	7.9	not specified
15th Aug., 1950	**28.50**	**96.70**	**Assam, India**	**8.7**	**1,526**
18th Nov., 1951	**30.50**	**91.00**	**Tibet**	**8.5*2)**	**not specified**
17th Aug., 1952	30.50	91.50	Tibet	7.5*2)	not specified
8th Oct., 2005	34.43	73.54	Kashmir, India	7.6 *3)	>74,500
4th April, 2011	29.70	80.75	Far Western Nepal	7.7*4)	not specified

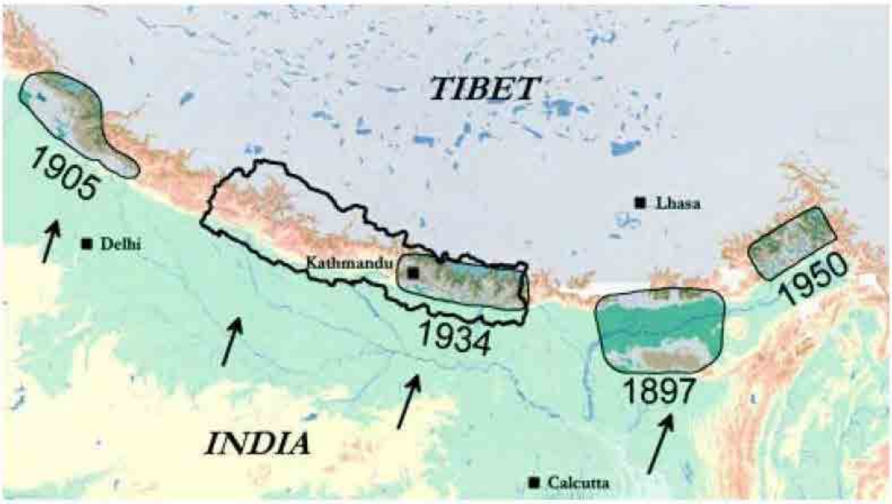
Source: modified from NSC (National Seismological Centre), ISC (International Seismological Center), NEA, etc.
None: Ml (Richter's Scale Magnitude), *1): Mb (body-wave Magnitude), *2): Ms (Surface Magnitude),
*3): Mw (Moment Magnitude), *4): Mwp (broadband moment magnitude)

Table 3.3.2-2 Large Earthquakes in Localized Areas around Nepal (M > 6.0)

Date	Latitude (deg N)	Longtitude (deg E)	Location	Magnitude
28th Aug., 1916	30.00	81.00	Far Western Nepal	7.5
14th Oct., 1911	31.00	80.50	Tibet (North of Far Western Nepal)	6.8*1)
6th Mar., 1913	30.00	83.00	Tibet (North of Western Nepal)	6.2*1)
6th Mar., 1913	30.00	83.00	Tibet (North of Western Nepal)	6.4*1)
15th Jan., 1934	26.50	86.50	Boundary of Bihar India - Eastern Nepal	8.4
5th Mar., 1935	29.75	80.25	Far Western Nepal	6.0*1)
21st May, 1935	28.75	89.25	Tibet (North of Eastern Nepal)	6.2*1)
27th May, 1936	28.50	83.50	Western Central Nepal (Dhaulagiri)	7.0
17th Oct., 1944	31.50	83.50	Tibet (North of Western Nepal)	6.8*1)
29th Oct., 1944	31.50	83.50	Tibet (North of Western Nepal)	6.8*1)
4th Oct., 1944	30.00	80.00	Uttarakhand, India (West of Nepal)	7.0*2)
4th Sep., 1954	28.30	83.80	Western Central Nepal	6.5*2)
14th April, 1957	30.64	84.21	Tibet (North of Central Nepal)	6.5*2)
28th Oct., 1958	30.61	84.47	Tibet (North of Central Nepal)	6.6*2)
28th Dec., 1958	30.01	79.94	Uttarakhand, India (West of Nepal)	6.3*2)
27th Mar., 1964	27.13	89.36	Bhutan	6.3*3)
26th Sep., 1964	29.96	80.46	Uttarakhand, India (West of Nepal)	6.2*3)
12th Jan., 1965	27.40	87.84	Eastern Nepal	6.1*3)
6th Mar., 1966	31.49	80.50	Tibet (North of Far Western Nepal)	6.5*2)
27th June, 1966	29.62	80.83	Far Western Nepal	6.5*2)
27th June, 1966	29.71	80.89	Far Western Nepal	6.5*2)
27th June, 1966	29.60	80.80	Far Western Nepal	6.0
15th Aug., 1966	28.67	78.93	Uttarakhand, India (West of Nepal)	6.2*2)
16th Dec., 1966	29.62	80.79	Far Western Nepal	6.2*2)
11th Feb., 1969	28.10	82.70	Western Central Nepal	6.2*2)
20th May, 1979	29.93	80.27	Uttarakhand, India (West of Nepal)	6.0*3)
29th July, 1980	29.60	81.10	Far Western Nepal	6.1
23rd Jan., 1982	31.68	82.28	Tibet (North of Mid Western Nepal)	7.0*1)
23rd Jan., 1982	31.56	82.21	Tibet (North of Mid Western Nepal)	6.0*1)
10th Jan., 1986	28.65	86.56	Tibet (North of Central Nepal)	6.1*1)
9th Aug., 1987	29.47	83.74	Tibet (North of Western Central Nepal)	6.3*1)
20th Aug., 1988	26.72	86.63	Eastern Nepal	6.8*1)
9th Jan., 1990	28.15	88.11	Tibet (North of Eastern Nepal)	6.4*1)
19th Oct., 1991	30.77	78.79	Tibet (North of Far Western Nepal)	7.0*1)
9th Dec., 1991	29.51	81.61	Mid Western Nepal	6.2*3)
20th Mar., 1993	29.03	87.33	Tibet (North of Eastern Nepal)	6.4*1)
3rd Sep., 1998	27.86	86.95	Eastern Nepal	6.1*1)
28th Mar., 1999	30.50	79.26	Uttarakhand, India (West of Nepal)	6.5
16th July, 2001	28.15	84.87	Tibet (North of Central Nepal)	6.0
27th Nov., 2001	29.69	81.72	Mid Western Nepal	6.1
27th Nov., 2001	29.64	81.70	Mid Western Nepal	6.1
4th June, 2002	30.71	81.34	Tibet (North of Far Western Nepal)	6.0
11th July, 2004	30.72	83.67	Tibet (North of Western Central Nepal)	6.6*1)
26th Oct., 2004	31.04	81.08	Tibet (North of Far Western Nepal)	6.3
7th April, 2005	30.52	83.66	Tibet (North of Western Central Nepal)	6.8
14th Feb., 2006	27.39	88.42	Sikkim, India (East of Nepal)	6.0
25th Aug., 2008	31.06	83.65	Tibet (North of Western Central Nepal)	6.9*1)
25th Aug., 2008	30.74	83.36	Tibet (North of Western Central Nepal)	6.4*1)
25th Sep., 2008	30.84	83.59	Tibet (North of Western Central Nepal)	6.3
8th Dec., 2008	29.99	82.09	Mid Western Nepal	6.4
24th July, 2009	31.17	85.96	Tibet (North of Central Nepal)	6.0
20th Nov., 2009	30.73	83.43	Tibet (North of Western Central Nepal)	6.2*3)
18th Jan., 2011	27.80	88.20	Sikkim, India (East of Nepal)	6.4*4)
13th Feb., 2011	27.35	86.96	Eastern Nepal	6.2*3)
4th April, 2011	29.92	80.54	Uttarakhand, India (West of Nepal)	7.7*4)
18th Sep., 2011	27.78	88.32	Sikkim, India (East of Nepal)	6.8

Note: Mone: Ml (Richter's Scale Magnitude), *1): Ms (Surface Magnitude), *2): M (unidentified Magnitude), *3): Mb (body-wave Magnitude)

Source: compiled and modified from NSC (National Seismological Centre), ISC (International Seismological Center), NEA, etc.



Source: Seismotectonics of the Nepal Himalaya from a Local Seismic Network, 1999

Figure 3.3.2-1 Distribution of Large Earthquakes and Probable Rupture Zones around Nepal

3.3.3 Hazard Map of Nepal

In Nepal, the Seismic Hazard Map was prepared by the National Seismological Centre (NSC) with the horizontal seismic acceleration contour map (Figure 3.3.3-1).

Source: M.R. Pandey, et. al., 2002

Figure 3.3.3-1 Seismic Hazard Map (2002)

As described, the mechanism of large (great) earthquakes of the Himalaya is considered and explained by the slipping of the Indian subcontinent plate along the low angle thrust or horizontal detachment plane (MHT) underneath the Himalaya. MHT reaches the surface along the foothills of Sub-Himalaya where it coincides with HFT (MFT), and extends and traces itself beneath the Higher Himalaya and southern Tibet (Figure 3.2.1-3).

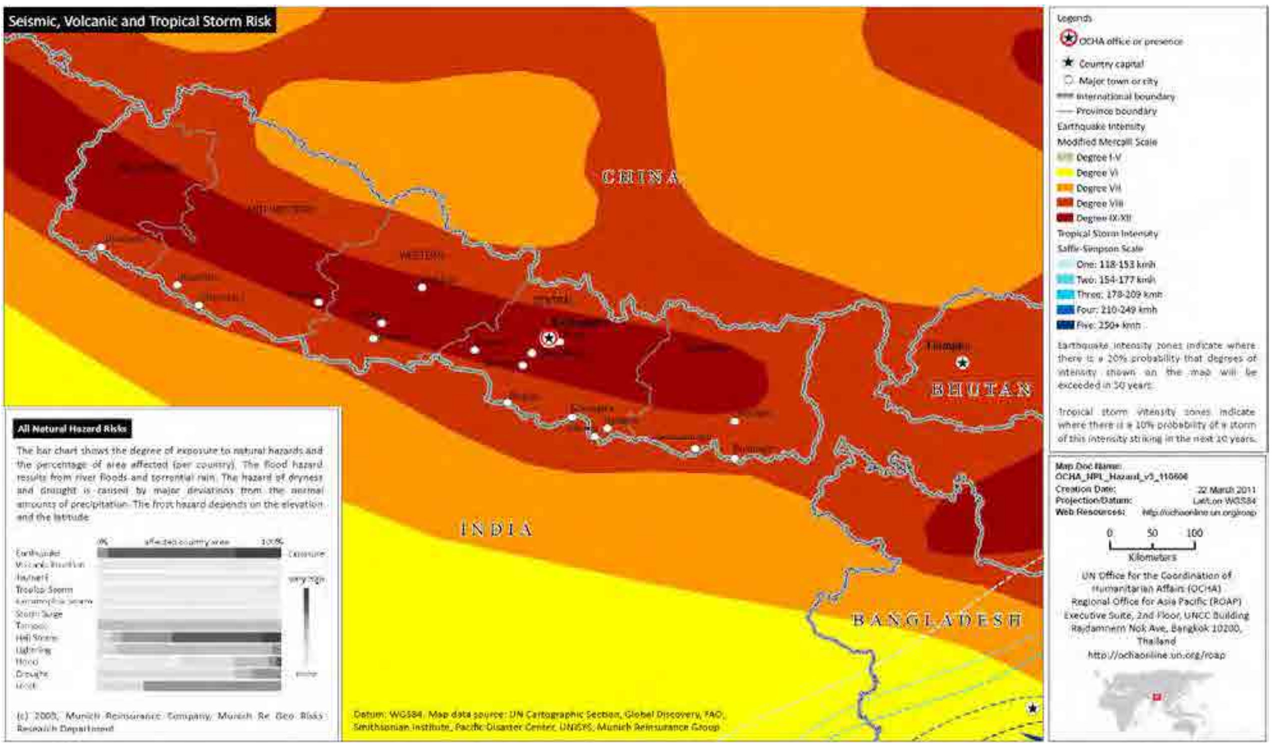
Microseismic monitoring reveals the microseismic activity in front of the southern front of Higher Himalayan range that coincides with the MHT surface, and almost all of it can be traced along the Nepal Himalaya (Seismic Belt). The uplift of a 50 km wide zone in front of the High Himalaya coincides with the Seismic Belt.

Two assumptions have been set for the sources of earthquakes.

- Large earthquakes associated along the segmentation of MHT (deep low angle thrust or a slipping detachment plane). The mean return period for these detachment earthquakes is not securely obtained, but the slip amount of the 1934 earthquake (M8.3) ranging from 3.6-12 m in conjunction with a long term average slip rate for MHT of 20 mm/yr enables a return period of 500 years for such scale of magnitude.
- Earthquakes along the Seismic Belt. It assumes a return period of once per year for M5 earthquakes from the frequency of actual earthquakes.

Such assumptions were applied for the estimation of horizontal seismic acceleration factors all over Nepal.

Since 2002, another seismic hazard map originated from the UN in 2011 (Figure 3.3.3-2). The map shows the earthquake intensity zones where there is a 20% probability that the degrees of intensity (Modified Mercalli Scale) shown on the map will be exceeded in 50 years. The map shown in Figure 3.3.3-2 in general coincides with Figure 3.3.3-1. It is noted that this map is kept as reference, as the detailed procedures of the analysis were not able to be identified.



Source: Nepal: Natural hazard risks, United Nations, 2011

Figure 3.3.3-2 Seismic Hazard Map (2011)

Chapter 4

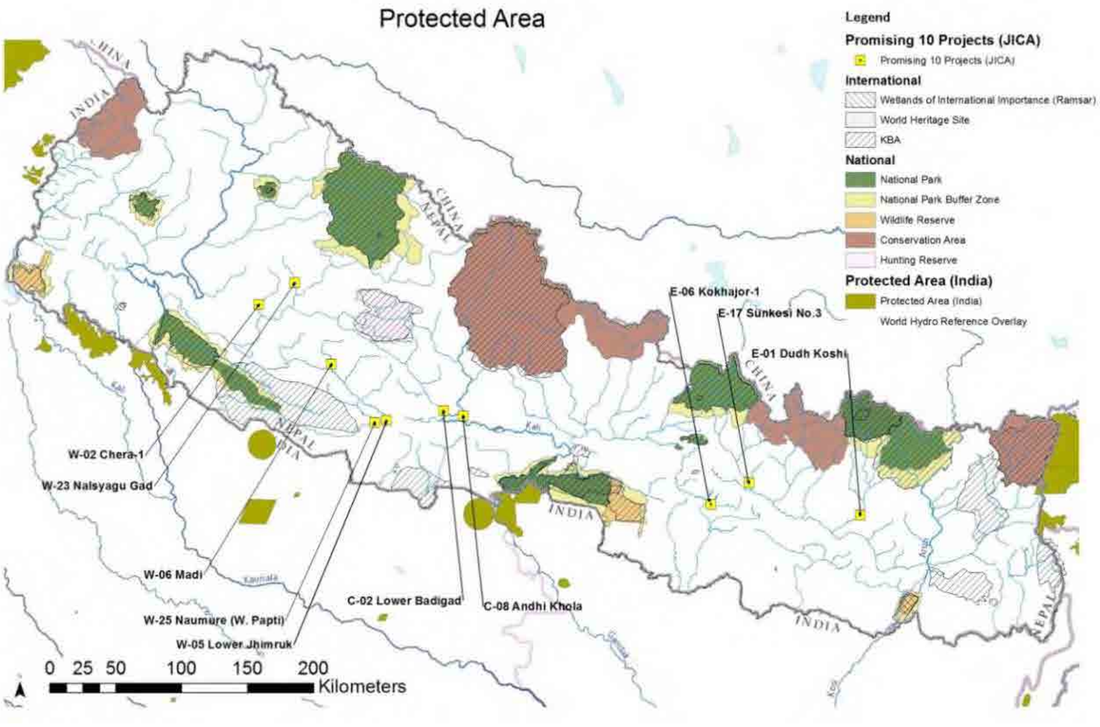
Natural and Social Environment

Chapter 4 Natural and Social Environment

4.1 Protected Area

Protected areas in Nepal have two types such as international protected areas and national protected areas.

International protected areas include World Heritage Sites, registered wetlands under the Ramsar Convention, and Key Biodiversity Areas (KBA)[1]. National protected areas designated by the National Parks and Wild Conservation Act 2029 (1973) are National Parks, Wildlife Reserves, Hunting Reserves, Conservation Areas and National Park/Wildlife Reserve Buffer Zones (See Figure 4.1-1, Table 4.1-1, 4.1-2 and 4.1-3). Development approval will be needed before hydro-electric development is done and additional regulation will be adapted for environmental flow. The protected areas indirectly affected by hydroelectric power development are the Bardia National Park downstream of the Kankaimai, Rapti and Babai rivers, the Chitwan National Park downstream of the Gandaki river, and the Koshi Tappu Wildlife Reserve downstream of the Koshi river.



Source: Ministry of Forests and Soil Conservation (2013), World Database of Protected Area (2011)

Figure 4.1-1 National Parks and World Heritage Sites

[1]Key biodiversity areas are places of international importance for the conservation of biodiversity through protected areas and other governance mechanisms. They are identified nationally using simple, standard criteria, based on their importance in maintaining species populations. As the building blocks for designing the ecosystem approach and maintaining effective ecological networks, key biodiversity areas are the starting point for conservation planning at a landscape level. Governments, intergovernmental organizations, NGOs, the private sector, and other stakeholders can use key biodiversity areas as a tool for identifying national networks of internationally important sites for conservation. (Source: IUCN)

Table 4.1-1 National protected Area in Nepal

Designation Type	***Name***	***Designated Year***
National Park	Langtang NP	1976
	Sagarmatha NP	1976
	Chitwan NP	1973
	Rara NP	1976
	Bardiya NP	1984
	Shey Phoksundo NP	1984
	Khaptad NP	1984
	Shivapuri Nagarjun NP	2002
	Makalu Barun NP	1991
	Banke NP	2010
National Park - Buffer Zone	Chitwan NP BZ	1999
	Bardiya NP BZ	1996
	Sagarmatha NP BZ	2002
	Rara NP BZ	2006
	Langtang NP BZ	1998
	Makalu Barun NP BZ	1999
	Khaptad NP BZ	2006
	Shey Phoksundo NP BZ	1998
	Banke NP BZ	2010
Wildlife Reserve	Shuklaphanta WR	1976
	Koshi Tappu WR	1976
	Parsa WR	1984
Wildlife Reserve- Buffer Zone	Parsa WR BZ	2005
	Koshi Tappu WR BZ	2004
	Shuklaphanta WR BZ	2004
Conservation Area	Annapurna CA	1992
	Kanchanjunga CA	1997
	Manasalu CA	1998
	Krishnasar CA	2009
	Gaurishankar CA	2010
	Api Nampa CA	2010
Hunting Reserve	Dhorpatan HR	1987

Table 4.1-2 Interational Protected Area in Nepal

Designation Type	***Name***	***Status***	***Year***
World Heritage Site	Sagarmatha National Park	Inscribed	1979
	Chitwan National Park	Inscribed	1984
Wetlands of International Importance (Ramsar)	Koshi Tappu	Designated	1987
	Gokyo and associated lakes	Designated	2007
	Gosaikunda and associated lakes	Designated	2007
	Phoksundo Lake	Designated	2007
	Rara Lake	Designated	2007
	Mai Pokhari	Designated	2008
	Beeshazar and associated lakes	Designated	2003
	Ghodaghodi Lake Area	Designated	2003
	Jagadishpur Reservoir	Designated	2003

Table 4.1-3 Key Biodiversity Areas in Nepal

Name	*Area (km²)*	*Source*
Shivapuri National Park	91.4	KBA data supplied by Jack Tordoff, BirdLife International
Bardia National Park	912.5	KBA data supplied by Jack Tordoff, BirdLife International
Dharan forests	771.4	KBA data supplied by Jack Tordoff, BirdLife International
Kanchenjungha Conservation Area	1,749.7	KBA data supplied by Jack Tordoff, BirdLife International
Langtang National Park	1,536.9	KBA data supplied by Jack Tordoff, BirdLife International
Sagarmatha National Park	1,130.0	KBA data supplied by Jack Tordoff, BirdLife International
Makalu Barun National Park	2,354.4	KBA data supplied by Jack Tordoff, BirdLife International
Annapurna Conservation Area	7,414.6	KBA data supplied by Jack Tordoff, BirdLife International
Chitwan National Park	1,184.3	WDPA 2009 - Latest Info: Official Agency reply (Dept. of National Parks and Wildlife Conservation - government focal point) received via D. Joshi (IUCN Nepal) for the UN List 2003 request, June 2003
Sukla Phanta Wildlife Reserve	370.8	WDPA 2009 - Latest Info: Official Agency reply (Dept. of National Parks and Wildlife Conservation - government focal point) received via D. Joshi (IUCN Nepal) for the UN List 2003 request, June 2003
Shey-Phoksundo National Park	3,649.1	WDPA 2009 - Latest Info: Official Agency reply (Dept. of National Parks and Wildlife Conservation - government focal point) received via D. Joshi (IUCN Nepal) for the UN List 2003 request, June 2003
Khaptad National Park	234.3	WDPA 2009 - Latest Info: Official Agency reply (Dept. of National Parks and Wildlife Conservation - government focal point) received via D. Joshi (IUCN Nepal) for the UN List 2003 request, June 2003.
Dhorpatan Hunting Reserve	1,320.2	WDPA 2009 - Latest Info: Official Agency reply (Dept. of National Parks and Wildlife Conservation - gov. focal point) received via D. Joshi (IUCN Nepal) for the UN List 2003 request, June 2003 & Dhorpatan HR Website, accessed 3/08/2004.
Parsa Wildlife Reserve	478.4	WDPA 2009 - Latest Info: Official Agency reply (Dept. of National Parks and Wildlife Conservation - government focal point) received via D. Joshi (IUCN Nepal) for the UN List 2003 request, June 2003
Tamur Valley and Watershed	1,339.7	KBA data supplied by Jack Tordoff, BirdLife International
Mai Valley Forests	579.1	KBA data supplied by Jack Tordoff, BirdLife International
Nawalparasi Forests	59.0	Based on feedback from Partner, IBA Directory and Google Earth
Rara National Park	116.8	Based on feedback from Partner, IBA Directory and Google Earth
Ghodaghodi Lake	11.0	Based on feedback from Partner, IBA Directory and Google Earth
Rampur Valley	27.9	Based on feedback from Partner, IBA Directory and Google Earth
Phulchowki Mountain Forests	11.5	Based on feedback from Partner, IBA Directory and Google Earth
Barandabhar Forests and Wetlands	168.3	Based on feedback from Partner, IBA Directory and Google Earth
Dang Deukhuri Foothill Forests and West Rapti Wetlands	3,502.0	Based on feedback from Partner, IBA Directory and Google Earth
Farmlands in the Lumbini Area	733.9	Based on feedback from Partner, IBA Directory and Google Earth
Jagdishpur Reservoir	4.6	Based on feedback from Partner, IBA Directory and Google Earth
Urlabari forest groves	22.1	Based on feedback from Partner, IBA Directory and Google Earth
Koshi Tappu Wildlife Reserve and Koshi Barrage	217.4	Based on feedback from Partner, IBA Directory and Google Earth

Source: Integrated Biodiversity Assessment Tool (2012), etc.

4.2 Conservation Species

88 species which are above rank VU (Vulnerable) are listed on the IUCN (International Union for Conservation of Nature) red list in Nepal (See Table 4.2-1). Distribution areas of some species are proved. The Government of Nepal also identifies 39 protected types of wildlife in the National Parks and Wildlife Conservation Act, 2029 (1973).

Table 4.2-1 IUCN Red-List Species and Protected Wildlife in Nepal

PLANTAE

Family	*Genus*	*Species*	*Common names (Eng.)*	*Status*
SCAPANIACEAE	*Andrewsianthus*	*ferrugineus*		EN
SOLENOSTOMATACEAE	*Diplocolea*	*sikkimensis*		EN
TAKAKIACEAE	*Takakia*	*ceratophylla*		VU
SOLENOSTOMATACEAE	*Scaphophyllum*	*speciosum*		VU
CYCADACEAE	*Cycas*	*pectinata*		VU
LEGUMINOSAE	*Dalbergia*	*latifolia*	Bombay Blackwood, Indian Rosewood, Indonesian Rosewood, Malabar Rosewood	VU
ULMACEAE	*Ulmus*	*wallichiana*		VU

MAMMALIA

Family	*Genus*	*Species*	*Common names (Eng.)*	*Status*	*GON*
SUIDAE	*Porcula*	*salvania*	Pygmy Hog	CR	
MURIDAE	*Apodemus*	*gurkha*	Himalayan Wood Mouse, Himalayan Field Mouse	EN	
CERVIDAE	*Axis*	*porcinus*	Hog Deer, Indochinese Hog Deer, Thai Hog Deer	EN	
BOVIDAE	*Bubalus*	*arnee*	Asian Buffalo, Asiatic Buffalo, Indian Buffalo, Indian Water Buffalo, Water Buffalo, Wild Asian Buffalo, Wild Water Buffalo	EN	x
LEPORIDAE	*Caprolagus*	*hispidus*	Hispid Hare, Assam Rabbit	EN	x
CANIDAE	*Cuon*	*alpinus*	Dhole, Asiatic Wild Dog, Indian Wild Dog, Red Dog	EN	
ELEPHANTIDAE	*Elephas*	*maximus*	Asian Elephant, Indian Elephant	EN	x
MANIDAE	*Manis*	*pentadactyla*	Chinese Pangolin	EN	x
MOSCHIDAE	*Moschus*	*chrysogaster*	Alpine Musk Deer, Himalayan Musk Deer	EN	x
MOSCHIDAE	*Moschus*	*fuscus*	Black Musk Deer, Dusky Musk Deer	EN	
MOSCHIDAE	*Moschus*	*leucogaster*	Himalayan Muskdeer, Himalayan Musk-deer, Himalayan Musk Deer	EN	
FELIDAE	*Panthera*	*tigris*	Tiger	EN	x
FELIDAE	*Panthera*	*uncia*	Snow Leopard, Ounce	EN	x
BOVIDAE	*Pantholops*	*hodgsonii*	Chiru, Tibetan Antelope	EN	x
PLATANISTIDAE	*Platanista*	*gangetica*	South Asian River Dolphin, Blind River Dolphin, Ganges Dolphin, Ganges River Dolphin, Ganges Susu, Indus River Dolphin	EN	x
FELIDAE	*Prionailurus*	*viverrinus*	Fishing Cat	EN	
AILURIDAE	*Ailurus*	*fulgens*	Red Panda, Lesser Panda, Red Cat-bear	VU	x
MUSTELIDAE	*Aonyx*	*cinerea*	Asian Small-clawed Otter, Oriental Small-clawed Otter, Small-clawed Otter	VU	
VIVERRIDAE	*Arctictis*	*binturong*	Binturong, Bearcat, Palawan Binturong	VU	
BOVIDAE	Bos	gaurus	Gaur, Indian Bison	VU	x

Family	*Genus*	*Species*	*Common names (Eng.)*	*Status*	*GON*
BOVIDAE	*Bos*	*mutus*	Wild Yak, Yak	VU	x
MUSTELIDAE	*Lutrogale*	*perspicillata*	Smooth-coated Otter, Indian Smooth-coated Otter	VU	
URSIDAE	*Melursus*	*ursinus*	Sloth Bear	VU	
VESPERTILIONIDAE	*Myotis*	*sicarius*	Mandelli's Mouse-eared Myotis, Mandelli's Mouse-eared Bat	VU	
FELIDAE	*Neofelis*	*nebulosa*	Clouded Leopard	VU	x
FELIDAE	*Pardofelis*	*marmorata*	Marbled Cat	VU	
RHINOCEROTIDAE	*Rhinoceros*	*unicornis*	Greater One-horned Rhino, Great Indian Rhinoceros, Indian Rhinoceros	VU	x
CERVIDAE	*Rucervus*	*duvaucelii*	Barasingha, Swamp Deer	VU	
CERVIDAE	*Rusa*	*unicolor*	Sambar, Sambar Deer	VU	
BOVIDAE	*Tetracerus*	*quadricornis*	Four-horned Antelope, Chousingha	VU	x
URSIDAE	*Ursus*	*thibetanus*	Asiatic Black Bear, Himalayan Black Bear	VU	
BOVIDAE	*Capricornis*	*thar*	Himalayan Serow	NT	
BOVIDAE	*Hemitragus*	*jemlahicus*	Himalayan Tahr	NT	
HYAENIDAE	*Hyaena*	*hyaena*	Striped Hyaena	NT	x
MUSTELIDAE	*Lutra*	*lutra*	Eurasian Otter, Common Otter, European Otter, European River Otter, Old World Otter	NT	
CERCOPITHECIDAE	*Macaca*	*assamensis*	Assam Macaque, Assamese Macaque	NT	x
BOVIDAE	*Naemorhedus*	*goral*	Himalayan Goral, Goral	NT	
BOVIDAE	*Ovis*	*ammon*	Argali, Wild Sheep	NT	x
FELIDAE	*Panthera*	*pardus*	Leopard	NT	
SCIURIDAE	*Petaurista*	*nobilis*	Bhutan Giant Flying Squirrel, Grays Giant Flying Squirrel, Noble Giant Flying Squirrel	NT	
SCIURIDAE	*Ratufa*	*bicolor*	Black Giant Squirrel, Malayan Giant Squirrel	NT	
CERCOPITHECIDAE	*Semnopithecus*	*Hector*	Tarai Gray Langur, Gray Langur, Hanuman Langur, Lesser Hill Langur, Tarai Sacred Langur	NT	
VIVERRIDAE	*Viverra*	*zibetha*	Large Indian Civet	NT	
Cervidae	*Cervus*	*duvaucelii*	Swamp Deer		x
Felidae	*Lynx*	*lynx*	Lynx		x
MANIDAE	*Manis*	*crasscaudata*	Pangolin		x
Canidae	*Canis*	*lupus*	Gray Wolf		x
Viverridae	*Prionodon*	*pardicolor*	Lingsang		x
FELIDAE	*Prionailurus*	*bengalensis*	Leopard Cat		x
Suidae	*Sus*	*salvanius*	Pygmy Hog		x
URSIDAE	*Ursus*	*arctos*	Himalayan Brown Beer		x

AVES

Family	*Genus*	*Species*	*Common names (Eng.)*	*Status*	*GON*
ARDEIDAE	*Ardea*	*insignis*	White-bellied Heron, Imperial Heron	CR	
ACCIPITRIDAE	*Gyps*	*bengalensis*	White-rumped Vulture, Asian White-backed Vulture, Oriental White-backed Vulture, White-backed Vulture	CR	
ACCIPITRIDAE	*Gyps*	*tenuirostris*	Slender-billed Vulture	CR	
OTIDIDAE	*Houbaropsis*	*bengalensis*	Bengal Florican, Bengal Bustard	CR	x
ACCIPITRIDAE	*Sarcogyps*	*calvus*	Red-headed Vulture, Indian Black Vulture, Pondicherry Vulture	CR	
ANATIDAE	*Rhodonessa*	*caryophyllacea*	Pink-headed Duck	CR	
ACCIPITRIDAE	*Neophron*	*percnopterus*	Egyptian Vulture, Egyptian Eagle	EN	
CICONIIDAE	*Leptoptilos*	*dubius*	Greater Adjutant	EN	
OTIDIDAE	*Sypheotides*	*indicus*	Lesser Florican, Likh	EN	
ACCIPITRIDAE	*Aquila*	*clanga*	Greater Spotted Eagle, Spotted Eagle	VU	
ACCIPITRIDAE	*Aquila*	*hastata*	Indian Spotted Eagle	VU	
ACCIPITRIDAE	*Aquila*	*heliaca*	Eastern Imperial Eagle, Asian Imperial Eagle, Imperial Eagle	VU	
PHASIANIDAE	*Catreus*	*wallichi*	Cheer Pheasant, Chir Pheasant, Wallich's Pheasant	VU	x
SYLVIIDAE	*Chaetornis*	*striata*	Bristled Grassbird	VU	
OTIDIDAE	*Chlamydotis*	*undulata*	Houbara Bustard, Houbara	VU	
TIMALIIDAE	*Chrysomma*	*altirostre*	Jerdon's Babbler	VU	
EMBERIZIDAE	*Emberiza*	*aureola*	Yellow-breasted Bunting	VU	
FALCONIDAE	*Falco*	*cherrug*	Saker Falcon, Saker	VU	
FALCONIDAE	*Falco*	*naumanni*	Lesser Kestrel	VU	
MUSCICAPIDAE	*Ficedula*	*subrubra*	Kashmir Flycatcher	VU	
PHASIANIDAE	*Francolinus*	*gularis*	Swamp Francolin	VU	
SCOLOPACIDAE	*Gallinago*	*nemoricola*	Wood Snipe	VU	
GRUIDAE	*Grus*	*antigone*	Sarus Crane	VU	x
ACCIPITRIDAE	*Haliaeetus*	*leucoryphus*	Pallas's Fish-eagle, Band-tailed Fish-eagle, Pallas's Fish Eagle, Pallas's Sea-eagle	VU	
CICONIIDAE	*Leptoptilos*	*javanicus*	Lesser Adjutant	VU	
PICIDAE	*Mulleripicus*	*pulverulentus*	Great Slaty Woodpecker	VU	
PLOCEIDAE	*Ploceus*	*megarhynchus*	Yellow Weaver, Finn's Baya Weaver, Finn's Weaver, Himalayan Weaver	VU	
CISTICOLIDAE	*Prinia*	*cinereocapilla*	Grey-crowned Prinia	VU	
LARIDAE	*Rynchops*	*albicollis*	Indian Skimmer	VU	
MUSCICAPIDAE	*Saxicola*	*insignis*	White-throated Bushchat, Hodgson's Bushchat, White-throated Bush Chat	VU	
TIMALIIDAE	*Turdoides*	*longirostris*	Slender-billed Babbler	VU	
ANATIDAE	*Anas*	*falcata*	Falcated Duck, Falcated Teal	NT	
ANHINGIDAE	*Anhinga*	*melanogaster*	Oriental Darter, Darter	NT	
ANATIDAE	*Aythya*	*nyroca*	Ferruginous Duck, Ferruginous Pochard, White-eyed Pochard	NT	
BUCEROTIDAE	*Buceros*	*bicornis*	Great Hornbill	NT	x
ACCIPITRIDAE	*Circus*	*macrourus*	Pallid Harrier, Pale Harrier	NT	
CICONIIDAE	*Ephippiorhynchus*	*asiaticus*	Black-necked Stork	NT	

Family	*Genus*	*Species*	*Common names (Eng.)*	*Status*	*GON*
FALCONIDAE	*Falco*	*jugger*	Laggar Falcon	NT	
SYLVIIDAE	*Graminicola*	*bengalensis*	Rufous-rumped Grassbird	NT	
ACCIPITRIDAE	*Ichthyophaga*	*humilis*	Lesser Fish-eagle, Lesser Fish Eagle, Lesser Fishing Eagle	NT	
ACCIPITRIDAE	*Ichthyophaga*	*ichthyaetus*	Grey-headed Fish-eagle, Grey-headed Fish Eagle, Grey-headed Fishing Eagle	NT	
INDICATORIDAE	*Indicator*	*xanthonotus*	Yellow-rumped Honeyguide	NT	
SCOLOPACIDAE	*Limosa*	*limosa*	Black-tailed Godwit	NT	
CICONIIDAE	*Mycteria*	*leucocephala*	Painted Stork	NT	
SCOLOPACIDAE	*Numenius*	*arquata*	Eurasian Curlew, Curlew		
PELECANIDAE	*Pelecanus*	*philippensis*	Spot-billed Pelican, Grey Pelican	NT	
SYLVIIDAE	*Phylloscopus*	*tytleri*	Tytler's Leaf-warbler, Tytler's Leaf Warbler	NT	
TIMALIIDAE	*Spelaeornis*	*caudatus*	Rufous-throated Wren-babbler, Short-tailed Wren-babbler, Tailed Wren-babbler	NT	
TIMALIIDAE	*Sphenocichla*	*humei*	Blackish-breasted Babbler	NT	
LARIDAE	*Sterna*	*acuticauda*	Black-bellied Tern	NT	
THRESKIORNITHIDAE	*Threskiornis*	*melanocephalus*	Black-headed Ibis	NT	
CICONIIDAE	*Ciconia*	*nigra*	Black Stork		x
CICONIIDAE	*Ciconia*	*ciconia*	White Stork		x
OTIDAE	*Eupodotis*	*indica*	Lesser Florican		x
PHASIANIDAE	*Lophophorus*	*impejanus*	Impeyon pheasant		x

REPTILIA

Family	*Genus*	*Species*	*Common names (Eng.)*	*Status*	*GoN*
GEOEMYDIDAE	*Batagur*	*kachuga*	Bengal Roof Turtle, Red-crowned Roofed Turtle	CR	
GAVIALIDAE	*Gavialis*	*gangeticus*	Gharial, Fish-eating Crocodile, Gavial, Indian Gavial, Indian Gharial, Long-nosed Crocodile	CR	x
TESTUDINIDAE	*Indotestudo*	*elongata*	Elongated Tortoise, Pineapple Tortoise, Red-nosed Tortoise, Yellow-headed Tortoise, Yellow Tortoise	EN	
GEOEMYDIDAE	*Hardella*	*thurjii*	Crowned River Turtle	VU	
TRIONYCHIDAE	*Nilssonia*	*hurum*	Indian Peacock Softshell Turtle, Peacock Soft-shelled Turtle	VU	
ELAPIDAE	*Ophiophagus*	*hannah*	Hamadryad, King Cobra	VU	
BOIDAE	*Python*	*molurus*	Asiatic Rock Python, Burmese Python, Indian Python, Tiger Python		x
Varanidae	*Varanus*	*flavescens*	Golden Monitor Lizard		x

AMPHIBIA

Family	*Genus*	*Species*	*Status*
DICROGLOSSIDAE	*Nanorana*	*minica*	VU
DICROGLOSSIDAE	*Nanorana*	*rostandi*	VU
MEGOPHRYIDAE	*Scutiger*	*nepalensis*	VU
RANIDAE	*Hylarana*	*chitwanensis*	NT
DICROGLOSSIDAE	*Nanorana*	*annandalii*	NT
DICROGLOSSIDAE	*Nanorana*	*ercepeae*	NT

ACTINOPTERYGII

Family	Genus	Species	Common names (Eng.)	Status
CYPRINIDAE	*Schizothorax*	*nepalensis*	Snow Trout	CR
CYPRINIDAE	*Schizothorax*	*raraensis*	RaraSnowtrout	CR
CLARIIDAE	*Clarias*	*magur*	Wagur, Mangur, Manguri	EN
CYPRINIDAE	*Tor*	*putitora*	Putitor Mahseer, Golden Mahaseer	EN
CYPRINIDAE	*Cyprinion*	*semiplotum*	Assamese Kingfish	VU
CYPRINIDAE	*Puntius*	*chelynoides*	Dark mahseer	VU
CYPRINIDAE	*Schizothorax*	*richardsonii*		VU
SCHILBEIDAE	*Ailia*	*coila*	Gangeticailia	NT
SISORIDAE	*Bagarius*	*bagarius*		NT
SISORIDAE	*Bagarius*	*yarrelli*		NT
NOTOPTERIDAE	*Chitala*	*chitala*		NT
CYPRINIDAE	*Labeo*	*pangusia*	Pangusialabeo	NT
CYPRINIDAE	*Neolissochilus*	*hexagonolepis*	Katli	NT
BALITORIDAE	*Schistura*	*devdevi*		NT
CYPRINIDAE	*Tor*	*tor*	mahseer	NT
SILURIDAE	*Wallago*	*attu*		NT

CHONDRICHTHYES

Family	Genus	Species	Common names (Eng)	Status
DASYATIDAE	*Himantura*	*fluviatilis*	Ganges Stingray	EN
CARCHARHINIDAE	*Carcharhinus*	*leucas*	Bull Shark	NT

INSECTA

Family	Genus	Species	Common names (Eng)	Sstatus
PLATYCNEMIDIDAE	*Calicnemia*	*nipalica*		VU
CHLOROGOMPHIDAE	*Chlorogomphus*	*selysi*		VU
EPIOPHLEBIIDAE	*Epiophlebia*	*laidlawi*	Relict Himalayan Dragonfly	NT
CORDULEGASTRIDAE	*Neallogaster*	*ornata*		NT

GASTROPODA

Family	Genus	Species	Status
POMATIOPSIDAE	*Tricula*	*mahadevensis*	VU

Source: IUCN Red List of Threatened Species. Version 2012.2

Most rare fishes which travel long distances are cold-water fish. These fishes are going down to low altitudes during the dry season, and are moving up to lay eggs in cold water during the rainy season. There are fishes which move over a large elevation difference; *Tor Tor, Labeo Pangusia,* and *Gagarium Yarreleli* move between altitudes from 140 m below sea level to 800 m, *Tor Putitora, Neolissochilus* move between altitudes from 140 m below sea level to 1,300 m, *Schizothorazrichardsonii* moves between altitudes from 140 m to higher than 1,300 m. Figure 4.2-1 shows the estimated habitats of important fishes in Nepal.

However, the distribution of rare fishes in Nepal has not been investigated enough and its distribution across the country is not fully figured out.

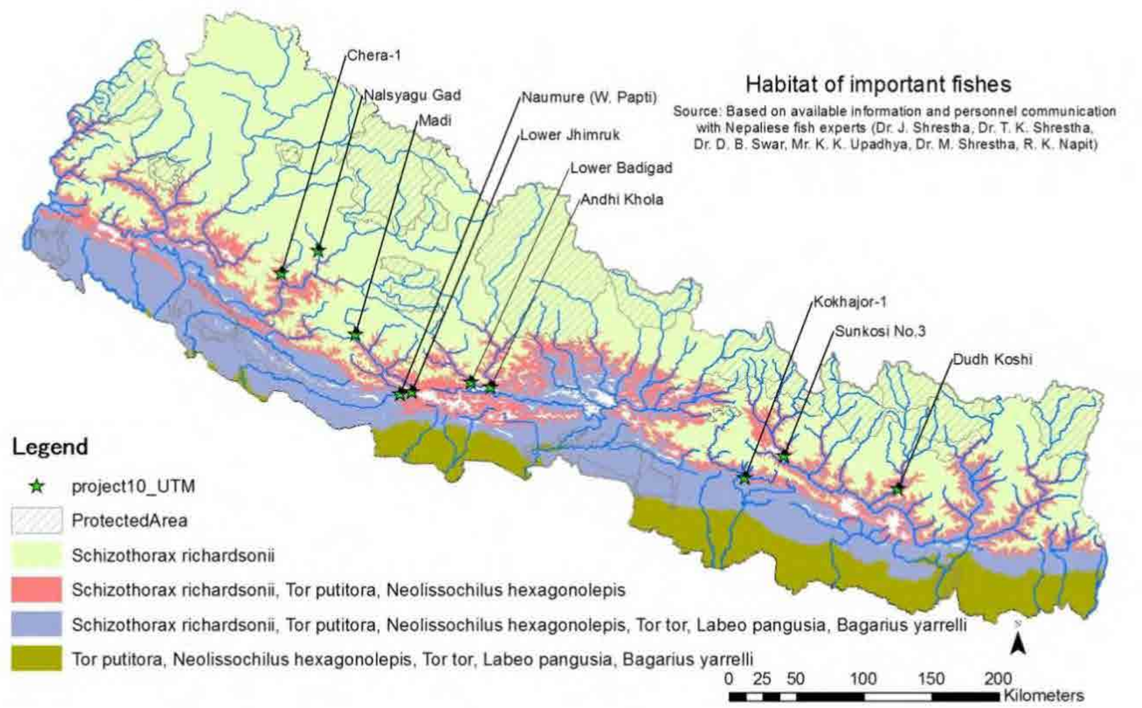
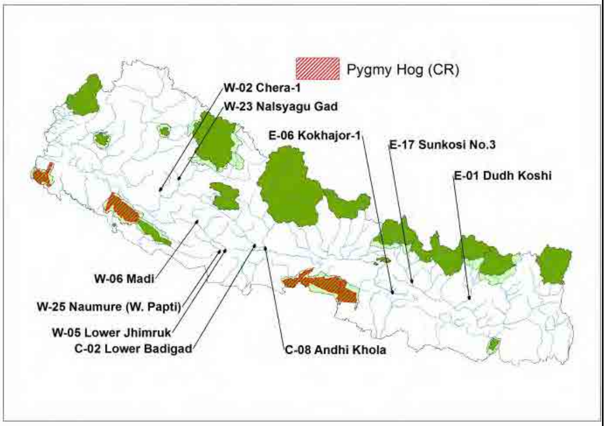
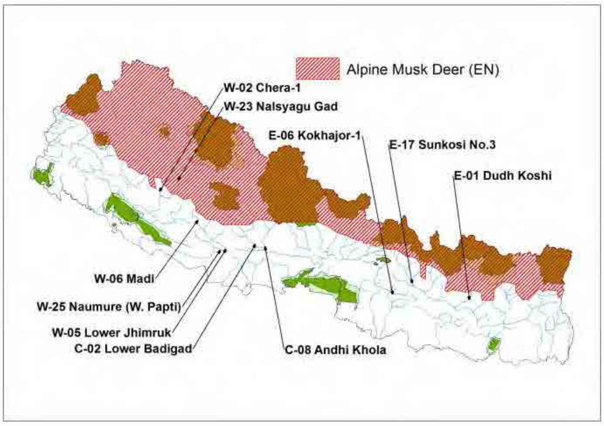
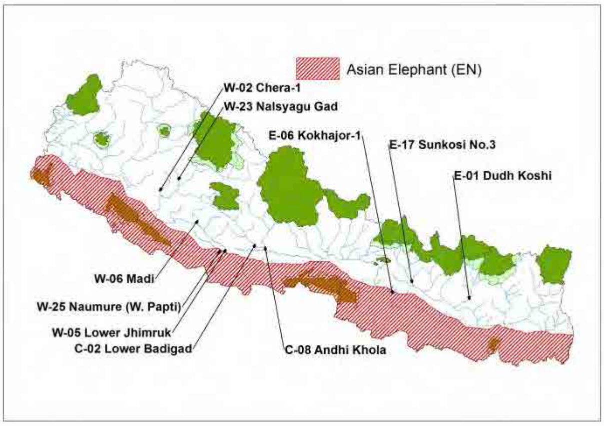


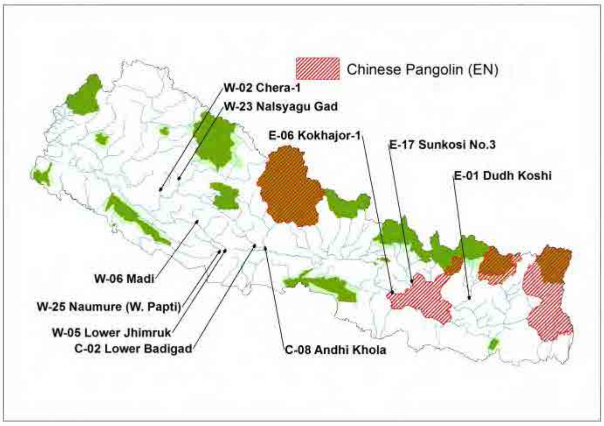
Figure 4.2-1 Habitat of Important Fishes in Nepal

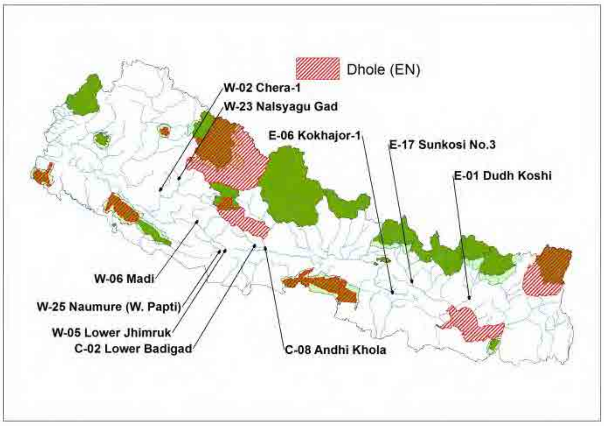
Table 4.2-2 Distribution Maps of National Red List Mammals in Nepal

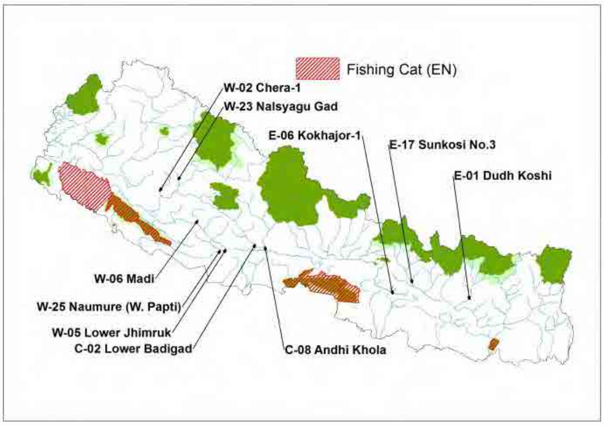


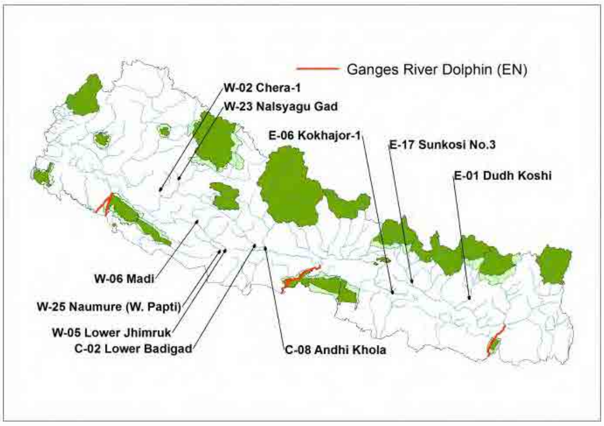


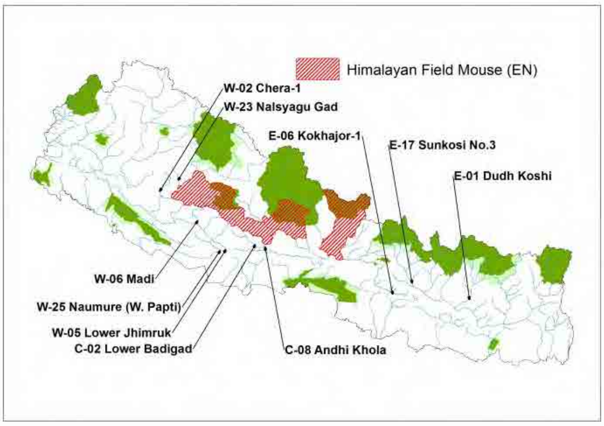


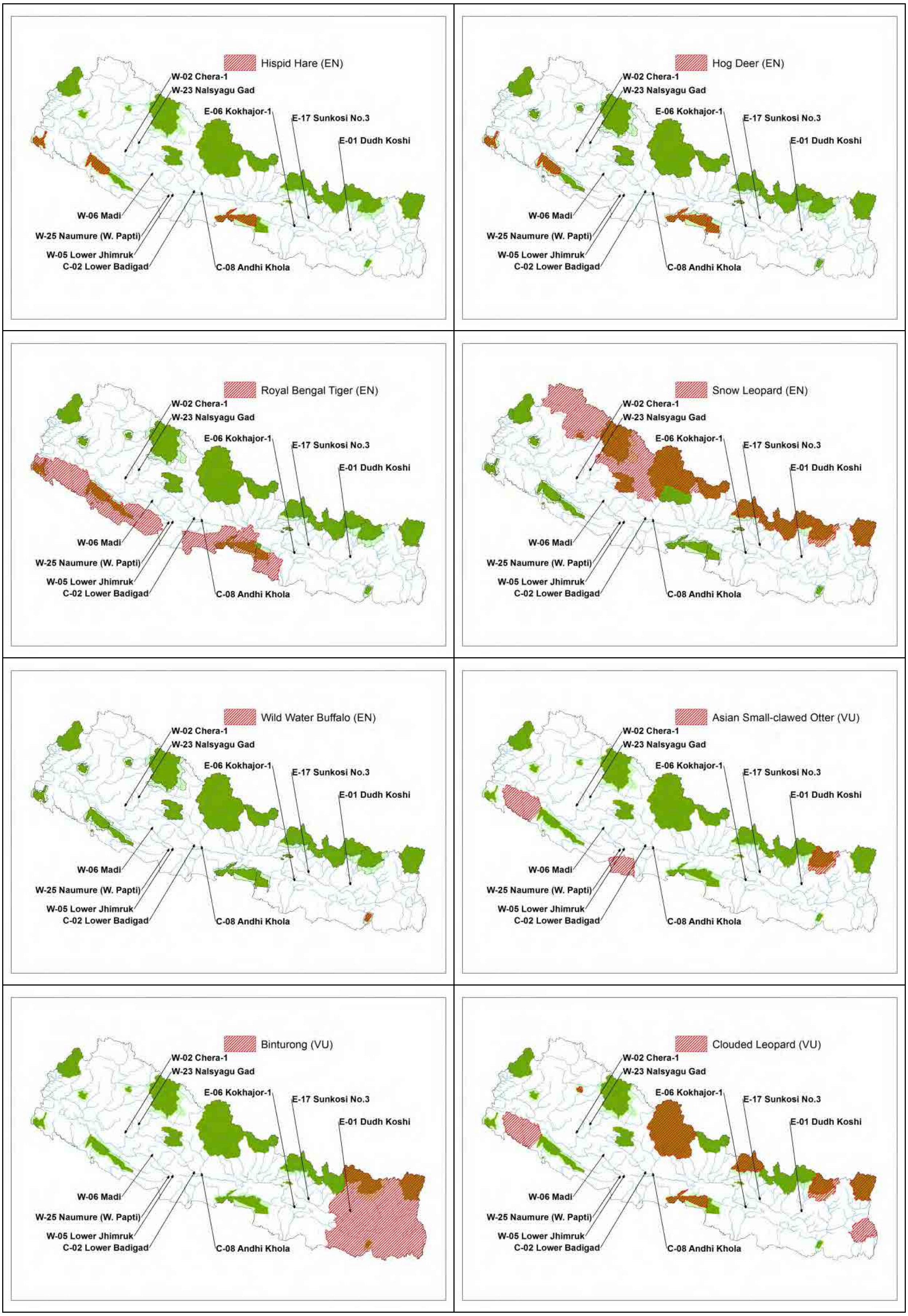


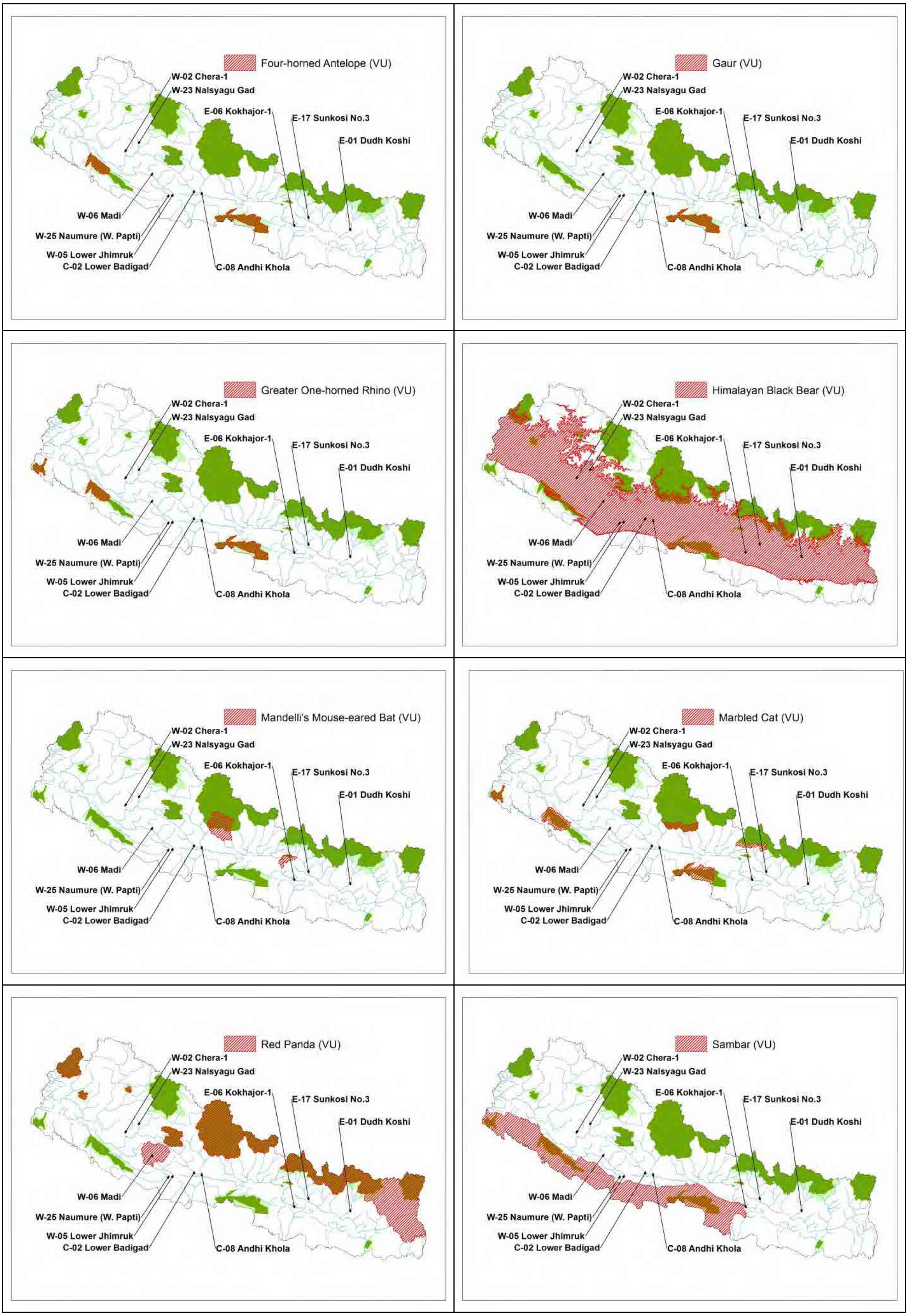


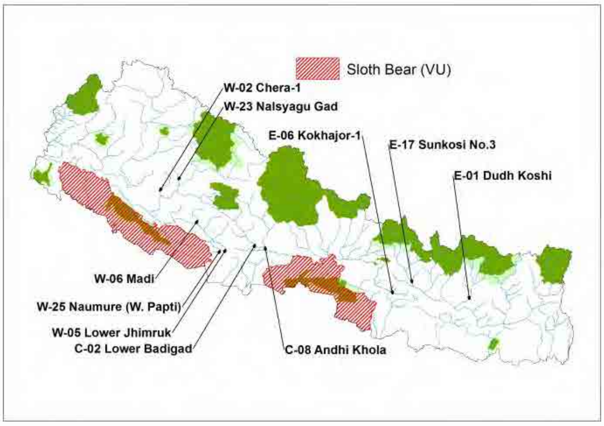







Hispid Hare (EN)
Hog Deer (EN)
Royal Bengal Tiger (EN)
Snow Leopard (EN)
Wild Water Buffalo (EN)
Asian Small-clawed Otter (VU)
Binturong (VU)
Clouded Leopard (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola


Four-horned Antelope (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola
Gaur (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola
Greater One-horned Rhino (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola
Himalayan Black Bear (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola
Mandelli's Mouse-eared Bat (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola
Marbled Cat (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola
Red Panda (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola
Sambar (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola


Sloth Bear (VU)
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W-23 Nalsyagu Gad
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E-17 Sunkosi No.3
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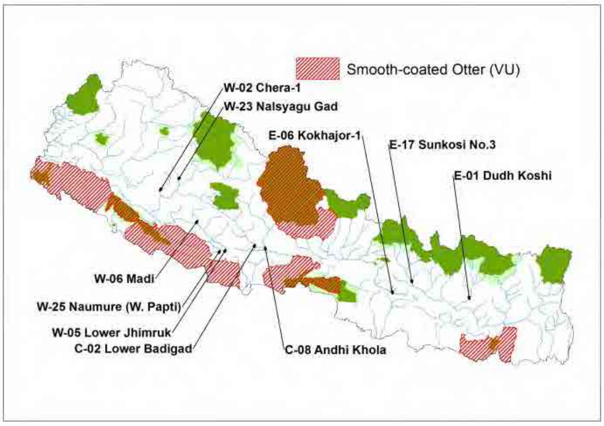
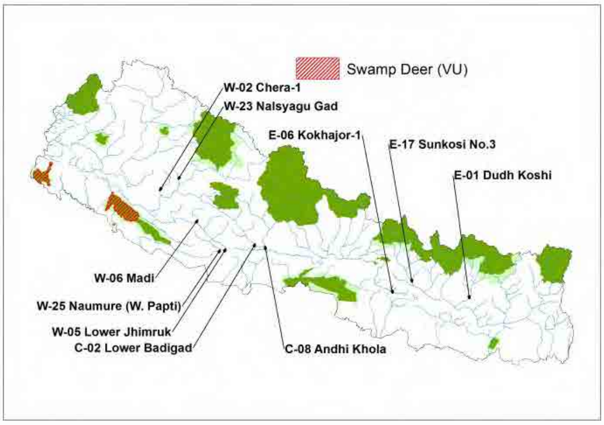
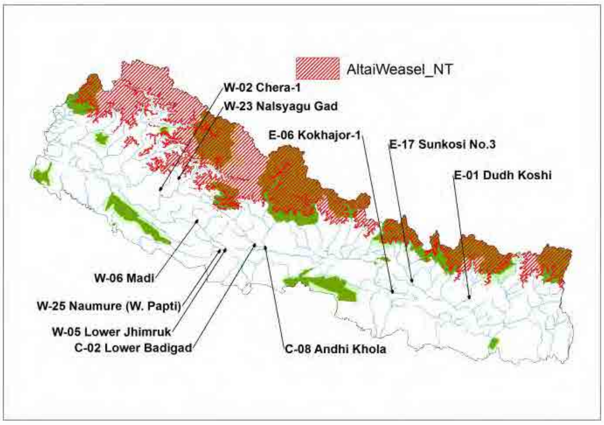
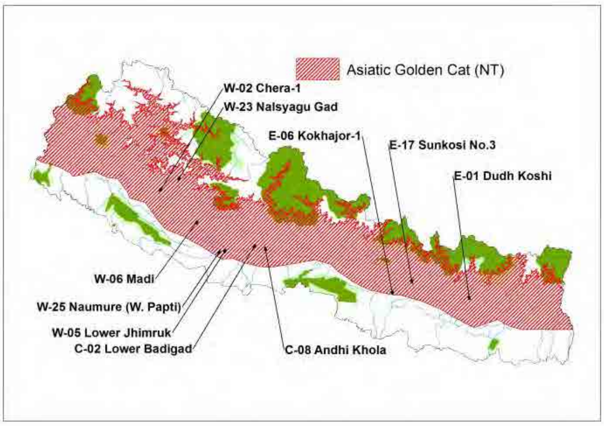
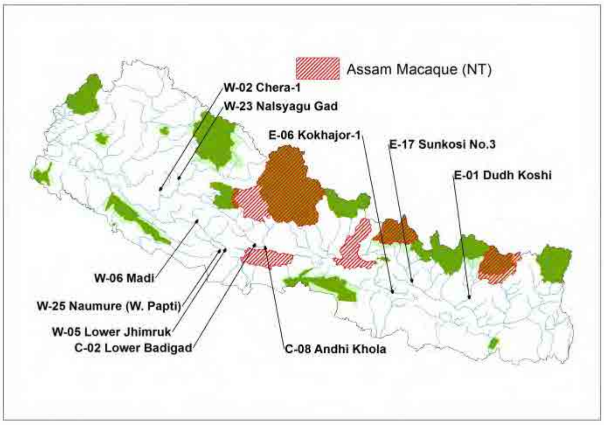
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

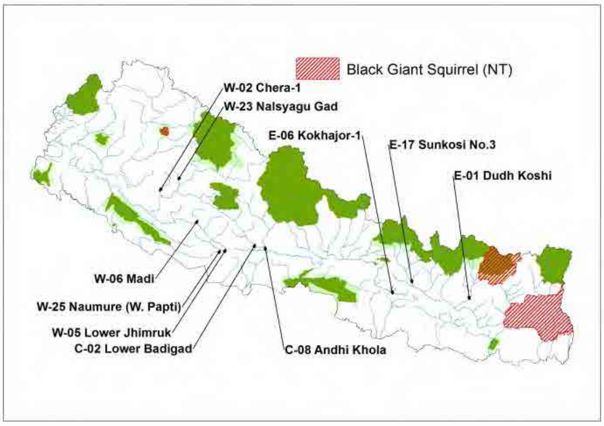

Smooth-coated Otter (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

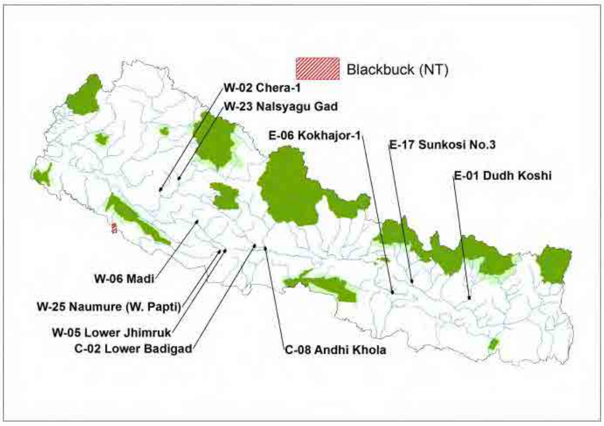

Swamp Deer (VU)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

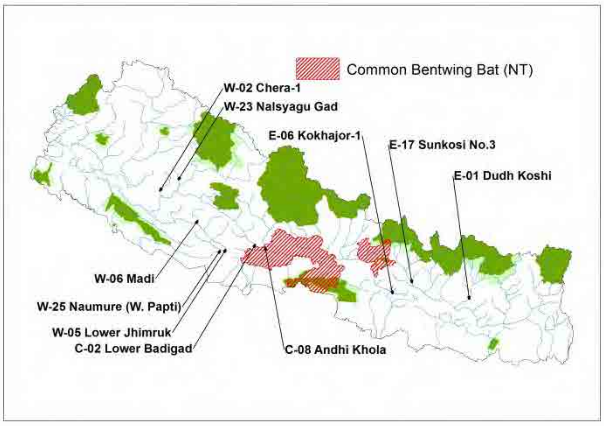

AltaiWeasel_NT
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

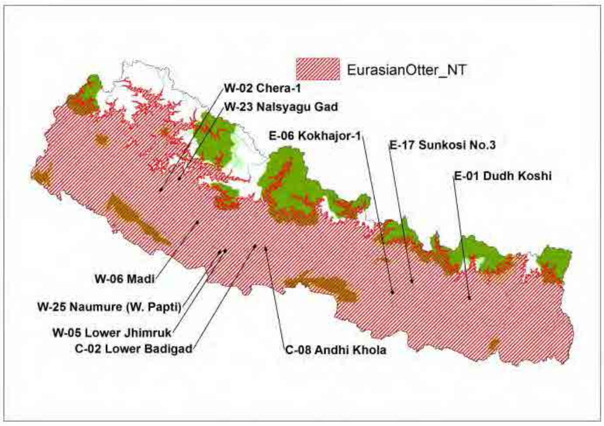

Asiatic Golden Cat (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

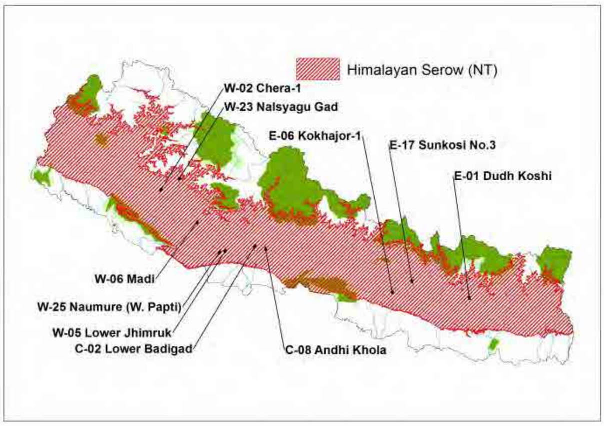

Assam Macaque (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

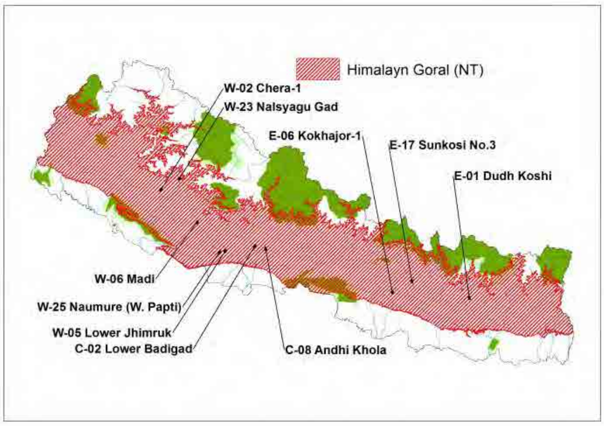

Black Giant Squirrel (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

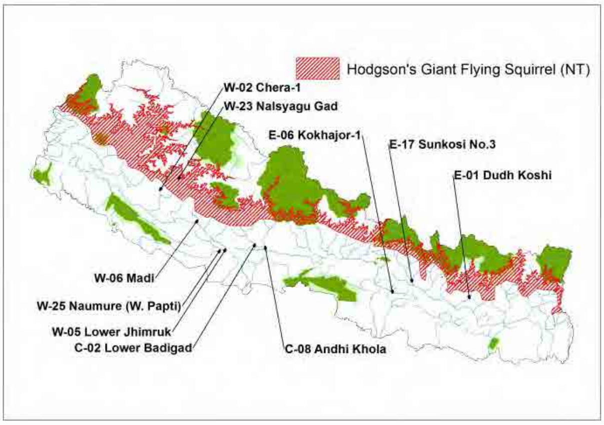

Blackbuck (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

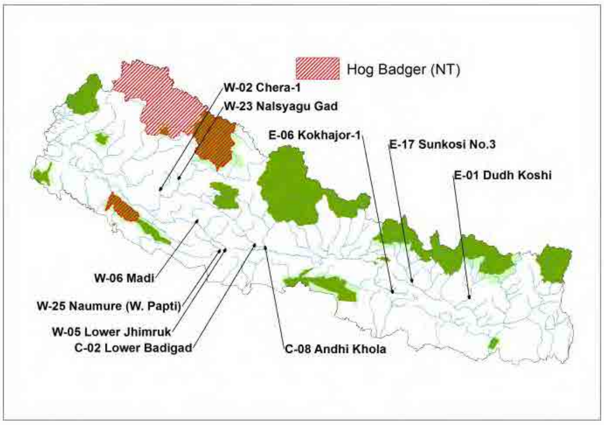

Common Bentwing Bat (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

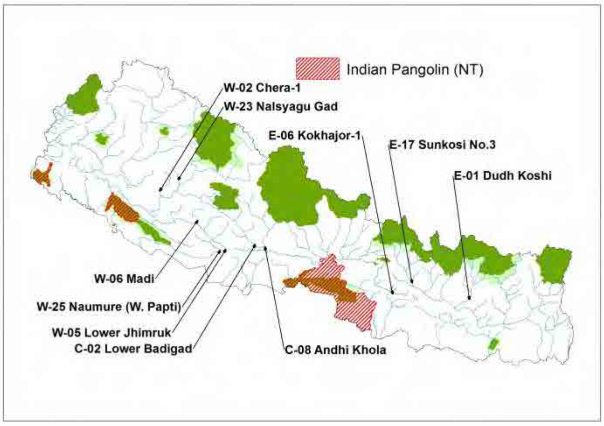

EurasianOtter_NT
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

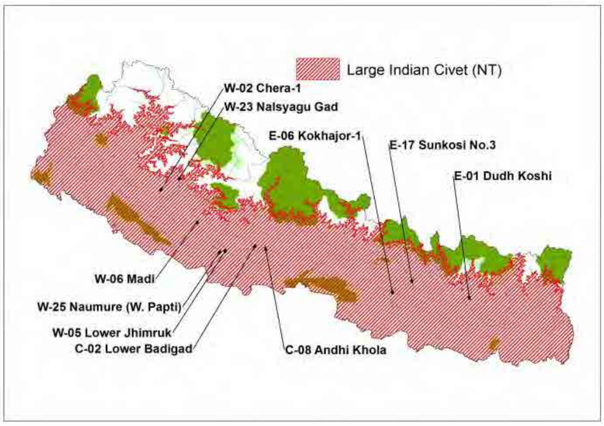

Himalayan Serow (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola

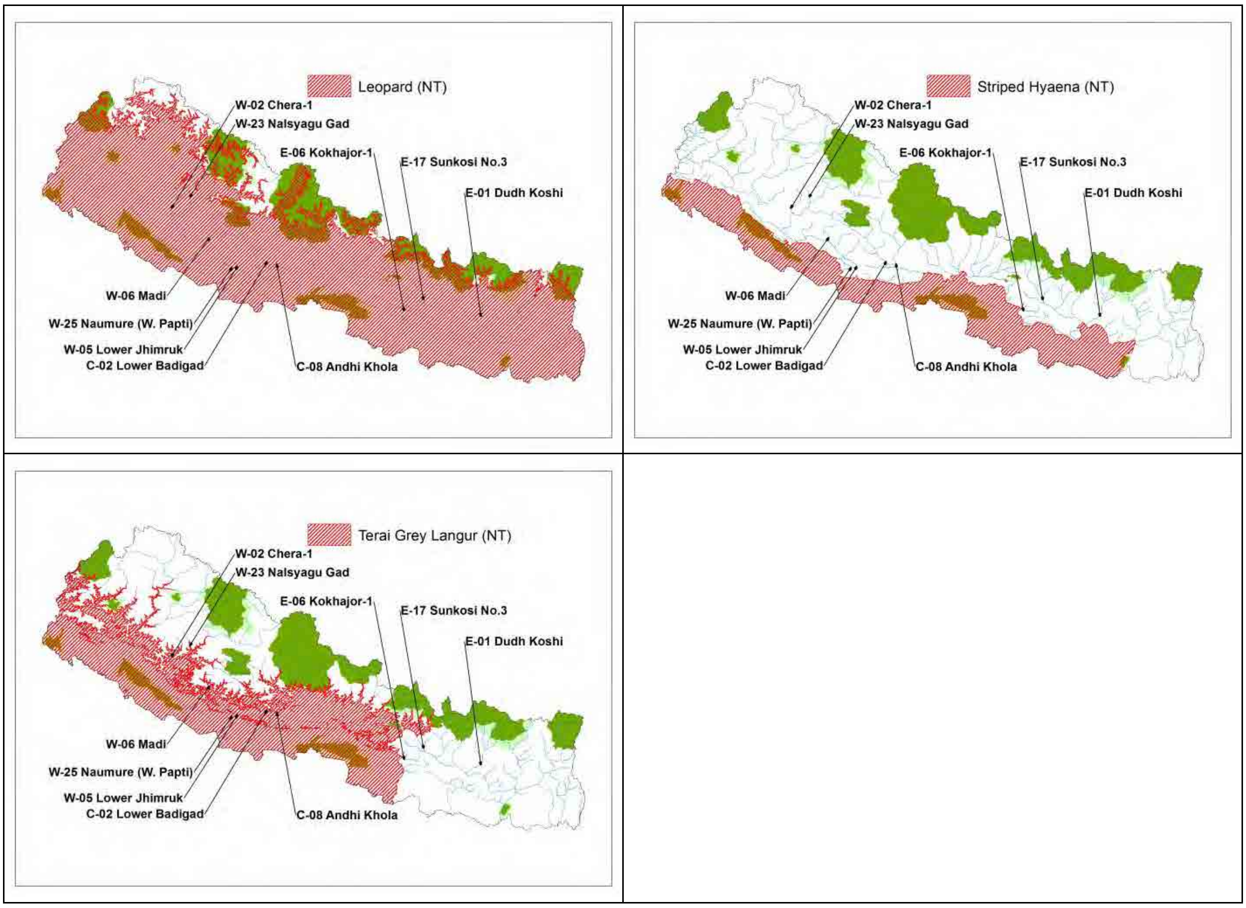

Himalayn Goral (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola


Hodgson's Giant Flying Squirrel (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola


Hog Badger (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola


Indian Pangolin (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola


Large Indian Civet (NT)
W-02 Chera-1
W-23 Nalsyagu Gad
E-06 Kokhajor-1
E-17 Sunkosi No.3
E-01 Dudh Koshi
W-06 Madi
W-25 Naumure (W. Papti)
W-05 Lower Jhimruk
C-02 Lower Badigad
C-08 Andhi Khola



Source: The Status of Nepal's Mammals: The National Red List Series (IUCN 2012)

4.3 Ethnicity

Nepal has various ethnic groups. 128 ethnic groups are recorded in the 2011 population census. These ethnic groups are classified in six groups such as Adivasi/Janajati, BCTS, Dalit, Madhesi, religious minorities, and others. Adivasi/Janajati are an indigenous people who account for 36% of the national total population (See Table 4.3-2). BCTS (Brahmin/Chhetri/Thakuri/Sanyashi Dalit) are a high caste people who account for 32%. Dalit are a bottom caste people who account for 14%. Madhesi are people living in the Tarai plain who account for 14%[2]. Religious minorities mean Islamic people who account for 4% (See Table 4.3-1). The National Foundation for Development of Indigenous Nationalities Act (2002) identified 59 ethnic groups as Adivasi/Janajati which have their own language, religion, tradition, culture, civilization and traditional egalitarian social structure and are classified in five groups from endangered to advantaged based on alienations. But it cannot be concluded that these counted groups are only indigenous people. 48 out of the 59 Adivasi/Janajatis are listed in the 2011 Census and other groups are under discussion if they are to be included in Adivasi/Janajati now. Then the classification of ethnic groups in Nepal is a matter of argument because of the history of Rana families who forced non-Hindu groups into the caste system and gave

[2]Total population of Madheshi of 71 ethnic groups which are listed in the 2011 Census out of 94 Madhesi ethnic groups (GoN on Magh 21, 2065 (2009) identified) are 12,449,631 people, which is 47% of the total national population. But this figure excluded the Madheshi, which are overlapped with Adivasi/Janajati or Dalit.

them various epithets.

Table 4.3-1 Population of Ethnic Groups

Category		Name	Madhesi	Population		Rate	
Adivasi/Janajati	Endangered	Meche	*	4,867	21,284	0.0%	0.1%
		Raji	*	4,235		0.0%	
		Lepcha		3,445		0.0%	
		Pattharkatta/ Kushwadiya	*	3,182		0.0%	
		Hayu		2,925		0.0%	
		Kisan	*	1,739		0.0%	
		Raute		618		0.0%	
		Kusunda		273		0.0%	
		Bankariya		-		-	
		Mugali		-		-	
	Highly marginalized	Dhanuk	*	219,808	594,030	0.8%	2.2%
		Danuwar	*	84,115		0.3%	
		Majhi	*	83,727		0.3%	
		Chepang /Praja		68,399		0.3%	
		Satar/ Santhal	*	51,735		0.2%	
		Jhangad/ Dhagar	*	37,424		0.1%	
		Thami	*	28,671		0.1%	
		Bote	*	10,397		0.0%	
		Brahmu/ Baramo		8,140		0.0%	
		Lhomi		1,614		0.0%	
		Thudam		-		-	
		Siyar (Chumba)		-		-	
	Marginalized	Tharu	*	1,737,470	3,891,696	6.6%	14.7%
		Tamang		1,539,830		5.8%	
		Kumal	*	121,196		0.5%	
		Gharti/Bhujel		118,650		0.4%	
		Rajbansi	*	115,242		0.4%	
		Kumhar	*	62,399		0.2%	
		Sunuwar		55,712		0.2%	
		Gangai	*	36,988		0.1%	
		Dhimal	*	26,298		0.1%	
		Tajpuriya	*	19,213		0.1%	
		Darai	*	16,789		0.1%	
		Pahari		13,615		0.1%	
		Bhote		13,397		0.1%	
		Dura		5,394		0.0%	
		Dolpo		4,107		0.0%	
		Lhopa		2,624		0.0%	
		Topkegola		1,523		0.0%	
		Walung		1,249		0.0%	
		Free		-		-	
		Mugali		-		-	
		Larke (Nupriba)		-		-	
	Disadvantaged	Magar		1,887,733	3,587,191	7.1%	13.5%
		Rai		620,004		2.3%	

Category		Name	Madhesi	Population		Rate	
		Gurung		522,641		2.0%	
		Limbu		387,300		1.5%	
		Sherpa		112,946		0.4%	
		Yakkha		24,336		0.1%	
		Chhantyal/Chhantel		11,810		0.0%	
		Hyolmo		10,752		0.0%	
		Jirel		5,774		0.0%	
		Byasi/Sauka		3,895		0.0%	
		Tangbe		-		-	
		Tin Gaunle Thakali		-		-	
		Bahra Gaunle		-		-	
		Marphali Thakali		-		-	
	Advanced	Newar		1,321,933	1,335,148	5.0%	5.0%
		Thakali		13,215		0.0%	
	Others	Janajati / Others		1,228	1,228	0.0%	0.0%
BCTS		Chhetree		4,398,053	8,412,507	16.6%	31.8%
		Brahman - Hill	*	3,226,903		12.2%	
		Thakuri		425,623		1.6%	
		Sanyasi/Dasnami	*	227,822		0.9%	
		Brahman - Tarai	*	134,106		0.5%	
Dalit		Kami		1,258,554	3,594,447	4.8%	13.6%
		Damai/Dholi		472,862		1.8%	
		Sarki		374,816		1.4%	
		Chamar/ Harijan/ Ram	*	335,893		1.3%	
		Musahar	*	234,490		0.9%	
		Dusadh/ Pasawan/ Pasi	*	208,910		0.8%	
		Dhobi	*	109,079		0.4%	
		Tatma/Tatwa	*	104,865		0.4%	
		Lohar	*	101,421		0.4%	
		Khatwe	*	100,921		0.4%	
		Bantar/Sardar	*	55,104		0.2%	
		Badi		38,603		0.1%	
		Dom	*	13,268		0.1%	
		Kori	*	12,276		0.0%	
		Gaine		6,791		0.0%	
		Sarbaria	*	4,906		0.0%	
		Halkhor		4,003		0.0%	
		Chidimar	*	1,254		0.0%	
		Kalar	*	1,077		0.0%	
		Dalit Others		155,354		0.6%	
Madhesi (Other)		Yadav	*	1,054,458	3,747,586	4.0%	14.1%
		Teli	*	369,688		1.4%	
		Koiri/Kushwaha	*	306,393		1.2%	
		Kurmi	*	231,129		0.9%	
		Mallaha	*	173,261		0.7%	
		Kewat	*	153,772		0.6%	
		Kathabaniyan	*	138,637		0.5%	
		Kalwar	*	128,232		0.5%	
		Kanu	*	125,184		0.5%	

Category	Name	Madhesi	Population		Rate	
	Hajam/Thakur	*	117,758		0.4%	
	Sudhi	*	93,115		0.4%	
	Halwai	*	83,869		0.3%	
	Baraee	*	80,597		0.3%	
	Bin	*	75,195		0.3%	
	Nuniya	*	70,540		0.3%	
	Sonar	*	64,335		0.2%	
	Kahar	*	53,159		0.2%	
	Marwadi	*	51,443		0.2%	
	Kayastha	*	44,304		0.2%	
	Rajput	*	41,972		0.2%	
	Lodh	*	32,837		0.1%	
	Badhaee	*	28,932		0.1%	
	Bangali	*	26,582		0.1%	
	Gaderi/Bhedihar	*	26,375		0.1%	
	Mali	*	14,995		0.1%	
	Dhunia	*	14,846		0.1%	
	Rajdhob	*	13,422		0.1%	
	Rajbhar	*	9,542		0.0%	
	Punjabi/Sikh	*	7,176		0.0%	
	Amat	*	3,830		0.0%	
	Munda	*	2,350		0.0%	
	Dev	*	2,147		0.0%	
	Kamar	*	1,787		0.0%	
	Koche	*	1,635		0.0%	
	Nurang	*	278		0.0%	
	Terai Others	*	103,811		0.4%	
Religious Minority	Musalman	*	1,164,255	1,164,255	4.4%	4.4%
Others	Kulung		28,613	145,132	0.1%	0.5%
	Ghale		22,881		0.1%	
	Khawas		18,513		0.1%	
	Undefined Others		15,277		0.1%	
	Nachhiring		7,154		0.0%	
	Yamphu		6,933		0.0%	
	Chamling		6,668		0.0%	
	Foreigners		6,651		0.0%	
	Aathpariya		5,977		0.0%	
	Bantaba		4,604		0.0%	
	Thulung		3,535		0.0%	
	Mewahang Bala		3,100		0.0%	
	Bahing		3,096		0.0%	
	Natuwa		3,062		0.0%	
	Dhankar/ Dharikar		2,681		0.0%	
	Dhandi		1,982		0.0%	
	Samgpang		1,681		0.0%	
	Khaling		1,571		0.0%	
	Loharung		1,153		0.0%	
Total			26,494,504		100.0%	

Source: Census 2011; Nepal Federation of Indigenous Nationalities Act(2004); GoN on 2065 Magh 21 (2009-2-3)

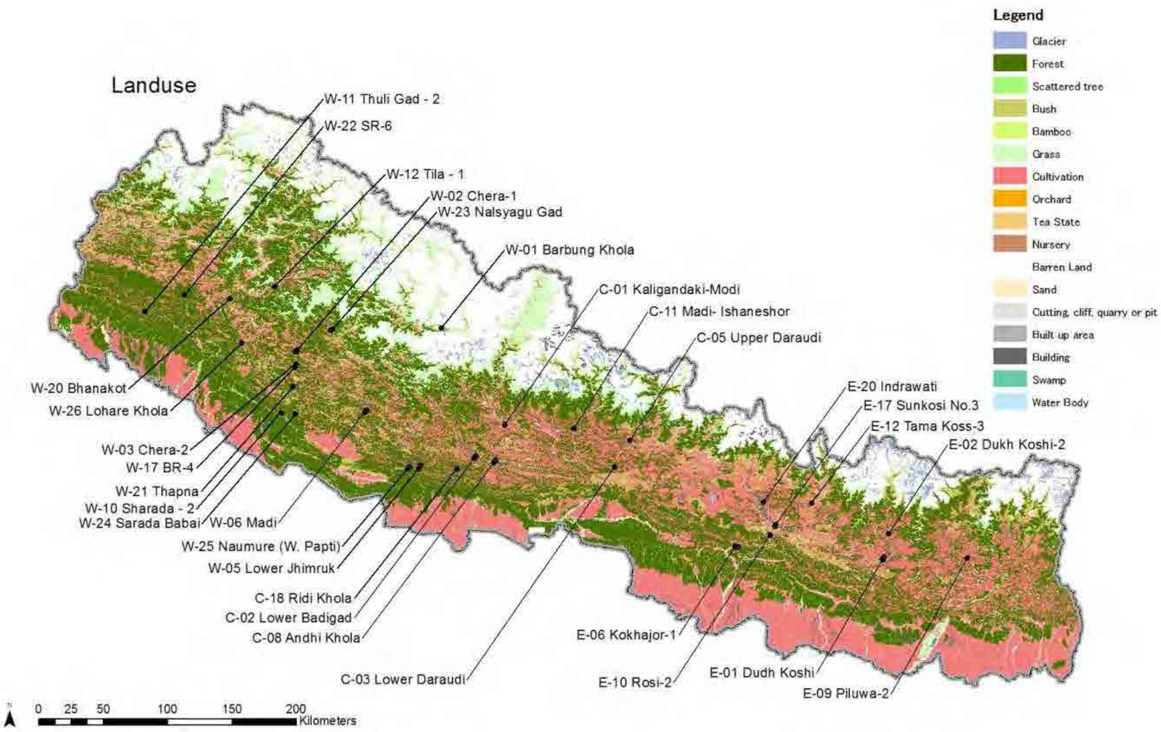
Table 4.3-2 Definition of Janajati

"Nationality (Janajati) is that community which has its own mother tongue and traditional culture, and yet does not fall under the conventional four folds of Varna of Hinduism or the Hindu hierarchical caste structure. A Janajati group has the following characteristics: • A distinct collective identity • Its own language, religion, tradition, culture and civilization; its own traditional egalitarian social structure • Traditional homeland or geographical area • Written or oral history • Having a "feeling of "us"" • Have had no decisive role in politics and government in modern Nepal; Who declares themselves as "Janajati""

Source: The National Committee for Development of Nationalities (1996)

4.4 Land Use

The land above an elevation of around 4,000 m is covered with ice and snow and elevations below 4,000 m are covered with forest and cultivated areas. Low land around the Indian border and the Kathmandu Valley are mainly used as cultivated areas. Figure 4.4-1 shows the Land Use map.



Source: 1:25,000 and 1:50,000 topography map (Survey Department, Nepal)

Figure 4.4-1 Land Use Map

4.5 Rafting

Rafting is one of the more popular tourism activities in Nepal. The main rafting routes are in the Karnali and Gandaki river systems. According to Nepal Tourism Statistics (2011), the number of tourists for rafting has been increasing 262% per year since 2007. It has been reported that 2,181 tourists enjoyed rafting in 2011. The main rafting routes are in the Karnali, Gandaki, and Koshi river systems. Figure 4.5-1 shows the main rafting routes.

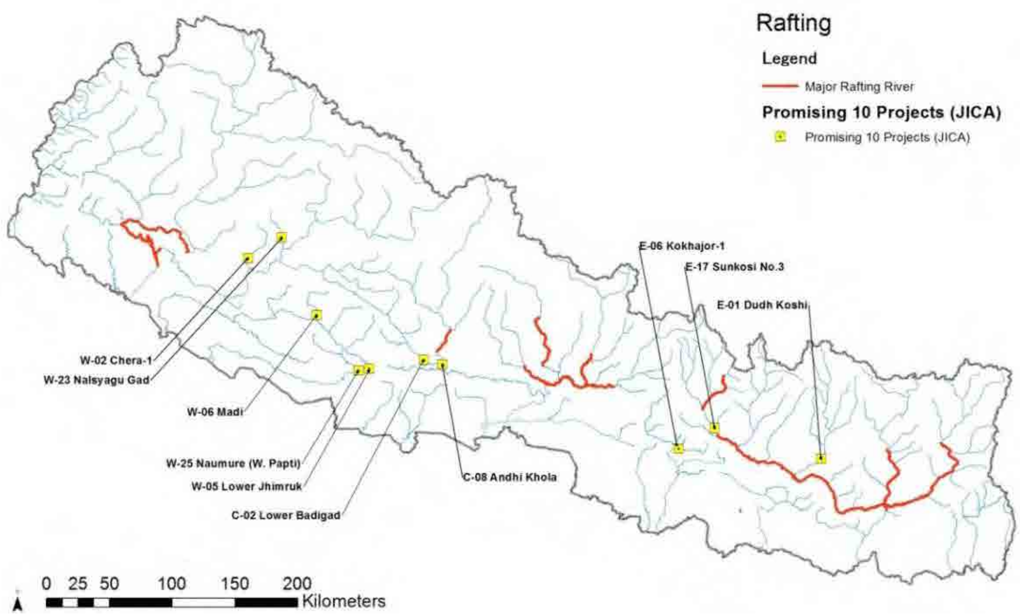


Figure 4.5-1 Rafting Map

Chapter 5

Social and Economic Situation

Chapter 5 Social and Economic Situation

5.1 Administration and Population

The administration map of the Federal Democratic Republic of Nepal (hereinafter referred to as "Nepal") is shown in Figure 5.1-1, which also indicates the distribution of population by the administration units of Nepal and the districts' development rankings. There are five Development Regions and fourteen Zones in Nepal. Under the Zones, 75 Districts, 58 municipalities, and 3,900 Village Development Committees (VDCs) are established as local governments. One VDC consists of 9 Wards, which contains several villages.

Local Government act 1992 establishes the framework of administrative and local governance, and defines the District Development Committee, Municipality, and VDC as administrative bodies of local governments. In addition to the act, the Local Self Governance Act 1999 also provides overall institutional arrangements, functions, and procedures of local governments (Sakumasu, 2010).

Source: ESRI Japan；Study Team.

Figure 5.1-1 Administration Map of Nepal

Table 5.1-1 Distribution and Growth of Population by Administration Units in Nepal (1/2)

Region	Zone	District	Eco-zone	Development ranking *1	Area	Population in 2001			Population in 2011			2001-2011 increase
						Total	% to national total	Pop. density	Total	% to national total	Pop. density	
					km2		%	/km2		%	/km2	%
Eastern	Mechi	Taplejung	Mountain	40	3,646	134,698	0.6%	37	127,461	0.5%	35	-5.4%
		Panchthar	Hill	42	1,241	202,056	0.9%	163	191,817	0.7%	155	-5.1%
		Ilam	Hill	12	1,703	282,806	1.2%	166	290,254	1.1%	170	2.6%
		Jhapa	Terai	11	1,606	688,109	3.0%	428	812,650	3.1%	506	18.1%
	Koshi	Morang	Terai	29	1,855	843,220	3.6%	455	965,370	3.6%	520	14.5%
		Sunsari	Terai	23	1,257	625,633	2.7%	498	763,487	2.9%	607	22.0%
		Dhankuta	Hill	13	891	166,479	0.7%	187	163,412	0.6%	183	-1.8%
		Terhathum	Hill	36	679	113,111	0.5%	167	101,577	0.4%	150	-10.2%
		Sankhuwasabha	Mountain	19	3,480	159,203	0.7%	46	158,742	0.6%	46	-0.3%
		Bhojpur	Hill	32	1,507	203,018	0.9%	135	182,459	0.7%	121	-10.1%
	Sagarmatha	Solukhumbu	Mountain	44	3,312	107,686	0.5%	33	105,886	0.4%	32	-1.7%
		Okhaldhunga	Hill	50	1,074	156,702	0.7%	146	147,984	0.6%	138	-5.6%
		Khotang	Hill	48	1,591	231,385	1.0%	145	206,312	0.8%	130	-10.8%
		Udayapur	Hill	45	2,063	287,689	1.2%	139	317,532	1.2%	154	10.4%
		Saptari	Terai	46	1,363	570,282	2.5%	418	639,284	2.4%	469	12.1%
		Siraha	Terai	64	1,188	572,399	2.5%	482	637,328	2.4%	536	11.3%
	Sub-total/average				28,456	5,344,476	23.1%	188	5,811,555	21.9%	204	8.7%
Central	Janakpur	Dhanusa	Terai	37	1,180	671,364	2.9%	569	754,777	2.8%	640	12.4%
		Mahottari	Terai	61	1,002	553,481	2.4%	552	627,580	2.4%	626	13.4%
		Sarlahi	Terai	52	1,259	635,701	2.7%	505	769,729	2.9%	611	21.1%
		Sindhuli	Hill	51	2,491	279,821	1.2%	112	296,192	1.1%	119	5.9%
		Ramechhap	Hill	56	1,546	212,408	0.9%	137	202,646	0.8%	131	-4.6%
		Dolakha	Hill	35	2,191	204,229	0.9%	93	186,557	0.7%	85	-8.7%
	Bagmati	Sindhupalchok	Mountain	43	2,542	305,857	1.3%	120	287,798	1.1%	113	-5.9%
		Kavrepalanchok	Hill	6	1,396	385,672	1.7%	276	381,937	1.4%	274	-1.0%
		Lalitpur	Hill	3	385	337,785	1.5%	877	468,132	1.8%	1,216	38.6%
		Bhaktapur	Hill	2	119	225,461	1.0%	1,895	304,651	1.1%	2,560	35.1%
		Kathmandu	Hill	1	395	1,081,845	4.7%	2,739	1,744,240	6.6%	4,416	61.2%
		Nuwakot	Hill	26	1,121	288,478	1.2%	257	277,471	1.0%	248	-3.8%
		Rasuwa	Mountain	59	1,544	44,731	0.2%	29	43,300	0.2%	28	-3.2%
		Dhading	Hill	41	1,926	338,658	1.5%	176	336,067	1.3%	174	-0.8%
		Makwanpur	Hill	15	2,426	392,604	1.7%	162	420,477	1.6%	173	7.1%
	Narayani	Rautahat	Terai	53	1,126	545,132	2.4%	484	686,722	2.6%	610	26.0%
		Bara	Terai	49	1,190	559,135	2.4%	470	687,708	2.6%	578	23.0%
		Parsa	Terai	39	1,353	497,219	2.1%	367	601,017	2.3%	444	20.9%
		Chitawan	Terai	4	2,218	472,048	2.0%	213	579,984	2.2%	261	22.9%
	Sub-total/average				27,410	8,031,629	34.7%	293	9,656,985	36.4%	352	20.2%
Western	Gandaki	Gorkha	Hill	25	3,610	288,134	1.2%	80	271,061	1.0%	75	-5.9%
		Lamjung	Hill	28	1,692	177,149	0.8%	105	167,724	0.6%	99	-5.3%
		Tanahu	Hill	10	1,546	315,237	1.4%	204	323,288	1.2%	209	2.6%
		Syangja	Hill	9	1,164	317,320	1.4%	273	289,148	1.1%	248	-8.9%
		Kaski	Hill	5	2,017	380,527	1.6%	189	492,098	1.9%	244	29.3%
		Manang	Mountain	20	2,246	9,587	0.0%	4	6,538	0.0%	3	-31.8%
	Dhaualagiri	Mustang	Mountain	14	3,573	14,981	0.1%	4	13,452	0.1%	4	-10.2%
		Myagdi	Hill	34	2,297	114,447	0.5%	50	113,641	0.4%	49	-0.7%
		Parbat	Hill	17	494	157,826	0.7%	319	146,590	0.6%	297	-7.1%
		Baglung	Hill	16	1,784	268,937	1.2%	151	268,613	1.0%	151	-0.1%

Table 5.1-1 Distribution and Growth of Population by Administration Units in Nepal (2/2)

Region	Zone	District	Eco-zone	Development ranking *1	Area	Population in 2001			Population in 2011			2001-2011
						Total	% to national total	Pop. density	Total	% to national total	Pop. density	increase
					(km²)		%	/km²		%	/km²	%
Western	Lumbini	Gulmi	Hill	33	1,149	296,654	1.3%	258	280,160	1.1%	244	-5.6%
		Palpa	Hill	7	1,373	268,558	1.2%	196	261,180	1.0%	190	-2.7%
		Nawalparasi	Terai	30	2,162	562,870	2.4%	260	643,508	2.4%	298	14.3%
		Rupandehi	Terai	8	1,360	708,419	3.1%	521	880,196	3.3%	647	24.2%
		Kapilbastu	Terai	55	1,738	481,976	2.1%	277	571,936	2.2%	329	18.7%
		Arghakhanchi	Hill	27	1,193	208,391	0.9%	175	197,632	0.7%	166	-5.2%
	Sub-total/average				29,398	4,571,013	19.7%	155	4,926,765	18.6%	168	7.8%
Mid-Western	Rapti	Pyuthan	Hill	54	1,309	212,484	0.9%	162	228,102	0.9%	174	7.4%
		Rolpa	Hill	66	1,879	210,004	0.9%	112	224,506	0.8%	119	6.9%
		Rukum	Hill	58	2,877	188,438	0.8%	65	208,567	0.8%	72	10.7%
		Salyan	Hill	47	1,462	213,500	0.9%	146	242,444	0.9%	166	13.6%
		Dang	Terai	22	2,955	462,380	2.0%	156	552,583	2.1%	187	19.5%
	Bheri	Banke	Terai	24	2,337	385,840	1.7%	165	491,313	1.9%	210	27.3%
		Bardiya	Terai	38	2,025	382,649	1.7%	189	426,576	1.6%	211	11.5%
		Surkhet	Hill	31	2,451	288,527	1.2%	118	350,804	1.3%	143	21.6%
		Dailekh	Hill	67	1,502	225,201	1.0%	150	261,770	1.0%	174	16.2%
		Jajarkot	Hill	62	2,230	134,868	0.6%	60	171,304	0.6%	77	27.0%
	Karnali	Dolpa	Mountain	70	7,889	29,545	0.1%	4	36,700	0.1%	5	24.2%
		Jumla	Mountain	68	2,531	89,427	0.4%	35	108,921	0.4%	43	21.8%
		Kalikot	Mountain	69	1,741	105,580	0.5%	61	136,948	0.5%	79	29.7%
		Mugu	Mountain	75	3,535	43,937	0.2%	12	55,286	0.2%	16	25.8%
		Humla	Mountain	74	5,655	40,595	0.2%	7	50,858	0.2%	9	25.3%
	Sub-total/average				42,378	3,012,975	13.0%	71	3,546,682	13.4%	84	17.7%
Far-Western	Seti	Bajura	Mountain	71	2,188	108,781	0.5%	50	134,912	0.5%	62	24.0%
		Bajhang	Mountain	73	3,422	167,026	0.7%	49	195,159	0.7%	57	16.8%
		Achham	Hill	72	1,680	231,285	1.0%	138	257,477	1.0%	153	11.3%
		Doti	Hill	63	2,025	207,066	0.9%	102	211,746	0.8%	105	2.3%
		Kailali	Terai	21	3,235	616,697	2.7%	191	775,709	2.9%	240	25.8%
	Mahakali	Kanchanpur	Terai	18	1,610	377,899	1.6%	235	451,248	1.7%	280	19.4%
		Dadeldhura	Hill	65	1,538	126,162	0.5%	82	142,094	0.5%	92	12.6%
		Baitadi	Hill	57	1,519	234,418	1.0%	154	250,898	0.9%	165	7.0%
		Darchula	Mountain	60	2,322	121,996	0.5%	53	133,274	0.5%	57	9.2%
	Sub-total/average				19,539	2,191,330	9.5%	112	2,552,517	9.6%	131	16.5%
National Total/average					147,181	23,151,423	100.0%	157	26,494,504	100.0%	180	14.4%

Note: 1) Development ranking based on the Composite Index (Source: Central Bureau of Statistics. 2003. District level indicators of Nepal for monitoring overall development. Kathmandu, Nepal.)

Source: Central Bureau of Statistics. 2001. National population census 2001. Kathmandu.; Central Bureau of Statistics. 2011. National population and housing census 2011. Kathmandu.

Table 5.1-1 shows district-wise population distributions in 2001 and 2011. In the period from 2001-2011, the national population increased by 14.4%. In the Eastern Development Region, Central Development Region and Western Development Region, the population decreased in the Mountain Eco-zone where the population density is low, and it increased in urban areas and the Terai Eco-zone. The Central Development Region and Eastern Development Region, which are characterized by outmigration from rural areas and growth in urban population, are the major economic centers in Nepal. Particularly as shown in Table 5.1-1, Kathmandu and its vicinity as well as the Terai areas in the regions with high population density are considered the center of the nation's economy, where the road networks are fairly well developed (Figure 5.1-2). In terms of electricity consumption, the Central Development Region and Eastern Development Regions, including these economic centers, have been the major load centers.

Source: Department of Roads, Ministry of Physical Planning and Works, Government of Nepal, 2010.

Figure 5.1-2 Major Roads in Nepal (2010)

5.2 Economy

Regarding the forecasts of electricity consumption introduced in Chapter 7 in this report, the period from FY1991/92 to FY2011/12 is set as a term for analysis of the past development of various economic parameters, and the period from FY2012/13 to FY2031/32 is set as the period for forecasting. In the forecasting, the Nepali economy is categorized into the domestic sector, industry sector, commerce and service (service) sector, irrigation (agriculture) sector, and other sectors mainly consisting of the public sector, and power demand forecasts were conducted for all the sectors. Therefore, the sectors' economic conditions are described to help examine parameters used in the forecasts. Table 5.2-1 shows GDP and related indicators since 1992 used for the demand forecasts.

In Nepal political instability is one of the major constraints for the recent deceleration of economic growth. In 2011 GDP showed 3.5% growth, which is significantly lower than the average growth rate of 5% during the period of 2007-2010. It was predicted that the GDP growth in 2012 would not reach 4%. The reasons for this anticipated low economic performance are continuing political instability, worsening security, and labor disputes which are particularly affecting industry (e.g. textile and food processing) and service sector performance and their growth in output.

The industry sector continuously demonstrates very sluggish performance. In 2011 GDP growth of the sector was 1.4%, which is slightly higher than the average growth rate of 1.2% for the period of 2008-2010. However, this does not indicate recovery of the sector. According to the interviews with business associations, load shedding became a very serious obstacle for their business operation in addition to political instability and labor problems. As shown in Figure 5.2-1, GDP share of the industry sector exceeded 20% in the 1990s, which has declined to 14% by 2011. This has resulted particularly from under performance of the manufacturing sub-sector in the industry sector. During the past 10 years, the manufacturing sub-sector only showed 0.3% growth, and from the mid-2000s it has shown an average growth of -0.3%. In 2011 the power and gas subsector showed a decline of -4%, calling for urgent measures to address its low performance. Addressing and mitigating the large supply and demand gap in the electricity market through development of hydropower is a prerequisite for an increase in productivity and production of the manufacturing sector to achieve economic growth in Nepal.

During the period from 2007-2010, GDP of the commerce and service sector grew on average by 6%, and the sector has been considered the performing and driving sector. However, in 2011 due to decline in purchasing power resulting from the slow growth of remittance from Nepali workers outside of Nepal, the sector exhibited only 3% GDP growth. Since the major source of investment funds provided by the financial sector has been remittance, slow growth of remittance should result in a tight supply for domestic money for investment.

In 2011, favorable weather resulted in 4.2% GDP growth of the agriculture sector. The growth is 1.3% higher than that of the previous year. A high growth of 3.7% of the sector is expected in 2012.

One of the characteristics of the current Nepali economy is a heavy dependence on remittance of Nepali workers outside of Nepal. The remittance is estimated to reach 25% of the GDP in 2011. As shown in Figure 5.2-2, the ratios of remittance to GDP have increased significantly during the 2000s. This indicates that the Nepali economy has become susceptible to the conditions of the international economy and political situations. For example, growth of the remittance declined from 48% in 2008 to 12% in 2011 due to the sluggish world economy and the deterioration of security in the Middle East, which is one of the major destinations of Nepali workers. As mentioned above, this has resulted in the deterioration of commerce and service sector growth. Increased purchasing power due to increased remittance is able to stimulate GDP growth. However, because the remittance is not a result of increased domestic production capacity, it does not directly contribute to the expansion of the country’s economy. For achievement of sustainable economic development, long-term investment for economic infrastructure including power is necessary. Obtaining sufficient financial resources the from domestic capital market under a low performing economy needs to be addressed.

In 2011 the real wage level had increased. Because of the recent fiscal expansion of the Government of Nepal, the economy has shown an inflationary trend. Demands for wage increases more than the rate of inflation are strong. In 2011, the national average wage level increased by

31%. Wages of agricultural workers, construction workers, and other workers have increased by 40%, 30%, and 33%, respectively. The high wage rates are partly attributed to the tight domestic labor market caused by outmigration of a large number of productive workers[1].

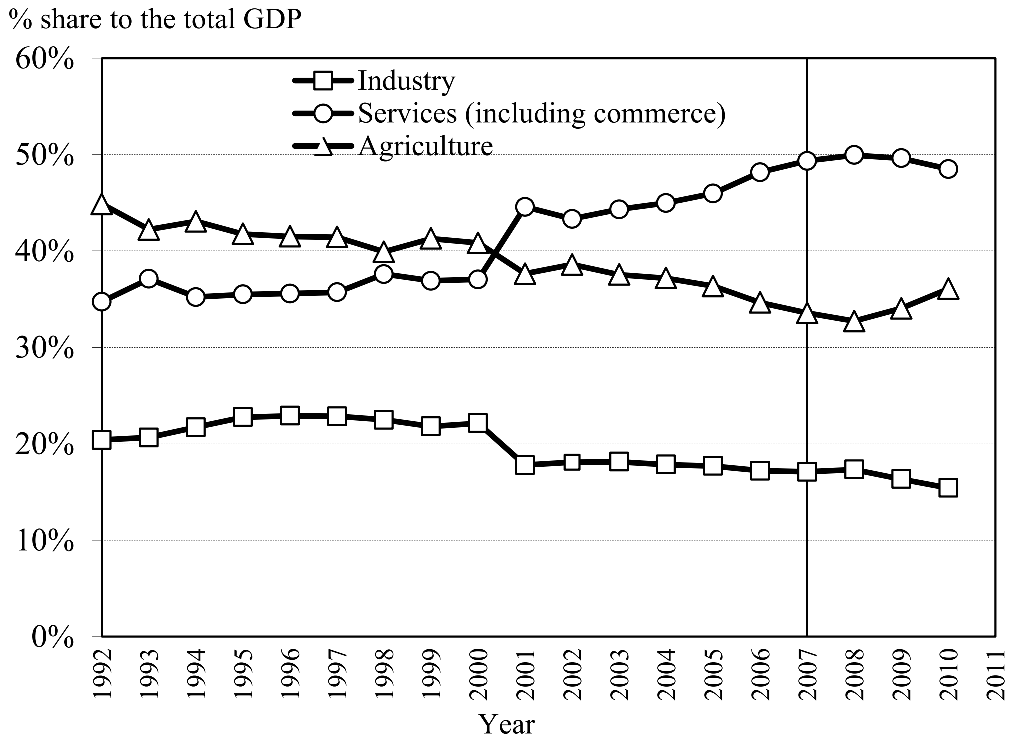
In 2011, the development aid budget reached 6% of GDP. However, due to the limited absorption capacity of the Government of Nepal, actual execution of donor funds should be lower than this figure.

1 According to 2011 national census 1.9 million Nepali workers which is about 14% of productive population are migrated to work outside of the country.

Table 5.2-1 GDP and Related Indicators

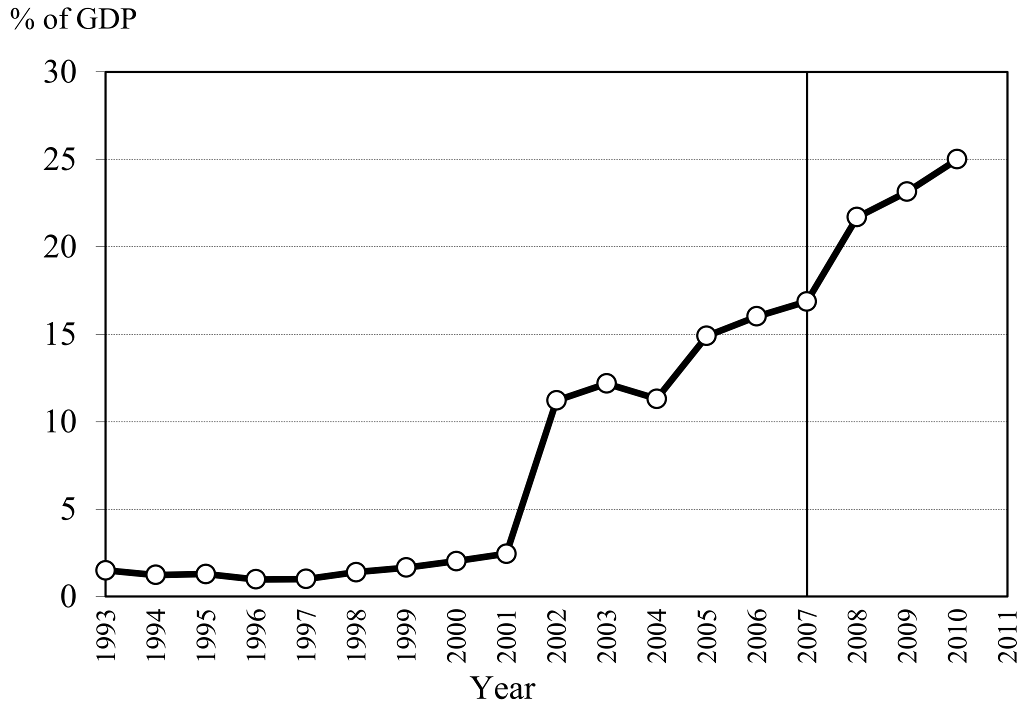
Categories	Unit	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
GDP (at 2010 constant value)																					
GDP Total	(Billion Rp)	545	566	613	634	668	701	723	754	801	840	841	874	915	947	978	1,012	1,074	1,121	1,172	
Value added total	(Billion Rp)	518	535	575	593	626	656	677	707	751	786	787	817	853	881	914	940	994	1,032	1,062	
Industry	(Billion Rp)	106	111	125	135	143	150	152	154	166	140	142	148	152	156	157	161	172	169	164	
Services	(Billion Rp)	180	198	203	210	223	234	255	261	278	350	341	362	384	405	440	464	496	512	515	
Agriculture	(Billion Rp)	233	226	248	247	260	272	270	292	306	296	304	307	317	320	317	315	325	351	383	
Taxes, etc.	(Billion Rp)	27	31	37	41	41	45	45	47	51	53	53	57	61	66	64	72	79	89	110	
GDP Composition																					
GDP Total	(%)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
Value added total	(%)	95%	94%	94%	93%	94%	94%	94%	94%	94%	94%	94%	94%	93%	93%	93%	93%	93%	92%	91%	
Industry	(%)	19%	20%	20%	21%	21%	21%	21%	20%	21%	17%	17%	17%	17%	16%	16%	16%	16%	15%	14%	
Services	(%)	33%	35%	33%	33%	33%	33%	35%	35%	35%	42%	41%	41%	42%	43%	45%	46%	46%	46%	44%	
Agriculture	(%)	43%	40%	40%	39%	39%	39%	37%	39%	38%	35%	36%	35%	35%	34%	32%	31%	30%	31%	33%	
Taxes, etc.	(%)	5%	6%	6%	7%	6%	6%	6%	6%	6%	6%	6%	6%	7%	7%	7%	7%	7%	8%	9%	
GDP Growth (at 2010 constant value)																					
GDP Growth	(%)	4.1%	3.8%	8.2%	3.5%	5.3%	5.0%	3.0%	4.4%	6.2%	4.8%	0.1%	3.9%	4.7%	3.5%	3.4%	3.4%	6.1%	4.4%	4.6%	3.5%
Value added growth	(%)	4.5%	3.2%	7.6%	3.0%	5.7%	4.8%	3.1%	4.4%	6.2%	4.7%	0.2%	3.8%	4.4%	3.2%	3.8%	2.8%	5.8%	3.8%	2.9%	
Industry																					
Before tax	(%)	16.8%	4.8%	9.0%	4.0%	8.3%	6.4%	2.3%	6.0%	8.2%	3.6%	0.9%	3.1%	1.4%	3.0%	4.5%	3.9%	1.7%	-1.4%	3.3%	1.4%
After tax	(%)	22.8%	4.5%	13.0%	7.9%	6.4%	4.6%	1.5%	1.3%	7.7%	-15.8%	1.8%	4.1%	2.7%	2.3%	0.9%	2.2%	7.3%	-2.1%	-2.8%	
Service	(%)																				
Before tax	(%)	6.4%	7.2%	7.2%	5.6%	5.4%	4.9%	6.4%	5.4%	6.1%	6.0%	-2.6%	4.4%	5.3%	3.1%	5.2%	3.8%	7.4%	6.3%	6.3%	3.0%
After tax	(%)	2.5%	10.2%	2.1%	3.8%	5.9%	5.2%	8.6%	2.5%	6.6%	26.0%	-2.6%	6.1%	6.0%	5.5%	8.8%	5.3%	7.1%	3.1%	0.6%	
Agriculture	(%)																				
Before tax	(%)	-1.1%	-0.6%	7.6%	-0.3%	4.4%	4.1%	1.0%	2.7%	5.0%	4.3%	3.1%	3.3%	4.8%	3.5%	1.8%	1.0%	5.8%	3.0%	1.3%	4.1%
After tax	(%)	-0.7%	-2.9%	9.7%	-0.1%	5.0%	4.7%	-0.7%	8.1%	4.9%	-3.4%	2.7%	0.9%	3.4%	0.9%	-1.1%	-0.4%	3.2%	7.9%	9.1%	
Taxes, etc.	(%)	-3.3%	17.0%	19.5%	10.4%	0.5%	8.3%	1.4%	4.0%	6.8%	5.7%	-0.5%	6.6%	8.5%	7.0%	-2.2%	12.4%	10.0%	12.4%	23.3%	
GDP per capita (at 2010 constant value)																					
GDP par capita	(Rp)	27,198	27,553	29,084	29,353	30,159	30,908	31,069	31,663	32,834	33,611	32,885	33,423	34,236	34,694	35,151	35,658	37,139	38,082	39,116	
Growth	(%)	1.6%	1.3%	5.6%	0.9%	2.7%	2.5%	0.5%	1.9%	3.7%	2.4%	-2.2%	1.6%	2.4%	1.3%	1.3%	1.4%	4.2%	2.5%	2.7%	
Indicies																					
Consumer Price Index (CPI)																					
Index (2010=100)		30.0	32.3	35.0	37.6	41.1	42.8	47.6	51.1	52.4	53.8	55.4	58.6	60.3	64.4	69.2	73.5	81.5	90.9	100.0	109.6
Annual change	(%)	17.1%	7.5%	8.3%	7.6%	9.2%	4.0%	11.2%	7.5%	2.5%	2.7%	3.0%	5.7%	2.8%	6.8%	7.6%	6.1%	10.9%	11.6%	10.0%	9.6%
GDP Deflator																					
Index		28.0	31.0	32.5	34.6	37.3	40.0	41.6	45.3	47.4	52.6	54.7	56.3	58.7	62.3	66.9	71.9	76.0	88.2	100.0	
Anncual change	(%)	18.5%	10.8%	4.8%	6.3%	7.8%	7.3%	4.1%	8.9%	4.5%	11.0%	3.9%	3.1%	4.2%	6.1%	7.4%	7.6%	5.6%	16.0%	13.4%	

Note: 1USD = 80Rs and 1USD = 80yen
Source: World Bank, 2011; Study Team



Source: World Bank, 2011

Figure 5.2-1 Historical Evolution of GDP Share of Sectors



Source: World Bank, 2011

Figure 5.2-2 Remittance from Abroad by Emigrant Workers

Chapter 6

Current Situation of the Power Sector in Nepal

Chapter 6 Current Situation of the Power Sector in Nepal

6.1 Energy Policies and Energy Supply

6.1.1 Energy Policies

The responsibilities of formulation and implementation, and monitoring and evaluation policy implementation are vested to the Ministry of Energy in Nepal. The Ministry of Forests and Soil Conservation, Ministry of Agriculture and Co-operatives, Ministry of Commerce and Supplies, Ministry of Environment, Ministry of Industry, National Planning Commission, Water and Energy Commission, Nepal Electricity Authority (NEA) Alternative Energy Promotion Centre, Timber Corporation of Nepal, and the Nepal Oil Corporation as public sector organizations are also involved in development and implementation of energy policies and strategies and coordination among concerned organizations. Table 6.1.1-1 shows the policies, strategies, laws and regulations applied to guide, regulate and enhance energy development, production and utilization. The energy policies are widely linked with other industrial policies and strategies, and contribute to industrial and commerce development[1].

Table 6.1.1-1 Policy Documents Guiding Energy Production, Development and Utilization

Titles of Policy Documents
Periodic development plans
Forest sector policies
Electricity Act 1992
Foreign Investment and One-window Policy 1992
Foreign Investment and Technology Transfer Act 1992
Forest Act 1992
Hydropower Development Policy 1992
Industrial Enterprises Act 1992
Industrial Policy 1992
Water Resources Act 1992
Environment Protection Act 1996
Hydropower Development Policy 2001
Water Resources Strategy 2002
Rural Energy Policy 2006
National Electricity Crisis Resolution Action Plan 2008
National Water Plan 2008
Report of the Task Force for Hydropower Development 2008
Nepal National Energy Strategy (draft in 2010)

Source: Sapkota, P. Pralhad. 2010.

The draft Nepal National Energy Strategy 2010[2] defines the foundation of the energy policy of Nepal. The vision of the strategy is that to achieve sustainable economic development and poverty reduction, natural resources are to be developed and utilized in an efficient manner to achieve energy security and to meet the nation's energy demands. To achieve this vision, the following strategic objectives are

[1] Sapkota, P. Pralhad. 2010. A country report of Nepal - presented at a training program on energy policy, Japan. Kathmandu: Ministry of Energy, Government of Nepal.

[2] In 2013 this strategy is still a draft strategy.

defined: 1) sustainable development and utilization of biomass energy, 2) hydropower as the main energy source, 3) lowering dependency on fossil energy sources, 4) development of alternative energy sources such as biomass, gas, solar and wind power.

Since 2010, the establishment of a new Law of Electricity has been under consideration. The Law is expected to include clauses defining: 1) the transparent process of granting power development licenses with a date of license expiration, 2) development of competitive power markets including domestic, export and import markets, 3) disbanding of generation, transmission, and distribution businesses, 4) improvement of private sector investment environment in the power sector, 5) reorganization of royalty arrangements, and 6) establishment of an independent power sector regulatory committee.

6.1.2 Energy Supply and Demand

The summary of energy demand and supply in 2005 in Nepal is shown in Table 6.1.2-1. A large portion of energy demand is met by the traditional energy sources such as firewood, charcoal, biomass and animal dung even in the year 2013. Among modern industrial energy sources such as petroleum, fossil fuel, natural gas, electricity, coal and renewable energy, a high dependence on fossil fuel is observed. All of the fossil fuel is imported by Nepal Oil Corporation, which monopolizes fossil fuel imports, distribution, and retail channels. Recently the demand of industrial energy sources has increased rapidly, and the Ministry of Energy gives high priority to the diversification of industrial energy sources to decrease dependence on imported energy sources and the realization of an open and competitive fossil fuel market by mobilizing private sector investment for the development of domestic hydropower projects.

Table 6.1.2-1 Energy Sources and Consumption in 2005

Energy source	Energy consumption	
	('000 GJ)	(% to total)
Traditional energy		
Firewood	286,960	78.1%
Biomass	13,964	3.8%
Animal dung	21,181	5.8%
Sub-total	322,105	87.7%
Commercial energy		
Petroleum	30,063	8.2%
Electricity	6,673	1.8%
Coal	6,459	1.8%
Sub-total	43,195	11.8%
Renewable energy	1,955	0.5%
Total	367,255	100.0%

Source: Sapkota, P. Pralhad. 2010.

6.1.3 Primary Energy Resources

The primary energy resources found in Nepal to meet most of the domestic demand are traditional energy resources such as firewood, biomass and animal dung. Although not fully exploited, Nepal has the large hydropower development potential not only to meet domestic demand, but also to export an excess supply of hydroelectric power. However, there are no petroleum, natural gas and coal resources, and most of such energy sources are imported from India. Currently there is no prospect of supplying these resources domestically[3].

6.2 Policies and Major Institutions of the Power Sector

6.2.1 Basic Power Sector Policies

The visions and long-term objectives of the power sector in Nepal are identified in the following policy documents.

(1) Hydropower Development Policy 2001:

The policy developed by the Ministry of Energy in 2011 defines objectives and rules to govern the hydroelectric sector. It provides for (i) the functions pertaining to the operation of the power centers, operation of electricity transmission and the national grid, and electricity distribution owned by the NEA; (ii) the creation of an independent (power) system operator; and (iii) encouragement of local body, community, and private sector participation in the operation of the electricity distribution system (ADB 2009). The policy does not provide a particular set of numerical targets.

(2) National Water Resource Strategy 2002:

The strategy was formulated by the Nepal Water and Energy Commission in 2002. Objectives of the policy are to fulfill basic human needs by 2007 and to realize maximum economic benefits by 2017 through effective utilization of water resources, and to achieve sustainable water resource management by 2027. This strategy has the key policy directives regarding the power sector. The document states that (i) the NEA is to become commercially viable through corporatization, improved management, and separation of its rural electrification operations; (ii) the NEA is to be unbundled by separately creating a transmission/load dispatch center; (iii) generation will be the responsibility of a separate corporation; (iv) distribution operations will be sold or contracted out to municipal or private operators; and (v) the NEA will operate as a holding company (ADB 2009).

(3) Three-Year Interim Plan (2008 - 2010):

The plan was established by the National Planning Commission in 2007 as a medium-term plan for the period from 2008-2010. The long-term vision for the power sector specified in this plan is the utilization of water resources to meet domestic power demand and the export of surplus power to increase the country's foreign earnings. Some of the key strategies to be adopted are (i) introducing effective regulation of generation, transmission, and distribution of electricity and related businesses; (ii) adopting a one-stop-shop approach to encourage investments in

[3] Asian Development Bank. 2013. South Asia working paper series: An overview of energy cooperation in South Asia. Manila: ADB.

hydropower development to allow investors to obtain all approvals from a single agency; (iii) consistent efforts in the expansion of electricity generation potential; (iv) expanding transmission capacity, targeting both local consumption and export potential; and (v) strengthening and expanding the electricity distribution system (ADB 2009). The plan envisages that 704 MW of generation capacity is to be achieved by 2010, and a total of Rs. 57 billion is to be invested in power development by the private and public sectors.

6.2.2 Major Institutions and their Functions in the Power Sector

The functions of major institutions of the power sector in Nepal are shown in Table 6.2.2-1. Within the Government of Nepal, the Ministry of Energy is responsible for formulation and implementation of energy sector policies. The Department of Electricity Development of the Ministry is responsible for promoting development of potential hydropower, establishment of transmission and distribution standards, and investigation and monitoring of power businesses. The Electricity Tariff Fixation Committee (ETFC) has the authority to examine and approve tariff proposals prepared by the NEA and/or IPPs. It is envisaged that in the near future the authorities of ETFC will be transferred to the Nepal Electricity Regulatory Commission (NERC), which is independent from the Government of Nepal with respect to fixation of electricity tariffs. Bills for establishment of the NERC were drafted and waiting approval by the Parliament. The NEA, which is owned by the Government, is responsible for generation, purchasing and trading, transmission, and distribution of power.

In addition to these organizations, privately owned Independent Power Producers (IPP) have been playing an important role in the power sector in Nepal since 1991. The Hydropower Development Policy 1991 and Electricity Act 1992 allow and promote participation of the private sector in the power sector. Since then, 25 IPPs (26 power stations) have participated mainly in hydropower generation, with a total generation capacity of 187.6 MW in 2012. The NEA has established Power Purchase Agreements (PPAs) with the IPPs to procure electricity in 2012. In addition, the NEA has negotiated with 22 IPPs for PPAs with 68 MW of capacity. The hydropower stations of the IPPs are under construction.

Table 6.2.2-1 Functions and Responsibilities of Power Sector Organizations

	Ministry of Energy (MOE)	Water and Energy Commission Secretariat (WECS)	Department of Electricity Development (DOED)	Electricity Tariff Fixation Committee (ETFC)	Nepal Electricity Authority (NEA)	Independent Power Producers (IPPs)
Hydropower development	●	○	●		○	○
Generation	○				●	○
Power sector policy	●	○	○			
System planning	○	○			●	
Project identification		○	●		○	○
Project selection			●		●	
Project licensing	●		○			
IPP promotion			●			○
Single Buyer/IMO					●	
Dispatch and high voltage transmission					●	
Distribution (< 66 kV)					●	
Bulk power export	●	○	○		○	
Multipurpose project	●	●	○		○	
Price regulation			○	●		
Other regulations	●		○			

Note: ● = Lead Role ○ = Supporting Role
Source: ADB, 2004. (Edited by the Study Team)

6.2.3 Nepal Electricity Authority (NEA): Current Development

The Nepal Electricity Authority (NEA) is a nationally owned parastatal organization established in 1985. Until 1991, the NEA monopolized power development, generation, transmission, and distribution activities. The Electricity Act 1992 effectively ended the NEA's monopoly, and power market revitalization had begun with participation of the private sector in the power sector. However, up to now, private sector participation as IPPs has been limited to generation only, and the NEA is still the major player in transmission and distribution. Since 1991, the NEA has adopted a Single Buyer Model under which, for example, the NEA procured 27% of the total electricity distributed[4]. However, because the NEA does not have the authority to issue power development licenses to IPPs, or to control IPPs' power development plans, the NEA is able to confirm the supply capacity of power only after Power Purchase Agreements are signed with concerned IPPs. This prohibits the NEA to establish a long-term power development plan. The responsibility of the licensing is vested to the Ministry of Energy; however, actual development by licensed IPPs depends on the progress of identification of investors, financing, construction, and generation. Therefore, even for the ministry, it is not clear when the licensed power developments will be materialized. Although market liberalization is the current policy direction, there is no central organization responsible for development of a long-term development plan and its implementation to guide the power sector to become liberalized.

Currently the NEA is an organization where generation, transmission, and distribution operations are vertically organized. However, according to the power market liberalization policy, the NEA is envisaged to be unbundled to establish independent companies, and the organizational restructuring

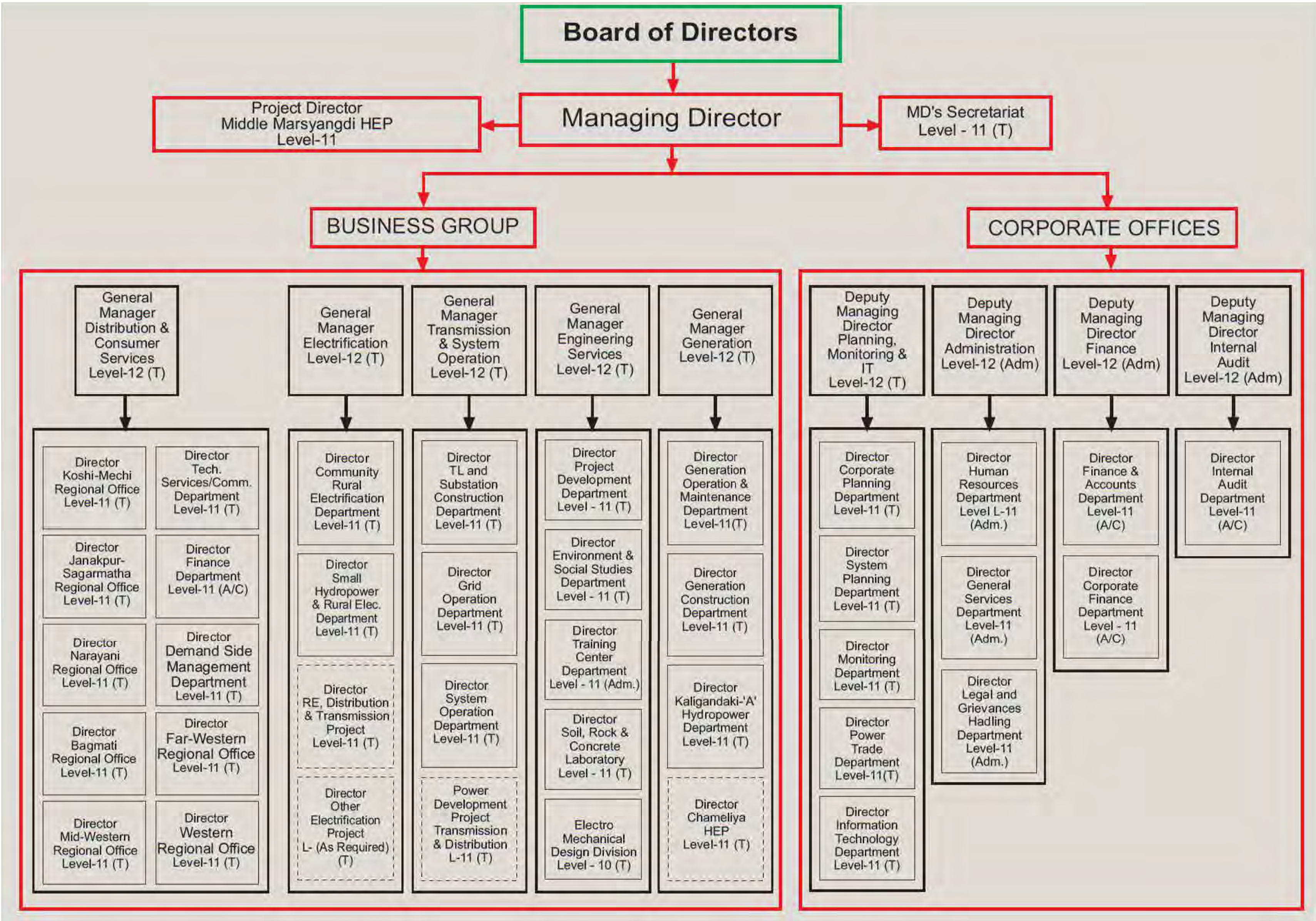
[4] In a PPA agreed between the NEA and an IPP, it employs a "Take-or- pay" procurement scheme. According to the scheme, the NEA has an obligation to purchase an agreed amount of power at an agreed price even though it is at a time when the NEA does not need to purchase power due to its own excess capacity to generate electricity. Because of this contractual arrangement, the NEA dispatches procured electricity from IPPs with the highest priority.

that took place in 2011 is considered a part of the unbundling process. In January 2012, the government has decided to allocate Rs. 25 billion for the establishment of a transmission company where the NEA's transmission departments are supposed to be absorbed in the near future. However, by February 2013 no actions had been taken so far to follow up on the decision of transmission company establishment. The final goal of the government's continuing efforts for liberalization of the power market is said to establish a whole sale competition model where a distribution company will be the controller of the market. Currently, bills for a new Electricity Act and Nepal Electricity Regulatory Commission Act which further provide a regulatory basis for market liberalization are pending Parliament approval. Interviews revealed that many of the concerned NEA staff members expresses their concerns regarding the uncertain effects of liberalization of the power sector under the situation of an unstable political environment and the NEA's own financial problems. Under the background of power sector liberalization, the NEA's reorganization is an ongoing process as the preparation of unbundling of generation, transmission, and distribution functions. However, the progress of the power sector restructuring has been slow. Figure 6.2.3-1 shows the NEA's organogram in 2010, and Figure 6.2.3-2 presents its organogram in 2011, when a major reorganization took place. The new 2011 organogram indicates the three business groups of departments that are organized to represent generation, transmission, and distribution functions accordingly. Each business group consists of 1) a development and construction department, and 2) an operation and maintenance department, and therefore, each business group is able to complete the task of, for example, generation business. Under the Managing Director there are 11 divisions consisting of eight business groups (Corporate Planning and Monitoring Department, Generation Construction Business Group, Generation Operation & Maintenance Business Group, Grid Development Business Group, Transmission and System Operation Business Group, Distribution and Consumer Services East Business Group, Distribution and Consumer Services West Business Group, and Engineering Services Business Group) and three administration divisions (Administration, Internal Audit, and Finance divisions). The Business Groups are headed by General Managers (GMs) and administrative divisions are headed by Deputy Managing Directors (DMDs). The management of these divisions is performance-based, and GMs and DMDs manage their respective divisions based on objectives and deliverables specified in the Performance Contract agreed to between the Managing Director and the GMs/DMDs. The Main Functions of Departments of the NEA in 2011 are shown in Table 6.2.3-1.

Table 6.2.3-1 Main Function of Departments of the NEA in 2011

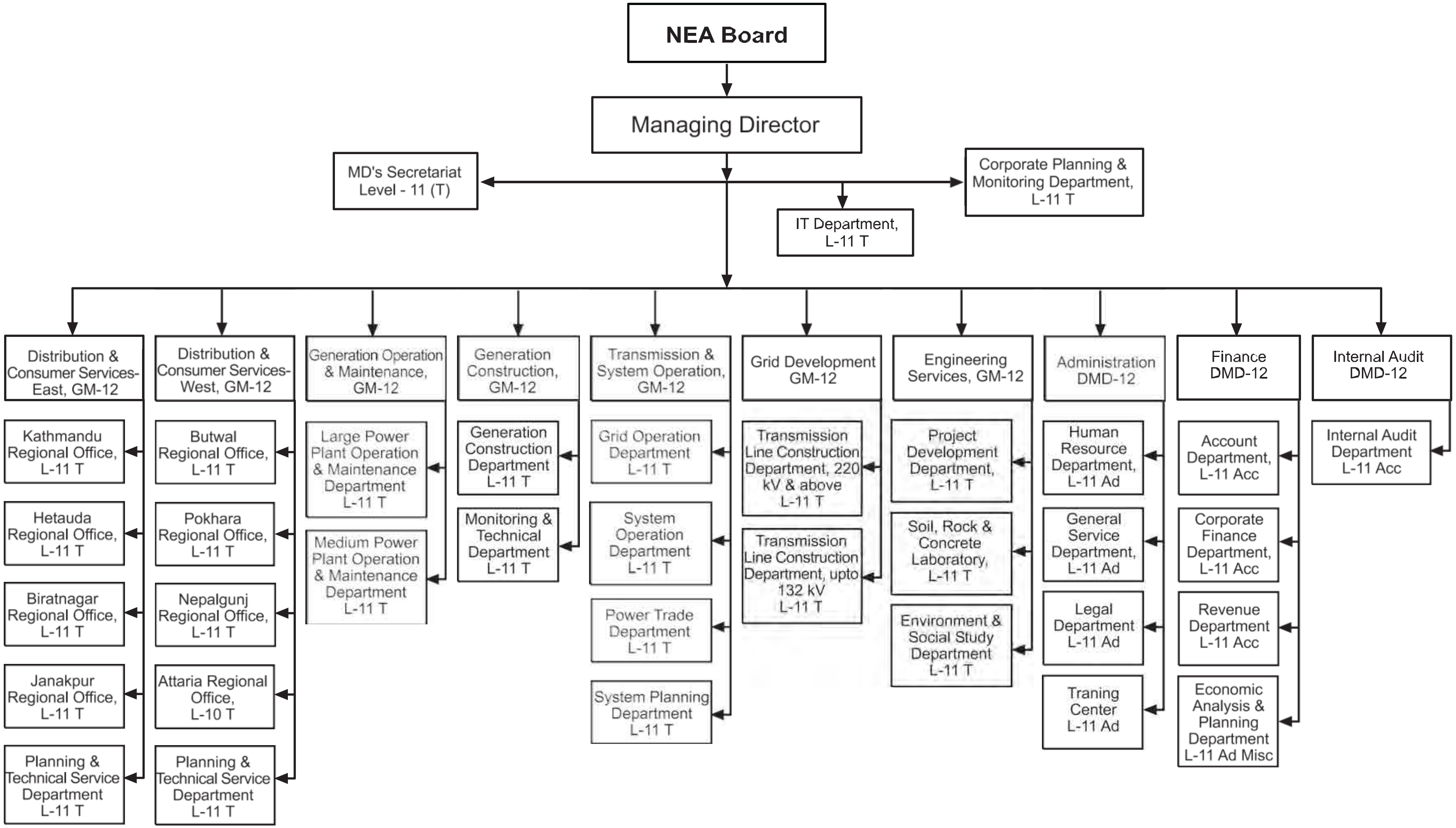
Name of Department	Main functions
Corporate Planning and Monitoring Department	• Development of long-term plans and monitoring of their implementation
Distribution and Consumer Services-East	• Provision of consumer services and collection of user fees charged in the eastern part of Nepal
Distribution and Consumer Services-West	• Provision of consumer services and collection of user fees charted in the western part of Nepal
Generation Operation and Maintenance	• Operation and maintenance of generation facilities owned by the NEA
Generation Construction	• Designing, costing, tendering, and supervision of construction of hydropower plants
Transmission and System Operation	• Operation of power dispatch and transmission
Grid Development	• Designing, costing, tendering, supervision of construction, and maintenance of transmission lines
Engineering Services	• Provision of in-house planning and engineering services
Administration	• Administration of the NEA
Finance	• Financing and accounting of NE operations
Internal Audit	• Implementation of internal audit

Table 6.2.3-2 exhibits staff profiles of the NEA. Eighty five percent (85%) of the NEA members are assistant-level employees, many of which are deployed to distribution and consumer service departments. Distribution business requires labor intensive service delivery to a huge number of consumers, and therefore, the previous distribution department is separated into two business groups in the new organogram. Engineering Service departments were kept unchanged due to its provision of crosscutting services to generation, transmission, and distribution businesses within the NEA. The former electrification business consisting of loss making rural electrification service was absorbed by the distribution businesses.



Source: NEA, 2010

Figure 6.2.3-1 Organogram of the NEA in 2010



Source: NEA, 2011

Figure 6.2.3-2 Organogram of the NEA since 2011

Table 6.2.3-2 Department-wise Number of Administration Staff in the NEA in 2011

Level Service	Approved position				Existing situation				
	Regular	Project	Pool	Total	Perma-nent	Periodi-cal	Daily wages/ contract	Total	
Managing Director	1			1					0.0%
GM/DMD (Level-12)	10			10	9			9	0.1%
Officer Level (Level 6-11)									
Technical	1,001	68	1	1,070	869	3	1	873	9.7%
Non-tech	469	21	0	490	430	1	1	432	4.8%
Total	1,470	89	1	1,560	1,299	4	2	1,305	14.5%
Assistant Level (Level 1-5)									
Technical	5,295		172	5,467	4,495	509	40	5,044	56.0%
Non-tech	2,996		291	3,287	2,481	163	11	2,655	29.5%
Total	8,291		463	8,754	6,976	672	51	7,699	85.4%
Grand Total	9,772	89	464	10,325	8,284	676	53	9,013	100.0%

Note: GM: General Manager; DMD: Deputy Managing Director
Source: NEA. 2012. A year in review - Fiscal year 2011/2012

6.3 Existing Power Generation Facilities

The breakdown of the existing generation facilities in Nepal as of the end of FY2012/13 is shown in Table 6.3.1. The total installed capacity in the country is 762,029 MW, and out of that total, 531,440 kW (70%) is owned by the NEA and 230,589 kW (30%) is owned by IPPs. Hydropower plants consist of 93% of the total and diesel power and solar power plants consist of 7%.

Since almost all hydropower plants are ROR-type, the generating capacity in the country drops and energy production decreases in the dry season because of a decrease in the river flow, and load shedding has to be dealt with for a long time.

Table 6.3-1 Existing Generation Facilities in Nepal

Name of Power Station	Installed Capacity (kW)	Type	Annual Generation (Design: GWh)	River
NEA's Major Hydropower Stations				
Middle Marsyangdi	70,000	ROR	398	Marsyangdi
Kaligandaki A	144,000	ROR	842	Kaligandaki
Marsyangdi	69,000	ROR	462	Marsyangdi
Kulekhani No. 1	60,000	STO	211	Kulekhani
Kulekhani No. 2	32,000	STO	104	Kulekuhani
Trhisuli	24,000	ROR	163	Trisuli
Gandak	15,000	ROR	106	Narayani
Modi Khola	14,800	ROR	92	Modi
Devighat	14,100	ROR	114	Trisuli
Sunkoshi	10,050	ROR	70	Sunkoshi
Puwakhola	6,200	ROR	48	Puwakhola
Subtotal	**459,150**			
NEA's Small Hydropower Stations	**14,244**			
NEA's Small Hydropower Stations (Isolated)	**4,536**			
Thermal Power Stations				
Duhabi Multifuel	39,000	Diesel		
Hetauda	14,410	Diesel		
Subtotal	**53,410**			
Solar Power Stations	**100**			
IPP's Hydropower Stations				
Khimit Khola	60,000	ROR	350	
Bhotekoshi Khola	45,000	ROR	246	
Chilime	22,000	ROR	137	
Indrawati-III	7,500	ROR		
Jhimruk Khola	12,000	ROR		
Andhi Khola	5,100	ROR		
Syange Khola	183	ROR		
Piluwa Khola	3,000	ROR	19	
Rairing Khola	500	ROR		
Sunkoshi Khola	2,500	ROR		
Chaku Khola	1,500	ROR		
Khudi Khola	3,450	ROR	24	
Baramchi Khola	4,200	ROR	8	
Thoppal Khola	1,650	ROR	11	
Sisne Khola	750	ROR	4	
Sari Nadi	232	ROR		
Pheme Khola	995	ROR	8	
Pati Khola	996	ROR		
Seti-II	979	ROR		
Ridi Khola	2,400	ROR		
Upper Hadi Khola	991	ROR		
Mardi Khola	4,800	ROR		
Mai Khola	4,500	ROR		
Lower Piluwa	990	ROR		
Hewa Khola	4,455	ROR		
Bijayapur-1	4,410	ROR		
Siuri Khola	4,950	ROR		
Lower Modi I	9,900	ROR		
Sipring Khola	9,658	ROR		
Solar	680	ROR		
Tadi Khola	5,000	ROR		
Middle Chaku	1,800	ROR		
Charnawati Khola	3,250	ROR		
Subtotal	**230,589**			
Total Hydro (NEA) - Grid Connected	**473,394**			
Total Hydro (NEA) - Isolated	**4,536**			
Total Hydro (NEA)	**477,930**			
Total Hydro (IPP)	**230,589**			
Total Hydro (Nepal)	**708,519**			
Total Thermal (NEA)	**53,410**			
Total Solar (NEA)	**100**			
Total Installed Capacity	**762,029**			

Source: A Year in Review FY2012/13, NEA.

6.4 Existing Transmission Lines and Substations

132 kV, 66 kV and 33 kV transmission voltages are adopted in Nepal, and the trunk transmission line (132 kV) extends from east to west along the national road. Electricity generated in the middle west area of Nepal is supplied to Kathmandu and the industrial area in the southeast, and the power flow is basically from west to east. The main part of the 132 kV trunk transmission line such as Duhabi - Dhalkerbar - Hetauda is a double circuit. However, the other 132 kV trunk transmission lines are single circuit. In particular, important transmission lines between the generating area and the consumption area such as Hetauda-Bharatpur and Marsyangdi-Siuchatar are also single circuit, and these might cause a blackout of the whole power system in case of unexpected accidents from the transmission lines.

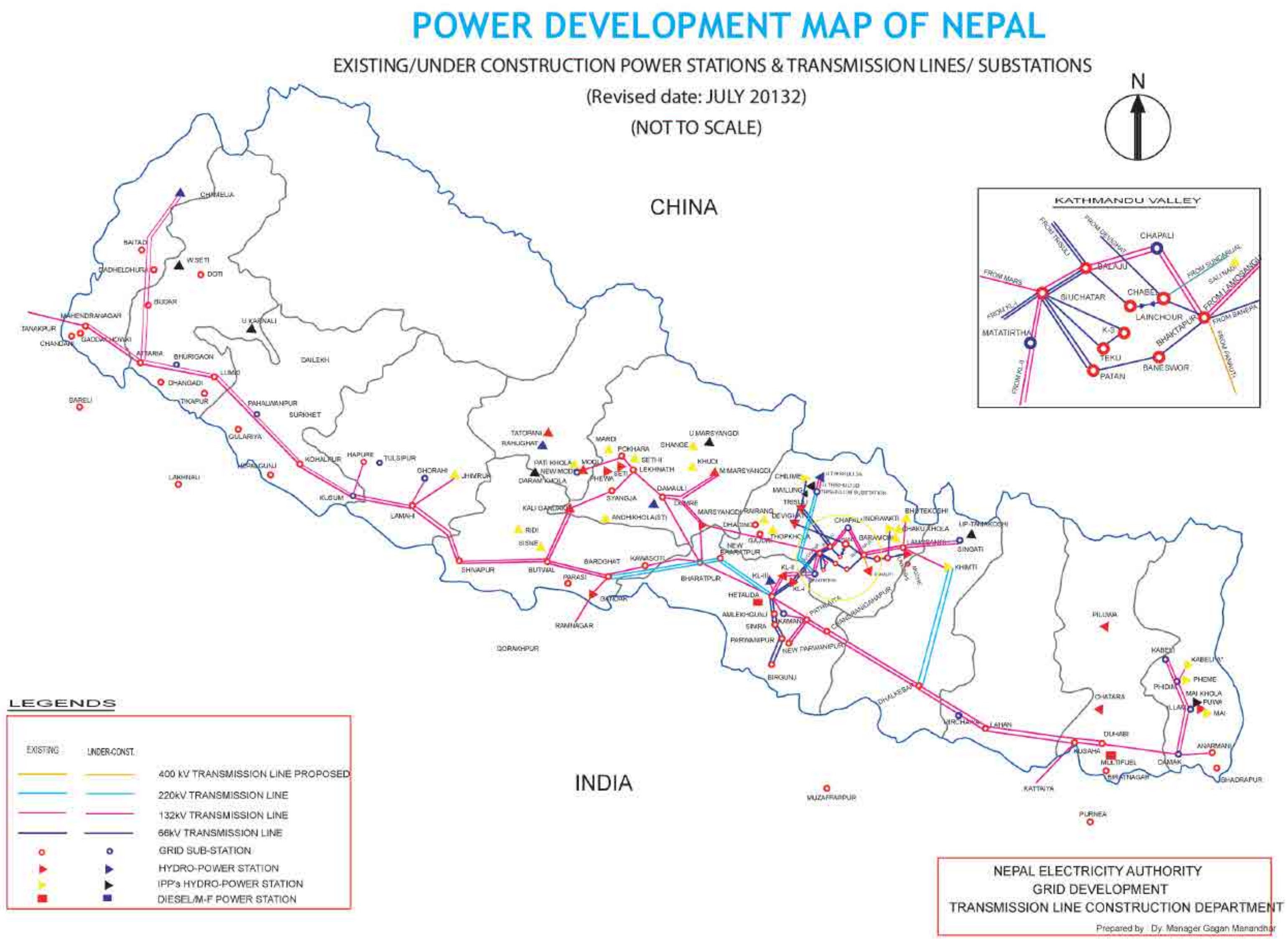
However, enforcement of bottleneck of the transmission lines, construction of new 220 kV transmission lines and interconnection transmission lines with India supported by the Asian Development Bank and World Bank are making progress and remedying the situation.

The main feature of the 132 kV transmission line is shown in Table 6.4-1 and the power system map in the Integrated Nepal Power System is shown in Figure 6.4-1 respectively.

Table 6.4-1 Existing Transmission Lines in the Integrated Nepal Power System

	Section		Length (km)	Type of Circuits	Thermal Capacity (MVA)
	From	To			
		132kV			
1	Anarmani	Duhabi	75.76	Single	142
2	Kusha	Katiya(India)	15.00	Single	142
3	Duhabi	Hetauda	598.00	Double	142
4	Hetauda	KL2 P/S	8.00	Single	142
5	Bharatpur	Marsyangdi P/S	25.00	Single	180
6	Hetauda	Bharatpur	70.00	Single	123
7	Marsyangdi P/S	Suichatar	84.00	Single	180
8	Siuchatar	KL2 P/S	36.00	Single	142
9	Siuchatar	New Bhaktapur	26.90	Single	142
10	NewBhaktapur	Lamosangu	96.00	Double	142
11	Lamosangu	Khimti P/S	46.00	Single	142
12	Lamosangu	Bhotekosi P/S	31.00	Single	142
13	Bharatpur	Damauli	39.00	Single	103
14	Bharatpur	Bardghat	70.00	Single	123
15	Bardghat	Gandak P/S	28.00	Double	123
16	Bardghat	Butwal	86.00	Double	142
17	Butwal	KGA P/S	116.00	Double	180
18	KGA P/S	Lekhnath	96.00	Double	180
19	Lekhnath	Damauli	45.00	Single	103
20	Lekhnath	Pokhara	7.00	Single	42
21	Pokhara	Modikhola P/S	37.00	Single	142
22	Butwal	Laamhi	112.00	Single	142
23	Lamahi	Jhimruk P/S	50.00	Single	42
24	Lamahi	Attaria	243.00	Single	142
25	Attaria	Gaddachauki	49.00	Single	142
26	Middle Marsyangdi	Marsyangdi	40.00	Single	213

Source: A Year in Review, Fiscal Year 2012/2013, NEA



Source: A Year in Review, Fiscal Year 2012/2013, NEA.

Figure 6.4-1 Power System Map in the Integrated Nepal Power System

The existing substations capacity by each voltage level at the end of FY2012/13 is shown in Table 6.4-2.

Table 6.4-2 Existing Substations in the Integrated Nepal Power System

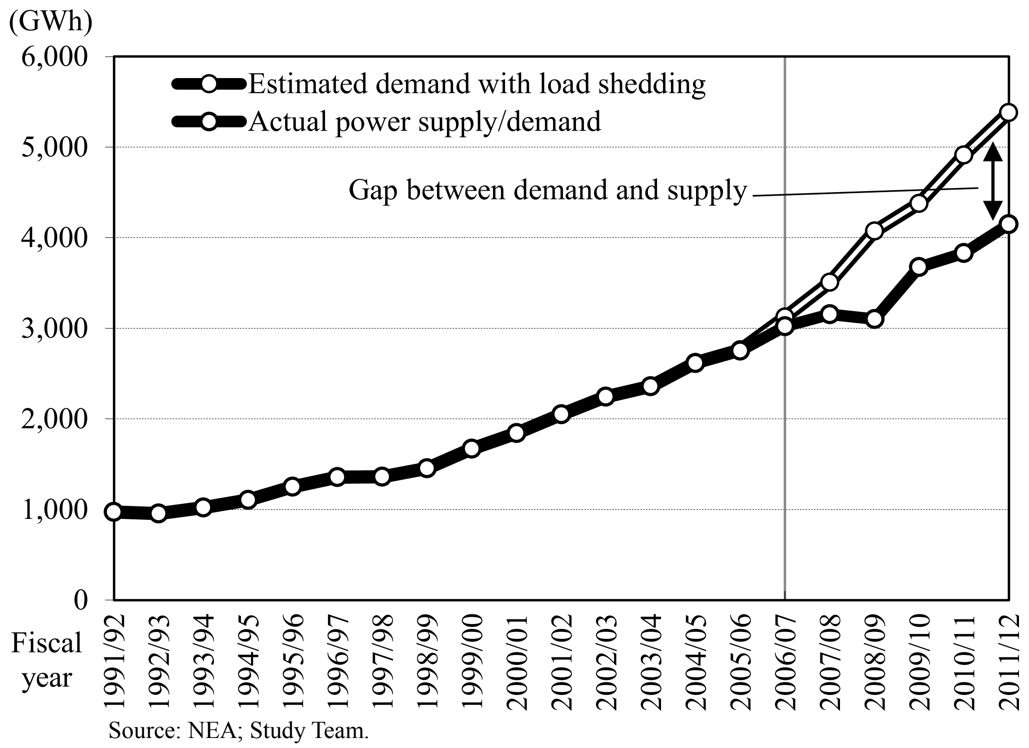
132 kV SS	Capacity (MW)	66 kV SS	Capacity (MW)
Mahendranagar	15.5	Birgung	55.0
Attariya	25.5	Amlekhgunj	3.2
Lumki	10.5	Simra	20.1
Kohalpur	37.5	Hetauda	20.0
Lamahi	18.0	Siuchatar	36.0
Shivapur	41.0	K-3	45.0
Butwal	142.6	Teku	45.0
Bardghat	13.5	Patan	36.0
Kawasoti	38.0	Baneshwor	36.0
Bharatpur	55.0	Bhaktapur	
hetauda	40.0	Banepa	22.5
Parwanipur	90.0	Panchkhal	10.0
Chabdranigahapur	38.0	Lainchour	45.0
Dhalkebar	68.0	New-Chabel	45.0
Lahan	74.0	Balaju	45.0
Dulabi	159.2		
Aharmani	75.0		
Pokhara	45.0		
Lekhnath	12.5		
Damauli	26.0		
Lamosangu	15.0		
Bhaktapur	94.5		
Balaju	45.0		
Siuchatar	113.4		
Matatirtha	22.5		
Pathlaiya	22.5		
Shyangja	38.0		
Total	1,375.7	Total	463.8

Source: A Year in Review, Fiscal Year 2011/2012, NEA.

6.5 Performance of Supply and Demand of Power

The power market in Nepal can be classified into three categories: 1) the wholesale power market consisting of the NEA, IPPs, and Indian electricity traders, 2) the retail power market consisting of the NEA and numerous consumers, and 3) the off-grid power market consisting of the NEA, small-scale hydropower generators, and rural communities. In this section, the performance of the retail power market dominated by the NEA is to be introduced.

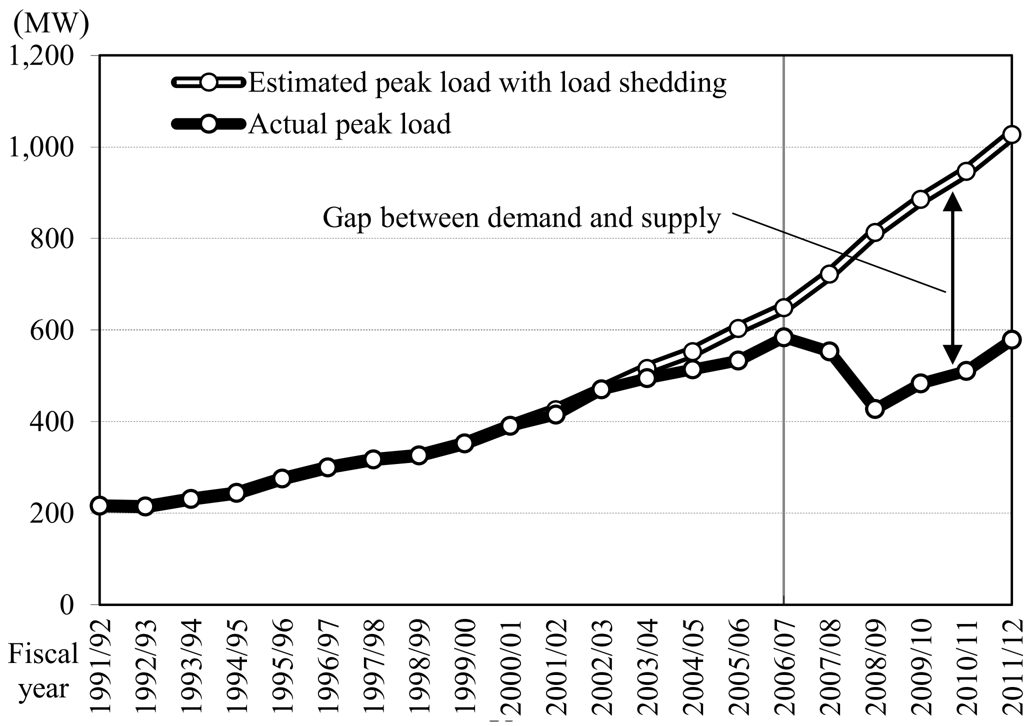
The significant characteristics of the current retail power market are: 1) huge supply and demand imbalance, particularly during the dry season prevalent since FY2006/07, adjusted by more than 14 hours of daily load shedding in 2012, 2) the number of consumers exceeds two million, dominated by domestic consumers (95% of the total consumers), 3) the majority of domestic consumers use electricity for lighting purposes, only requiring, on average, less than 100 W of capacity per consumer, whereas 38% of power consumption is coming from a small number of industry consumers (1.6% of the total consumers), and 4) although the increase in power supply is seriously constrained, the annual expansion rate of the consumer base has been about 10% and unchecked. The rate of household electrification by the NEA can be estimated at 38% in FY2011/12, assuming that one consumer consists of one household. (The details are described in Page 6-20.) The evolution of actual demand and estimated demand with an assumed lost power supply due to load shedding is shown in Figure 6.5-1. The evolution of actual peak load and estimated peak load with an assumed lost power supply due to load shedding is shown in Figure 6.5-2. The difference between estimated demand and actual power supply is reconciled by the load shedding. Table 6.5-1 shows the actual and estimated power supply and peak load and Table 6.5-2 presents the actual energy sales and estimated load shed supplies by sector. After FY2006/07, the imbalance between supply and demand of power became significant and has been widened after this point in time. Based on this observation, economic interpretation of actual power supply and demand must be understood differently. In FY2008/09, the actual energy supplied and peak load declined from those recorded in 2008. These declines were caused by insufficient hydro electric supply from IPPs due to the record low rainfall in 2009, and due to damage of the main transmission line used to import electricity from India in the same year.[5]



Source: NEA; Study Team.

Figure 6.5-1 Actual Power Supply / Demand and Estimated Demand with Load Shedding

[5] NEA. 2009. A year in Review Fiscal year 2008/2009.



Source: NEA; Study Team.

Figure 6.5-2 Actual Peak Load and Estimated Peak Load with Load Shedding

Table 6.5-1 Actual and Estimated Power Supply and Peak Load

Fiscal year	Power supply and demand (GWh)			Installed capacity	Peak load (MW)		
	Actual power supply a	Load shed estimate b	Estimated power demand c=a+b	d	Actual peak load e	Load shed estimate f	Estimated peak load g=e+f
1991/92	971		971	246	216		216
1992/93	954		954	246	214		214
1993/94	1,020		1,020	259	231		231
1994/95	1,106		1,106	271	244		244
1995/96	1,250		1,250	275	275		275
1996/97	1,355		1,355	275	300		300
1997/98	1,359		1,359	314	317		317
1998/99	1,451		1,451	328	326		326
1999/00	1,672		1,672	403	352		352
2000/01	1,844		1,844	448	391		391
2001/02	2,048	2	2,050	593	416	11	426
2002/03	2,244	0	2,244	618	470	0	470
2003/04	2,359	1	2,360	619	495	20	515
2004/05	2,617	3	2,619	621	514	38	552
2005/06	2,751	8	2,759	630	533	70	603
2006/07	3,019	103	3,122	630	584	65	648
2007/08	3,155	350	3,506	700	553	169	722
2008/09	3,100	972	4,072	702	428	385	813
2009/10	3,675	701	4,376	702	483	402	885
2010/11	3,827	1,084	4,912	702	510	436	946
2011/12	4,146	1,233	5,380	722	579	448	1,027

Note: 1) Load shedding form 1991/92 to 2000/01 is insignificant.
Source: NEA annual reports

Table 6.5-2 Actual Energy Sales and Estimated Load Shedding by Sectors

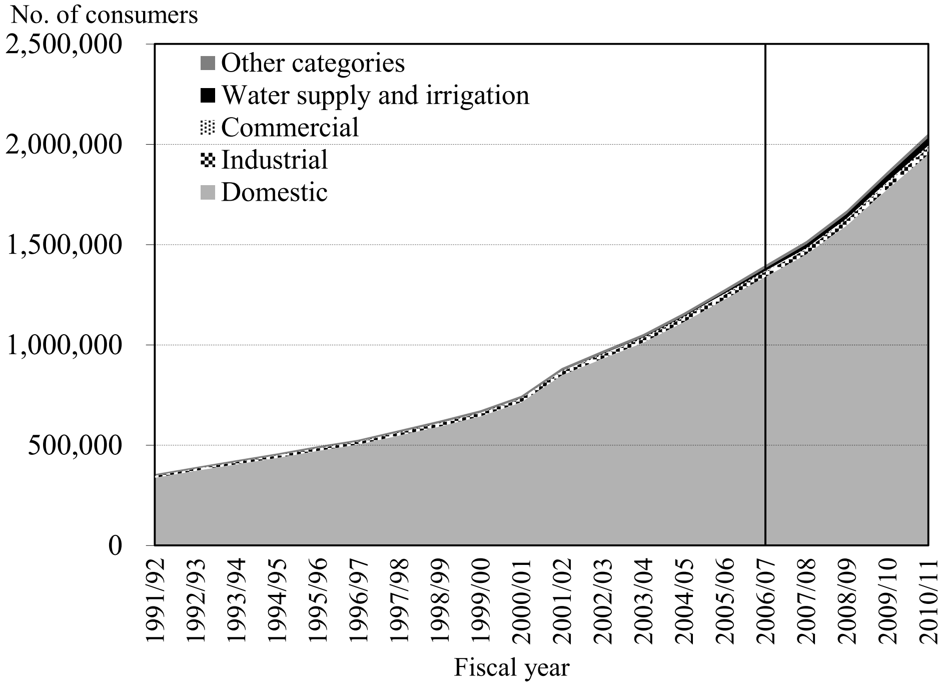
(GWh)

Fiscal year	Estimation		Actual energy sales								Estimated load shed energy at consumer								Total energy	
	Total generation	Estimated load shedding	Domestic	Industry	Commerce	Other	WS & Irrigation	Total Nepal	Energy export	Total sales	Domestic	Industry	Commerce	Other	WS & Irrigation	Total Nepal	Energy export	Total		Load shedding %
	a	b	c	d	e	f	g	h	i	j=h+i	k	l	m	n	o	p	q	r=p+q	s=j+r	t=r/s
1991/92	No data[*1]		275	246	45	57	28	652	85	737									737	
1992/93	No data[*1]		260	274	48	58	24	663	46	709									709	
1993/94	No data[*1]		275	304	49	59	19	706	51	757									757	
1994/95	No data[*1]		302	328	59	69	28	785	39	825									825	
1995/96	No data[*1]		329	359	63	74	25	850	87	937									937	
1996/97	No data[*1]		355	377	68	83	28	910	100	1,011									1,011	
1997/98	No data[*1]		379	414	71	91	29	984	67	1,051									1,051	
1998/99	No data[*1]		411	441	77	98	23	1,049	64	1,114									1,114	
1999/00	No data[*1]		467	508	82	101	16	1,174	95	1,269									1,269	
2000/01	No data[*1]		518	521	94	119	29	1,281	126	1,407									1,407	
2001/02	2,207	3	552	597	90	132	29	1,400	134	1,534	1	1	0	0	0	2		2	1,536	0%
2002/03	2,389	0	612	630	93	140	30	1,505	192	1,697	0	0	0	0	0	0		0	1,697	0%
2003/04	2,608	1	671	690	108	154	32	1,654	141	1,795	0	0	0	0	0	1		1	1,796	0%
2004/05	2,804	3	758	764	109	172	50	1,854	111	1,964	1	1	0	0	0	2		2	1,966	0%
2005/06	3,001	9	806	786	120	179	46	1,936	97	2,033	2	2	0	0	1	6		6	2,038	0%
2006/07	3,246	109	893	849	142	195	48	2,127	77	2,204	31	30	5	2	7	74		74	2,278	3%
2007/08	3,341	367	931	901	154	217	47	2,250	60	2,310	105	102	17	5	24	254		254	2,564	10%
2008/09	3,204	994	909	846	146	209	48	2,158	46	2,205	288	268	46	15	66	684		684	2,889	24%
2009/10	3,894	736	1,109	960	187	214	56	2,526	75	2,602	216	187	36	11	42	492		492	3,093	16%
2010/11	3,932	1,105	1,171	1,043	206	230	55	2,705	30	2,735	333	296	59	16	65	769		769	3,503	22%

Note: 1) Load shedding form 1992 to 2001 is insignificant. Source: NEA; Study Team

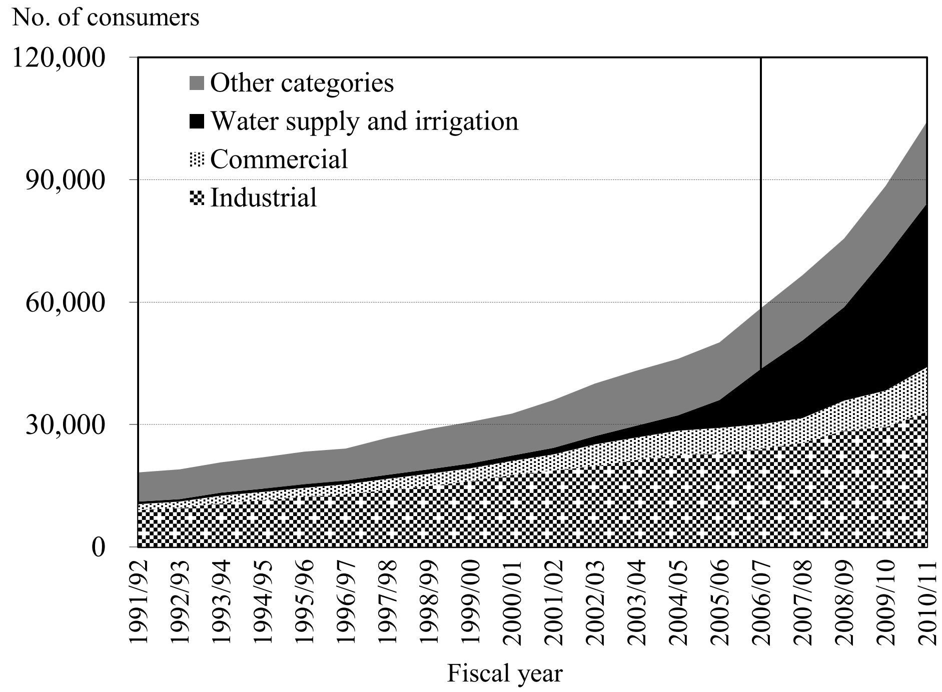
Figure 6.5-3 and Figure 6.5-4 show the evolution of the number of consumers by consumer type. According to Figure 6.5-3, a large portion of consumers are domestic users (95%), and to show in detail the composition of other types of consumers, Figure 6.5-4 is presented without domestic consumers. The total number of consumers is 2.053 million. Although the demand and supply gap has widened after 2007, the increase in numbers of domestic and irrigation consumers is large. The average power price for irrigation consumers is about 4 Rs./kWh, which is lower than the average price of other sectors (about 6.5 Rs./kWh). This indicates that the increase in these types of consumers is the government's policy under an acute shortage of electricity supply. This inconsistent policy can be a cause of the current electricity crisis other than generation constraints resulting from inappropriate long-term investment strategies.

Figure 6.5-5 and Figure 6.6-6 represent annual electricity consumption per consumer. Due to the large difference between the domestic sector and other sectors, Figure 6.5-6 only shows the consumption of domestic consumers and the national average. The significant characteristic of electricity consumption after 2007 is the decline in electricity consumption, particularly in the industry sector, as well as the commerce and service sector. The demands from these production sectors have shrunk, and this is consistent with the observation that the GDP growth of these sectors has deteriorated significantly after 2007. The consumption of power in the production sectors is important input for the growth of value addition, and the decline in their consumption is alarming. Regarding the irrigation sector, per consumer consumption has a long history of a declining trend, indicating a long-term transition from a small number of large irrigations to numerous farm-level small irrigations. The level of domestic consumption is small, which also shows a slight declining trend, particularly after 2007.



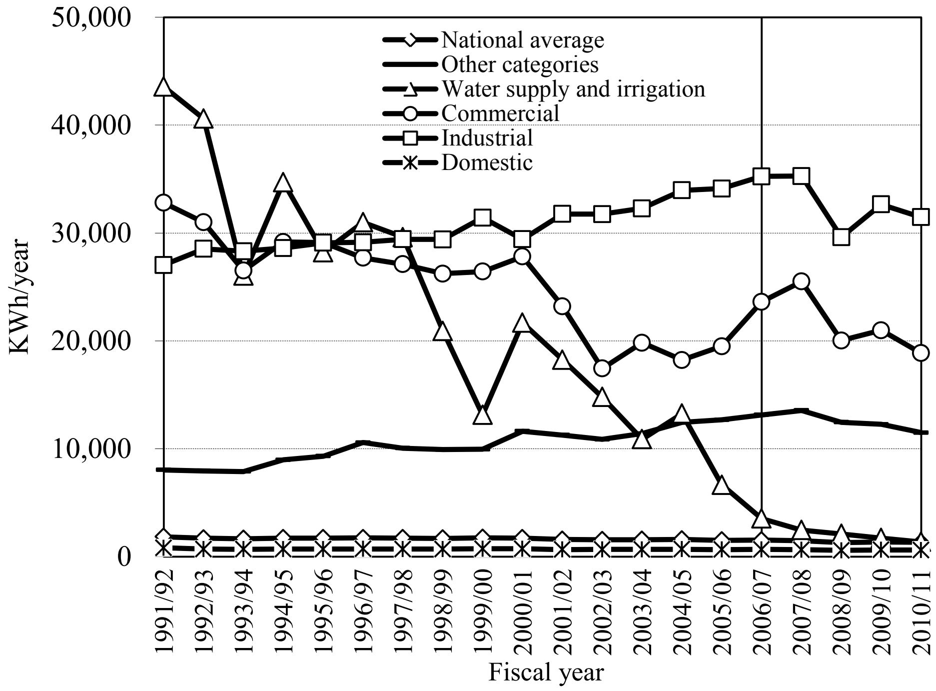
Source: NEA

Figure 6.5-3 Numbers of Connected Consumers



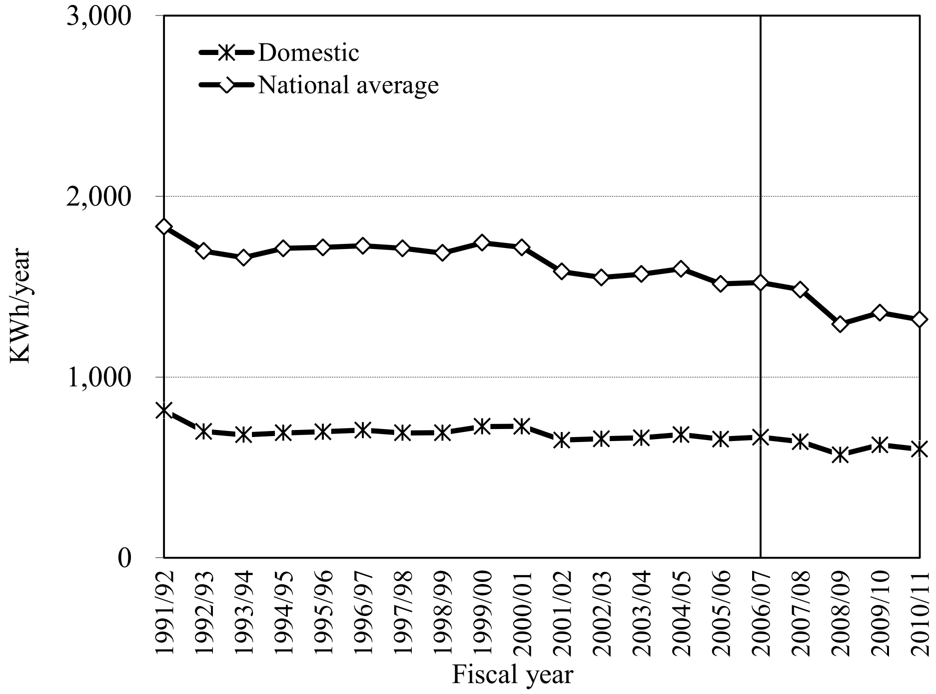
Source: NEA

Figure 6.5-4 Numbers of Connected Consumers (excluding Domestic Consumers)



Source: NEA; Study Team

Figure 6.5-5 Per-consumer Annual Electricity Consumption by Sectors



Source: NEA; Study Team

Figure 6.5-6 Per-consumer Annual Electricity Consumption of the Domestic Sector and the National Average

The type of lighting facilities of households in 2001 and 2011 by Eco-zone and District are shown in Table 6.5-3 and Table 6.5-4, respectively. It is assumed that in Nepal all electrified households use electric lamps for lighting, and therefore, the household-electrification rate should be represented by rate of households using electric lamps. According to the results of the 2001 and 2011 censuses where households using electric lamps powered by public and/or solar panel electricity can be interpreted as electrified households, 39% of the households were electrified in 2001, whereas 74% of the households were electrified in 2011. In the latter case, the 75% electrification rate is disaggregated into 7% of the households dependent on solar electricity and 64% of the households dependent on electricity supplied by the power grid and other sources. These results indicate that during the period of 2001-2011 the rate of electrification had doubled. In the case of electrification achieved by non-solar panel electricity supply, the electrification rate in the Mountain Eco-zone had become more than double (from 18% to 45%), followed by the Terai Eco-zone and Hill Eco-zone, where their rates had doubled (from 39% to 70% and 43% to 68%, respectively). Electrification by solar panels had increased rapidly during the period from 2001-2011. There were no households using solar panels in 2001, but 25% of the households in the Mountain Eco-zone and 11% of households in the Hill Eco-zone were using solar panels in 2011.

The trends of electrification during the period from 2001-2011 indicate the NEA's significant contribution to rural electrification in this period. At the bottom of Table 6.5-3, the total numbers of electrified households by the NEA and the ratios against the total number of households in Nepal in 2001 and 2011 are indicated. In 2001, the number of the NEA's consumers was approximately 746 thousand, which was about 18% of the total households in the year. Since the national electrification rate in the same year was estimated to be 39%, almost half of the electrified households were consumers of the NEA. It is often the case that one consumer contract with the NEA involves multiple consumers (households). In this case, the electrification rate of households due to connection to the NEA grids is larger than the rate calculated simply by the number of recorded NEA consumers. By 2011 the number of recorded NEA consumers became 2,053,000, showing about a 300% increase from the number in 2001. NEA consumers were 38% of the total households in 2011. Since the estimated electrification rate derived from the 2011 National Census is 67% (excluding households with electricity generated by solar panels), at least 60% of electrified households were connected to NEA grids. Electrified households not connected to NEA grids obtained electricity from off-grid small-scale hydropower systems, solar panels, and generators.

The NEA considers rural electrification in Nepal as a loss-making business, which is difficult to be profitable due to the high cost of electricity distribution and fee collection, and the households' limited electricity consumption in rural areas. However, 25% of the households were still not electrified in rural areas, and therefore how to handle rural electrification needs under the NEA's constrained business environment should be of great concern to the government.

Table 6.5-3 Type of Lighting Facilities of Households in 2001 and 2011 by Eco-zone

Region	Eco-zone	Type of lighting facilities of households (HHs) in 2001					Type of lighting facilities of households (HHs) in 2011					
		Total no. of HHs	% to the total no. of HHs				Total no. of HHs	% to the total no. of HHs				
			Total	Elect-ricity	Kero-sene	Other		Total	Elect-ricity	Kero-sene	Solar	Other
Eastern	Mountain	77,197	100%	18%	80%	2%	84,844	100%	47%	29%	20%	5%
	Hill	309,149	100%	21%	77%	2%	346,373	100%	48%	25%	19%	8%
	Terai	614,095	100%	37%	62%	1%	799,526	100%	72%	26%	1%	1%
	Sub-total/average	1,000,441	100%	30%	68%	2%	1,230,743	100%	64%	26%	7%	3%
Central	Mountain	66,345	100%	28%	71%	1%	76,376	100%	86%	10%	2%	2%
	Hill	728,499	100%	67%	32%	1%	1,060,423	100%	86%	8%	4%	3%
	Terai	670,909	100%	40%	58%	2%	825,439	100%	65%	31%	2%	2%
	Sub-total/average	1,465,753	100%	53%	46%	2%	1,962,238	100%	77%	17%	3%	2%
Western	Mountain	5,019	100%	63%	35%	3%	4,753	100%	77%	2%	20%	1%
	Hill	568,898	100%	40%	58%	2%	676,987	100%	79%	12%	6%	3%
	Terai	289,128	100%	46%	52%	2%	383,859	100%	77%	20%	2%	2%
	Sub-total/average	863,045	100%	42%	56%	2%	1,065,599	100%	78%	15%	4%	2%
Mid-Western	Mountain	31,384	100%	12%	18%	70%	68,802	100%	21%	1%	41%	37%
	Hill	239,100	100%	18%	68%	13%	332,025	100%	26%	9%	30%	35%
	Terai	209,333	100%	35%	63%	2%	294,187	100%	65%	22%	4%	9%
	Sub-total/average	479,817	100%	25%	63%	12%	695,014	100%	42%	14%	20%	24%
Far-Western	Mountain	67,976	100%	6%	76%	18%	83,265	100%	22%	15%	33%	30%
	Hill	142,837	100%	19%	71%	10%	161,891	100%	28%	16%	17%	39%
	Terai	154,588	100%	34%	63%	3%	224,547	100%	72%	17%	4%	6%
	Sub-total/average	365,401	100%	23%	69%	9%	469,703	100%	48%	16%	14%	22%
All Regions	Mountain	247,921	100%	18%	68%	15%	318,040	100%	45%	14%	23%	18%
	Hill	1,988,483	100%	43%	53%	4%	2,577,699	100%	68%	12%	11%	10%
	Terai	1,938,053	100%	39%	60%	2%	2,527,558	100%	70%	25%	2%	3%
National total/average		4,174,457	100%	39%	57%	3%	5,423,297	100%	67%	18%	7%	7%
NEA's domestic consumers		745,992					2,053,259					
% of NEA's consumers		18%					38%					

Source: 1) Central Bureau of Statistics. 2001. National population census 2001. Kathmandu.
2) Central Bureau of Statistics. 2011. National population and housing census 2011. Kathmandu.
3) NEA annual reports.

Table 6.5-4 Type of Lighting Facilities of Households in 2001 and 2011 by District

Region	Zone	District	Eco-zone	Type of lighting facilities of households (HHs) in 2001					Type of lighting facilities of households (HHs) in 2011					
				Total no. of HHs	% to the total no. of HHs				Total no. of HHs	% to the total no. of HHs				
					Total	Elect-ricity	Kero-sene	Other		Total	Elect-ricity	Kero-sene	Solar	Other
Eastern	Mechi	Taplejung	Mountain	24,764	100%	8%	90%	2%	26,471	100%	25%	45%	28%	2%
		Panchthar	Hill	37,260	100%	5%	92%	3%	41,176	100%	28%	40%	27%	6%
		Ilam	Hill	54,565	100%	43%	56%	1%	64,477	100%	66%	23%	7%	5%
		Jhapa	Terai	125,947	100%	33%	66%	1%	184,384	100%	82%	16%	1%	1%
	Koshi	Morang	Terai	167,875	100%	36%	64%	1%	213,870	100%	76%	22%	1%	1%
		Sunsari	Terai	120,378	100%	42%	57%	1%	162,279	100%	82%	17%	1%	1%
		Dhankuta	Hill	32,571	100%	46%	53%	1%	37,616	100%	84%	12%	3%	1%
		Terhathum	Hill	20,682	100%	13%	83%	4%	22,084	100%	67%	20%	9%	4%
		Sankhuwasabha	Mountain	30,766	100%	30%	68%	2%	34,615	100%	53%	23%	19%	5%
		Bhojpur	Hill	39,481	100%	5%	92%	2%	39,393	100%	15%	27%	42%	16%
	Sagarmatha	Solukhumbu	Mountain	21,667	100%	13%	84%	2%	23,758	100%	63%	20%	10%	7%
		Okhaldhunga	Hill	30,121	100%	6%	92%	2%	32,466	100%	42%	28%	22%	9%
		Khotang	Hill	42,866	100%	4%	93%	3%	42,647	100%	31%	28%	25%	16%
		Udayapur	Hill	51,603	100%	32%	66%	2%	66,514	100%	51%	22%	20%	7%
		Saptari	Terai	101,141	100%	41%	58%	2%	121,064	100%	42%	55%	1%	2%
		Siraha	Terai	98,754	100%	32%	67%	2%	117,929	100%	67%	30%	1%	1%
	Sub-total/average			1,000,441	100%	30%	68%	2%	1,230,743	100%	64%	26%	7%	3%
Central	Janakpur	Dhanusa	Terai	117,417	100%	44%	54%	3%	138,225	100%	73%	24%	1%	2%
		Mahottari	Terai	94,229	100%	25%	74%	1%	111,298	100%	63%	35%	1%	1%
		Sarlahi	Terai	111,076	100%	28%	70%	2%	132,803	100%	47%	49%	2%	2%
		Sindhuli	Hill	47,710	100%	29%	70%	2%	57,544	100%	38%	22%	27%	13%
		Ramechhap	Hill	40,386	100%	7%	91%	2%	43,883	100%	46%	30%	21%	3%
		Dolakha	Hill	37,292	100%	46%	54%	1%	45,658	100%	82%	13%	3%	3%
	Bagmati	Sindhupalchok	Mountain	57,649	100%	27%	72%	1%	66,635	100%	88%	9%	1%	1%
		Kavrepalanchok	Hill	70,509	100%	63%	35%	1%	80,651	100%	87%	8%	2%	2%
		Lalitpur	Hill	68,922	100%	87%	12%	1%	109,505	100%	97%	2%	0%	1%
		Bhaktapur	Hill	41,253	100%	97%	1%	1%	68,557	100%	98%	1%	0%	1%
		Kathmandu	Hill	235,387	100%	97%	2%	1%	435,544	100%	98%	1%	0%	1%
		Nuwakot	Hill	53,169	100%	51%	47%	2%	59,194	100%	83%	13%	2%	2%
		Rasuwa	Mountain	8,696	100%	33%	65%	2%	9,741	100%	71%	12%	6%	10%
		Dhading	Hill	62,759	100%	14%	85%	1%	73,842	100%	63%	19%	11%	7%
		Makwanpur	Hill	71,112	100%	61%	37%	2%	86,045	100%	73%	18%	8%	2%
	Narayani	Rautahat	Terai	88,162	100%	26%	73%	1%	106,652	100%	47%	50%	1%	2%
		Bara	Terai	87,706	100%	44%	55%	2%	108,600	100%	68%	29%	1%	1%
		Parsa	Terai	79,456	100%	45%	53%	2%	95,516	100%	72%	24%	2%	2%
		Chitawan	Terai	92,863	100%	68%	30%	2%	132,345	100%	86%	5%	6%	3%
	Sub-total/average			1,465,753	100%	53%	46%	2%	1,962,238	100%	77%	17%	3%	2%
Western	Gandaki	Gorkha	Hill	58,923	100%	42%	55%	3%	66,458	100%	76%	17%	4%	2%
		Lamjung	Hill	36,525	100%	31%	67%	2%	42,048	100%	77%	15%	7%	2%
		Tanahu	Hill	62,898	100%	43%	55%	2%	78,286	100%	77%	10%	9%	3%
		Syangja	Hill	64,746	100%	53%	46%	1%	68,856	100%	87%	9%	3%	1%
		Kaski	Hill	85,075	100%	68%	31%	1%	125,459	100%	95%	3%	1%	1%
		Manang	Mountain	1,776	100%	80%	19%	0%	1,448	100%	89%	2%	9%	1%
	Dhaualagiri	Mustang	Mountain	3,243	100%	53%	43%	4%	3,305	100%	71%	2%	25%	1%
		Myagdi	Hill	24,435	100%	26%	70%	4%	27,727	100%	69%	13%	11%	7%
		Parbat	Hill	32,731	100%	25%	73%	1%	35,698	100%	80%	14%	4%	1%
		Baglung	Hill	53,565	100%	40%	58%	2%	61,482	100%	82%	12%	4%	3%

Source: 1) Central Bureau of Statistics. 2001. National population census 2001. Kathmandu.
2) Central Bureau of Statistics. 2011. National population and housing census 2011. Kathmandu..

Table 6.5-4 Type of Lighting Facilities of Households in 2001 and 2011 by District (cont.)

Region	Zone	District	Eco-zone	Type of lighting facilities of households (HHs) in 2001: Total no. of HHs	2001: % to the total no. of HHs: Total	2001: Elect-ricity	2001: Kero-sene	2001: Other	Type of lighting facilities of households (HHs) in 2011: Total no. of HHs	2011: % to the total no. of HHs: Total	2011: Elect-ricity	2011: Kero-sene	2011: Solar	2011: Other
Western	Lumbini	Gulmi	Hill	59,189	100%	15%	82%	3%	64,887	100%	64%	21%	12%	3%
		Palpa	Hill	49,942	100%	52%	46%	2%	59,260	100%	73%	15%	8%	4%
		Nawalparasi	Terai	98,340	100%	41%	58%	1%	128,760	100%	81%	12%	4%	3%
		Rupandehi	Terai	117,856	100%	61%	37%	1%	163,835	100%	81%	18%	0%	1%
		Kapilbastu	Terai	72,932	100%	28%	69%	3%	91,264	100%	64%	34%	0%	2%
		Arghakhanchi	Hill	40,869	100%	9%	88%	3%	46,826	100%	59%	22%	12%	6%
	Sub-total/average			863,045	100%	42%	56%	2%	1,065,599	100%	78%	15%	4%	2%
Mid-Western	Rapti	Pyuthan	Hill	40,183	100%	17%	79%	5%	47,716	100%	54%	22%	7%	18%
		Rolpa	Hill	38,512	100%	4%	86%	10%	43,735	100%	21%	5%	47%	26%
		Rukum	Hill	33,501	100%	8%	75%	18%	41,837	100%	15%	6%	46%	34%
		Salyan	Hill	10,926	100%	16%	82%	3%	46,524	100%	15%	19%	35%	32%
		Dang	Terai	82,495	100%	33%	65%	2%	116,347	100%	65%	22%	4%	9%
	Bheri	Banke	Terai	67,269	100%	48%	49%	2%	94,693	100%	69%	22%	3%	6%
		Bardiya	Terai	59,569	100%	22%	76%	2%	83,147	100%	63%	23%	3%	12%
		Surkhet	Hill	50,691	100%	48%	45%	7%	72,830	100%	44%	4%	14%	39%
		Dailekh	Hill	41,140	100%	17%	71%	12%	48,915	100%	14%	4%	37%	45%
		Jajarkot	Hill	24,147	100%	1%	52%	47%	30,468	100%	4%	2%	41%	52%
	Karnali	Dolpa	Mountain	4,414	100%	1%	48%	52%	7,466	100%	23%	1%	50%	25%
		Jumla	Mountain	12,147	100%	19%	11%	70%	19,291	100%	29%	0%	44%	26%
		Kalikot	Mountain	2,026	100%	5%	77%	18%	23,008	100%	12%	1%	37%	50%
		Mugu	Mountain	5,844	100%	6%	5%	90%	9,600	100%	14%	1%	56%	30%
		Humla	Mountain	6,953	100%	12%	5%	83%	9,437	100%	31%	0%	23%	46%
	Sub-total/average			479,817	100%	25%	63%	12%	695,014	100%	42%	14%	20%	24%
Far-Western	Seti	Bajura	Mountain	18,359	100%	5%	76%	19%	24,888	100%	23%	1%	22%	54%
		Bajhang	Mountain	28,588	100%	5%	72%	23%	33,773	100%	17%	13%	40%	30%
		Achham	Hill	44,005	100%	6%	81%	13%	48,318	100%	18%	4%	24%	53%
		Doti	Hill	36,465	100%	30%	61%	9%	41,383	100%	30%	10%	12%	48%
		Kailali	Terai	94,430	100%	31%	65%	3%	142,413	100%	70%	14%	6%	9%
	Mahakali	Kanchanpur	Terai	60,158	100%	38%	60%	2%	82,134	100%	75%	22%	1%	2%
		Dadeldhura	Hill	21,980	100%	21%	64%	15%	27,023	100%	48%	7%	10%	34%
		Baitadi	Hill	40,387	100%	22%	72%	6%	45,167	100%	25%	40%	18%	17%
		Darchula	Mountain	21,029	100%	8%	83%	9%	24,604	100%	27%	33%	33%	7%
	Sub-total/average			365,401	100%	23%	69%	9%	469,703	100%	48%	16%	14%	22%
National Total/average				4,174,457	100%	39%	57%	3%	5,423,297	100%	67%	18%	7%	7%

Source: 1) Central Bureau of Statistics. 2001. National population census 2001. Kathmandu.
2) Central Bureau of Statistics. 2011. National population and housing census 2011. Kathmandu.

6.6 Electricity Tariff Rates

The NEA's financial position has deteriorated over the years, and its current position is very serious, incurring an accumulated loss of Rs. 27 billion. The most fundamental cause of the situation is inappropriate and electricity tariff rates that are too low and that have been kept constant for more than ten years. Table 6.6-1 shows the nominal power prices of each sector calculated by dividing sales by the amount of power sold. Figure 6.6-1 indicated real electricity prices at 2011 prices over the past 20 years. Although the prices have in general doubled over the last ten years, the nominal electricity price has been kept constant, resulting in the decline of the real electricity price. Considering this with the rate of inflation, the prices have been effectively cut by nearly half from the early 2000s.

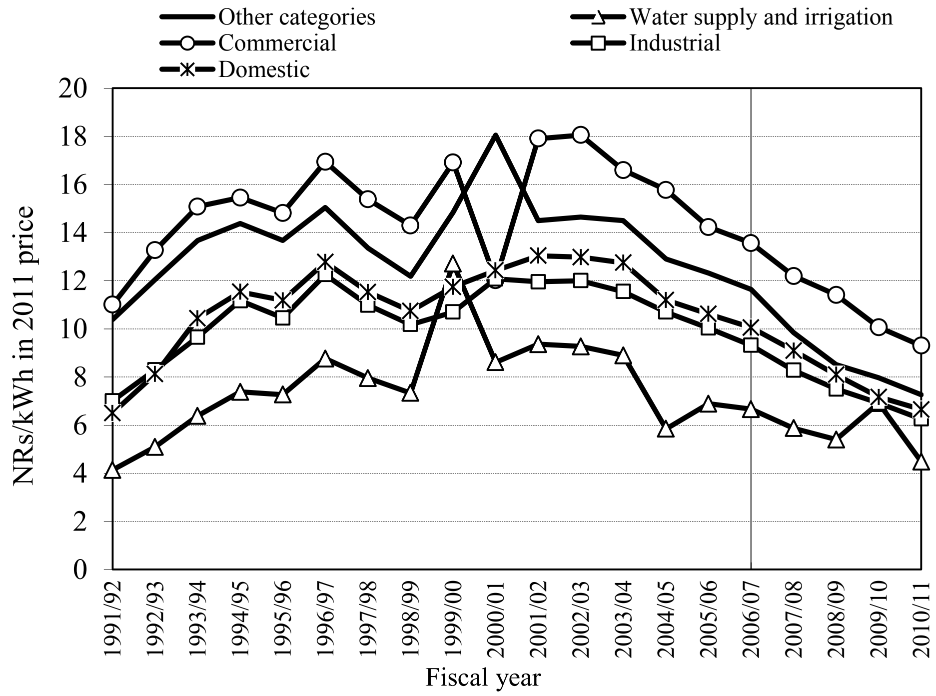
Following the decline in the tariff rates, the sales of electricity at the 2011 constant value have also declined significantly particularly after FY2006/07 where load shedding had declined significantly. From Figure 6.6-2, the negative impact over the sales caused by the bankruptcy of the Lehman Brothers and the subsequent slow-down of the world economy is clearly identified.

Against the declining business performance of the NEA, the increase in the electricity tariff schedule was approved by the Electricity Tariff Fixation Commission in July 2012. It is expected that this price adjustment will increase overall electricity prices by 20%.

Table 6.6-1 Nominal Price of Electricity since 1992 by Sector (Rs./kWh)

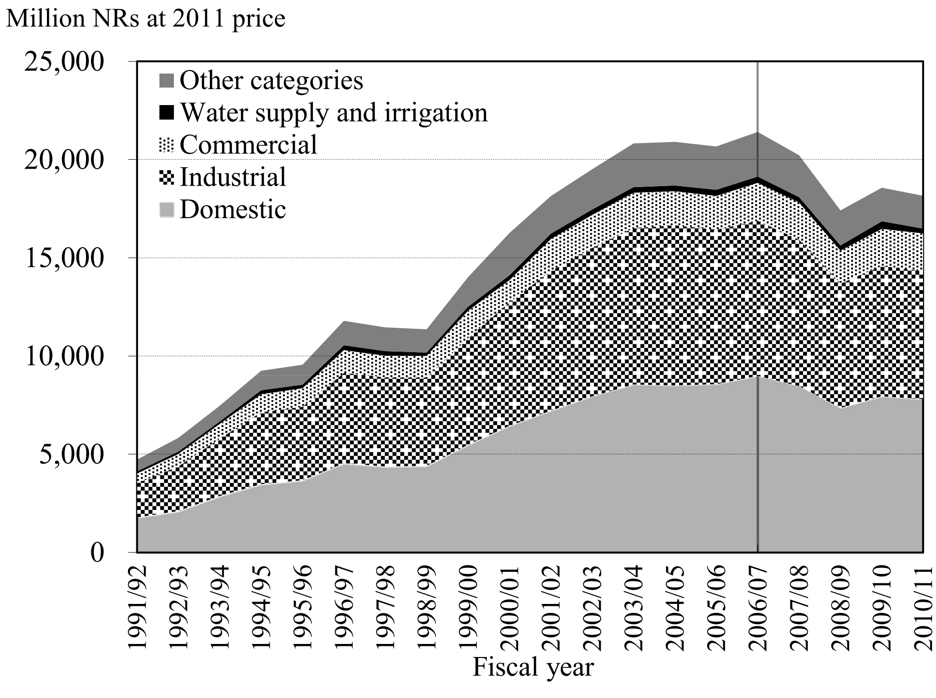
Fiscal year	Domestic		Industrial		Commercial		Water supply and		Other categories		National average		Export to India		Average price	
	Value	Growth	Value	Growth	Value	Growth	Value	Growth	Value	Growth	Value	Growth	Value	Growth	Value	Growth
1991/92	1.78		1.92		3.02		1.13		2.85		1.99		1.71		1.95	
1992/93	2.39	34.2%	2.44	27.3%	3.91	29.5%	1.50	32.4%	3.55	24.8%	2.59	30.5%	1.64	-4.2%	2.53	29.4%
1993/94	3.33	39.3%	3.08	26.1%	4.81	23.2%	2.04	35.7%	4.36	22.9%	3.38	30.3%	1.81	10.6%	3.27	29.4%
1994/95	3.96	19.0%	3.84	24.5%	5.31	10.3%	2.54	24.5%	4.94	13.1%	4.05	19.8%	2.47	36.6%	3.97	21.4%
1995/96	4.20	5.9%	3.92	2.2%	5.56	4.7%	2.73	7.5%	5.13	3.9%	4.22	4.3%	2.38	-3.9%	4.05	1.9%
1996/97	4.98	18.8%	4.78	21.9%	6.61	19.0%	3.42	25.5%	5.87	14.4%	5.05	19.8%	2.49	4.7%	4.80	18.6%
1997/98	5.01	0.4%	4.77	-0.3%	6.67	1.0%	3.45	0.9%	5.80	-1.2%	5.05	0.0%	2.97	19.2%	4.92	2.5%
1998/99	5.01	0.1%	4.75	-0.5%	6.67	-0.1%	3.42	-0.9%	5.68	-2.0%	5.05	-0.1%	3.09	4.1%	4.94	0.3%
1999/00	5.61	12.1%	5.11	7.7%	8.09	21.3%	6.08	77.5%	7.09	24.9%	5.70	13.0%	3.45	11.7%	5.53	12.1%
2000/01	6.10	8.6%	5.93	15.9%	5.90	-27.0%	4.23	-30.4%	8.86	24.9%	6.23	9.2%	3.14	-8.9%	5.95	7.6%
2001/02	6.59	8.1%	6.05	2.0%	9.05	53.4%	4.74	12.0%	7.33	-17.3%	6.55	5.1%	3.84	22.2%	6.31	6.0%
2002/03	6.94	5.2%	6.42	6.1%	9.65	6.6%	4.95	4.6%	7.83	6.8%	6.93	5.8%	4.21	9.6%	6.62	4.9%
2003/04	7.01	1.0%	6.35	-1.0%	9.12	-5.5%	4.89	-1.3%	7.97	1.8%	6.92	-0.1%	4.77	13.4%	6.75	2.0%
2004/05	6.58	-6.1%	6.28	-1.1%	9.26	1.6%	3.43	-29.8%	7.58	-4.9%	6.62	-4.3%	5.51	15.4%	6.56	-2.8%
2005/06	6.71	2.0%	6.34	0.9%	8.99	-3.0%	4.35	26.7%	7.78	2.7%	6.74	1.8%	6.00	9.0%	6.71	2.3%
2006/07	6.74	0.5%	6.24	-1.5%	9.09	1.1%	4.47	2.6%	7.80	0.2%	6.74	0.0%	5.58	-7.0%	6.70	-0.1%
2007/08	6.76	0.3%	6.15	-1.4%	9.07	-0.3%	4.37	-2.2%	7.32	-6.2%	6.68	-1.0%	6.01	7.7%	6.66	-0.6%
2008/09	6.71	-0.7%	6.22	1.2%	9.47	4.4%	4.48	2.5%	7.07	-3.4%	6.69	0.2%	6.37	6.0%	6.69	0.4%
2009/10	6.54	-2.6%	6.31	1.4%	9.19	-2.9%	6.31	40.8%	7.28	3.0%	6.71	0.2%	8.06	26.5%	6.75	0.9%
2010/11	6.65	1.7%	6.26	-0.8%	9.30	1.2%	4.48	-28.9%	7.27	-0.2%	6.71	0.1%	7.80	-3.2%	6.72	-0.3%
Aerage	5.48	7.8%	5.16	6.9%	7.44	7.3%	3.85	10.5%	6.47	5.7%	5.53	7.1%	4.16	8.9%	5.42	7.1%

Source: NEA



Source: NEA; Study Team

Figure 6.6-1 Electricity Prices by Consumer Categories since 1992 (at 2011 Prices)



Source: NEA; Study Team

Figure 6.6-2 Electricity Sales by Consumer Categories since 1992 (at 2011 Prices)

6.7 Financial Status of the NEA

The NEA is incurring a huge accumulated loss of Rs. 27 billion, whereas its annual sales value is about 20 billion. In January 2012 the Government of Nepal decided to write off the loss by reducing the government's shares invested in the NEA. This means that tax money was used to cover the loss. In effect, the NEA's capital base shrank by Rs. 27 billion, and fundamental management and financial issues such as low tariff rates were not addressed. The decision was made with respect to the proposals reported by a special committee established by the Ministry of Energy in 2010. At the same time, there were a number of important decisions made, such as the establishment of a Transmission Company and the government's investment in the company.

Table 6.7-1 and Table 6.7-2 show the NEA's balance sheet and profit and loss statement over the past 13 years, respectively.

Table 6.7-1 Balance Sheet of the NEA since FY1998/99

(Million NRs)

Particular	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
Capital and Liabilities													
Capital and Reserve													
Share Capital	13,366	14,634	15,360	16,601	16,977	18,216	20,162	23,113	26,382	28,610	33,659	38,652	42,002
Reserve and Accumulated Profit													
Capital & other Reserve				418	425	478	514	550	999	1,408	1,498	1,631	1,631
Accumulated profit				279	(1,695)	(3,475)	(4,808)	(6,096)	(6,650)	(8,986)	(14,099)	(21,022)	(27,534)
Total reserve and accumulated profit	1,403	1,600	1,627	697	(1,270)	(2,998)	(4,294)	(5,545)	(5,651)	(7,578)	(12,601)	(19,391)	(25,903)
Secured Long Term Loan	23,824	30,156	36,708	37,326	39,637	41,103	44,538	46,488	47,616	51,369	53,788	58,232	62,212
Deferred Tax				-	-	-	-	-	848	791	693	693	693
Grand Total	38,593	46,390	53,695	54,623	55,344	56,321	60,405	64,056	69,196	73,192	75,540	78,186	79,005
Asset													
Property, Plant & Equipment	20,586	25,106	28,238	51,081	50,095	51,415	52,167	51,743	51,782	52,030	81,239	83,106	85,763
Capital Work in Progess	16,543	18,947	23,640	4,838	8,655	10,620	16,060	21,992	29,145	35,700	13,550	17,040	20,634
Investment	326	521	517	553	613	713	777	820	882	1,620	2,140	4,974	4,974
Sub Total	37,454	44,575	52,395	56,472	59,363	62,748	69,004	74,555	81,809	89,350	96,929	105,120	111,371
Current Asset													
Inventories	740	982	961	1,058	1,017	1,048	1,373	1,355	1,498	1,800	2,159	2,432	2,510
Sundry Debtors and Other Receivable	1,531	1,526	1,679	2,285	3,380	3,736	3,698	4,088	5,151	5,721	4,854	6,098	7,282
Cash and Bank Balance	1,148	1,321	1,039	665	1,076	1,036	1,323	1,259	1,448	1,337	1,725	1,245	1,288
Prepaid,Advance, Loan and Deposits	1,634	1,932	2,635	3,314	2,217	2,063	2,099	2,294	2,226	2,320	2,495	2,734	2,821
Total Currents Asset	5,053	5,761	6,314	7,322	7,690	7,883	8,492	8,995	10,323	11,178	11,233	12,508	13,901
Less: Current Liabilities and Provision													
Sundry Creditors and Payables	4,350	4,489	5,071	8,853	11,594	13,857	16,769	19,144	22,119	25,482	29,221	33,651	38,433
Provision	437	989	1,043	1,244	753	681	698	710	693	2,085	3,331	5,577	7,630
Total Currrent Liabilities and Provision	4,787	5,477	6,114	10,097	12,347	14,538	17,466	19,854	22,812	27,567	32,552	39,228	46,063
Net Currents Assets	267	284	200	(2,775)	(4,657)	(6,655)	(8,975)	(10,859)	(12,489)	(16,389)	(21,319)	(26,720)	(32,162)
Deferred Expenditures	615	1,303	979	917	507	250	127	32	131	423	361	324	334
Inter Unit Balance(Net)	257	229	121	10	131	(22)	249	327	(255)	(192)	(431)	(538)	(538)
Total Def. Exp.& Inter.	872	1,532	1,100	927	637	228	376	360	(124)	231	(70)	(214)	(204)
Grand Total	38,593	46,390	53,695	54,623	55,344	56,321	60,405	64,056	69,196	73,192	75,540	78,186	79,005

Note: 1) Provisional figures. Final figures of 2011 and provisional figures for 2012 are not included in this table due to the change in the balance sheet format in the 2012 NEA annual report.

Source: NEA 2007 and NEA 2011.

Table 6.7-2 Profit and Loss Statement of the NEA since FY1998/99

(Million NRs.)

Particulars	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
Sales	5,397	6,856	8,161	9,476	11,013	11,875	12,605	13,332	14,450	15,041	14,406	17,165	17,947	20,079
Cost of sales	1,951	2,190	4,481	5,887	5,348	6,765	7,462	8,333	9,035	9,531	9,935	12,475	12,624	14,884
Generation	1,849	2,069	4,343	478	422	544	642	811	856	980	1,120	1,541	930	1,757
Power Purchase				4,659	4,087	5,416	5,760	6,392	6,968	7,437	7,691	9,747	10,494	11,732
Royalty				591	660	606	844	898	970	839	796	850	855	936
Transmission	101	122	137	158	179	200	216	232	241	275	328	338	346	459
Gross profit	3,446	4,666	3,680	3,590	5,665	5,109	5,143	4,999	5,415	5,511	4,471	4,689	5,323	5,195
Other income	385	356	593	460	513	671	618	640	1,017	935	1,602	1,188	1,383	1,350
Distribution Expenses	600	712	982	1,174	1,309	1,376	1,484	1,704	1,834	2,110	2,575	3,091	3,004	3,671
Administrative Expenses	629	703	850	447	536	489	622	420	480	684	652	790	867	1,009
Profit from operation	2,601	3,607	2,441	2,427	4,332	3,916	3,654	3,516	4,118	3,651	2,846	1,997	2,835	1,865
Interest	1,141	1,244	1,188	1,396	2,973	2,992	3,080	3,051	2,385	2,274	2,493	3,669	3,594	3,780
Depreciation	976	949	1,119	1,420	1,657	1,686	1,734	1,817	1,856	1,895	2,361	2,903	3,031	3,105
(Profit) loss on foreign Exchange	0	0	0	272	-	59	(230)	43	(493)	484	814	29	85	897
Street light dues written off				-	-	-	-	-	-	-	863	-	-	580
Provision for losses on property. plant, etc.	0	0	0	37	192	-	40	65	60	60	-	- -	-	
Provisions including retirement benefit plan										1,354	1,246	2,246	1,890	2,053
Deferred revenue expenditure written off	237	441	427	513	411	320	123	105	43	109	97	112	324 -	
Sub total	2,354	2,634	2,734	3,637	5,233	5,057	4,747	5,081	3,851	6,176	7,873	8,959	8,924	10,416
Profit (loss) from operation in the current year	247	973	(294)	(1,209)	(900)	(1,141)	(1,093)	(1,565)	267	(2,525)	(5,028)	(6,962)	(6,089)	(8,551)
Prior years (Income) Expenses	(79)	(217)	292	492	444	345	220	(297)	(47)	(152)	163	(38)	77	
Net profit (loss) before tax	168	757	(2)	(717)	(456)	(1,486)	(1,313)	(1,268)	314	(2,373)	(5,191)	(6,924)	(6,089)	(8,551)
Provision for Tax	264	571	49	143	1,498	274	-	-	-	-	-	-	-	-
Deferred Tax Expenses (Income)				-	-	-	-	-	73	(57)	(98)	-	-	-
Net profit (loss) after tax	(96)	185	(51)	(861)	(1,954)	(1,760)	(1,313)	(1,268)	241	(2,315)	(5,093)	(6,924)	(6,089)	(8,551)
Balance of profit as per last account	1,182	1,065	1,231	-	279	(1,695)	(3,475)	(4,808)	(6,096)	(6,650)	(8,986)	(14,099)	(21,022)	
Prior years Deferred Tax Expenses				-	-	-	-	-	775	-	-	-		
Total profit Available for appropriation	1,086	1,251	1,180	(861)	(1,675)	(3,455)	(4,788)	(6,076)	(6,630)	(8,966)	(14,079)	(21,022)	(27,188)	(8,551)
Insurance fund	20	20	20	20	20	20	20	20	20	20	20	-	-	-
Accumulated Loss Adjusted													27,188	
Profit (loss) transferred to balance sheet	1,065	1,231	1,160	279	(1,695)	(3,475)	(4,808)	(6,096)	(6,650)	(8,986)	(14,099)	(21,022)		(8,551)

Note: 1) Provisional figures
Source: NEA 2007 and NEA 2012

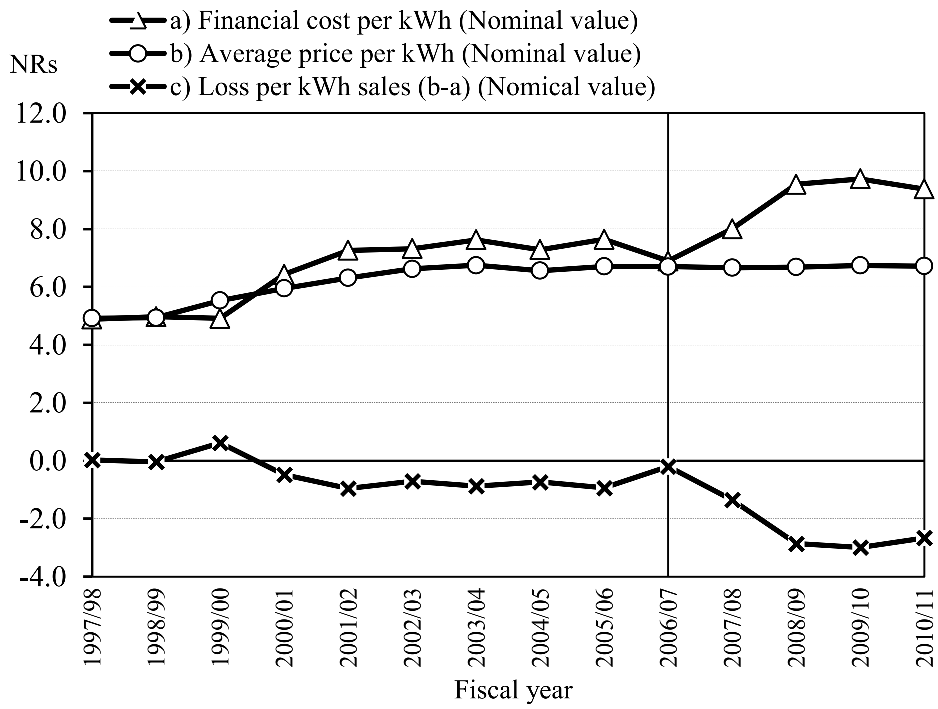
The NEA's financial position has been deteriorating from FY2002/03 when the accumulated loss amounted to Rs. 1.6 billion. By the end of FY2010/11, the loss reached Rs. 27.4 billion. During the last three years the annual net loss after taxes exceeded Rs. 5 billion. By considering that the sales in FY2010/11 were Rs. 18 billion, the NEA as the institution responsible for nation-wide supply of electricity exhibits a very undesirable financial position. In FY2010/11, repayment of interest of the loans applied to past investments amounts to Rs. 3 billion, which ate up much of the operational profit. This situation indicates that further investments for additional generation capacity must be difficult due to limited liquidity capacity. At the same time, the cost of power purchasing from IPPs amounts to more than Rs. 10 billion, which is more than 80% of the sales cost. It is clear that this purchase cost diminishes the NEA's profitability of its business significantly. On the other hand, the administrative cost is relatively small, amounting to Rs. 0.784 billion. However, assuming that there are 9,000 staff members in the NEA, an average monthly salary is about Rs. 7,250, which seems to be reasonable.

Although the NEA does not publish its cash flow statement, its cash flow status can be understood by interpreting the published profit and loss statement and balance sheet. Cash flow by operation is negative due to the high power purchase price and low sales price setting, and due to high interest payments. The cash flow by financial operation is positive due to large borrowing operations to fill negative cash flow by operation. For example, the total cash inflow in FY2010/11 was Rs. 19.2 billion, which was the sum of Rs. 18.0 billion of electricity salesand Rs. 1.2 billion of other income (see Table 6.7-2). Whereas cash outflow in the same year was Rs. 22.7 billion which was the sum of the cost of sales (the electricity purchase from IPP accounts for 83% of the cost of sales) of Rs. 13.2 billion and

Rs. 9.5 billion of the cost of distribution[6]. Due to the fact that the cash outflow exceeded the cash inflow, the NEA experienced a net cash outflow of Rs. 3.5 billion. The NEA had to fill the shortage of cash by borrowing, and the outstanding debts have been increasing rapidly in recent years.

The outstanding debt in FY2010/11 was over Rs. 62 billion. This situation has discouraged the NEA from investing in development and improvement of its facilities. The cash flow through investment activities is small, indicating an insufficient increase in its generation capacity and system efficiency.

Figure 6.7-1 and Table 6.7-3 present the financial cost and average price of electricity, and loss per unit kWh. The financial cost per kWh is calculated by dividing the total costs reported in the profit loss statements by electric energy sold to the consumers[7]. If this unit financial cost is equal to the power price charged (i.e. break-even price) the NEA's financial cost becomes equal to the income from power sales.



Source: Study Team

Figure 6.7-1 Per-kWh Cost of Electricity and Loss Incurred by the NEA

6 For cash flow analysis, depreciation is not considered as cash flow and is ignored in the analysis.

7 This is the comprehensive cost based on a pricing method to determine the power price to be charged to cosumers.

Table 6.7-3 Per-kWh Cost of Electricity and Loss Incurred by the NEA

(Nominal NRs)

Fiscal year	a) Financial cost (NRs/kWh) a	b) Average sale price (NRs/kWh) b	c) Loss (NRs/kWh) c=b-a
1997/98	4.89	4.92	0.03
1998/99	4.97	4.94	-0.03
1999/00	4.92	5.53	0.62
2000/01	6.43	5.95	-0.48
2001/02	7.26	6.31	-0.95
2002/03	7.32	6.62	-0.70
2003/04	7.62	6.75	-0.87
2004/05	7.29	6.56	-0.73
2005/06	7.64	6.71	-0.94
2006/07	6.90	6.70	-0.19
2007/08	8.01	6.66	-1.35
2008/09	9.54	6.69	-2.86
2009/10	9.73	6.75	-2.99
2010/11	9.38	6.72	-2.66

Source: NEA annual reports

In FY2010/11 the average sales price of electricity was Rs. 6.72/kWh, whereas the estimated cost of electricity delivery to a consumer was Rs. 9.38/kWh. The difference between the average price and cost was Rs. 2.66 and was a loss to be incurred for each unit of electricity sales.

The special committee established by the Ministry of Energy in 2010 argued the following points as the major reasons for the NEA's high cost services.

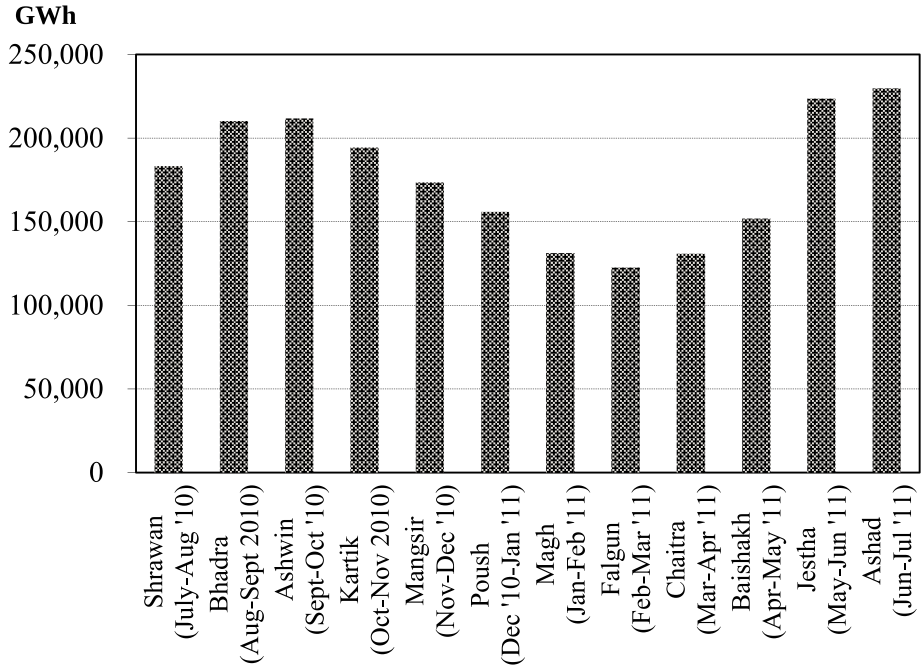
- The high cost of electricity purchase from IPPs by the NEA (Effective power purchase rate from IPPs and import is higher (Rs. 8.97/kWh) than the NEA's average sale price (Rs. 6.58/kWh), and the NEA incurs a direct loss of Rs. 2.25 on the sale of every kWh. PPAs are on a "Take-or-Pay" basis. Thus, even during wet season, the NEA is compelled to buy energy from IPPs and spill the water from its generators.) For example, the average purchase price from an IPP in FY2010/11 is 6.13 Rs./kWh, whereas the average sale price of electricity in the same year is 6.72 Rs./kWh, leaving the NEA with a 0.59 Rs./kWh margin, which is not sufficient to cover distribution costs. During the dry season, the NEA has to import power from India on commercial terms to meet energy demands.
- No adjustment in electricity tariffs since September 2001 (the electricity tariff was increased by 10% in September 2001, but no adjustment has been made since. According to the estimation made by the committee, the current price of electricity should be at 13 Rs./kWh.)
- A high interest rate (8%) of loans invested to past power development projects
- Grants from donor agencies to the government are provided to the NEA as loans from the government, and this makes for an increase in debt of the NEA to the government.
- High royalty of the government for electricity generation

- Arrears from the government on the account of street lights, etc.
- Delay in the completion of new power development projects
- No electricity generation as per the installed capacity

6.8 Load Shedding and Estimated Seasonal Electricity Prices

A brief introduction of negative impact felt by the interviewed businesspeople due to load shedding was introduced before. Businesses and production activities of industry, as well as the commerce and service sectors require a stable power supply, and therefore, capital investment to improve and stabilize power supply should have been done with sufficient funds provided by private capital market. However, it was reported that intensive power shedding due to an insufficient power supply infrastructure has significantly damaged their production and business bases, particularly after FY2006/07. The one important structural reason for the underinvestment to the sector is the distorted power market, partly due to inappropriate pricing policies.

In terms of technical aspects, the short supply of electricity is caused by 1) insufficient peak supply due to a large hourly fluctuation of power demand, and 2) insufficient power supply during the dry season due to a large fluctuation of water levels. As shown in Figure 6.8-1, the seasonal fluctuation of river flows is especially large during the dry season.



Source: NEA 2011

Figure 6.8-1 Seasonal Variance of Electricity generated by the NEA and IPPs

Nepal's power demand is characterized by the domination of domestic consumption, which exhibits peak load from 17:00 to 20:00. To manage such a daily peak demand Time of Day (TOD) Tariff Rates are introduced to charge for industrial use of electricity. On the other hand, managing the seasonality in power generation must involve investment for the development of storage type hydropower stations. Currently, there are only two storage type hydropower plants (Kulekhani No. 1 and No. 2) in Nepal, and an appropriate generation portfolio with more storage type dams and power stations should be considered to fulfill power demand during the dry season. Although the cost of development of storage type hydropower stations is relatively high, the scarcity and high appreciation of dry season electricity must be considered for investment decision-making.

If power market is competitive, the dry season electricity should be traded with higher prices than prices of electricity in the rainy season. This argument justifies the feasibility of higher and active investment for dry season electricity development. In terms of power demands from industry, and the commerce and service sectors, consistent and continuous supply of power without interruption must be highly appreciated since most of the industry and commercial operations need to continue without seasonal interruptions. This means that such economic agents tend to pay higher prices of electricity during times with scarce power under the competitive power market. It also means that instead of adjusting demand by load shedding without considering the different needs of consumers, raising electricity prices can be considered an alternative way of limiting the demand of electricity. Generally speaking, the latter method should be considered efficient because productive consumers are able to pay for highly priced electricity, and such consumers are selected by raising the price. The forecasting model adopted price elasticity of consumption of -0.4, which is used to derive theoretical monthly electricity prices. The parameter means that under the competitive market, one unit price causes the decline of 0.4 units of electricity consumption. Based on this logic, the current level of actual energy generation, estimated lost demand by load shedding, the current electricity price, and price elasticity of domestic consumption, the theoretical monthly market price at which demand and supply match is estimated. The economic mode applied to calculate the theoretical prices is the first term of the forecasting model for the domestic sector introduced in Section 7.1. This model is established based on the idea that matching demand and supply in a decentralized manner by increasing power prices makes the supply and demand in equilibrium instead of by limiting the supply centrally through load shedding. In the former case consumers will adopt and economize their consumption behavior with respect higher electricity price.

Table 6.8-1 Theoretical Seasonal Electricity Prices and Lost Sales by the NEA

Year	2010					2011							12 days	Estimated
Day	Aug. 6	Sept. 5	Oct. 5	Nov. 14	Dec. 6	Jan. 10	Jan. 28	Feb. 13	Mar. 17	Apr. 17	Jun. 5	Jun. 23	total	annual total
Season	Wet season			Dry season							Wet season			
Generated power estimated from data on the days with the maximum load (MWh)														
Demanded power	13,260	13,689	13,976	12,587	13,640	14,055	14,034	13,567	14,108	13,957	14,083	14,649	165,605	5,037,154
Supplied power	10,757	12,754	13,156	11,525	11,291	10,052	9,128	8,137	8,333	8,532	12,228	13,379	129,272	3,932,025
Load shed power	2,503	935	820	1,062	2,349	4,003	4,906	5,430	5,775	5,425	1,855	1,270	36,333	1,105,129
Assumed system loss	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Power supplied to consumers (MWh)														
Demanded power	9,945	10,267	10,482	9,440	10,230	10,541	10,525	10,175	10,581	10,468	10,562	10,987	124,204	3,777,866
Supplied power	8,068	9,566	9,867	8,644	8,469	7,539	6,846	6,103	6,250	6,399	9,171	10,035	96,954	2,949,019
Load shed power	1,877	701	615	797	1,762	3,002	3,680	4,073	4,331	4,069	1,391	953	27,250	828,847
% to demand														
Demanded power	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Supplied power	81%	93%	94%	92%	83%	72%	65%	60%	59%	61%	87%	91%	78%	78%
Load shed power	19%	7%	6%	8%	17%	28%	35%	40%	41%	39%	13%	9%	22%	22%
Estimated electricity price calculated by the model														
(Model: P_e = (Supplied power/Demanded power)^(1/-0.4)*P_a where P_e=estimated price and P_a= actual price.														
Actual price (Pa) (Rs./KWh) (Averaged 2011 price)	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72		
Price elasticity	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4		
Estimated seasonal price (Rs./KWh)	11.34	8.02	7.82	8.38	10.78	15.54	19.71	24.14	25.08	23.01	9.57	8.43		
Assumed loss of NEA's income by load shedding														
a. Actual supply of power (MWh)	8,068	9,566	9,867	8,644	8,469	7,539	6,846	6,103	6,250	6,399	9,171	10,035	96,954	2,949,019
b. Actual sales price (Rs/KWh)	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72	6.72		
c. Estimated sales price (Rs/KWh)	11.34	8.02	7.82	8.38	10.78	15.54	19.71	24.14	25.08	23.01	9.57	8.43		
d. Actual sales (Million Rs.)	54	64	66	58	57	51	46	41	42	43	62	67	652	19,828
e. Estimated sales (Million Rs)	92	77	77	72	91	117	135	147	157	147	88	85	1,285	39,085
f. Loss (d-e) (Million Rs)	-37	-12	-11	-14	-34	-66	-89	-106	-115	-104	-26	-17	-633	-19,257

Source: Study Team

Results of calculation of the theoretical monthly prices of electricity, and also estimated foregone profit that would have been obtained by the NEA are presented in Table 6.8-1. In this table the demanded power is calculated by adding the actual consumption of the area of load shedding achieved by the same area a day or several more days before the day of load shedding to the actual consumption achieved. Actual data used for this simulation with a theoretical model is obtained from the Load Dispatch Centre of the NEA. The center provided hourly power supply data on the day with the highest load during a period of one month[8]. Data from twelve such days during the period of one year are used for the simulation. The data contains estimates with load shed power derived from the past consumption patterns of scheduled areas subject to load shedding. According to the data, load shedding was practiced throughout FY2009/10 and 2010/11, indicating the severity of the supply and demand gap. The actual average sale price of electricity is 6.72 Rs./kWh and was unchanged throughout the year. On the other hand, the theoretical prices fluctuate from 11.34 Rs./kWh in August down to 7.82 Rs./kWh in October. The highest price was 25.08 Rs./kWh, marked in March, which was almost four times higher than the actual price charged by the NEA. From then on the price declined down to 8.43 Rs./kWh in July. Due to the scarce supply of electricity and the tight market conditions during the dry season, supply and demand equilibrium occurs at the high market price of electricity.

These theoretically derived equilibrium prices indicate that under the competitive market power could be sold at higher price than the actual price the NEA charges. Assuming that the actual amount of electricity sales 2,949 GWh, would be sold at the theoretical prices, the estimated revenue would increase from Rs. 19.8 billion to Rs. 39.1 billion. This means that the NEA could have earned more than double the amount of revenue than the amount actually obtained from consumers. Thus, the NEA’s foregone profit is considered to be large under the conditions of the competitive market.

The above simulation with a theoretical model is just an example of a probable scenario under different market conditions without considering the public and social aspect of electricity supply. However, at least the simulation infers that if consistent and stable supply of electricity has a large economic significance, the value of electricity during the dry season must have a higher economic value than that of the rainy season. In order words, although the annual amount of energy is the same, a constant supply of electricity should yield higher production than a fluctuating supply. Therefore, larger investment for generation of power during the dry season must be justified. The simulation also indicates that an undistorted or a less distorted market should be secured to attract private sector investment for long-term power development. In the next section, the development of less distorted market is to be considered through, for example, power pricing.

6.9 Power Import from India

As of FY2012/13, Nepal imports electricity from India according to the following agreements.

- Revised Agreement between His Majesty's Government of Nepal and The Government of India

[8] Because the data obtained from the Load Dispatch Centre is electricity consumption of the day achieving the highest peak load in a concerned month, it is estimated that consumption on the day is about 5% higher than consumptions of days with an ordinary level of consumption. Therefore, it can be assumed that load shed power is also estimated to be about 5% higher than it is supposed to be.

on The Kosi Project (1975): Maximum 10 MW

- Minutes of Meeting of 8th Indo-Nepal Power Exchange Committee Meeting (2007): Maximum 70 MW (Duhabi - Kataiya 132 kV TL: 50 MW, Tanakpur HPP: 20 MW)
- Agreement between PTC India Limited and NEA (2013): Maximum 30 MW (dry season only)
- Records of Discussion held on October 12, 2012, between NEA officials and officials of Bihar State Power Co., Ltd. at Vidhyut Bhawan, Patna on the issuers of supply or additional Power to Nepal: Maximum 137 MW

The total capacity of these agreements is 247 MW, however the actual imports in FY2012/13 were about 180 MW.

In addition to the above-mentioned agreement, the following agreement was signed in 2012, a transmission line for importing 150 MW of electricity from July 2015 which is now under construction

- Power Sales Agreement between PTC India Limited and Nepal Electricity Authority (2011)

The Nepal-India Joint Committee on Water Resources (JCWR) and its technical arms of Nepal-India Joint Standing Committee (JSTC) have been functioning as coordination bodies to determine a framework of trade volume and terms. Functions of these coordination bodies supplement the market based electricity trade in India in order to secure, and in particular, power purchasing by the NEA at the time of insufficient supply of locally generated electricity supply.

Chapter 7

Power Demand Forecast

Chapter 7 Power Demand Forecast

7.1 Objective

The objective of the power demand forecast is to forecast the 20-year evolution of power demand by setting the model parameters representing the following economic, policy and technical factors of the power market: 1) the future path of economic development in Nepal, 2) the pricing scenarios developed to ease market distortion in order to attract private sector investment, 3) a modality to handle the lost electricity demand because of intensive power shedding, and 4) the way to handle assumed damage caused by the load shedding to the industry and service sectors. In addition to the above factors, the NEA’s and IPPs' future electricity supply plans, efficiency improvement of the NEA’s core businesses, assumed power generation, purchase and power trade portfolio, and generation facility development schedules were examined to set the values of the parameters. In the master plan, the demand forecast was optimized based on the proposed power development master plans.

7.2 Current Demand Forecasting Model and its Evaluation

The demand forecasting model adopted by the NEA for the nation-wide power demand forecast is a dynamic model employing principles of economic theories. The model calculates demand of a year based on the demand of previous year and parameters defined prior to the model run. The structure of the model is relatively simple, necessary parameters are not numerous, and the requirement of information to be fed to the model is moderate. In the case of Nepal, socioeconomic data sets necessary to feed into the model are fairly easy to correct. The parameters of the forecasting model can be set in such a way that future prices of electricity are determined to correct the distorted power market, and that magnitudes of future economic growth can be determined to reflect, for example, the desired process of economic recovery. The model was employed to determine 1997 forecasts financed by the ADB, and 2008 forecast done by the NEA. Thus, comparisons with other demand forecasts can be implemented easily. Because of the above reasons in this study, the model is selected to forecast the future demand of electricity. In the previous section, the first term of the model for the consumer sector was used to determine equilibrium seasonal prices of electricity.

NEA’s model consists of three sub-models: namely, 1) a sub-model for domestic sector demand, 2) a sub-model for industry, and the commerce and service sector, and 3) a sub-model for irrigation. Since the demands from 2) and 3) are demands for production activities, the supply of power to the demands should be prioritized.

The three sub-models are described below:

(1) Domestic sector

$$D_t = D_{t-1}(1 + a_t b)\left(\frac{\Delta P_t}{\Delta CPI_t}\right)^c + 0.5\Delta N_{t-1} d_{t-1}\,(1 + a_t b)\left(\frac{\Delta P_t}{\Delta CPI_t}\right)^c + 0.5\Delta N_t d_t$$

where

D_t : Electricity consumption in period t

$\Delta P_t = P_t/P_{t-1}$: Change in price of electricity in period t

$\Delta CPI_t = CPI_t/CPI_{t-1}$: Change in the consumer price index in period t

ΔN_t : New consumers connected in period t

a_t : Real income growth rate in period t

b : Income elasticity for electricity

c : Price elasticity for electricity for households

d_t : Average consumption for new consumers in period t

(2) Industry, commerce and service, and other sectors

$$D_{t,i} = D_{t-1,i}\left(1 + a_{t,i}b_i\right)\left(\frac{\Delta P_{t,i}}{\Delta CPI_t}\right)^c + \Delta L_{t,i}$$

where

$D_{t,i}$: Electricity consumption by sector i in period t

$\Delta P_{t,i} = P_{t,i}/P_{t,i-1}$: Change in the price of electricity for sector i in period t

$\Delta CPI_t = CPI_t/CPI_{t-1}$: Change in the consumer price index in period t

$a_{t,I}$: GDP growth rate for sector i in period t

b_i : Propensity to increase electricity consumption in relation to GDP changes in sector i

c_i : Price elasticity for electricity for sector i

$\Delta L_{t,I}$: Consumption by large new projects in sector i in period t

(3) Irrigation sector

$$D_t = D_{t-1}(1 + a) + \Delta A_t b$$

where

D_t : Electricity consumption through existing schemes in period t

A : Change in electricity requirements of existing schemes (annual growth rate)

ΔA_t : Large, incremental increases in irrigated land area (hectares in specific projects) in period t

b : Average electricity consumption per hectare of irrigated land

7.3 Power Demand Forecast with Consideration of Lost Demand

7.3.1 Determination of Economic Development and Power Pricing Scenarios

Scenarios of economic development and power pricing are represented by the parameter values set to run the power demand forecast model. Among these parameters, the price elasticity with respect to electricity consumption, income elasticity with respect to electricity consumption, and the propensity of electricity consumption with respect to changes in GDP growth are not easy to measure, and there are limited numbers of studies to determine these parameters. For this study, these parameters are adopted from the study supported by the ADB in 1997, and they are modified according to the assumptions established for consumer behaviors. Other parameters are examined and defined based on past performance, and the measured values are representing current economic conditions. By changing these parameters, the base case, low case and high case scenarios are established for calculation and implementation of sensitivity analysis.

7.3.2 Establishment of Parameters and Sensitivity Analysis

(1) Establishment of Base Case Parameters

In Table 7.3.2-,1 assumed GDP growth, income elasticity, and the propensity of electricity consumptions for the next 20 years from FY2012/13 to FY2031/32 for the domestic sector, industry sector, the commerce and service sectors, and other sectors are presented. Table 7.3.2-2 shows the prices of electricity over 20 years for the domestic sector, the industry sector, the commerce and service sector, and other sectors. In Table 7.3.2-3, there is the price elasticity of power consumption and other parameters.

Expected GDP growth for the domestic sector and other sectors is selected based on the current performance of the sectors, expected real price increases of electricity until FY2018/19, and the subsequent constant electricity price during the period of FY2019/20 to FY2031/32. During the period of electricity price increases, the GDP growth of all sectors are to become slow, and then once the prices become stable, the best growth performance based on past data is given to the mode. The maximum growth rates are 4.5% in the domestic sector, 7% in the industry sector, and in the commerce and service sectors and other sectors, it is 7%. In addition, the initial growth rates for parts of the industry sector which are affected by load shedding are moderate at 3%.

Income elasticity with respect to electricity consumption for the domestic sector is 1.3 until the fifth year, and afterwards a value of 1.4 is assigned. As for the income elasticity, the larger the value, the rate of increase in electricity consumption becomes larger with respect to the increase in income. If the elasticity is 1.3, a 1% increase in income should result in a 1.3 % increase in electricity consumption. The major consumption of electricity by the domestic sector is light. It is assumed that as GDP (or income) grows more electric household items are purchased, and hence the consumption of electricity increases. For the industry sector, it is also assumed that along with economic development, mechanization will take place and the consumption of electricity will increase accordingly. Therefore, the propensity to electricity consumption will be increased from 1.2 to 1.4 by FY2020/21. In terms of the commerce and service sector, their electricity consumption is less responsive with respect to GDP growth, and thus the value of 1.2 is assigned throughout the forecasting period. For the other sector, consisting of mainly the public sector, the propensity to consume with respect to GDP growth should be low because the public sector is less responsive to changes in GDP growth. Therefore, the other sector is given a propensity of 1.1 throughout the period.

Regarding the price of electricity, it is assumed that in the 8th year of the forecasting period (FY2020/21), the price is assumed to reach 12 Rs/kWh, which should be an appropriate price of electricity for the NEA based on examination of the balance sheet and profit and loss statements. A too rapid increase in price must not be economically and politically viable, and therefore small rates of price increases are assigned. In the table, if the parameter is 1, then this year’s price is the same as last year. If the value is 1.1, then a 10% increase from the previous year is achieved, and the same value is 0.9, then a 10% decrease is achieved. Electricity prices of all the sectors will reach 12 Rs/kWh in FY2018/19 except for prices of the irrigation sector and exports to India. The price of irrigation is a subsidized price of 4.48 Rs/kWh, and it is assumed to be subsidized continuously with a slight increase in the prices up to the NEA's break-even price of 9 Rs/kWh. By the same token, considering the lower Indian electricity price, the price of electricity imports will gradually increase up to the break down price of 9 Rs/kWh by FY2018/19.

Price elasticity with respect to electricity consumption is usually a negative value due to the fact that a higher price level yields a lower level of consumption. The lowest price elasticity of -0.4 is assigned to the domestic sector. It means that if the price increases by 1%, then consumption decreases by 0.4%. It is assumed that the demand of the domestic sector is more elastic than the demand of industry, and the commerce and service sectors. Up to FY2020/21 it is assumed that the industry sector shows a relatively elastic price, and after then the demand become less elastic with respect to price due to a relatively lower electricity cost against higher value added products. Therefore, a value of -0.2 for the industry sector is assigned after FY2021/22.

Table 7.3.2-1 Parameters for Base Case Power Demand Forecasting: GDP Growth Rates, Income Elasticity, and Propensity to Increase Electricity

	Fiscal year	Sector-wise GDP growth					Income or GDP elasticity of electricity demand			
		Domestic	Industry	Commerce	Other	Irrigation	Domestic	Industry	Commerce	Other
		Par capita real GDP growth (%)	Growth of industry value added (%)	Growth of services, etc.value added (%)	Growth of other value added (%)	Growth of agriculture value added (%)	Income elasticity for electricity demand	Propensity to increase electricity consumption wrt. GDP	Propensity to increase electricity consumption wrt. GDP	Propensity to increase electricity consumption wrt. GDP
		a_t	$a_{t,i}$	$a_{t,i}$	$a_{t,i}$		b	b_i	b_i	b_i
Actual figures	1991/92	1.57%	16.83%	6.39%	6.39%	-1.06%				
	1992/93	1.30%	4.76%	7.16%	7.16%	-0.62%				
	1993/94	5.56%	9.03%	7.15%	7.15%	7.60%				
	1994/95	0.93%	3.96%	5.57%	5.57%	-0.33%				
	1995/96	2.75%	8.30%	5.42%	5.42%	4.42%				
	1996/97	2.48%	6.36%	4.87%	4.87%	4.13%				
	1997/98	0.52%	2.31%	6.42%	6.42%	1.04%				
	1998/99	1.91%	5.99%	5.36%	5.36%	2.72%				
	1999/00	3.70%	8.21%	6.12%	6.12%	4.97%				
	2000/01	2.37%	3.60%	5.97%	5.97%	4.30%				
	2001/02	-2.16%	0.86%	-2.59%	-2.59%	3.08%				
	2002/03	1.64%	3.09%	4.44%	4.44%	3.33%				
	2003/04	2.43%	1.43%	5.27%	5.27%	4.81%				
	2004/05	1.34%	3.01%	3.09%	3.09%	3.50%				
	2005/06	1.32%	4.47%	5.16%	5.16%	1.78%				
	2006/07	1.44%	3.95%	3.81%	3.81%	0.97%				
	2007/08	4.15%	1.74%	7.36%	7.36%	5.82%				
	2008/09	2.54%	-1.37%	6.30%	6.30%	3.02%				
	2009/10	2.72%	3.32%	6.35%	6.35%	1.27%				
	2010/11	3.50%	(tbd)	(tbd)	(tbd)	(tbd)				
	2011/12	(tbd)	(tbd)	(tbd)	(tbd)	(tbd)				
	Average	2.10%	4.73%	5.24%	5.24%	2.88%				
Forecasted figures	2012/13	2.50%	3.00%	5.50%	5.50%		1.4	1.2	1.2	1.1
	2013/14	3.00%	3.60%	5.50%	5.50%		1.4	1.2	1.2	1.1
	2014/15	3.50%	4.10%	5.50%	5.50%		1.4	1.2	1.2	1.1
	2015/16	3.50%	4.10%	5.50%	5.50%		1.4	1.3	1.2	1.1
	2016/17	3.50%	4.60%	5.50%	5.50%		1.4	1.3	1.2	1.1
	2017/18	3.50%	4.70%	5.50%	5.50%		1.4	1.3	1.2	1.1
	2018/19	3.50%	4.70%	5.50%	5.50%		1.4	1.3	1.2	1.1
	2019/20	4.00%	5.20%	6.00%	5.50%		1.4	1.4	1.2	1.1
	2020/21	4.10%	5.20%	6.00%	5.50%		1.4	1.4	1.2	1.1
	2021/22	4.20%	5.30%	6.00%	6.00%		1.4	1.4	1.2	1.1
	2022/23	4.30%	5.50%	6.50%	6.00%		1.4	1.4	1.2	1.1
	2023/24	4.40%	6.00%	6.50%	6.00%		1.4	1.4	1.2	1.1
	2024/25	4.50%	6.00%	6.50%	6.00%		1.4	1.4	1.2	1.1
	2025/26	4.50%	6.00%	6.50%	6.00%		1.4	1.4	1.2	1.1
	2026/27	4.50%	6.00%	6.50%	6.00%		1.4	1.4	1.2	1.1
	2027/28	4.50%	6.50%	6.50%	6.00%		1.4	1.4	1.2	1.1
	2028/29	4.50%	6.50%	7.00%	6.00%		1.4	1.4	1.2	1.1
	2029/30	4.50%	6.50%	7.00%	6.00%		1.4	1.4	1.2	1.1
	2030/31	4.50%	7.00%	7.00%	6.00%		1.4	1.4	1.2	1.1
	2031/32	4.50%	7.00%	7.00%	6.00%		1.4	1.4	1.2	1.1
	Average	4.00%	5.38%	6.18%	5.78%		1.4	1.4	1.2	1.1

Note: Shaded fiscal year indicates the year of electricity-tariff-adjustment completion.

Source: Department of Roads, Ministry of Physical Planning and Works, Government of Nepal, 2010

Table 7.3.2-2 Parameters for Base Case Power Demand Forecasting: Price of Electricity

	Fiscal year	CPI (2011=100)	Change in real electricity price (2011 price) (Rs/KWh)											
			Domestic		Industry		Commerce		Other		Irrigation		Export	
			Real price	Change of real price $\Delta P_t / \Delta CPI_t$	Real price	Change of real price $\Delta P_t / \Delta CPI_t$	Real price	Change of real price $\Delta P_t / \Delta CPI_t$	Real price	Change of real price $\Delta P_t / \Delta CPI_t$	Real price	Change of real price	Real price	Change of real price
Actual figures	1991/92	27.4	6.51		7.01		11.01		10.39		4.14		6.23	
	1992/93	29.5	8.12	1.248	8.30	1.184	13.26	1.205	12.05	1.160	5.10	1.232	5.55	0.891
	1993/94	31.9	10.44	1.286	9.66	1.164	15.08	1.137	13.68	1.135	6.38	1.253	5.67	1.021
	1994/95	34.3	11.54	1.105	11.17	1.157	15.45	1.025	14.37	1.051	7.38	1.157	7.20	1.270
	1995/96	37.5	11.19	0.969	10.45	0.936	14.81	0.959	13.67	0.951	7.27	0.984	6.33	0.880
	1996/97	39.0	12.77	1.142	12.26	1.172	16.94	1.144	15.04	1.100	8.77	1.206	6.38	1.007
	1997/98	43.4	11.53	0.903	10.99	0.897	15.38	0.908	13.36	0.888	7.95	0.907	6.83	1.072
	1998/99	46.6	10.74	0.931	10.18	0.926	14.30	0.930	12.18	0.912	7.34	0.923	6.62	0.969
	1999/00	47.8	11.75	1.094	10.70	1.051	16.92	1.183	14.84	1.219	12.71	1.732	7.22	1.090
	2000/01	49.1	12.43	1.058	12.08	1.129	12.02	0.711	18.05	1.216	8.61	0.678	6.40	0.887
	2001/02	50.6	13.04	1.049	11.96	0.990	17.90	1.489	14.50	0.803	9.37	1.087	7.60	1.186
	2002/03	53.5	12.98	0.996	12.00	1.004	18.05	1.008	14.64	1.010	9.27	0.990	7.87	1.036
	2003/04	55.0	12.75	0.982	11.55	0.962	16.59	0.919	14.50	0.990	8.90	0.960	8.68	1.103
	2004/05	58.7	11.20	0.878	10.70	0.926	15.77	0.951	12.91	0.890	5.84	0.657	9.37	1.080
	2005/06	63.2	10.62	0.948	10.03	0.938	14.23	0.902	12.32	0.955	6.89	1.178	9.50	1.013
	2006/07	67.0	10.06	0.947	9.31	0.928	13.56	0.953	11.64	0.945	6.66	0.967	8.33	0.876
	2007/08	74.3	9.10	0.904	8.28	0.889	12.20	0.899	9.84	0.845	5.88	0.882	8.08	0.971
	2008/09	83.0	8.09	0.890	7.50	0.906	11.41	0.936	8.52	0.866	5.40	0.919	7.68	0.950
	2009/10	91.2	7.17	0.886	6.92	0.922	10.07	0.883	7.98	0.936	6.91	1.281	8.83	1.150
	2010/11	100.0	6.65	0.928	6.26	0.905	9.30	0.924	7.27	0.911	4.48	0.649	7.80	0.883
	2011/12	108.3	6.03	0.907	5.90	0.942	9.00	0.967	6.44	0.886	3.99	0.890	7.00	0.898
	Average		10.22	1.00	9.68	0.996	13.97	1.002	12.29	0.983	7.11	1.027	7.39	1.012
Forecasted figures	2012/13		6.64	1.100	6.49	1.100	9.36	1.040	7.02	1.090	4.43	1.110	7.21	1.030
	2013/14		7.30	1.100	7.14	1.100	9.73	1.040	7.65	1.090	4.96	1.120	7.57	1.050
	2014/15		8.10	1.110	7.92	1.110	10.12	1.040	8.34	1.090	5.56	1.120	7.95	1.050
	2015/16		8.99	1.110	8.79	1.110	10.63	1.050	9.17	1.100	6.28	1.130	8.35	1.050
	2016/17		9.98	1.110	9.76	1.110	11.16	1.050	10.09	1.100	7.10	1.130	8.60	1.030
	2017/18		10.98	1.100	10.83	1.110	11.61	1.040	11.10	1.100	8.02	1.130	8.86	1.030
	2018/19		12.00	1.093	12.00	1.108	12.00	1.034	12.00	1.081	9.00	1.122	9.00	1.016
	2019/20		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2020/21		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2021/22		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2022/23		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2023/24		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2024/25		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2025/26		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2026/27		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2027/28		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2028/29		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2029/30		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2030/31		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	2031/32		12.00	1.000	12.00	1.000	12.00	1.000	12.00	1.000	9.00	1.000	9.00	1.000
	Average		11.00	1.036	10.95	1.037	11.53	1.015	11.07	1.033	8.12	1.043	8.73	1.013

Note: Shaded fiscal year indicates the year of electricity-tariff-adjustment completion.

Prepared by the JICA Study Team based on information provided by the Central Bureau of Statistics

Table 7.3.2-3 Parameters for Base Case Power Demand Forecasting: Price Elasticity and Other Parameters

	Fiscal year	Price elasticity for electricity consumption				Other parameters					
		Domestic	Industry	Commerce	Other	Domestic		Industry	Irrigation		Export
						New connection per year (No.)	Annual demand per newly connected consumer (KWh)	New large project (NEA estimate in 2008) (GWh)	Annual growth of irrigation load (%)	New irrigation project (GWh)	Annual growth of export (%)
		c	c	c	c	ΔN_t	d_t	$\Delta L_{t,i}$	a	$\Delta A_t b$	a
Actual figures	1991/92						815				
	1992/93					34,260	699		-12.97%		-45.98%
	1993/94					32,477	680		-19.54%		9.49%
	1994/95					32,179	691		42.45%		-21.85%
	1995/96					34,968	697		-9.21%		120.41%
	1996/97					31,731	706		11.51%		15.17%
	1997/98					44,780	691		3.81%		-32.74%
	1998/99					45,358	692		-21.39%		-4.82%
	1999/00					49,846	726		-31.05%		48.07%
	2000/01					69,993	727		81.68%		32.63%
	2001/02					135,233	651		2.51%		6.24%
	2002/03					82,014	658		2.27%		43.62%
	2003/04					80,165	664		5.64%		-26.54%
	2004/05					103,021	681		57.81%		-21.62%
	2005/06					113,555	657		-8.96%		-12.78%
	2006/07					111,958	667		5.41%		-20.38%
	2007/08					111,001	642	1.6	-2.29%		-21.82%
	2008/09					144,761	570	0.8	2.73%		-22.83%
	2009/10					180,556	625	42.2	16.29%		61.86%
	2010/11					173,959	600	37.2	47.91%		-58.57%
	2011/12					253,439	608	27.2	-22.00%		-86.75%
	Average					93,263	674	21.8	7.63%		-1.96%
Forecasted figures	2012/13	-0.4	-0.3	-0.1	0.0	262,751	400	40.5	6.00%	4.2	1.00%
	2013/14	-0.4	-0.3	-0.1	0.0	272,063	400	26.5	6.00%	4.2	1.00%
	2014/15	-0.4	-0.3	-0.1	0.0	281,376	400	26.6	6.00%	4.2	1.00%
	2015/16	-0.4	-0.3	-0.1	0.0	290,688	400	26.6	6.00%	4.2	1.00%
	2016/17	-0.4	-0.3	-0.1	0.0	300,000	400	26.6	5.00%	4.2	1.00%
	2017/18	-0.4	-0.3	-0.1	0.0	300,000	400	26.6	5.00%	4.2	1.00%
	2018/19	-0.4	-0.3	-0.1	0.0	300,000	650	26.6	5.00%	4.2	1.00%
	2019/20	-0.4	-0.3	-0.1	0.0	300,000	650	26.6	5.00%	4.2	1.00%
	2020/21	-0.4	-0.3	-0.1	0.0	300,000	650	26.6	5.00%	4.2	1.00%
	2021/22	-0.4	-0.2	-0.1	0.0	150,000	650		5.00%	4.2	1.00%
	2022/23	-0.4	-0.2	-0.1	0.0	150,000	650		5.00%	4.2	1.00%
	2023/24	-0.4	-0.2	-0.1	0.0	150,000	650		5.00%	4.2	1.00%
	2024/25	-0.4	-0.2	-0.1	0.0	150,000	650		5.00%	4.2	1.00%
	2025/26	-0.4	-0.2	-0.1	0.0	100,000	650		5.00%	4.2	1.00%
	2026/27	-0.4	-0.2	-0.1	0.0	100,000	650		5.00%	4.2	1.00%
	2027/28	-0.4	-0.2	-0.1	0.0	100,000	650		5.00%	4.2	1.00%
	2028/29	-0.4	-0.2	-0.1	0.0	100,000	650		5.00%	4.2	1.00%
	2029/30	-0.4	-0.2	-0.1	0.0	50,000	650		5.00%	4.2	1.00%
	2030/31	-0.4	-0.2	-0.1	0.0	50,000	650		5.00%	4.2	1.00%
	2031/32	-0.4	-0.2	-0.1	0.0	50,000	650		5.00%	4.2	1.00%
	Average	-0.4	-0.2	-0.1	0.0	187,844	575	28.1	5.20%	4.2	1.00%

Note: Shaded fiscal year indicates the year of electricity-tariff-adjustment completion.

Prepared by the JICA Study Team based on information provided by the Central Bureau of Statistics

Due to the inelastic price nature of electricity consumption by the commerce and service sector, a price elasticity of -0.1 is assigned throughout the forecasting period. A portion of the cost of electricity must be small in this sector, and it will likely respond in a small magnitude with respect to changes in the electricity price. Regarding the other sector, mainly consisting of the public sector, the elasticity of the sector must be small, and is considered to be 0 throughout the forecasting period. The sector does not respond to price changes due to the public nature of electricity consumption.

For the number of new connections, it is assumed that 263,000 new connections are added in 2013 and the number of new connections gradually increases up to 300,000 in FY2016/17. After that the numbers are set to reflect a gradual decline in the number of new connections. These assumptions are set based on past performance and the current rural electrification policy. The annual average consumption of newly connected consumers is assumed to be 400 kWh in FY2012/13, and the consumption gradually increases up to 650 kWh/year. Regarding the consumption of newly established industries, the value set by NEA in their 2008 forecasting is followed. Up to FY2021/22, about 22 GWh of new demand is added to the forecast. For the irrigation sector, by referring to the actual growth rates achieved in the past, it is determined that the annual growth rate of electricity demand from the sector is 6%, and the annual incremental demand from newly established irrigation projects is determined to 4.2 GWh throughout the forecasting period based on the assumptions established by the NEA's 2008 forecasting. For electricity trading, based on the actual declining growth trend in the past annual growth rate of electricity, exports are determined as 1% throughout the forecasting period.

As shown in Table 7.3.2-4, parameters regarding efficiency of generation, transmission, and distribution of NEA operation are the system loss and system load factors. Based on past data, system loss including the NEA’s own consumption reached 27% in FY2011/12, and during the past 20 years, an improvement of the factor is hardly recognized. In FY2008/09 and FY2010/11, the system loss reached 29%. System loss includes technical loss and non-technical loss such as electricity theft. However, both types of losses should be decreased if technical capacity and consumer management are improved. In any case, additional investments should be considered to address these issues, and normalization of a pricing regime must be achieved to secure resources for investment. It is assumed that such resources are available and the technical loss will decline up to 17% by FY 2023/24. The average load factor in the past is about 62%, reflecting dominance of domestic consumption. It can be envisaged that the load factor will increase due to an increase in the industry consumption ratio to the total energy supply. However, it is determined that for the time being, dominance of the domestic sector will continue, and a highly assessed load factor will be adjusted to be low by reduction in load shedding. Therefore, a 52% load factor is assumed during the period of forecasting.

The last discussion regarding the parameter setting for the demand forecasting is whether the departing point is the actual supply/consumption of power in FY2010/11, or the FY 2010/11 consumption including the assumed demand loss caused by load shedding. In this case, by assuming that if there is no load shedding, the assumed lost demand by the load shedding is recovered completely, and thus, it is determined that the starting point of the demand forecasting is FY2010/11 consumption, including the assumed demand loss. However, if the load shedding continues for a sufficient period of time, the industry sector and other production sectors can be damaged to an irreversible state. In this case, the assumed lost demand cannot be recovered, and the selection of initial demand for forecasting needs to be determined carefully with additional information.

(2) Sensitivity Analysis of Power Demand Forecasting

To perform a sensitivity analysis, a high case and a low case are established with respect to the base case. The parameters chosen for the sensitivity analysis are power prices and GDP growth rates in concerned sectors (i.e. domestic, industry, commerce, other, irrigation (agriculture), and power export sectors). The selection of these parameters are based on the assumption that the adjustment of the power market by increasing the power prices results in both improvement of the NEA's financial position and by laying a foundation for Nepalese economic development.

<Power prices>

As shown in Table 7.3.2-4, the sector-wise power prices are calculated from the NEA's financial data in FY2010/11. The prices in 2011 are: domestic sector: 6.65 Rs/kWh; industry sector: 6.26 Rs/kWh; commerce sector: 9.30 Rs/kWh; other sector (mainly public sector): 7.27 Rs/kWh; irrigation (agriculture) sector: 4.48 Rs/kWh; and power export sector: 7.80 Rs/kWh. By considering that the 2012 price adjustment would result in a 20% price increase in the same year, the prices in FY2012/13 are determined. The discussion in the previous section indicates that the financially viable prices for the NEA are estimated to be 12.00 Rs/kWh for the domestic, industry, commerce and other sectors, whereas it is 9.00 Rs/kWh for the irrigation and export sectors. Based on these pricing schedules, the high case and low cases are established by setting an earlier or later financial year than that of the base case when the financially viable pricing is achieved.

For base case, it was already assumed that the financially viable pricing is achieved in FY2018/19. With respect to this timing, for the high case, FY2016/17 (two years earlier than that of the base case) is set for the year to reach the viable pricing, and for the low case, FY2021/22 (three years later than that of the base case) is set for the year to reach the viable pricing. In the former case the favourable environment for economic development can be achieved five years earlier than that of the base case, and in the latter case the unfavourable condition lasts five years longer than the condition of the base case. Because the price elasticity of power for electricity consumption is negative, a rapid increase in power prices results in a decrease in power demand. Therefore, it is expected that in the high case although power market adjustment can be achieved within a short period of time, the rapid increase in power prices must depress the growth of power demand during the same period.

Table 7.3.2-4 Base Case, High Case, and Low Case Parameters: Pricing of Power

No.	Fiscal year	Tariff adjustment year	Change in real electricity price (2011 price) (Rs/kWh)																	
			Domestic			Industry			Commerce			Other			Irrigation			Export		
			Target price 12.00			Target price 12.00			Target price 12.00			Target price 12.00			Target price			Target price		
			P_t			P_t			P_t			P_t			P_t			P_t		
			Base case	High case	Low case	Base case	High case	Low case	Base case	High case	Low case	Base case	High case	Low case	Base case	High case	Low case	Base case	High case	Low case
1	2012/13		6.64	6.94	6.46	6.49	6.78	6.31	9.36	9.54	9.27	7.02	7.28	6.82	4.43	4.67	4.31	7.21	7.21	7.14
2	2013/14		7.30	7.98	6.91	7.14	7.80	6.75	9.73	10.11	9.55	7.65	8.29	7.23	4.96	5.51	4.66	7.57	7.57	7.29
3	2014/15		8.10	9.18	7.39	7.92	8.97	7.22	10.12	10.72	9.83	8.34	9.45	7.67	5.56	6.50	5.03	7.95	8.03	7.43
4	2015/16		8.99	10.55	7.91	8.79	10.40	7.73	10.63	11.36	10.13	9.17	10.68	8.13	6.28	7.67	5.43	8.35	8.51	7.58
5	2016/17	High case	9.98	12.00	8.46	9.76	12.00	8.27	11.16	12.00	10.43	10.09	12.00	8.62	7.10	9.00	5.92	8.60	9.00	7.81
6	2017/18		10.98	12.00	9.05	10.83	12.00	8.85	11.61	12.00	10.75	11.10	12.00	9.22	8.02	9.00	6.45	8.86	9.00	8.04
7	2018/19	Base case	12.00	12.00	9.78	12.00	12.00	9.56	12.00	12.00	11.07	12.00	12.00	9.86	9.00	9.00	7.03	9.00	9.00	8.28
8	2019/20		12.00	12.00	10.56	12.00	12.00	10.32	12.00	12.00	11.40	12.00	12.00	10.55	9.00	9.00	7.67	9.00	9.00	8.53
9	2020/21		12.00	12.00	11.30	12.00	12.00	11.15	12.00	12.00	11.74	12.00	12.00	11.29	9.00	9.00	8.36	9.00	9.00	8.79
10	2021/22	Low case	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
11	2022/23		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
12	2023/24		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
13	2024/25		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
14	2025/26		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
15	2026/27		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
16	2027/28		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
17	2028/29		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
18	2029/30		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
19	2030/31		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
20	2031/32		12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	9.00	9.00	9.00	9.00
Average			11.00	11.33	10.49	10.95	11.30	10.41	11.53	11.68	11.31	11.07	11.38	10.57	8.12	8.42	7.69	8.73	8.76	8.49

Note: 1) Prices in 2011/12 are the same as the actual average prices in 2010/11.
2) Shaded fiscal year indicates the year of electricity-tariff-adjustment completion.

Prepared by the JICA Study Team.

<Sector-wise GDP growth rate>

Consistent with the assumption that the adoption of the financially viable pricing schedule of the NEA by the power market also lays the foundation for accelerated economic development, sector-wise GDP growth rates for all the sectors for the high case and the low case are determined in relation to the rates selected for the base case. The determined rates for the base, high, and low cases are shown in Table 7.3.2-5.

For the high case, the sector-wise power prices reach the viable price schedule in FY2016/17, and therefore, the growth rates for all sectors are set higher than those of the base case after FY2016/17. In particular, the growth rates of the domestic and industry sectors are set higher from 2016/17 through FY2031/32, the last year of the forecasting. In the case of the commerce and other sectors, which generally show higher growth rates than those of the domestic and industry sectors, they are assumed to have higher growth rates than those of the base case only in the period from FY2016/17 to FY2018/19 when the viable price schedule is achieved in the base case.

For the low case the sector-wise power prices increase gradually until FY2021/22 when the viable price schedule is attained. The distortion of the power market and the allocation of public subsidies to the market are assumed to last for fifteen years. This should result in the reduction of public investment for infrastructure and other measures necessary to achieve faster economic growth. Thus, growth rates of industry, commerce, and other sectors are set lower than those of the base case from the early years of the forecasting period. Regarding the domestic sector, because a large part of the population in the sector depends on the primary sector economy in rural areas, and the inflows of overseas remittance to the population are significant, the low performance of the industry and commerce sectors are assumed to have a small impact on the domestic sector. Therefore, the growth rates of the domestic sector are set the same as the ones in the base case.

Table 7.3.2-5 Base Case, High Case, and Low Case Parameters: GDP Growth by Sector

No.	Fiscal year	Tariff adjustment year	Sector-wise GDP growth											
			Domestic			Industry			Commerce			Other		
			Par capita real GDP growth (%) a_t			Growth of industry value added (%) $a_{t,i}$			Growth of services, etc.value added (%) $a_{t,i}$			Growth of other value added (%) $a_{t,i}$		
			Base case	High case	Low case	Base case	High case	Low case	Base case	High case	Low case	Base case	High case	Low case
1	2012/13		2.50%	2.50%	2.50%	3.00%	3.00%	3.00%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
2	2013/14		3.00%	3.00%	3.00%	3.60%	3.60%	3.60%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
3	2014/15		3.50%	3.50%	3.50%	4.10%	4.10%	4.10%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
4	2015/16		3.50%	3.50%	3.50%	4.10%	4.10%	4.10%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
5	2016/17	High case	3.50%	3.50%	3.50%	4.60%	4.60%	4.60%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%
6	2017/18		3.50%	4.00%	3.50%	4.70%	5.20%	4.70%	5.50%	6.00%	5.50%	5.50%	5.50%	5.50%
7	2018/19	Base case	3.50%	4.00%	3.50%	4.70%	5.20%	4.70%	5.50%	6.00%	5.50%	5.50%	5.50%	5.50%
8	2019/20		4.00%	4.00%	3.50%	5.20%	5.20%	4.70%	6.00%	6.00%	5.50%	5.50%	5.50%	5.50%
9	2020/21		4.10%	4.00%	3.50%	5.20%	5.50%	4.70%	6.00%	6.50%	5.50%	5.50%	5.50%	5.50%
10	2021/22	Low case	4.20%	4.00%	4.00%	5.30%	6.00%	4.70%	6.00%	6.50%	5.50%	6.00%	6.00%	6.00%
11	2022/23		4.30%	4.30%	4.20%	5.50%	6.00%	5.00%	6.50%	6.50%	5.50%	6.00%	6.00%	6.00%
12	2023/24		4.40%	4.50%	4.40%	6.00%	6.00%	5.00%	6.50%	6.50%	6.00%	6.00%	6.00%	6.00%
13	2024/25		4.50%	4.50%	4.50%	6.00%	6.00%	5.00%	6.50%	6.50%	6.00%	6.00%	6.00%	6.00%
14	2025/26		4.50%	5.00%	4.50%	6.00%	6.50%	5.50%	6.50%	7.00%	6.00%	6.00%	6.00%	6.00%
15	2026/27		4.50%	5.00%	4.50%	6.00%	6.50%	5.80%	6.50%	7.00%	6.00%	6.00%	6.00%	6.00%
16	2027/28		4.50%	5.00%	4.50%	6.50%	6.50%	6.04%	6.50%	7.00%	6.00%	6.00%	6.00%	6.00%
17	2028/29		4.50%	5.00%	4.50%	6.50%	7.00%	6.10%	7.00%	7.00%	6.00%	6.00%	6.00%	6.00%
18	2029/30		4.50%	6.00%	4.50%	6.50%	8.00%	6.20%	7.00%	8.00%	6.00%	6.00%	6.00%	6.00%
19	2030/31		4.50%	7.00%	4.50%	7.00%	8.00%	6.20%	7.00%	8.00%	6.00%	6.00%	6.00%	6.00%
20	2031/32		4.50%	8.00%	4.50%	7.00%	8.00%	6.20%	7.00%	8.00%	6.00%	6.00%	6.00%	6.00%
Average			4.00%	4.52%	3.93%	5.38%	5.75%	5.00%	6.18%	6.50%	5.73%	5.78%	5.78%	5.78%

Note: 1) Prices in 2011/12 are the same as the actual average prices in 2010/11.
2) Shaded fiscal year indicates the year of electricity-tariff-adjustment completion.

Prepared by the JICA Study Team.

7.3.3 Results of Sensitivity Analysis

Results of the base case demand forecast with the set parameters are shown in Figure 7.3.3-1, Figure 7.3.3-2, Table 7.3.3-1, Table 7.3.3-2, Table 7.3.3-3, Table 7.3.3-4, and Table 7.3.3-5.

The power demand will gradually grow until FY2021/22, and increase relatively faster after FY2021/22. In the last year (FY2031/32) of the forecast, demand for power at the generation point will reach 19,493 GWh, which is almost 3.6 times higher than electricity including lost demand by load shedding (5,380 GWh) in FY2011/12. If compared with the actual power supply of 4,146 GWh in FY2011/12, the demand in the last year of the forecast period is 4.7 times larger than the actual supply in FY2011/12. In this case, during the coming 20 years, the supply capacity must be four to five times larger than the current capacity.

Regarding peak load forecasting, by FY2031/32 the peak load at the generation point needs to reach 4,279 MW. The current peak load with lost consumption by load shedding is 1,027 MW, and thus, at least the generation capacity should be increased fourfold. If the actual peak load of 579 MW in FY2011/12 is considered, the total system capacity must be increased by seven times.

The forecasted evolution of power demand and associated peak load, as well as the slow growth of the electricity market will continue until FY2018/19 due to the gradual increase of the real price of electricity and moderate settings of economic growth rates. This indicates that the adjustment of the power market will require economic costs, and the cost may be increased as measured to address the distortion of power market delays. Therefore, it is recommended that the market adjustment should be started as soon as possible to increase the NEA's revenue for its necessary investment. At the same time, the NEA must improve its productivity and efficiency in order to reduce the cost of electricity supply and system losses.

Table 7.3.3-4 shows the forecasted growth rates of power generation and peak load. The average growth rate of power during the 20-year forecasting period is 7%, and the average growth of the peak load is also 7%. The actual average growth rate of power generation during the last 20 years is 9% for energy and 8% for generation capacity, and it is assumed that keeping an average growth rate of 7% in the next 20 years must be a moderate target. On the other hand, development of an appropriate generation portfolio requires development of an appropriate number of storage type power plants, which require a relatively long gestation period and high development cost to ensure a constant and steady supply of electricity throughout the year. In addition to a higher level of investment, the market adjustment and improvement of the NEA's financial position have to be achieved concurrently. Therefore, keeping 7% average growth must require multidimensional investment, market adjustment, and an institutional strengthening approach.

Table 7.3.3-5 indicates the base case power demand structure and growth rates by sector. In terms of the sector-wise growth of power demand, rapid growth of power demand from the irrigation sector is worth mentioning. Although the sector's power demand is 2.7% of the total demand, the sector shows an average growth rate of 7.6%, indicating recent good performance of the agriculture sector. However, the sector could suffer from erratic weather, so the power demand growth has to be monitored closely. The commerce and service sector shows an annual average growth of 7.3%, and the domestic sector shows an average annual growth rate of 8%. Increased purchase power due to a recent increase in remittances is one positive factor for the power demand growth from the commerce and service sector. However, the economy, which is heavily dependent on remittances, may erode its production base. From this point of view, the industry sector's slow growth of power demand indicated by an annual average growth of 7.1% during the forecasting period is a concern. The power supply should be stabilized as soon as possible, particularly to support the development of this sector in order to enhance the production capacity of Nepal.

The comparison with other forecasts performed by various organizations reveals that 1991 forecasts by the EDF and 1997 forecasts by the ADB are close to the actual past of demand development and peak load development. Their forecasts seem to be moderate. The development of the demand with assumed lost demand due to load shedding is close to the NEA's 2008 forecast. The current demand and supply gap is mainly caused by sluggish development of generation capacity and expansion of the distribution network, that is proceeding to quickly, and it is recommended that the balanced development of both fronts must be promoted.

Based on the current situation of power market distortion, the NEA's financial issues, and intensive load shedding as a result of inadequate planning in the past, the forecasting exercise was performed by addressing these issues. Thus, during the forecast period, 7 years until FY2018/19 are allocated for the adjustment of the distorted (underpriced) power market which requires decision-making with a long-term vision, planning, and investment for the development of an appropriate mixture of generation options including storage type hydropower plants. This adjustment scenario expects the recovery and growth of the economy after FY2018/19. The power demand forecast presented in this section is based on a scenario of growth which requires the firm determination of policy makers, the NEA, and other major players involved with the power sector in Nepal.

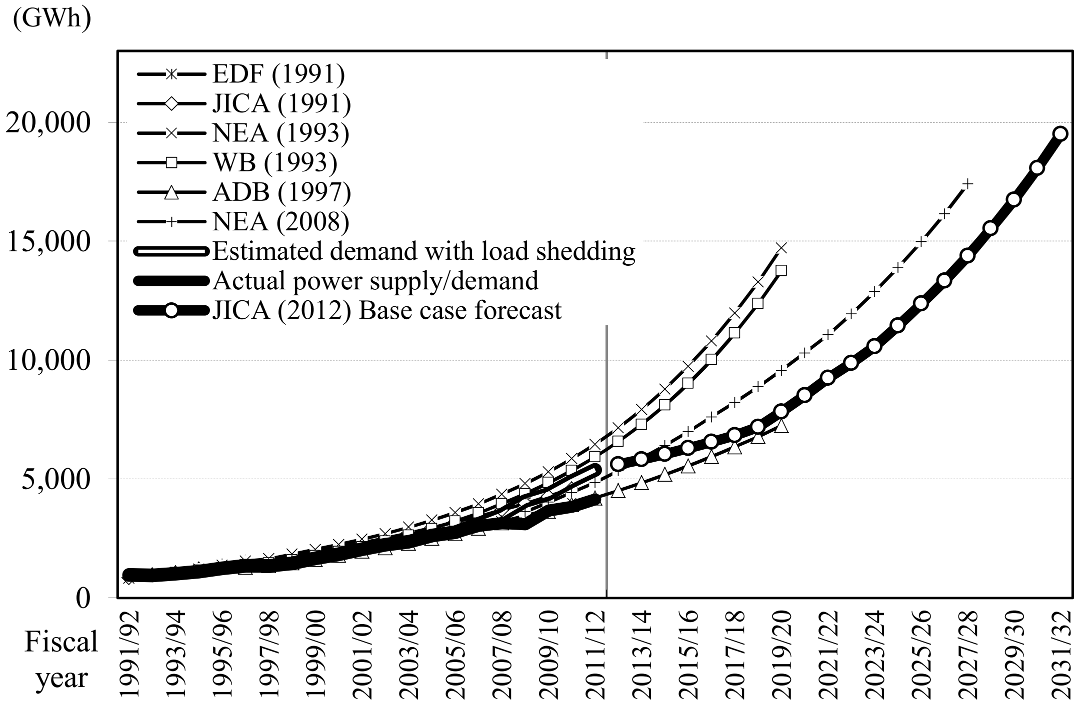


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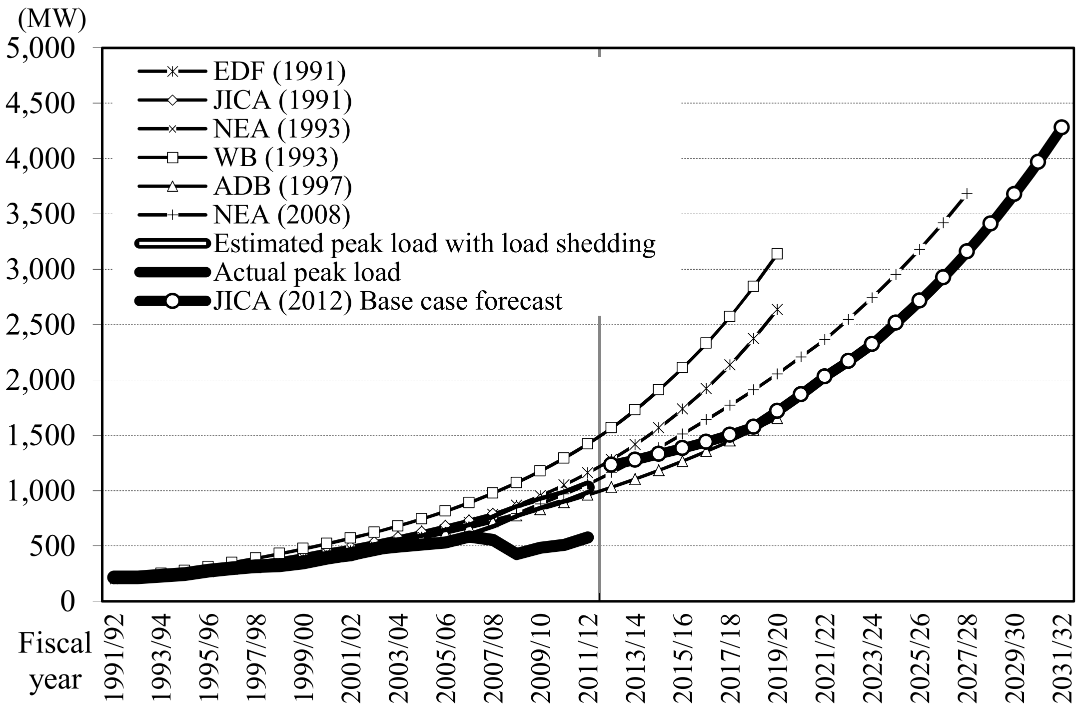
Figure 7.3.3-1 Comparison between Various Base Case Power Demand Forecasts



Prepared by the JICA Study Team.

Figure 7.3.3-2 Comparison between Various Base Case Peak Load Forecasts

Table 7.3.3-1 Comparison between Various Base Case Power Demand Forecasts

(GWh)

	Fiscal year	Organization and year of forecasting							Actual power supply	Load shed estemate	Estimated power demand
		EDF 1991	JICA 1991	NEA 1993	WB 1993	ADB[*1] 1997	NEA 2008	JICA[*2] 2012 Base case			
		a	b	c	d	e	f	g	h	i	j=h+i
	1991/92	820	843						**971**		**971**
	1992/93	928	961						**954**		**954**
	1993/94	1,015	1,059	1,062	1,050				**1,020**		**1,020**
	1994/95	1,146	1,210	1,219	1,163				**1,106**		**1,106**
	1995/96	1,244	1,338	1,366	1,254				**1,250**		**1,250**
	1996/97	1,374	1,493	1,546	1,382	1,279			**1,355**		**1,355**
	1997/98	1,437	1,576	1,645	1,448	1,349			**1,359**		**1,359**
	1998/99	1,578	1,747	1,839	1,598	1,478			**1,451**		**1,451**
	1999/00	1,734	1,939	2,036	1,764	1,617			**1,672**		**1,672**
	2000/01	1,894	2,149	2,244	1,942	1,788			**1,844**		**1,844**
	2001/02	2,052	2,328	2,465	2,145	1,967			**2,048**	2	**2,050**
	2002/03	2,211	2,520	2,703	2,373	2,110			**2,244**	0	**2,244**
	2003/04	2,382	2,727	2,971	2,629	2,300			**2,359**	1	**2,360**
	2004/05	2,566	2,950	3,266	2,913	2,502			**2,617**	3	**2,619**
	2005/06	2,765	3,192	3,591	3,227	2,702			**2,751**	8	**2,759**
	2006/07	2,971	3,424	3,952	3,567	2,922			**3,019**	103	**3,122**
	2007/08	3,208	3,692	4,356	3,954	3,150			**3,155**	350	**3,506**
	2008/09	3,456	3,970	4,805	4,376	3,377	3,620		**3,100**	972	**4,072**
	2009/10	3,724	4,268	5,302	4,843	3,637	4,018		**3,675**	701	**4,376**
	2010/11	4,012	4,589	5,851	5,357	3,914	4,431		**3,827**	1,084	**4,912**
	2011/12			6,458	5,923	4,205	4,851		**4,146**	1,233	**5,380**
20 year JICA forecasting period	2012/13			7,144	6,566	4,514	5,350	**5,607**			
	2013/14			7,920	7,296	4,840	5,860	**5,818**			
	2014/15			8,782	8,108	5,185	6,404	**6,049**			
	2015/16			9,738	9,011	5,550	6,984	**6,294**			
	2016/17			10,796	10,013	5,937	7,604	**6,556**			
	2017/18			11,972	11,128	6,347	8,219	**6,836**			
	2018/19			13,274	12,367	6,782	8,870	**7,176**			
	2019/20			14,719	13,744	7,244	9,563	**7,823**			
	2020/21						10,300	**8,504**			
	2021/22						11,054	**9,252**			
	2022/23						11,929	**9,881**			
	2023/24						12,870	**10,572**			
	2024/25						13,882	**11,447**			
	2025/26						14,971	**12,364**			
	2026/27						16,143	**13,325**			
	2027/28						17,404	**14,386**			
	2028/29							**15,531**			
	2029/30							**16,744**			
	2030/31							**18,066**			
	2031/32							**19,493**			

Note: 1) The forecasts were made by Norconsult. 2) The forecasts were made by the JICA Study Team. 3) Estimated energy demand and required capacity by the Study Team are indicated with bold letters. 4) Shaded fiscal year indicates the year of electricity-tariff-adjustment completion.

Prepared by the JICA Study Team.

Table 7.3.3-2 Comparison between Various Base Case Peak Load Forecasts

(MW)

	Fiscal year	Organization and year of forecasting							Actual peak load	Load shed estemate	Estimated peak load
		EDF 1991	JICA 1991	NEA 1993	WB 1993	ADB[*1] 1997	NEA 2008	JICA[*2] 2012 Base case			
		a	b	c	d	e	f	g	h	i	j=h+i
	1991/92		200	185					**216**		**216**
	1992/93		219	204					**214**		**214**
	1993/94	229	240	223	249				**231**		**231**
	1994/95	244	265	245	276				**244**		**244**
	1995/96	266	293	269	311				**275**		**275**
	1996/97	287	321	296	349	293			**300**		**300**
	1997/98	310	352	326	387	308			**317**		**317**
	1998/99	336	385	359	430	337			**326**		**326**
	1999/00	363	422	395	475	369			**352**		**352**
	2000/01	392	462	436	520	408			**391**		**391**
	2001/02	429	495	470	570	449			**416**	11	**426**
	2002/03	473	536	506	621	482			**470**	0	**470**
	2003/04	522	581	545	679	525			**495**	20	**515**
	2004/05	579	629	587	743	571			**514**	38	**552**
	2005/06	643	681	632	813	617			**533**	70	**603**
	2006/07	713	733	681	891	667			**584**	65	**648**
	2007/08	785	790	733	977	719			**553**	169	**722**
	2008/09	866	852	790	1,071	771	793		**428**	385	**813**
	2009/10	955	918	850	1,176	831	879		**483**	402	**885**
	2010/11	1,052	989	916	1,292	894	967		**510**	436	**946**
	2011/12	1,160			1,420	960	1,057		**579**	448	**1,027**
20 year JICA forecasting period	2012/13	1,280			1,565	1,031	1,163	**1,231**			
	2013/14	1,416			1,729	1,105	1,272	**1,277**			
	2014/15	1,568			1,909	1,184	1,387	**1,328**			
	2015/16	1,736			2,109	1,267	1,510	**1,382**			
	2016/17	1,921			2,329	1,355	1,641	**1,439**			
	2017/18	2,134			2,572	1,449	1,770	**1,501**			
	2018/19	2,371			2,841	1,548	1,907	**1,575**			
	2019/20	2,634			3,137	1,654	2,052	**1,717**			
	2020/21						2,206	**1,867**			
	2021/22						2,363	**2,031**			
	2022/23						2,545	**2,169**			
	2023/24						2,741	**2,321**			
	2024/25						2,951	**2,513**			
	2025/26						3,177	**2,714**			
	2026/27						3,419	**2,925**			
	2027/28						3,679	**3,158**			
	2028/29							**3,410**			
	2029/30							**3,676**			
	2030/31							**3,966**			
	2031/32							**4,279**			

Note: 1) The forecasts were made by Norconsult. 2) The forecasts were made by the JICA Study Team. 3) Estimated energy demand and required capacity by the Study Team are indicated with bold letters. 4) Shaded fiscal year indicates the year of electricity-tariff-adjustment completion.

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Table 7.3.3-3 Base Case Power Demand Forecasts by Sectors

	Fiscal year	Domestic load forecast			Industrial load forecast			Commercial load forecast			Other load forecast			Irrigation and water supply load forecast			Total Nepal load forecast			Energy export load forecast			Total load determined by market			
		Supplied (sold) (GWh)	Load shedding (GWh)	Total demand (GWh)	Supplied (sold) (GWh)	Load shedding (GWh)	Total demand (GWh)	Supplied (sold) (GWh)	Load shedding (GWh)	Total demand (GWh)	Supplied (sold) (GWh)	Load shedding (GWh)	Total demand (GWh)	Supplied (sold) (GWh)	Load shedding (GWh)	Total demand (GWh)	Supplied (sold) (GWh)	Load shedding (GWh)	Total demand (GWh)	Supplied (sold) (GWh)	Load shedding (GWh)	Total demand (GWh)	Supplied (sold) (GWh)	Load shedding (GWh)	Total demand (GWh)	Growth (%)
Actual supply/consumption	1991/92	275		275	246		246	45		45	57		57	28		28	652		652	85		85	737		737	
	1992/93	260		260	274		274	48		48	58		58	24		24	663		663	46		46	709		709	-4%
	1993/94	275		275	304		304	49		49	59		59	19		19	706		706	51		51	757		757	7%
	1994/95	302		302	328		328	59		59	69		69	28		28	785		785	39		39	825		825	9%
	1995/96	329		329	359		359	63		63	74		74	25		25	850		850	87		87	937		937	14%
	1996/97	355		355	377		377	68		68	83		83	28		28	910		910	100		100	1,011		1,011	8%
	1997/98	379		379	414		414	71		71	91		91	29		29	984		984	67		67	1,051		1,051	4%
	1998/99	411		411	441		441	77		77	98		98	23		23	1,049		1,049	64		64	1,114		1,114	6%
	1999/00	467		467	508		508	82		82	101		101	16		16	1,174		1,174	95		95	1,269		1,269	14%
	2000/01	518		518	521		521	94		94	119		119	29		29	1,281		1,281	126		126	1,407		1,407	11%
	2001/02	552	1	553	597	1	597	90	0	91	132	0	132	29	0	29	1,400	2	1,402	134	0	134	1,534	2	1,536	9%
	2002/03	612	0	612	630	0	630	93	0	93	140	0	140	30	0	30	1,505	0	1,505	192	0	192	1,697	0	1,697	10%
	2003/04	671	0	671	690	0	690	108	0	108	154	0	154	32	0	32	1,654	1	1,655	141	0	141	1,795	1	1,796	6%
	2004/05	758	1	759	764	1	765	109	0	109	172	0	172	50	0	50	1,854	2	1,856	111	0	111	1,964	2	1,966	9%
	2005/06	806	2	808	786	2	788	120	0	121	179	1	180	46	0	46	1,936	6	1,942	97	0	97	2,033	6	2,038	4%
	2006/07	893	32	925	849	30	879	142	5	147	195	7	202	48	2	50	2,127	75	2,202	77	0	77	2,204	75	2,279	12%
	2007/08	931	106	1,038	901	103	1,004	154	18	172	217	25	241	47	5	52	2,250	257	2,507	60	0	60	2,310	257	2,567	13%
	2008/09	909	291	1,200	846	271	1,117	146	47	193	209	67	276	48	15	64	2,158	691	2,849	46	0	46	2,205	691	2,896	13%
	2009/10	1,109	218	1,327	960	189	1,149	187	37	224	214	42	256	56	11	67	2,526	496	3,023	75	0	75	2,602	496	3,098	7%
	2010/11	1,169	335	1,504	1,002	287	1,289	204	58	263	239	68	307	83	24	107	2,697	773	3,469	31	0	31	2,728	773	3,500	13%
	2011/12	1,340	399	1,739	1,124	335	1,459	241	72	313	268	80	348	65	19	84	3,038	905	3,942	4	0	4	3,042	905	3,947	13%
20 year forecast by JICA (from 2013)	2012/13			1,785			1,509			332			369			93			4,089			4			4,093	4%
	2013/14			1,898			1,556			353			392			103			4,301			4			4,305	5%
	2014/15			2,020			1,609			374			415			113			4,533			4			4,537	5%
	2015/16			2,147			1,669			397			441			124			4,779			4			4,783	5%
	2016/17			2,279			1,741			421			467			135			5,044			4			5,048	6%
	2017/18			2,422			1,817			447			496			146			5,328			4			5,332	6%
	2018/19			2,610			1,897			475			526			157			5,664			4			5,669	6%
	2019/20			2,956			2,061			510			557			169			6,254			4			6,258	10%
	2020/21			3,327			2,238			546			591			182			6,884			5			6,888	10%
	2021/22			3,674			2,404			586			630			195			7,489			5			7,494	9%
	2022/23			3,996			2,589			631			672			209			8,097			5			8,102	8%
	2023/24			4,343			2,806			680			716			224			8,770			5			8,775	8%
	2024/25			4,718			3,042			734			763			240			9,496			5			9,501	8%
	2025/26			5,099			3,298			791			814			256			10,257			5			10,262	8%
	2026/27			5,488			3,575			852			867			273			11,055			5			11,060	8%
	2027/28			5,901			3,900			919			924			291			11,935			5			11,940	8%
	2028/29			6,340			4,255			996			986			309			12,886			5			12,891	8%
	2029/30			6,791			4,642			1,080			1,051			329			13,892			5			13,897	8%
	2030/31			7,252			5,097			1,170			1,120			350			14,990			5			14,995	8%
	2031/32			7,743			5,597			1,269			1,194			372			16,174			5			16,179	8%

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Table 7.3.3-4 Base Case Forecast of Peak Load based on the Power Demand Forecast

	Fiscal year	Total energy demand determined by market				System losses (excluding self consumption)	Annual total generation requirement forecast							System Load Factor*3	System peak load forecast					
		Supplied (sold) energy*1	Estimated energy demand lost by load shedding	Total energy demand	Growth		Avai-lable energy*2	Self con-sump-tion	Avai-lable energy for con-sumers	Growth	Adjusted estimated load shed energy	Total	Grow-th		Actual system peak load	Growth	Estima-ted load shed peak load	Requi-red system peak load*4	Growth	Date of annual maximum peak load recorded
		(GWh)	(GWh	(GWh)	(%)	(%)	(GWh	(GWh)	(GWh)	(%)	(GWh)	(GWh)	(%)	(%)	(MW)	(%)	(MW)	(MW)	(%)	(date)
		a	b=j*(1-e)	c=a+b	d	e=(h-a)/h	f	g	h=f-g	i	j	k=h+j	l	m=h*1000/(n*8	n	o	p	q=n+p	r	s
Actual supply/consumption	1991/92	737		737		24%	981	10 *5	971			971		51.3%	216			216		
	1992/93	709		709	-4%	26%	963	10 *5	954	-2%		954	-2%	50.9%	214	-1%		214	-1%	
	1993/94	757		757	7%	26%	1,031	10 *5	1,020	7%		1,020	7%	50.4%	231	8%		231	8%	
	1994/95	825		825	9%	25%	1,117	11 *5	1,106	8%		1,106	8%	51.8%	244	6%		244	6%	
	1995/96	937		937	14%	25%	1,263	13 *5	1,250	13%		1,250	13%	51.9%	275	13%		275	13%	
	1996/97	1,011		1,011	8%	25%	1,369	14 *5	1,355	8%		1,355	8%	51.5%	300	9%		300	9%	
	1997/98	1,051		1,051	4%	23%	1,373	14 *5	1,359	0%		1,359	0%	49.0%	317	6%		317	6%	
	1998/99	1,114		1,114	6%	23%	1,475	24	1,451	7%		1,451	7%	50.8%	326	3%		326	3%	
	1999/00	1,269		1,269	14%	24%	1,701	30	1,672	15%		1,672	15%	54.2%	352	8%		352	8%	
	2000/01	1,407		1,407	11%	24%	1,868	24 *5	1,844	10%		1,844	10%	53.8%	391	11%		391	11%	
	2001/02	1,534	2	1,536	9%	25%	2,066	19	2,048	11%	2	2,050	11%	56.3%	416	6%	11	426	9%	Dec 12, 2001
	2002/03	1,697	0	1,697	10%	24%	2,261	18	2,244	10%	0	2,244	9%	54.5%	470	13%	0	470	10%	Nov 28, 2002
	2003/04	1,795	1	1,796	6%	24%	2,381	22 *5	2,359	5%	1	2,360	5%	54.4%	495	5%	20	515	10%	Dec 30, 2003
	2004/05	1,964	2	1,966	9%	25%	2,643	26 *5	2,617	11%	3	2,619	11%	58.1%	514	4%	38	552	7%	Jan 25, 2005
	2005/06	2,033	6	2,038	4%	26%	2,781	30	2,751	5%	8	2,759	5%	58.9%	533	4%	70	603	9%	Jan 12, 2006
	2006/07	2,204	75	2,279	12%	27%	3,052	33	3,019	10%	103	3,122	13%	59.0%	584	9%	65	648	7%	Dec 21, 2006
	2007/08	2,310	257	2,567	13%	27%	3,186	31	3,155	4%	350	3,506	12%	65.2%	553	-5%	169	722	11%	Dec 31, 2007
	2008/09	2,205	691	2,896	13%	29%	3,131	31	3,100	-2%	972	4,072	16%	82.8%	428	-23%	385	813	13%	Jan 20, 2009
	2009/10	2,602	496	3,098	7%	29%	3,712	37	3,675	19%	701	4,376	7%	86.8%	483	13%	402	885	9%	Jan 19, 2010
	2010/11	2,728	773	3,500	13%	29%	3,858	31	3,827	4%	1,084	4,912	12%	85.7%	510	6%	436	946	7%	Jan 28, 2011
	2011/12	3,042	905	3,947	13%	27%	4,179	32	4,146	8%	1,233	5,380	10%	81.8%	579	13%	448	1,027	9%	Jan 13, 2012
	Average				9%	26%				8%			9%	62.2%		5%			8%	
20 year forecast by JICA (from 2013)	2012/13			4,093	4%	27%						**5,607**	4%	52.0%				**1,231**	20%	
	2013/14			4,305	5%	26%						**5,818**	4%	52.0%				**1,277**	4%	
	2014/15			4,537	5%	25%						**6,049**	4%	52.0%				**1,328**	4%	
	2015/16			4,783	5%	24%						**6,294**	4%	52.0%				**1,382**	4%	
	2016/17			5,048	6%	23%						**6,556**	4%	52.0%				**1,439**	4%	
	2017/18			5,332	6%	22%						**6,836**	4%	52.0%				**1,501**	4%	
	2018/19			5,669	6%	21%						**7,176**	5%	52.0%				**1,575**	5%	
	2019/20			6,258	10%	20%						**7,823**	9%	52.0%				**1,717**	9%	
	2020/21			6,888	10%	19%						**8,504**	9%	52.0%				**1,867**	9%	
	2021/22			7,494	9%	19%						**9,252**	9%	52.0%				**2,031**	9%	
	2022/23			8,102	8%	18%						**9,881**	7%	52.0%				**2,169**	7%	
	2023/24			8,775	8%	17%						**10,572**	7%	52.0%				**2,321**	7%	
	2024/25			9,501	8%	17%						**11,447**	8%	52.0%				**2,513**	8%	
	2025/26			10,262	8%	17%						**12,364**	8%	52.0%				**2,714**	8%	
	2026/27			11,060	8%	17%						**13,325**	8%	52.0%				**2,925**	8%	
	2027/28			11,940	8%	17%						**14,386**	8%	52.0%				**3,158**	8%	
	2028/29			12,891	8%	17%						**15,531**	8%	52.0%				**3,410**	8%	
	2029/30			13,897	8%	17%						**16,744**	8%	52.0%				**3,676**	8%	
	2030/31			14,995	8%	17%						**18,066**	8%	52.0%				**3,966**	8%	
	2031/32			16,179	8%	17%						**19,493**	8%	52.0%				**4,279**	8%	
	Average				8%	20%							7%	52.0%					7%	

Note: 1) Source: NEA annual reports. 2) Source: NEA annual reports. Available energy includes imports from India. 3) The average system load factor from FY 1991/92 to 2000/01 is 52%, which is used for the 20 year JICA forecast. The high system load factors shown in FY2001/02 through FY2011/12 are due to the load shedding, which made attained load curves flatter than the load curves estimated with lost supply by load shedding. 4) Source: NEA annual reports. 5) Estimated by the study team. Other values are obtained from NEA annual reports. 6) Shaded fiscal year indicates the year of electricity-tariff-adjustment completion. 7) Estimated energy demand and required capacity are indicated with bold letters.

Prepared by the JICA Study Team.

Table 7.3.3-5 Base Case Power Demand Structure and Growth Rates by Sectors

	Fiscal year	Domestic load forecast			Industrial load forecast			Commercial load forecast			Other load forecast			Irrigation and water supply load forecast			Total Nepal load forecast			Energy export load forecast			Total load determined by market		
		Load (GWh)	Growth (%)	% to the total (%)	Load (GWh)	Growth (%)	% to the total (%)	Load (GWh)	Growth (%)	% to the total (%)	Load (GWh)	Growth (%)	% to the total (%)	Load (GWh)	Growth (%)	% to the total (%)	Load (GWh)	Growth (%)	% to the total (%)	Load (GWh)	Growth (%)	% to the total (%)	Load (GWh)	Growth (%)	% to the total (%)
Actual supply/consumption	1991/92	275		37.3	246		33.4	45		6.1	57		7.8	28		3.8	652		88.4	85		11.6	737		100.0
	1992/93	260	-5.6	36.6	274	11.1	38.6	48	5.3	6.7	58	0.9	8.2	24	-13.0	3.4	663	1.7	93.5	46	-46.0	6.5	709	-3.8	100.0
	1993/94	275	5.9	36.4	304	11.0	40.2	49	2.9	6.5	59	1.1	7.7	19	-19.5	2.6	706	6.4	93.3	51	9.5	6.7	757	6.6	100.0
	1994/95	302	9.7	36.6	328	8.0	39.8	59	19.6	7.1	69	17.8	8.4	28	42.4	3.4	785	11.2	95.2	39	-21.8	4.8	825	9.0	100.0
	1995/96	329	9.0	35.1	359	9.2	38.3	63	7.4	6.7	74	7.7	7.9	25	-9.2	2.7	850	8.2	90.7	87	120.4	9.3	937	13.6	100.0
	1996/97	355	8.0	35.1	377	5.0	37.3	68	7.5	6.7	83	11.7	8.2	28	11.5	2.8	910	7.1	90.1	100	15.2	9.9	1,011	7.9	100.0
	1997/98	379	6.7	36.0	414	9.8	39.4	71	5.7	6.8	91	9.7	8.7	29	3.8	2.8	984	8.1	93.6	67	-32.7	6.4	1,051	4.0	100.0
	1998/99	411	8.4	36.9	441	6.6	39.6	77	8.2	6.9	98	7.4	8.8	23	-21.4	2.1	1,049	6.6	94.2	64	-4.8	5.8	1,114	5.9	100.0
	1999/00	467	13.8	36.8	508	15.3	40.1	82	5.8	6.4	101	3.7	8.0	16	-31.0	1.2	1,174	11.9	92.5	95	48.1	7.5	1,269	14.0	100.0
	2000/01	518	11.0	36.8	521	2.4	37.0	94	15.1	6.7	119	17.8	8.5	29	81.7	2.0	1,281	9.1	91.0	126	32.6	9.0	1,407	10.9	100.0
	2001/02	553	6.7	36.0	597	14.8	38.9	91	-3.8	5.9	132	10.6	8.6	29	2.5	1.9	1,402	9.5	91.3	134	6.2	8.7	1,536	9.2	100.0
	2002/03	612	10.8	36.1	630	5.4	37.1	93	2.4	5.5	140	6.0	8.2	30	2.3	1.8	1,505	7.3	88.7	192	43.6	11.3	1,697	10.5	100.0
	2003/04	671	9.6	37.4	690	9.6	38.4	108	16.6	6.0	154	9.8	8.6	32	5.7	1.8	1,655	10.0	92.1	141	-26.5	7.9	1,796	5.8	100.0
	2004/05	759	13.1	38.6	765	10.8	38.9	109	1.2	5.6	172	12.2	8.8	50	57.9	2.5	1,856	12.1	94.4	111	-21.6	5.6	1,966	9.5	100.0
	2005/06	808	6.5	39.6	788	3.0	38.7	121	10.3	5.9	180	4.2	8.8	46	-8.8	2.2	1,942	4.7	95.3	97	-12.8	4.7	2,038	3.7	100.0
	2006/07	925	14.4	40.6	879	11.6	38.6	147	21.6	6.4	202	12.6	8.9	50	8.8	2.2	2,202	13.4	96.6	77	-20.4	3.4	2,279	11.8	100.0
	2007/08	1,038	12.2	40.4	1,004	14.2	39.1	172	17.2	6.7	241	19.3	9.4	52	5.1	2.0	2,507	13.8	97.7	60	-21.8	2.3	2,567	12.6	100.0
	2008/09	1,200	15.6	41.4	1,117	11.2	38.6	193	12.3	6.7	276	14.6	9.5	64	21.7	2.2	2,849	13.7	98.4	46	-22.8	1.6	2,896	12.8	100.0
	2009/10	1,327	10.6	42.8	1,149	2.9	37.1	224	15.9	7.2	256	-7.4	8.3	67	5.4	2.2	3,023	6.1	97.6	75	61.9	2.4	3,098	7.0	100.0
	2010/11	1,504	13.4	43.0	1,289	12.2	36.8	263	17.2	7.5	307	19.9	8.8	107	59.0	3.0	3,469	14.8	99.1	31	-58.6	0.9	3,500	13.0	100.0
	2011/12	1,739	15.6	44.1	1,459	13.2	37.0	313	19.1	7.9	348	13.4	8.8	84	-21.3	2.1	3,942	13.6	99.9	4	-86.8	0.1	3,947	12.7	100.0
	Average		9.7	39.6		9.3	38.1		10.2	6.7		9.4	8.7		5.7	2.3		9.4	95.3		-14.1	4.7		8.7	100.0
20 year forecast by JICA (from 2013)	2012/13	1,785	2.7	43.6	1,509	3.5	36.9	332	6.2	8.1	369	6.1	9.0	93	11.1	2.3	4,089	3.7	99.9	4	1.0	0.1	4,093	3.7	100.0
	2013/14	1,898	6.3	44.1	1,556	3.1	36.2	353	6.2	8.2	392	6.1	9.1	103	10.5	2.4	4,301	5.2	99.9	4	1.0	0.1	4,305	5.2	100.0
	2014/15	2,020	6.5	44.5	1,609	3.4	35.5	374	6.2	8.3	415	6.1	9.2	113	10.1	2.5	4,533	5.4	99.9	4	1.0	0.1	4,537	5.4	100.0
	2015/16	2,147	6.3	44.9	1,669	3.7	34.9	397	6.1	8.3	441	6.1	9.2	124	9.7	2.6	4,779	5.4	99.9	4	1.0	0.1	4,783	5.4	100.0
	2016/17	2,279	6.1	45.1	1,741	4.3	34.5	421	6.1	8.3	467	6.1	9.3	135	8.4	2.7	5,044	5.5	99.9	4	1.0	0.1	5,048	5.5	100.0
	2017/18	2,422	6.3	45.4	1,817	4.4	34.1	447	6.2	8.4	496	6.1	9.3	146	8.1	2.7	5,328	5.6	99.9	4	1.0	0.1	5,332	5.6	100.0
	2018/19	2,610	7.8	46.0	1,897	4.4	33.5	475	6.2	8.4	526	6.1	9.3	157	7.9	2.8	5,664	6.3	99.9	4	1.0	0.1	5,669	6.3	100.0
	2019/20	2,956	13.3	47.2	2,061	8.7	32.9	510	7.2	8.1	557	6.1	8.9	169	7.7	2.7	6,254	10.4	99.9	4	1.0	0.1	6,258	10.4	100.0
	2020/21	3,327	12.5	48.3	2,238	8.6	32.5	546	7.2	7.9	591	6.1	8.6	182	7.5	2.6	6,884	10.1	99.9	5	1.0	0.1	6,888	10.1	100.0
	2021/22	3,674	10.4	49.0	2,404	7.4	32.1	586	7.2	7.8	630	6.6	8.4	195	7.3	2.6	7,489	8.8	99.9	5	1.0	0.1	7,494	8.8	100.0
	2022/23	3,996	8.8	49.3	2,589	7.7	32.0	631	7.8	7.8	672	6.6	8.3	209	7.2	2.6	8,097	8.1	99.9	5	1.0	0.1	8,102	8.1	100.0
	2023/24	4,343	8.7	49.5	2,806	8.4	32.0	680	7.8	7.8	716	6.6	8.2	224	7.0	2.6	8,770	8.3	99.9	5	1.0	0.1	8,775	8.3	100.0
	2024/25	4,718	8.6	49.7	3,042	8.4	32.0	734	7.8	7.7	763	6.6	8.0	240	6.9	2.5	9,496	8.3	100.0	5	1.0	0.0	9,501	8.3	100.0
	2025/26	5,099	8.1	49.7	3,298	8.4	32.1	791	7.8	7.7	814	6.6	7.9	256	6.8	2.5	10,257	8.0	100.0	5	1.0	0.0	10,262	8.0	100.0
	2026/27	5,488	7.6	49.6	3,575	8.4	32.3	852	7.8	7.7	867	6.6	7.8	273	6.7	2.5	11,055	7.8	100.0	5	1.0	0.0	11,060	7.8	100.0
	2027/28	5,901	7.5	49.4	3,900	9.1	32.7	919	7.8	7.7	924	6.6	7.7	291	6.6	2.4	11,935	8.0	100.0	5	1.0	0.0	11,940	8.0	100.0
	2028/29	6,340	7.4	49.2	4,255	9.1	33.0	996	8.4	7.7	986	6.6	7.6	309	6.5	2.4	12,886	8.0	100.0	5	1.0	0.0	12,891	8.0	100.0
	2029/30	6,791	7.1	48.9	4,642	9.1	33.4	1,080	8.4	7.8	1,051	6.6	7.6	329	6.4	2.4	13,892	7.8	100.0	5	1.0	0.0	13,897	7.8	100.0
	2030/31	7,252	6.8	48.4	5,097	9.8	34.0	1,170	8.4	7.8	1,120	6.6	7.5	350	6.3	2.3	14,990	7.9	100.0	5	1.0	0.0	14,995	7.9	100.0
	2031/32	7,743	6.8	47.9	5,597	9.8	34.6	1,269	8.4	7.8	1,194	6.6	7.4	372	6.2	2.3	16,174	7.9	100.0	5	1.0	0.0	16,179	7.9	100.0
	Average		8.0	48.1		7.1	33.3		7.3	7.9		6.4	8.1		7.6	2.5		7.5	99.9		1.0	0.1		7.5	100.0

Note: Shaded fiscal year indicates the year of electricity-tariff-adjustment completion.
Prepared by JICA Study Team.

7.3.4 Adopted Demand Forecast Scenario

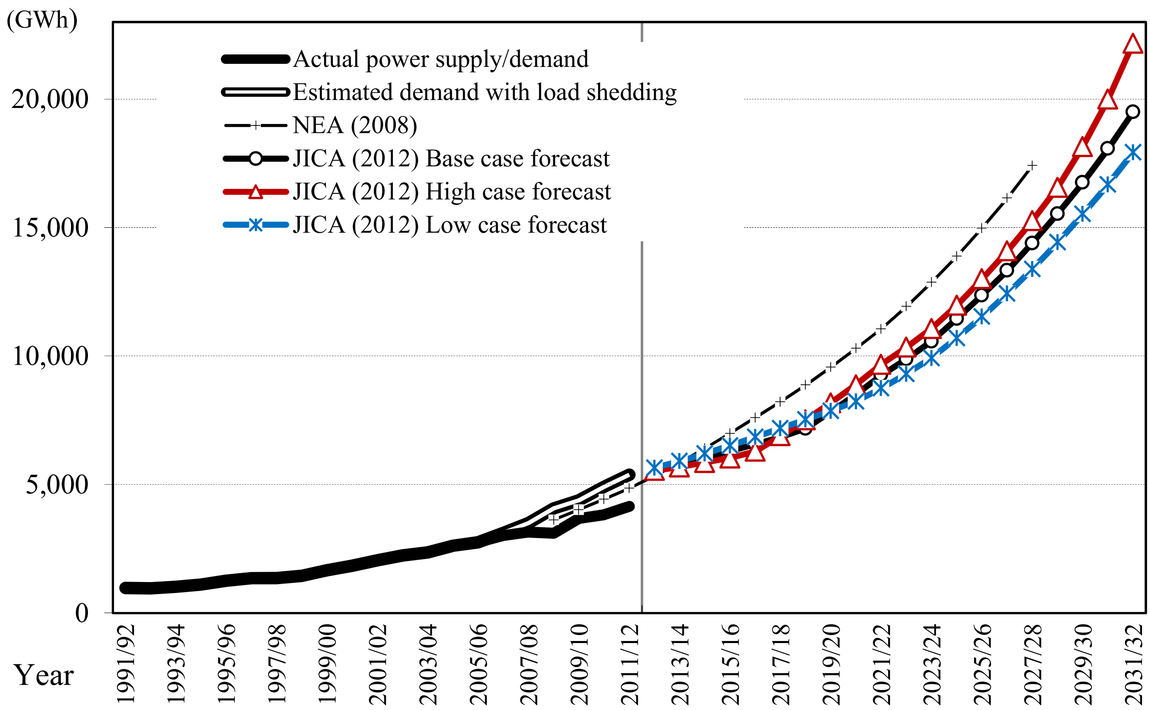
The results of the sensitivity analysis with the base, high, and low cases are shown in Table 7.3.4-1, Figure 7.3.4-1, and Figure 7.3.4-2. The high case exhibits the lowest demand growth during the first five years from FY2012/13 due to a rapid increase in the power prices. This period considers the power market adjustment period with rapid elimination of the government's subsidies to correct the market distortion. This result indicates that once the financially viable price schedule is achieved in FY2016/17, robust economic growth can be expected thereafter. The power demand in the high case catches up to the demands of the base and low cases in FY2018/19, and reaches 22,166 GWh in FY2031/32.

The low case shows more or less the same demand increase with the demand increase of the base case until FY2021/22, when the viable price schedule is achieved in the base case. However, the base case's growth in demand thereafter stagnates and the difference between the power demands of the base and low cases increases over time. At the end of the master plan period in FY2031/32, the demand of the low case reaches 17,921 GWh, which is about 80% of the high case demand in the same fiscal year.

Table 7.3.4-1 Sensitivity Analysis of Power Demand Peak Load Forecasts

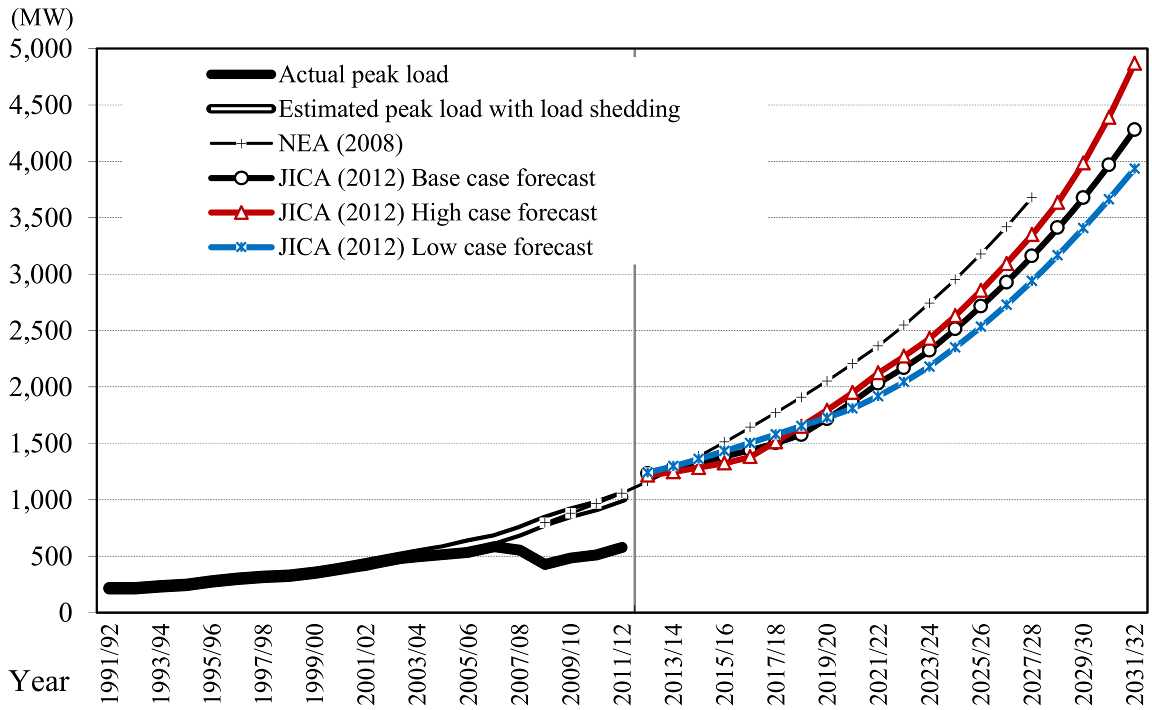
No.	Fiscal year	Tariff adjustment year	Comparision of energy demand forecasts (GWh)			Comparision of generation capacity forecasts (MW)		
			Base case	High case	Low case	Base case	High case	Law case
1	2012/13		5,607	5,537	5,650	1,231	1,216	1,240
2	2013/14		5,818	5,678	5,907	1,277	1,247	1,297
3	2014/15		6,049	5,851	6,202	1,328	1,284	1,361
4	2015/16		6,294	6,031	6,514	1,382	1,324	1,430
5	2016/17	High case	6,556	6,290	6,847	1,439	1,381	1,503
6	2017/18		6,836	6,888	7,192	1,501	1,512	1,579
7	2018/19	Base case	7,176	7,512	7,522	1,575	1,649	1,651
8	2019/20		7,823	8,174	7,869	1,717	1,794	1,728
9	2020/21		8,504	8,880	8,237	1,867	1,949	1,808
10	2021/22	Low case	9,252	9,670	8,738	2,031	2,123	1,918
11	2022/23		9,881	10,342	9,307	2,169	2,270	2,043
12	2023/24		10,572	11,066	9,922	2,321	2,429	2,178
13	2024/25		11,447	11,974	10,702	2,513	2,629	2,349
14	2025/26		12,364	13,002	11,538	2,714	2,854	2,533
15	2026/27		13,325	14,089	12,426	2,925	3,093	2,728
16	2027/28		14,386	15,260	13,390	3,158	3,350	2,939
17	2028/29		15,531	16,557	14,426	3,410	3,635	3,167
18	2029/30		16,744	18,147	15,524	3,676	3,984	3,408
19	2030/31		18,066	19,993	16,680	3,966	4,389	3,662
20	2031/32		19,493	22,166	17,921	4,279	4,866	3,934

Note: 1) Shaded fiscal year indicates the year of electricity-tariff-adjustment completion.
Prepared by the JICA Study Team.



Prepared by the JICA Study Team.

Figure 7.3.4-1 Sensitivity Analysis of Power Demand Forecasts



Prepared by the JICA Study Team.

Figure 7.3.4-2 Sensitivity Analysis of Peak Load Forecasts

For forecasting the peak load for all three cases, it is assumed that the structure of the domestic sector dominating the power market stays unchanged during the forecasting period. Since the Nepalese power market structure during the past 20 years is dominated by the domestic sector, and shows on average about 62% of the load factor, a load factor of 52% is assumed during the entire period of the forecasting. This assumption of a constant load factor results in the same trend exhibited both by the power demand forecasts and peak load forecasts. In the high case, the peak load in the last forecasting year (FY2031/32) reaches 4,866 MW, whereas in the low case the peak load reaches 3,934 MW, which is about 80% of the high case peak load in the same year.

The results of the sensitivity analysis indicate that from the point of view of long-term economic development, earlier adjustment of a distorted power market is recommended for implementation. Although in the short run the quick adjustment comes with the temporal stagnation of the economy due to an increase in power prices, in the long run recovery from stagnation and robust economic growth can be expected once the adjustment of the market is achieved.

Chapter 8

Power Development Plan

Chapter 8 Power Development Plan

In this chapter, a power development plan to meet the demand that was forecasted in Chapter 7 is worked out taking into consideration the existing generation facilities, the projects under construction and stages in preparation[1], and the candidates of storage-type projects selected in Chapter 10.

8.1 Existing Power Generation Facilities

As of the end of FY2011/12[2], the existing power generation facilities in Nepal consist of 459,150 kW of large-scale hydroelectric power plants (HPPs) and 18,380 kW of small-scale HPPs owned by the NEA, 187,581 kW of HPPs owned by IPPs, and 53,410 kW of diesel power plants and 100 kW of photovoltaic power plants owned by the NEA. The total installed capacity is 718,621 kW. (Table 8.1-1)

Table 8.1-1 Installed Capacity of Existing Generation Facilities

Power Station	Installed Capacity (kW)
NEA's Major Hydro	**459,150**
Middle Marsyangdi	70,000
Kaligandaki A	144,000
Marsyangdi	69,000
Kulekhani No. 1	60,000
Kulekhani No. 2	32,000
Trhisuli	24,000
Gandak	15,000
Modi Khola	14,800
Devighat	14,100
Sunkoshi	10,050
Puwakhola	6,200
NEA's Small Hydro	**13,844**
NEA's Small Hydro (Isolated)	**4,536**
IPP's Major Hydro	**142,600**
Khimit	60,000
Bhotekoshi	36,000
Chilime	22,000
Indrawati No. 3	7,500
Jhimruk	12,000
Andhi Khola	5,100
IPP's Small Hydro	**44,981**
Hydro Total	**665,111**
Diesel	**53,410**
Duhabi Multifuel	39,000
Hetauda	14,410
NEA's Solar	**100**
Grand Total	**718,621**

Source: A Year in Review FY2011/12, NEA

1 Projects that are in the detailed design stage or their PPA have been concluded.

2 Since the planning period of power development plan is from FY2012/13 to FY2031/32, the existing facilities at the end of FY2011/12 were used as the existing power generation facilities. The power generation facilities at the end of FY 2012/13 are shown in Clause 6.3.

8.2 Problems of the Existing Power Generation System

There are two major problems in the existing power generation system in Nepal. One is the absolute shortage of supply capacity, and the other is the decrease in generating capacity in the dry season.

8.2.1 Absolute Shortage of Supply Capacity

In Nepal, power demand has surpassed supply capacity since the mid-2000s. Since then, the country has been under the situation of an absolute power shortage, and long hours of load shedding have been inevitable. In January 2013, load shedding for 14 hours a day, 97 hours a week was implemented for about half a month. As shown in Table 8.2.1-1, power demand increased 379 MW (58%) from 648 MW to 1,027 MW in the five years from FY2006/07 to FY2011/12, but generating capacity increased only 103 MW (17%) from 616 MW to 719 MW in the same period. Even if NEA's power development plan shown in Table 8.5-1 had been implemented according to the schedule, the increase in supply capacity would have been 257 MW, it would not have been able to catch up with the increase in power demand.

In FY2011/12, the peak demand was 1,027 MW and the total installed capacity of generation facilities in the country was 719 MW, equivalent to only 70% of the peak demand. In addition, the supply capacity falls in the dry season as described in Clause 8.2.2, the electricity actually supplied was about 580 MW, including imports from India, and it was less than 60% of the power demand.

From now on, development of supply capacity more than the increase in power demand is required to resolve the shortage in supply capacity and to meet the increase in power demand.

Table 8.2.1-1 Increase in Installed Capacity and Peak Demand

Fiscal Year	2006/07	2007/08	2008/09	2008/10	2010/11	2011/12
Installed Capacity (kW)	616	617	689	698	706	719
Ratio to FY2006/07(%)	-----	100.2	111.9	113.3	114.6	116.7
Peak Demand (kW)	648	644	794	885	946	1,027
Ratio to FY2006/07(%)	-----	99.4	122.5	136.6	146.0	158.5

Source: A Year in Review, NEA

8.2.2 Decrease in Generating Capacity in the Dry Season

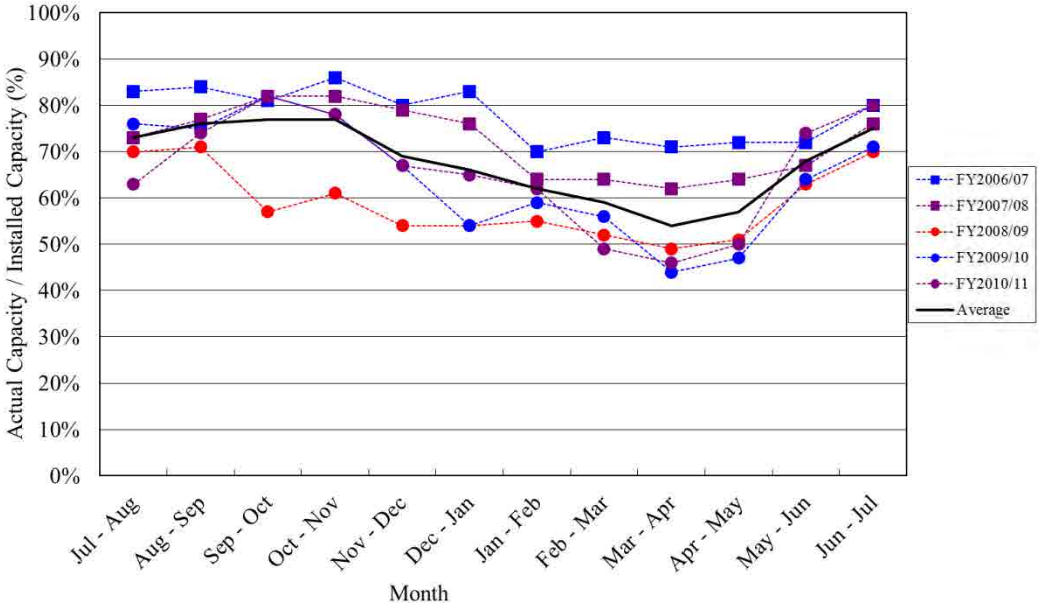
Another problem is a decrease in generating capacity in the dry season. In Nepal, about 86% of the total installed capacity is ROR-type and PROR-type HPPs. Since power plants of these types are, in general, operated in accordance with river flow, their generating capacity decreases in the dry season when the river flow is low. Figure 8.2.2-1 shows rates of the maximum output[3] of the country in each month to the total installed capacity, and Figure 8.2.2-2 shows rates of the maximum output of existing ROR- and PROR-type HPPs in each month to the total installed capacity of ROR- and PROR-type HPPs.

The supply capacity for the whole country falls from December to May. It sinks to about 55%, and in

[3] Output of diesel power plants and imports from India are included.

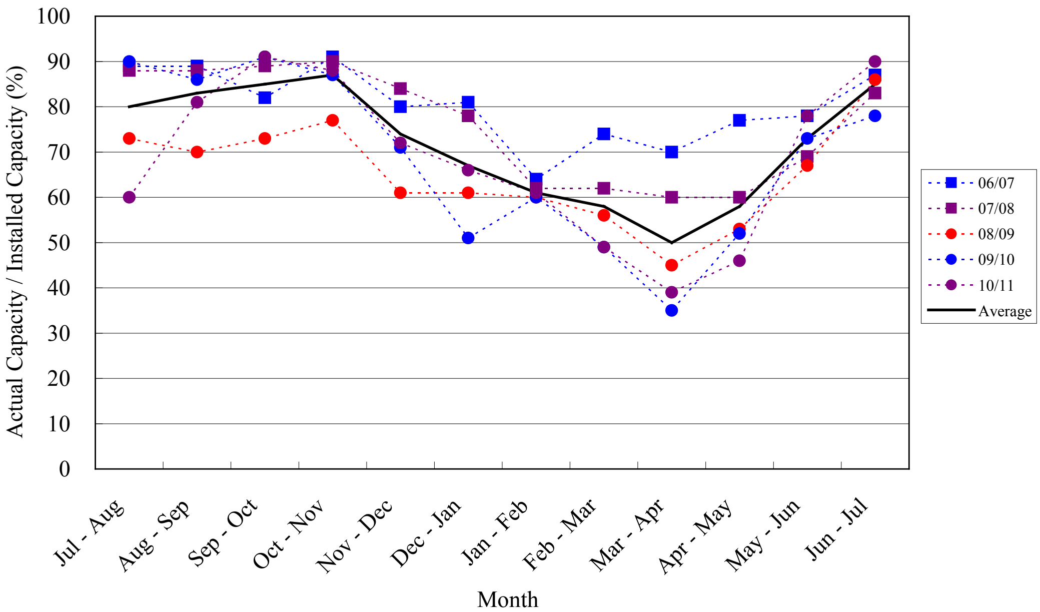
some years to about 45%, from mid-March to mid-April.

Regarding ROR- and PROR-type HPPs, the supply capacity sinks to about 50%, and in some years to about 40%, in the same period.



Source: Load Dispatch Center of NEA, and “A Year in Review” (FY2006/07 - 2010/11), NEA.
Note: The dry season is from mid-December to mid-April (Poush to Chaitra on the Vikram calendar).

Figure 8.2.2-1 Rates of Maximum Output of Each Month to Installed Capacity

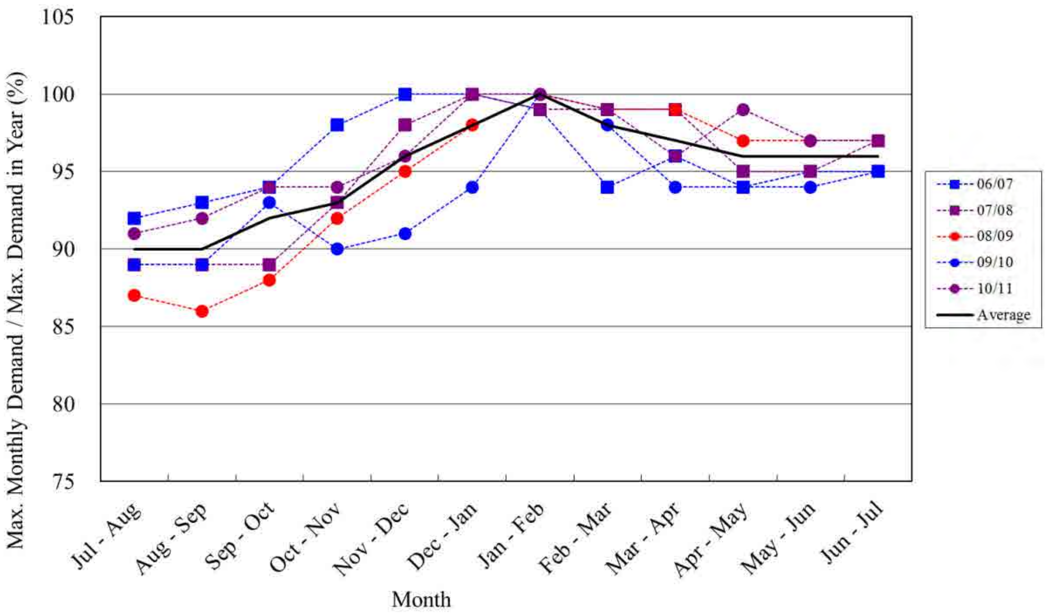


Source: Load Dispatch Center of NEA, and “A Year in Review” (FY2006/07 - 2010/11), NEA.
Note: The dry season is from mid-December to mid-April (Poush to Chaitra on the Vikram calendar).

Figure 8.2.2-2 Rates of Maximum Output of Each Month to the Installed Capacity of Existing ROR- and PROR-type HPPs

As shown in Figure 8.2.2-3, on the other hand, the monthly change of power demand is not large like supply capacity, even in the month with the minimum demand, the demand in that month is about 90% of the demand in the month with the maximum demand. The demand increases from December to April when the supply capacity sinks, and it is relatively small from July to October when the supply capacity is large.

In the generation expansion from now on, it is necessary to enhance supply capacity in the dry season from December to April.



Source: Load Dispatch Center of NEA, and "A Year in Review" (FY2006/07 - 2010/11), NEA.
Note: The dry season is from mid-December to mid-April (Poush to Chaitra on the Vikram calendar).

Figure 8.2.2-3 Rates of Maximum Demand of Each Month to the Maximum Demand in a Year

8.3 Power Generation in Nepal

8.3.1 Situation of Primary Energy

Nepal is located on the southern slope of the Himalayas, and the country is rich in hydropower resources. Its potential hydropower is estimated at 83,000 MW and the economically exploitable hydropower is estimated at 42,000 MW. Development of hydroelectric power generation has been one of its national policies.

Meanwhile, the deposits of fossil energy are very limited. Regarding coal, domestic production in 2009 was about 16,000 tons and imports were about 308,000 tons. The great part of coal is consumed as industrial fuel. The county does not produce oil and natural gas, and all petroleum products are dependent on imports. The annual import of LPG was 141,000 tons, gasoline was 115,000 tons, jet kerosene was 64,000 tons, diesel fuel was 503,000 tons, and other fuel was 45,000 tons[4].

[4] Source: IEA Energy Statistics, 2009.

Table 8.3.1-1 shows the energy balance in 2009. According to this table, about 0.4% equivalent to terms of tons of oil was used for power generation.

Table 8.3.1-1 Energy Balance for Nepal (2009)

Unit: ktoe*

Supply and Consumption	Coal and Peat	Oil Products	Hydro	Biofuels and Waste	Electricity	Heat	Total**
Production	10	0	267	8,545	0	0	8,821
Imports	185	979	0	0	53	0	1,216
Exports	0	0	0	0	-6	0	-6
International Aviation Bunkers	0	-71	0	0	0	0	-71
Stock Changes	0	0	0	0	0	0	0
Total Primary Energy Supply	**194**	**908**	**267**	**8,545**	**46**	**0**	**9,960**
Transfers	0	0	0	0	0	0	0
Statistical Differences	-1	2	0	22	0	0	22
Electricity Plants	0	-4	-267	0	268	0	-3
CHP Plants	0	0	0	0	0	0	0
Heat Plants	0	0	0	0	0	0	0
Gas Works	0	0	0	0	0	0	0
Oil Refineries	0	0	0	0	0	0	0
Coal Transformation	0	0	0	0	0	0	0
Liquefaction Plants	0	0	0	0	0	0	0
Other Transformation	0	0	0	-14	0	0	-14
Energy Industry Own Use	0	0	0	0	-3	0	-3
Losses	0	0	0	0	-84	0	-84
Final Energy Consumption	**193**	**905**	**0**	**8,552**	**227**	**0**	**9,878**
Industry	193	21	0	52	87	0	353
Transport	0	571	0	0	1	0	571
Other	1	314	0	8,499	140	0	8,954
Residential	1	133	0	8,450	99	0	8,682
Commercial and Public Services	0	73	0	50	32	0	155
Agriculture / Forestry	0	109	0	0	5	0	113
Fishing	0	0	0	0	0	0	0
Non-Specified	0	0	0	0	4	0	4
Non-Energy Use	0	0	0	0	0	0	0

Source: International Energy Agency, 2009.
*: Thousand tones of oil equivalent (on a net calorific value basis)
**: Totals may not add up due to rounding.

8.3.2 Characteristics of Each Power Generation Method

Power generation methods in Nepal are compared taking the above-mentioned situation of primary energy into account. (See Table 8.3.2-1)

(1) Hydroelectric power generation

As of the end of FY2011/12, the total installed capacity of hydroelectric power generation was 665.1 MW (92.6%) out of 718.6 MW of the total installed capacity of the country.

Since rivers flowing down in the country are steep and the valleys are narrow, there are many sites suitable for implementation of run-of-river (ROR) type hydroelectric power development projects, and many ROR-type and PROR-type hydroelectric power plants (HPPs) have been constructed. As of the end of FY2011/12, 74 out of 76 HPPs were ROR- or PROR-type HPPs, the total installed capacity of these HPPs was 573.1 MW accounting for 86% of the total installed capacity of all HPPs in the country. Meanwhile, there were only two storage-type

HPPs, the Kulekhani No. 1 HPP (60 MW) and the Kulekhani No. 2 HPP (32 MW). Their total installed capacity was 92 MW accounting for only 14% of the total of all HPPs.

Hydroelectric power generation is able to follow the fluctuation of power demand relatively easily, and its generation cost is low compared with other power generation methods as shown in Table 8.3.2-1. Therefore, large- and medium/small-scale HPPs will be constructed as the power source that are connected with the Integrated Nepal Power System (INPS). As described in above, about 86% of existing hydroelectric power generation is either ROR or PROR type. In general, constraints on construction of ROR-/PROR-type HPPs by topographical and geological conditions are smaller than those on storage-type HPPs that require construction of large dams and reservoirs, so many ROR-/PROR-type HPPs will be constructed now and in the future.

However, since the supply capacity of ROR-/PROR-type HPPs decreases in the dry season, other power sources that have sufficient supply capacity even in the dry season should also be developed. In addition, mini and micro HPPs are suitable for electrification of remote areas to where the distance from the existing power system is long.

(2) Thermal electric power generation

The NEA has two thermal (diesel) power plants totaling 53.4 MW, about 7.4% of the total installed capacity of the country. Since generation costs of these plants are as high as 27 Rs/kWh (estimated by the Study Team), the capacity factor of diesel power generation in FY2011/12 was 0.7%, and the rate of generated energy was only 0.1% to the total generated energy in the country. However, many diesel generators ranging from several kilowatts to several hundreds of kilowatts are used by hotels, shops, and wealthy families as a countermeasure for load shedding.

As described in Section 8.3.1, Nepal depends on imports for almost all fossil fuels, and a large amount of foreign exchange is necessary for operating thermal electric power plants. In addition, since Nepal is a landlocked country, substantial cost for long-distance land transportation is required to import a large amount of fossil fuel for power generation. Therefore, construction of coal-fired and LNG-fired thermal power plants for base demand and gas-turbine power plant for peak demand is an unrealistic idea.

(3) Power generation with renewable energy

There are two 50 kW wind power plants that are connected with the national power grid as power generation facilities using renewable energy. Since the impact on the environment by power generation with renewable energy like wind power and solar power is relatively small, these are promising power generation methods in the long term.

Wind power generation, in particular, is promising as one of the power sources connected to the national power grid since it has a lot of examples in many countries, and its generation cost is relatively low, from 8 to 15 Rs/kWh as shown in Table 8.3.2-1. However, it has an upper limit of the rate of its total installed capacity in the national power grid because its output fluctuates largely by wind conditions, and operation keeping up with demand is difficult. In the case that wind power generation is used in a small independent power network or by itself, electricity storage facilities like rechargeable batteries are required for stable supply.

As for solar power generation, its generation cost is relatively high at present, from 20 to 40 Rs/kWh as shown in Table 8.3.2-1. Its output fluctuates according to the weather, and a large area of land is required for construction of a large-scale solar power plant. In Nepal, therefore, small-scale distributed solar power generation for residential use and electrification of remote areas is more preferable than large-scale solar power plants that are connected to the INPS for the time being. However, since they are only able to generate power in the daytime and their output fluctuates according to the weather, it is necessary for them to be used together with rechargeable batteries in the case that they are used as a distributed power system.

Regarding biogas power generation, large-scale power plans that are connected to the INPS require establishment of an effective organic waste collection system and construction of large-scale gasification plants. Meanwhile, similar to solar power generation, this power generation method is suitable as small-scale distributed power source for facilities like schools, hotels, barracks, and small communities. The government of Nepal provides subsidies to these small-scale biogas power plants for promoting dissemination. Therefore, biogas power generation will be utilized as small-scale distributed power sources that are not connected to the INPS directly.

Table 8.3.2-1 Comparison of Electric Power Generation Methods in Nepal

	Hydropower	Solar Power	Wind Power	Thermal Power (Diesel, gas turbine)
Domestic potential	42,000 MW	2,100 MW [1)] (grid connected)	3,000 MW [1)]	―
Responsiveness to demand	Fair (ROR-type is inferior to storage-type	Poor (Fair if electric storage devises are used)	Poor (Fair if electric storage devises are used)	Good
Generation Cost (Rs./kWh)	ROR (NEA): 3.1 [2)] ROR (IPP): 5.4 - 6.5 [2)] Storage (NEA): 5.0 [2)]	Household use: 28 - 32 [3)] Mega solar: 20 - 40 [3)]	8 - 15 [3)]	Diesel (NEA): 27 [2)]
Impact on Environment	Fair (Storage-type is inferior to ROR-type)	Good	Good	Poor
Expected Role	- Main power source for the national grid - Rural electrification by mini/micro hydro	- Rural electrification of each household/public facility - Street light, etc.	- Power source for the national grid - Rural electrification	- Emergency power source

1) Alternative Energy Promotion Centre, Nepal.
2) Estimated by JICA Study Team for existing facilities.
3) National Policy Unit, Japan. 2010 price, on the assumption that JPY 1.0 = Rs 0.85.

8.4 Measures for Decrease in Generating Capacity in the Dry Season

As described in the above, most power generation facilities in Nepal are ROR- and PROR-type HPPs, their generating capacity decrease in the dry season from December to April. On the other hand, since power demand is large in this season, it is necessary to construct power generation facilities whose generating capacities do not drop, or drop only by a small amount, even in the dry season.

(1) Thermal electric power generation

In countries that have a rainy season and dry season, the generating capacity of hydroelectric power generation, ROR-type HPPs in particular, drops in the dry season because of a decrease in river flow. In these countries in general, diversification of power sources like introducing coal-fired and LNG-fired thermal power generation is promoted to cope with the drop of supply capacity of hydroelectric power generation in the dry season.

However, as described in the above, this is not a suitable power generation methods in Nepal as one of the major power sources in the national grid from the viewpoints of generation cost and foreign currency.

(2) ROR-type hydroelectric power generation

As described in Chapter 7, the peak demand in FY2031/32 is forecasted at 4,279 MW in the base case, and meanwhile, the actual supply capacity in the dry season in FY2011/12 was 579 MW including imports from India. Therefore, the supply capacity should be increased by about 3,700 MW 20 years from now. Even taking into consideration the supply capacity in the dry season of the projects under construction and projects with a high probability of construction shown in Table 8.8-1 (1,296 MW) as well as imports from India (162 MW), it is necessary to newly construct power generation facilities having a supply capacity totaling 2,242 MW. If this role is only undertaken by ROR-type HPPs, it is necessary to construct ROR-type HPPs with an installed capacity totaling about 4,500 MW (= 2,242 / 0.5) taking into account the decrease in supply capacity in the dry seasons to 50% of the installed capacity. (See Figure 8.2.2-2)

The installed capacities of a ROR-type HPP are, in general, smaller than those of a storage-type HPP, so it is necessary to construct a large number of facilities to meet the demand in the dry season. Even the development scale of individual ROR-type HPPs is small and negative effects by development are small when compared with construction of one storage-type HPP, and the effects as a whole are considerable and occur at many locations.

(3) Storage-type hydroelectric power generation

Storage-type hydroelectric power generation is able to play a role to alleviate the decrease in the supply capacity of the national grid in the dry season by storing river flow in the wet season and to release the stored water in the dry season to supplement a shortage of river flow and increase power generation.

Currently, since there are only two storage-type HPPs in Nepal, the Kulekhani No. 1 and No. 2 HPPs, necessary and appropriate data for evaluating supply capacity of storage-type power generation in the dry season are not available. For this reason, the supply capacity of storage-type HPPs is estimated on the following conditions.

- The equivalent duration of peaking is presumed to be 12 hours for storage-type HPPs to be constructed from now.

- The load factor in the dry season is presumed to be 57%, which is same as the load factor used in the power demand forecast described in Chapter 7.

From these conditions, the supply capacity of storage-type HPPs in the dry season is estimated at 88% (= (12 hrs / 24 hrs) / 0.57 × 100) of the installed capacity. Therefore, if all the newly required supply capacity(2,242 MW) is assumed by only storage-type HPPs, it is necessary to construct storage-type HPPs totaling 2,550 MW (= 2,242 / 0.8). This is about 57% in the total capacity compared to the case that all the newly required supply capacity is only secured by ROR-type HPPs.

Contrary to the above-mentioned ROR-type power generation, reservoir areas of storage-type HPPs are in general larger than ROR-type HPPs, and construction of storage-type HPPs has a larger impacts on the natural and social environment[5] than ROR-type HPPs. Meanwhile, since the installed capacity of one storage-type HPP is larger than one ROR-type HPP in general, and a decrease in the generating capacity of storage-type HPPs in the dry season is smaller than ROR-type HPPs, the number of storage-type HPPs necessary to be constructed is smaller than the number ROR-type HPPs that have a similar supply capacity in the dry season.

Since thermal power generation is difficult in Nepal as described above, and required installed capacity of ROR-type hydroelectric power generation to meet the demand in the dry season is about twice as much as the demand, construction of storage-type HPPs is the most realistic countermeasure to cope with the supply shortage in the dry season.

8.5 Existing Generation Expansion Plan by NEA

In FY2005/2006, NEA drew up the generation expansion plan up to FY2019/20, however the plan has not yet been revised since that time According to the NEA, it is very difficult to draw up a new plan because IPPs that have obtained construction licenses from the DOED (Department of Electricity Development) do not implement their projects following the schedule they applied.

Table 8.5-1 shows the above-mentioned generation expansion plan, and the table also shows the status of the project as of January 2012.

[5] In general, the following items are pointed out as the impact caused by construction of storage-type HPPs.

- Impact on the natural environment: extinction of the existing ecosystems by submergence of forest, etc., division of rivers, extinction or change of the existing river ecosystem in the recession area, deterioration of water quality in the reservoir and in the downstream area by discharge of deteriorated water, change of the existing river ecosystem by the change of flow pattern in the downstream area, sedimentation of earth and sand in and upstream area of the reservoir, change of suspended and sediment load, etc.
- Impacts on the social environment: large-scale non-voluntary resettlement, impact on livelihood of inhabitants who live near and depend on forests and rivers, etc.

Table 8.5-1 NEA's Generation Expansion Plan (FY2005/06)

FY	Project	Installed Capacity (MW)	Type[1)]	Developer	Status[2)] in 2006	Status[2)] as of January 2012
2006/07	Khudi	3.5	ROR	IPP	UC	IO (Dec. 2006)
	Sinsne Khola	0.75	ROR	IPP	UC	IO (Sep. 2007)
	Sali Nadi	0.232	ROR	IPP	Request for PPA	IO (Nov. 2007)
	Baramchi	0.98 [3)]	ROR	IPP	UC	IO (2011)
2007/08	Middle Marsyangdi	70.0	PROR	NEA	UC	IO (Dec. 2008)
	Pheme	0.995	ROR	IPP	UC	IO (2007)
	Tadi Khola	0.97	ROR	IPP	PPA concluded	UC
	Toppal Khola	1.4	ROR	IPP	UC	IO (Oct. 2007)
2008/09	Lower Indrawati	4.5	ROR	IPP	UC	UC
	Lower Nyadi	4.5	ROR	IPP	UC	UC
	Mardi	3.1	ROR	IPP	PPA concluded	IO (Jan. 2010)
2009/10	Kulekhani-III	14	ROR	NEA	UC	Suspended
	Mailung	5.0	ROR	IPP	PPA concluded	
	Upper Mai Khola	3.0	ROR	IPP	PPA concluded	
	Daram Khola	5.0	ROR	IPP	PPA concluded	Canceled
	Upper Mode	14.0	ROR	IPP	UC	
	Madi-I	10.0	ROR	IPP	UC	
2010/11	Chameliya	30.0	PROR	NEA	UC	UC
	Mewa	18.0	ROR	NEA	Planned	
	Hewa	10.0	ROR	NEA	Planned	
	Lower Modi	19.0	ROR	Private		
	Sanjen	–	–	–	–	
2011/12	Upper Trishuli	44.0	ROR	NEA	Planned	
2012/13	Upper Tamakoshi	309.0	ROR	NEA-Private JV		
2013/14	Tamor	83.0	ROR	NEA	Planned	
	Upper Seti	122.0	Storage	NEA	Planned	
	Kankai	60.0	Storage	NEA	Planned	
	Upper Karnali [4)]	75.0	PROR	NEA-Private JV		
2014/15	West Seti [5)]	75.0	Storage	Private		
2015/16	–	–	–	–	–	
2016/17	–	–	–	–	–	
2017/18	–	–	–	–	–	
2018/19	Kebeli-A	30.0	PROR	Private		
	Upper Marsyangdi A	121.0	PROR	NEA	Planned	
	Likha-4	40.0	PROR	NEA	Planned	
	Upper Modi A	42.0	ROR	NEA	Planned	
2019/20	Dudhi Koshi	300.0	Storage	NEA	Planned	

1) ROR: Run-of-river type, PROR: Peaking ROR type.
2) UC: Under construction, IO: In operation.
3) Installed capacity was changed to 4.2 MW.
4) Export project (NEA 75 MW = 25% of installed capacity of 300 MW)
5) Export project (NEA 75 MW = 10% of installed capacity of 750 MW)

According to this table, the projects completed by FY2011/12 are the projects that were scheduled to be completed by FY2008/09 or earlier. Construction of some projects with PPA in 2006 has not yet started even in 2012, and PPAs of some projects had been canceled.

8.6 Fundamental Scenarios for the Power Development Plan

The power development plan for the next 20 years is made out based on the following scenario, taking into consideration the above-mentioned problems of the power generation system and the characteristics of power generation methods in Nepal.

- The main electric power source in the national grid (INPS) is hydroelectric power generation utilizing hydropower energy that is one of the country's abundant domestic resources.
- Storage-type hydroelectric power generation is developed for securing the supply capacity of the INPS by compensating the decrease in supply capacity of ROR-type hydroelectric power generation in the dry season.
- ROR-type hydroelectric power generation is developed continuously for utilizing abundant hydropower energy.
- Import of electricity from India is kept on for power supply to the areas near the border.
- Power generation with renewable energies like wind power and solar power is promising in the long term. However, this is not considered in the power development plan in the next two decades because the proportion in the INPS is considered to be very small taking into consideration its generation cost and effects on stability of the power network.

8.7 Installed Capacity of Existing Power Generation Facilities

As described in Section 8.1, the total installed capacity of power generation facilities owned by the NEA and IPPs is 718,621 kW. Among this capacity, 714,085 kW is connected to the INPS.

In the power development plan in this chapter, the following supply capacities are also considered as the supply capacity of existing power generation facilities based on the information obtained from NEA about the power supply plan in FY2013/14.

- Increment in the total installed capacity of small-scale HPPs owned by IPPs: 136,089 kW

Since information on the commencement year of commercial operation of "The incremental amount of the total installed capacity of small-scale HPPs owned by IPPs" was not obtained, this is considered to be a part of the existing supply capacity in FY2011/12. Therefore the total installed capacity of small-scale HPPs owned by IPPs is 181,070 kW (= 44,981 + 136,089) in the power development plan. As for the existing wind power plants, they are not considered in the power development plan because the supply capacity is very small in the INPS and detailed information on them was not available.

As a result, the total installed capacities of exiting generation facilities as of the end of FY2011/12 in the power development plan are 796,664 kW of hydroelectric power generation and 53,410 kW of diesel power generation, the total is 850,074 kW. (The right column of Table 8.7-1)

Table 8.7-1 Installed Capacity of Existing Generation Facilities

Power Station	Installed Capacity in FY2011/12 (kW)	
	A Year in Review FY2011/12	Generation Expansion Plan
NEA's Major Hydro	**459,150**	**459,150**
Middle Marsyangdi	70,000	70,000
Kaligandaki A	144,000	144,000
Marsyangdi	69,000	69,000
Kulekhani No. 1	60,000	60,000
Kulekhani No. 2	32,000	32,000
Trhisuli	24,000	24,000
Gandak	15,000	15,000
Modi Khola	14,800	14,800
Devighat	14,100	14,100
Sunkoshi	10,050	10,050
Puwakhola	6,200	6,200
NEA's Small Hydro	13,844	13,844
NEA's Small Hydro (Isolated)	**4,536**	-----
IPP's Major Hydro	**142,600**	**142,600**
Khimit	60,000	60,000
Bhotekoshi	36,000	36,000
Chilime	22,000	22,000
Indrawati No. 3	7,500	7,500
Jhimruk	12,000	12,000
Andhi Khola	5,100	5,100
IPP's Small Hydro	**44,981**	**181,070**
Hydro Total	**665,111**	**796,664**
NEA's Diesel	**53,410**	**53,410**
Duhabi Multifuel	39,000	39,000
Hetauda	14,410	14,410
NEA's Solar	**100**	-----
Grand Total	**718,621**	**850,074**

8.8 Projects under Construction and Projects with a High Probability of being Constructed

As of June 2013, the projects listed in Table 8.8-1 are under construction or with a high probability of being constructed. In the power development plan in this study, these projects are considered to be implemented and put into commercial operation according to schedule.

Table 8.8-1 Projects under Construction or with a High Probability of being Constructed

Project Name	Type	Installed Capacity (MW)	Annual Energy (GWh)	Commercial Operation (FY)	Remarks
Kulekhani III	STO	14	40.85	2015/16	
Chameliya	PROR	30	184.21	2015/16	
Khani Khola	ROR	25	114	2015/16	
Upper Sanjen	ROR	11	82.4	2016/17	
Sanjen	ROR	42.9	251.9	2016/17	
Upper Trishuli 3A	ROR	60	489.9	2016/17	
Upper Tamakoshi	PROR	456	2,281	2016/17	
Madhya (Middle) Bhotekoshi	ROR	102	542	2017/18	
Rasuwagadi	ROR	111	613.88	2017/18	
Rahughat	PROR	32	186.12	2017/18	
Upper Marsyangdi	ROR	50	317	2017/18	
Mistri	ROR	42	225	2017/18	
Upper Trishuli 3B	ROR	37	296.34	2019/20	
Upper Modi A	ROR	42	214.87	2020/21	
Tanahu	STO	140	484.4	2020/21	
Budhi Gandaki	STO	600	2,674	2022/23	
Total		1,794.9	8,997.87		

Source: NEA

8.9 Candidate Projects for Hydroelectric Power Generation

8.9.1 Promising Storage-type Hydroelectric Power Projects selected by Study Team

As described in Chapter 10, the Study Team ranked the 67 storage-type hydroelectric power projects (including two projects that were added later) in the long list prepared by NEA in 2009 by comparison study from technical, environmental and economical aspects. Then the Study Team selected ten projects listed in Table 8.9.1-1 as the candidate projects for the power development plan in the next two decades. The details of these projects are described in Clause 10.2.1.

Detailed studies including a site survey were conducted on these ten projects. Since the results proved that the Kokhajor-1 project is not feasible from the viewpoint of economic efficiency, this project was excluded from the candidates of the power development plan.

The result of the detailed studies also proved that since the planned powerhouse site of the Lower Jhimruk project is located in the planned reservoir area of the Naumure project, these two projects are not able to coexist. Regarding the Naumure project, the Ministry of Irrigation has a plan of an irrigation project at this site and this irrigation project is not able to coexist with the Lower Jhimruk project either. Meanwhile, there is a possibility of implementing the Naumure project as a multipurpose project for power generation and irrigation. Taking these points into consideration, the Naumure project was selected as one of the candidate projects and the Lower Jhimruk project was excluded from them. (See Section 10.2.2.3)

The earliest possible year of commercial operation of each candidate project was determined taking into consideration the evaluation results described in Chapter 10.

Table 8.9.1-1 Candidates Storage-type Hydroelectric Power Project selected by the Study Team

Project Name	Type	Installed Capacity (MW)	Annual Energy (GWh)	Project Cost* (MUS$)	The Earliest Possible Commissioning Year (FY)	Remarks
Dudh Koshi	STO	300	1,909.6	1,141.0	2023/24	
Nalsyau Gad	STO	410	1,406.1	966.9	2023/24	
Andhi Khola	STO	180	648.7	665.8	2025/26	
Chera-1	STO	148.7	563.2	576.9	2027/28	
Madi	STO	199.8	621.1	637.3	2027/28	
Naumure	STO	245	1,157.5	954.5	2027/28	
Sun Koshi No. 3	STO	536	1,883.6	1,690.5	2028/29	
Lower Badigad	STO	380.3	1,366.0	1,209.8	2028/29	
(Kokhajor-1)	STO	111.5	278.9	476.5	-----	Excluded from the candidates in this study. (Low economical efficiency)
(Lower Jhimruk)	STO	142.5	454.7	520.9	-----	Excluded from the candidates in this study. (Overlapping with the Naumure Project)

*: FY2012/13 price

8.9.2 Development of ROR-type Hydroelectric Power Generation

In Table 8.8-1, in the projects under construction or with a high probability of being constructed, other than the Upper Modi A project that is scheduled to be put into operation in FY2019/20, there is not any specific ROR-type project that is scheduled to be put into operation in and after FY2018/19. Nevertheless, many survey or construction licenses for ROR-type HPPs have been issued by the DOED. It is presumed that since many of them have been issued to IPPs, it is difficult for the NEA (or the government) to estimate the commissioning year of these projects.

However, development of ROR-type hydroelectric power generation must be continued even after FY2018/19 for utilizing plentiful hydropower energy in the country. In the power development plan in this chapter, development of ROR-type hydroelectric power generation is considered as follows.

- The total installed capacity of candidate ROR-type HPPs in and after FY2018/19 is about 100 MW/year including the Tamakoshi V and Upper Arun HPPs brought by the NEA.
- In the same way as the promising storage-type HPPs listed in Table 8.9.1-1, these ROR-type HPPs are not necessarily to be put into operation in the earliest possible commissioning year shown in the table. If the reference year's supply reliability is satisfied by construction of HPPs by the previous years, the implementation schedule of the said ROR-type HPPs is postponed one or more years.
- Annual energy production and the project cost of these projects other than the Tamakoshi V and Upper Arun projects are estimated from the projects listed in Table 8.8-1.

Table 8.9.2-1 shows these candidates of ROR-type projects.

Table 8.9.2-1 Candidates of ROR-type Project

Project Name	Type	Installed Capacity (MW)	Annual Energy (GWh)	Project Cost* (MUS$)	The Earliest Possible Commissioning Year (FY)	Remarks
ROR-1	ROR	100	594	183	2018/19	
ROR-2					2019/20	
ROR-3					2020/21	
Tamakoshi V		87	460.5	189	2021/22	
ROR-4		100	594	183	2022/23	
ROR-5					2023/24	
Upper Arun	PROR	335	2,734.2	748	2024/25	
ROR-6	ROR	100	594	183	2027/28	
ROR-7					2028/29	
ROR-8					2029/30	
ROR-9					2030/31	
ROR-10					2031/32	

*: FY2012/13 price

8.9.3 Power Imports from India

As described in Section 6.9, the maximum contract amount of power imports from India is 247 MW until FY2014/15, and 397 MW in and after FY2015/16. In the power development plan in this chapter, however, the following two long-term import contracts were considered based on the result of discussion with the NEA.

- Power Sales Agreement between PTC India Limited and Nepal Electricity Authority (2011): 150 MW from FY 2015/16
- Free annual energy from Tanakpur HPP based on Minutes of Meeting of 8th Indo-Nepal Power Exchange Committee Meeting (2007): 12 MW (equivalent to 70 GWh)

As a result, the maximum amount of power imports from India in the power development plan is 12 MW until FY2014/15, and 162 MW in and after FY2015/16.

8.10 Key Parameters

Key parameters adopted for formulating the power development plan are as follows.

(1) Planning period

The planning period is 20 years from FY2012/13 to FY2031/32.

(2) Power demand

The power demands are the “Base Case,” “High Case,” and “Low Case” forecasted in Chapter 7. (See Table 8.10-1)

Table 8.10-1 Power Demand from FY2013 to FY2032

FY	Peak Demand (MW)			Energy Demand (GWh)		
	Base Case	High Case	Low Case	Base Case	High Case	Low Case
2013	1,231	1,216	1,240	5,607	5,537	5,650
2014	1,277	1,247	1,297	5,818	5,678	5,907
2015	1,328	1,284	1,361	6,049	5,851	6,202
2016	1,382	1,324	1,430	6,294	6,031	6,514
2017	1,439	1,381	1,503	6,556	6,290	6,847
2018	1,501	1,512	1,579	6,836	6,888	7,192
2019	1,575	1,649	1,651	7,176	7,512	7,522
2020	1,717	1,794	1,728	7,823	8,174	7,869
2021	1,867	1,949	1,808	8,504	8,880	8,237
2022	2,031	2,123	1,918	9,252	9,670	8,738
2023	2,169	2,270	2,043	9,881	10,342	9,307
2024	2,321	2,429	2,178	10,572	11,066	9,922
2025	2,513	2,629	2,349	11,447	11,974	10,702
2026	2,714	2,854	2,533	12,364	13,002	11,538
2027	2,925	3,093	2,728	13,325	14,089	12,426
2028	3,158	3,350	2,939	14,386	15,260	13,390
2029	3,410	3,635	3,167	15,531	16,557	14,426
2030	3,676	3,984	3,408	16,744	18,147	15,524
2031	3,966	4,389	3,662	18,066	19,993	16,680
2032	4,279	4,866	3,934	19,493	22,166	17,921

Note: FY2013 means FY2012/13.

(3) Rate of monthly peak demand to annual peak demand

The rates of each monthly peak demand to the annual peak demand were estimated from the average of past record from FY2001/02 to FY2010/11. (See Table 8.10-2)

Table 8-10-2 Ratio of Monthly Peak Demand to Annual Peak Demand

Month	Ratio
Jul	0.9158
Aug	0.9219
Sep	0.9381
Oct	0.9544
Nov	0.9793
Dec	0.9953
Jan	1.0000
Feb	0.9765
Mar	0.9484
Apr	0.9583
May	0.9649
Jun	0.9659

Source: Load Dispatch Center, NEA.

(4) Discount rate

The discount rate was estimated at 10% taking into account the lending interest rates of commercial banks of Nepal to industries as of July 2011, which were in a range from 8.0% to 13.5%[6].

(5) Depreciable cost

The depreciable cost was estimated at 90% of the total project cost from the cost structures of 10 promising projects

(6) Ratio of domestic / foreign currencies in the project cost

The rate of domestic currency and foreign currency in the project cost was estimated at 10% and 80%.

(7) Supply reliability

Loss of load probability (LOLP) is one of the indicators of supply reliability. LOLP is a rate of days in a shortage of power supply in one year, and its value is about 1% in general, equivalent to several days a year. In Nepal today, however, load shedding is enforced for a considerable period in a year, and the LOLP is considerably large. For the period after the supply capacity comes up with demand by construction of many power plants in the future, the power development plan is formulated to keep the upper limit of LOLP.

In this power development plan, the LOLP after load shedding is resolved is set at 1.375%, equivalent to five days a year of shortage in the supply capacity.

(8) Economic loss by load shedding

According to the study[7] by the USAID in 2003, economic loss caused by load shedding (ENS cost) in the industrial sector in Nepal was estimated to be between 0.03 US$/kWh and 0.25 US$/kWh in 2001 prices, and a large part of this is considered to be the fuel cost of private power generation for carrying out business during load shedding.

According to the Nepal Oil Corporation, the diesel oil price was 26.5 Rs/L in January 2001 and 89.9 Rs/L on average in 2012. Meanwhile, the exchange rates of these years were 75.06 Rs/US$ and 85.00 Rs/US$ respectively. This shows that the diesel oil price on a US$ basis in 2012 is 3.03 times that in 2001. On the assumption that the ENS cost is proportionate to the diesel oil price, the ENS cost in the industrial sector in 2012 is estimated between 0.09 US$/kWh and 0.76 US$/kWh. In this study, 0.76 US$/kWh was adopted taking into account economic losses in sectors other than the industrial sector.

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6 Nepal Rastra Bank Quarterly Economic Bulletin, Volume 46, Mid-July 2012, No. 4

7 Economic Impact of Poor Quality on Industry: Nepal, USAID, October 2003.

8.11 Power Development Plan

8.11.1 Practical Development Scenario

The projects under construction or with a high probability of being constructed listed in Table 8.8-1 commence commercial operation according to schedule. The candidate projects to be developed after these projects are the promising storage-type HPPs selected by the Study Team listed in Table 8.9.1-1, and ROR-type HPPs listed in Table 8.9.2-1.

With these projects, a power development plan that is able to resolve the load shedding as early as possible and then secure the required LOLP is drawn up using WASP-IV, the latest version of the “Wien Automatic System Planning Package,” a computer program developed by the IAEA. This program draws up a power development plan, or combination of generation facilities to be constructed and their commissioning year, and the least of its total cost (construction cost, fuel cost and O&M cost) in terms of present value. The results of the evaluation of promising projects described in Section 10.2 such as the number of inundated households, impact on agriculture and fishery, geological conditions, current study stage, etc. are indirectly taken into consideration by reflecting the costs for environmental mitigation and contingencies.

Other than the projects described in Section 8.9.1 and 8.9.2, some storage-type projects are proposed by the NEA. The power development plan in which these projects are also taken into consideration is described in Appendix 4.

8.11.2 Power Development Plan

(1) Year of commissioning

Table 8.11.2-1 to Table 8.11.2-3 show the power plants to be constructed and their commissioning years for the base case, the high case, and the low case of demand forecast, respectively.

For the base case, the total installed capacity of generation facilities that are put into operation for the 20 years from FY2012/13 to FY2031/32 is 4,256 MW including the increment in imports from India, and 1,993 MW of this is storage-type hydroelectric power generation.

For the high case, the total installed capacity of generation facilities that are put into operation for the 20 years from FY 2012/13 to FY2031/32 is 5,317 MW, which is 1,061 MW larger than that for the base case. Storage-type hydroelectric power generation is 3,154 MW, which is 1,161 MW larger than for the base case.

For the low case, the total installed capacity of generation facilities that are put into commercial operation for the 20 years from FY 2012/13 to FY2031/32 is 3,807 MW, which is 449 MW smaller than that for the base case. Storage-type hydroelectric power generation is 1,644 MW, which is 349 MW smaller than for the base case.

Table 8.11.2-1 Generation Expansion Plan (Base Case)

FY		2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Existing	——	850.1	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Kulekhani No. 3	**STO**					**14.0**	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Chameliya	PROR					30.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Khani Khola	ROR					25.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Sanjen	ROR						11.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Sanjen	ROR						42.9	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Trishuli 3A	ROR						60.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Tamakoshi	PROR						456.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Madhya (Middle) Bhotekosh	ROR							102.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Rasuwagadi	ROR							111.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Rahughat	PROR							32.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Marsyangdi	ROR							50.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Mistri	ROR							42.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
ROR-1	ROR								100.0	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Trishuli 3B	ROR									37.0	→	→	→	→	→	→	→	→	→	→	→	→
ROR-2	ROR									100.0	→	→	→	→	→	→	→	→	→	→	→	→
Tanahu	**STO**										**140.0**	→	→	→	→	→	→	→	→	→	→	→
Upper Mode A	ROR										42.0	→	→	→	→	→	→	→	→	→	→	→
ROR-3	ROR										100.0	→	→	→	→	→	→	→	→	→	→	→
Tamakshi V	ROR											87.0	→	→	→	→	→	→	→	→	→	→
Budhi Gandaki	**STO**												**600.0**	→	→	→	→	→	→	→	→	→
ROR-4	ROR														100.0	→	→	→	→	→	→	→
Upper Arun	PROR															335.0	→	→	→	→	→	→
ROR-5	ROR															100.0	→	→	→	→	→	→
Dudh Koshi	**STO**																**300.0**	→	→	→	→	→
Nalsyau Gad	**STO**																		**410.0**	→	→	→
Andhi Khola	**STO**																				**180.0**	→
ROR-6, -7, -8	ROR																				300.0	→
Chera-1	**STO**																					**149.0**
Madi	**STO**																					**200.0**
Import from India	——	12.0	→	→	→	162.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Added Installed Capacity (MW)		——	0.0	0.0	0.0	219.0	569.9	337.0	100.0	137.0	282.0	87.0	600.0	0.0	100.0	435.0	300.0	0.0	410.0	0.0	480.0	349.0
Total Installed Capacity (MW)		862.1	862.1	862.1	862.1	1,081.1	1,651.0	1,988.0	2,088.0	2,225.0	2,507.0	2,594.0	3,194.0	3,194.0	3,294.0	3,729.0	4,029.0	4,029.0	4,439.0	4,439.0	4,919.0	5,268.0
LOLP* (%)		——	**50.375**	**53.789**	**57.975**	**32.637**	**2.733**	**1.575**	**1.927**	**2.579**	**1.919**	**3.087**	0.130	0.516	1.225	0.666	0.336	1.079	0.440	1.331	1.330	1.232

*: The critical LOLP is 1.375%, equivalent to 5 days/year.

Note: Projects in boldface are storage-type projects.

The total install capacity includes imports from India.

Table 8.11.2-2 Generation Expansion Plan (High Case)

FY		2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Existing	—	850.1	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Kulekhani No. 3	**STO**					**14.0**	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Chameliya	PROR					30.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Khani Khola	ROR					25.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Sanjen	ROR						11.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Sanjen	ROR						42.9	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Trishuli 3A	ROR						60.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Tamakoshi	PROR						456.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Madhya (Middle) Bhotekoshi	ROR							102.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Rasuwagadi	ROR							111.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Rahughat	PROR							32.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Marsyangdi	ROR							50.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Mistri	ROR							42.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
ROR-1	ROR								100.0	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Trishuli 3B	ROR									37.0	→	→	→	→	→	→	→	→	→	→	→	→
ROR-2	ROR									100.0	→	→	→	→	→	→	→	→	→	→	→	→
Tanahu	**STO**										**140.0**	→	→	→	→	→	→	→	→	→	→	→
Upper Mode A	ROR										42.0	→	→	→	→	→	→	→	→	→	→	→
ROR-3	ROR										100.0	→	→	→	→	→	→	→	→	→	→	→
Tamakshi V	ROR											87.0	→	→	→	→	→	→	→	→	→	→
Budhi Gandaki	**STO**												**600.0**	→	→	→	→	→	→	→	→	→
Upper Arun	PROR														335.0	→	→	→	→	→	→	→
ROR-4, -5	ROR														200.0	→	→	→	→	→	→	→
Dudh Koshi	**STO**																**300.0**	→	→	→	→	→
Nalsyau Gad	**STO**																	**410.0**	→	→	→	→
Andhi Khola	**STO**																			**180.0**	→	→
Chera-1	**STO**																			**149.0**	→	→
Madi	**STO**																				**200.0**	→
Naumure	**STO**																				**245.0**	→
ROR-6	ROR																				100.0	→
Sun Koshi No. 3	**STO**																					**536.0**
Lower Badigad	**STO**																					**380.0**
ROR-7, -8	ROR																					100.0
Import from India	—	12.0	→	→	→	162.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Added Installed Capacity (MW)		—	0.0	0.0	0.0	219.0	569.9	337.0	100.0	137.0	282.0	87.0	600.0	0.0	535.0	0.0	300.0	410.0	0.0	329.0	545.0	1,016.0
Total Installed Capacity (MW)		862.1	862.1	862.1	862.1	1,081.1	1,651.0	1,988.0	2,088.0	2,225.0	2,507.0	2,594.0	3,194.0	3,194.0	3,729.0	3,729.0	4,029.0	4,439.0	4,439.0	4,768.0	5,313.0	6,329.0
LOLP* (%)		—	**49.198**	**51.573**	**54.322**	**27.323**	**1.945**	**1.680**	**2.695**	**3.334**	**2.625**	**3.923**	0.345	0.967	0.403	1.218	0.824	0.309	1.167	1.397	1.025	0.672

*: The critical LOLP is 1.375%, equivalent to 5 days/year.

Note: Projects in boldface are storage-type projects.

The total install capacity includes imports from India.

Table 8.11.2-3 Generation Expansion Plan (Low Case)

FY		2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Existing	—	850.1	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Kulekhani No. 3	**STO**					**14.0**	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Chameliya	PROR					30.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Khani Khola	ROR					25.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Sanjen	ROR						11.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Sanjen	ROR						42.9	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Trishuli 3A	ROR						60.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Tamakoshi	PROR						456.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Madhya (Middle) Bhotekoshi	ROR							102.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Rasuwagadi	ROR							111.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Rahughat	PROR							32.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Marsyangdi	ROR							50.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Mistri	ROR							42.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→
ROR-1	ROR								100.0	→	→	→	→	→	→	→	→	→	→	→	→	→
Upper Trishuli 3B	ROR									37.0	→	→	→	→	→	→	→	→	→	→	→	→
ROR-2	ROR									100.0	→	→	→	→	→	→	→	→	→	→	→	→
Tanahu	**STO**										**140.0**	→	→	→	→	→	→	→	→	→	→	→
Upper Mode A	ROR										42.0	→	→	→	→	→	→	→	→	→	→	→
ROR-3	ROR										100.0	→	→	→	→	→	→	→	→	→	→	→
Tamakoshi V	ROR											87.0	→	→	→	→	→	→	→	→	→	→
Budhi Gandaki	**STO**												**600.0**	→	→	→	→	→	→	→	→	→
ROR-4	ROR															100.0	→	→	→	→	→	→
Upper Arun	PROR																335.0	→	→	→	→	→
ROR-5	ROR																100.0	→	→	→	→	→
Dudh Koshi	**STO**																	**300.0**	→	→	→	→
Nalsyau Gad	**STO**																			**410.0**	→	→
Andhi Khola	**STO**																					**180.0**
ROR-6, -7	ROR																					200.0
Import from India	—	12.0	→	→	→	162.0	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→	→
Added Installed Capacity (MW)		—	0.0	0.0	0.0	219.0	569.9	337.0	100.0	137.0	282.0	87.0	600.0	0.0	0.0	100.0	435.0	300.0	0.0	410.0	0.0	380.0
Total Installed Capacity (MW)		862.1	862.1	862.1	862.1	1,081.1	1,651.0	1,988.0	2,088.0	2,225.0	2,507.0	2,594.0	3,194.0	3,194.0	3,194.0	3,294.0	3,729.0	4,029.0	4,029.0	4,439.0	4,439.0	4,819.0
LOLP* (%)		—	**51.054**	**55.341**	**60.972**	**36.845**	**3.802**	**2.389**	**2.716**	**2.678**	**1.453**	**2.135**	0.017	0.144	0.621	1.338	0.712	0.370	1.117	0.435	1.275	1.351

*: The critical LOLP is 1.375%, equivalent to 5 days/year.

Note: Projects in boldface are storage-type projects.

The total install capacity includes imports from India.

(2) Supply-demand balance

Table 8.11.2-4, Table 8.11.2-5 and Table 8.11.2-6, and Figure 8.11.2-1, Figure 8.22.1-2 and Figure 8.11.2-3 show the supply-demand balance, LOLP, and reserve margin for the base case, the high case and the low case of demand forecast, respectively.

In these tables, some peak supply capacities are smaller than peak demand even though LOLP is smaller than the allowable upper limit, 1.375%, and this is equivalent to less than 5 days/year of shortage in the supply capacity. In general, shortage in the supply capacity of ROR-type HPPs concentrates in the dry season, and energy supply by ROR-type HPPs decreases significantly. To cope with this, a part of the storage-type HPPs are operated at the output lower than the installed capacity for a long time to supply base demand. Therefore, the shortage of peak supply capacity occurs for some days within the above-mentioned allowable range. Regarding energy, on the other hand, nearly 100% is supplied in years when the LOLP is within the allowable range.

For the base case, though the Kulekhani No. 3 HPP (14 MW), the Chameliya HPP (30 MW), and the Khani Khola HPP (25 MW) will be put into operation in FY2015/16, the supply capacity is not able to meet the peak demand. The LOLP is improved by comparison with previous years. It is, however, a significantly large value, 33%. In FY2016/17, the Upper Tamakoshi HPP (456 MW), the Upper Sanjen HPP (11 MW), the Sanjen HPP (42.9 MW), and the Upper Trishuli 3A HPP (60 MW) are put into operation, and the LOLP becomes lower than 3%, however it is larger than 1.375%, the allowable upper limit. After then, between FY2017/18 and FY2021/22, the Nadhya (Middle) Botekoshi HPP (102 MW), the Rasuwagad HPP (111 MW), the Rahughat HPP (32 MW), the Upper Marsyangdi HPP (50 MW), the Mistri HPP (42 MW), the Upper Trishuli 3B HPP (37 MW), the Tanahu HPP (140 MW), the Upper Modi A HPP, and the Tamakoshi V HPP (87 MW) are put into operation. Other than these HPPs, ROR-type HPPs totaling 300 MW are also put into operation, and the LOLP fluctuates in a range between 1.5% and 3%.

In FY2022/23, commissioning of the Budhi Gandaki HPP (600 MW) makes the power demand and supply balanced, and the LOLP becomes lower than the allowable upper limit, 1.375%. Then the Upper Arun HPP (335 MW) is put into operation in FY2025/26, the Dudh Koshi HPP (300 MW) in FY2026/27, the Nalsyau Gad HPP (410 MW) in FY2028/29, the Andhi Khola HPP (180 MW) in FY2030/31, and the Chera-1 HPP (149 MW) and the Madi HPP (200 MW) are put into operation in FY2031/32. Other than these HPPs, ROR-type HPPs totaling 500 MW are also put into operation, stable supply-demand situation continues until FY2031/32. (See Table 8.11.2-1)

The power development plan for the high case of the demand forecast is much the same as that for the base case until commissioning of the Budhi Gandaki HPP in FY2022/23. After then, the Upper Arun (PROR type), the Nalsyau Gad, the Andhi Khola, and the Madi HPPs are put into operation in FY2024/25, FY2027/28, FY2029/30, and FY2031/31 respectively. Their commissioning are one year earlier than the base case, and commissioning of the Chela-1 HPP is two years earlier than the base case, in FY2029/30. In addition, the Naumure HPP (245 MW) is put into operation in FY2030/31 and the Sun Koshi No. 3 HPP (536 MW) and the Lower

Badigad HPP (380 MW) are put into operation in FY2031/32. These three HPPs are not put into operation in and before FY2031/32 in the power development plan for the base case of demand forecast. (See Table 8.11.2-2)

The power development plan for the low case of demand forecast is also much the same as that for the base case until commissioning of the Budhi Gandaki HPP in FY2022/23. After then, commissioning of the Upper Arun, the Dudh Koshi, and the Nalsyau Gad HPPs are FY2026/27, FY2027/28 and FY2029/30 respectively, one year later than for the base case of demand forecast, and commissioning of the Andhi Khola HPP is FY2031/32, one year later than for the base case. The Chela-1 and the Madi HPPs are not put into operation in and before FY2031/32. (See Table 8.11.2-3)

In Nepal, since almost all of the country's power comes from hydroelectric power generation, and a significant portion of this consists of ROR-type HPPs whose supply capacity drops in the dry season when the power demand is high, the reserve margin shows a relatively large figure. In the commissioning years of large-scale HPPs like the Budhi Gandaki, the Nalsyau Gad, and the Upper Arun, the reserve margin shows a particularly large figure.

Table 8.11.2-4 Balance of Supply and Demand, LOLP, and Reserve Margin (Base Case)

FY	Installed Capacity (MW)	Peak Demand (MW)	Supply Capacity (MW)	Supply – Demand (MW)	Energy Demand (GWh)	Supply Energy (GWh)	Supply / Demand (%)	LOLP (%)	Reserve Margin (%)
	a	b	c	d = c – b	e	f	g = f / e	h	i = a / b – 1
2012/13	862	1,231	479	-752	5,607	4,707	84.0	**50.375**	-30.0
2013/14	862	1,277	477	-800	5,818	4,787	82.3	**53.789**	-32.5
2014/15	862	1,328	476	-852	6,049	4,865	80.4	**57.975**	-35.1
2015/16	1,081	1,382	696	-686	6,294	5,747	91.3	**32.637**	-21.8
2016/17	1,651	1,439	1,224	-215	6,556	6,527	99.6	**2.733**	14.7
2017/18	1,988	1,501	1,346	-155	6,836	6,819	99.8	**1.575**	32.5
2018/19	2,088	1,575	1,375	-200	7,176	7,154	99.7	**1.927**	32.5
2019/20	2,225	1,717	1,436	-281	7,823	7,788	99.6	**2.579**	29.6
2020/21	2,507	1,867	1,617	-250	8,504	8,481	99.7	**1.919**	34.3
2021/22	2,594	2,031	1,636	-395	9,252	9,198	99.4	**3.087**	27.7
2022/23	3,194	2,169	2,236	67	9,881	9,880	100.0	0.130	47.3
2023/24	3,194	2,321	2,236	-85	10,572	10,568	100.0	0.516	37.6
2024/25	3,294	2,513	2,265	-248	11,447	11,428	99.8	1.225	31.1
2025/26	3,729	2,714	2,537	-177	12,364	12,358	100.0	0.666	37.4
2026/27	4,029	2,925	2,837	-88	13,325	13,320	100.0	0.336	37.7
2027/28	4,029	3,158	2,837	-321	14,386	14,370	99.9	1.079	27.6
2028/29	4,439	3,410	3,247	-163	15,531	15,526	100.0	0.440	30.2
2029/30	4,439	3,676	3,247	-429	16,744	16,721	99.9	1.331	20.8
2030/31	4,919	3,966	3,515	-451	18,066	18,042	99.9	1.330	24.0
2031/32	5,268	4,279	3,712	-567	19,493	19,465	99.9	1.232	23.1

*: Critical LOLP is 1.375%, equivalent to 5 days/year.

Table 8.11.2-5 Balance of Supply and Demand, LOLP, and Reserve Margin (High Case)

FY	Installed Capacity (MW)	Peak Demand (MW)	Supply Capacity (MW)	Supply – Demand (MW)	Energy Demand (GWh)	Supply Energy (GWh)	Supply / Demand (%)	LOLP (%)	Reserve Margin (%)
	a	b	c	d = c – b	e	f	g = f / e	h	i = a / b – 1
2012/13	862	1,216	479	-737	5,537	4,682	84.5	**49.198**	-29.1
2013/14	862	1,247	477	-770	5,678	4,735	83.4	**51.573**	-30.8
2014/15	862	1,284	476	-808	5,851	4,798	82.0	**54.322**	-32.9
2015/16	1,081	1,324	696	-628	6,031	5,608	93.0	**27.323**	-18.3
2016/17	1,651	1,381	1,224	-157	6,290	6,274	99.7	**1.945**	19.6
2017/18	1,988	1,512	1,346	-166	6,888	6,873	99.8	**1.680**	31.5
2018/19	2,088	1,649	1,375	-274	7,512	7,478	99.6	**2.695**	26.6
2019/20	2,225	1,794	1,436	-358	8,174	8,125	99.4	**3.334**	24.0
2020/21	2,507	1,949	1,617	-332	8,880	8,844	99.6	**2.625**	28.6
2021/22	2,594	2,123	1,636	-487	9,670	9,594	99.2	**3.923**	22.2
2022/23	3,194	2,270	2,236	-34	10,342	10,339	100.0	0.345	40.7
2023/24	3,194	2,429	2,236	-193	11,066	11,056	99.9	0.967	31.5
2024/25	3,729	2,629	2,265	-364	11,974	11,969	100.0	0.403	41.9
2025/26	3,729	2,854	2,537	-317	13,002	12,984	99.9	1.218	30.6
2026/27	4,029	3,093	2,837	-256	14,089	14,079	99.9	0.824	30.3
2027/28	4,439	3,350	2,837	-513	15,260	15,258	100.0	0.309	32.5
2028/29	4,439	3,635	3,247	-388	16,557	16,538	99.9	1.167	22.1
2029/30	4,768	3,984	3,247	-737	18,147	18,123	99.9	1.397	19.7
2030/31	5,313	4,389	3,515	-874	19,993	19,966	99.9	1.025	21.1
2031/32	6,329	4,866	3,712	-1,154	22,166	22,140	99.9	0.672	30.1

*: Critical LOLP is 1.375%, equivalent to 5 days/year.

Table 8.11.2-6 Balance of Supply and Demand, LOLP, and Reserve Margin (Low Case)

FY	Installed Capacity (MW)	Peak Demand (MW)	Supply Capacity (MW)	Supply – Demand (MW)	Energy Demand (GWh)	Supply Energy (GWh)	Supply / Demand (%)	LOLP (%)	Reserve Margin (%)
	a	b	c	d = c – b	e	f	g = f / e	h	i = a / b – 1
2012/13	862	1,240	479	-761	5,650	4,727	83.7	**51.054**	-30.5
2013/14	862	1,297	477	-820	5,907	4,818	81.6	**55.341**	-33.5
2014/15	862	1,361	476	-885	6,202	4,915	79.2	**60.972**	-36.7
2015/16	1,081	1,430	696	-734	6,514	5,857	89.9	**36.845**	-24.4
2016/17	1,651	1,503	1,224	-279	6,847	6,803	99.4	**3.802**	9.8
2017/18	1,988	1,579	1,346	-233	7,192	7,165	99.6	**2.389**	25.9
2018/19	2,088	1,651	1,375	-276	7,522	7,489	99.6	**2.716**	26.4
2019/20	2,225	1,728	1,436	-292	7,869	7,834	99.6	**2.678**	28.8
2020/21	2,507	1,808	1,617	-191	8,237	8,220	99.8	**1.453**	38.6
2021/22	2,594	1,918	1,636	-282	8,738	8,712	99.7	**2.135**	35.2
2022/23	3,194	2,043	2,236	193	9,307	9,307	100.0	0.017	56.3
2023/24	3,194	2,178	2,236	58	9,922	9,921	100.0	0.144	46.6
2024/25	3,194	2,349	2,265	-84	10,702	10,697	100.0	0.621	36.0
2025/26	3,294	2,533	2,537	4	11,538	11,521	99.9	1.338	30.0
2026/27	3,729	2,728	2,837	109	12,426	12,417	99.9	0.712	36.7
2027/28	4,029	2,939	2,837	-102	13,390	13,386	100.0	0.370	37.1
2028/29	4,029	3,167	3,247	80	14,426	14,408	99.9	1.117	27.2
2029/30	4,439	3,408	3,247	-161	15,524	15,519	100.0	0.435	30.3
2030/31	4,439	3,662	3,515	-147	16,680	16,658	99.9	1.275	21.2
2031/32	4,819	3,934	3,712	-222	17,921	17,899	99.9	1.351	22.5

*: Critical LOLP is 1.375%, equivalent to 5 days/year.

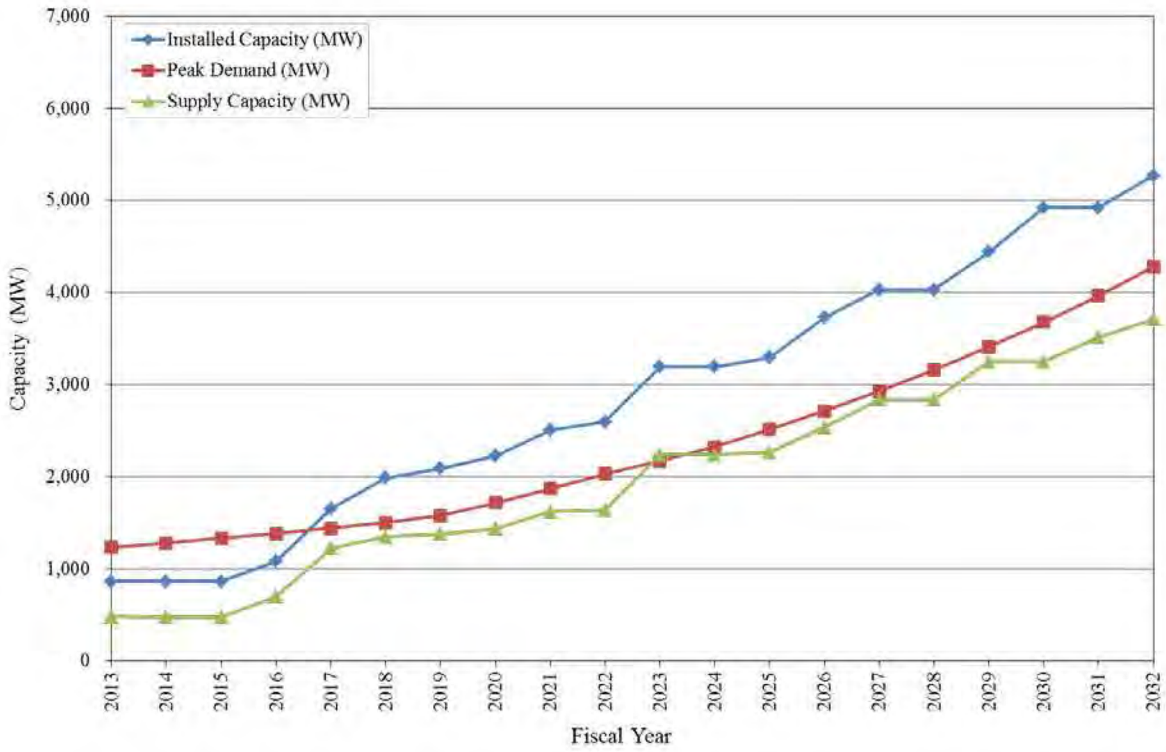

Figure 8.11.2-1 Balance of Supply and Demand (Base Case)

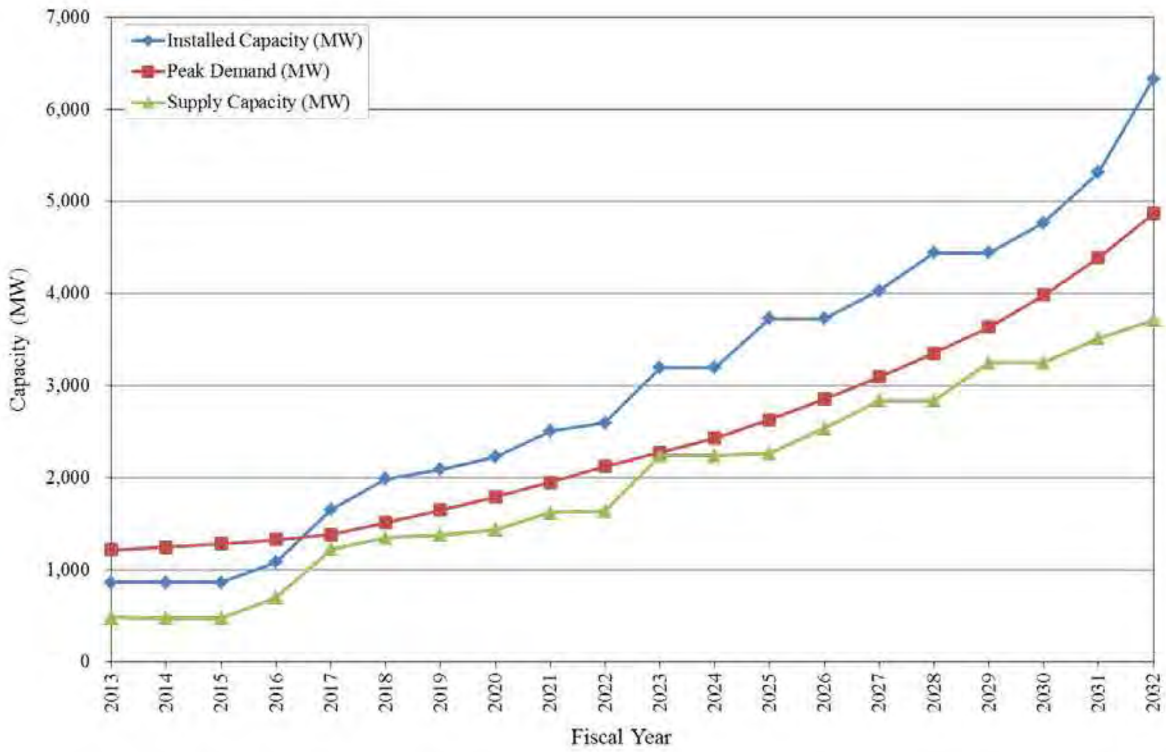

Figure 8.11.2-2 Balance of Supply and Demand (High Case)

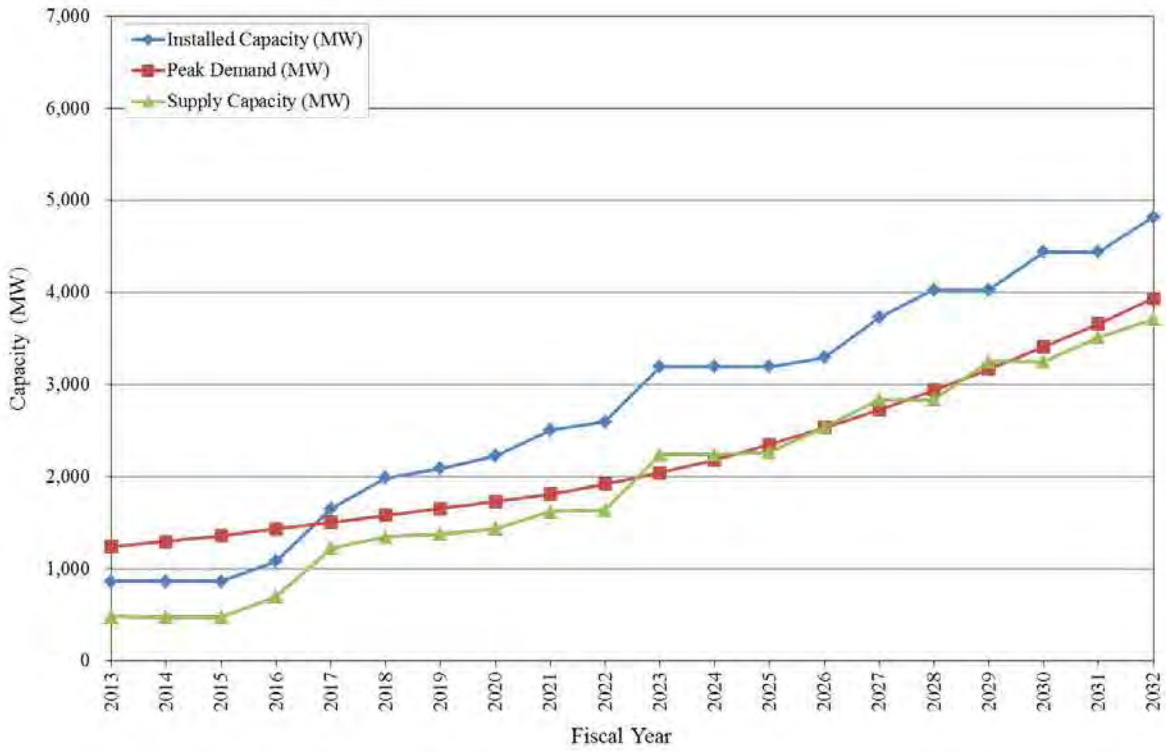

Figure 8.11.2-3 Balance of Supply and Demand (Low Case)

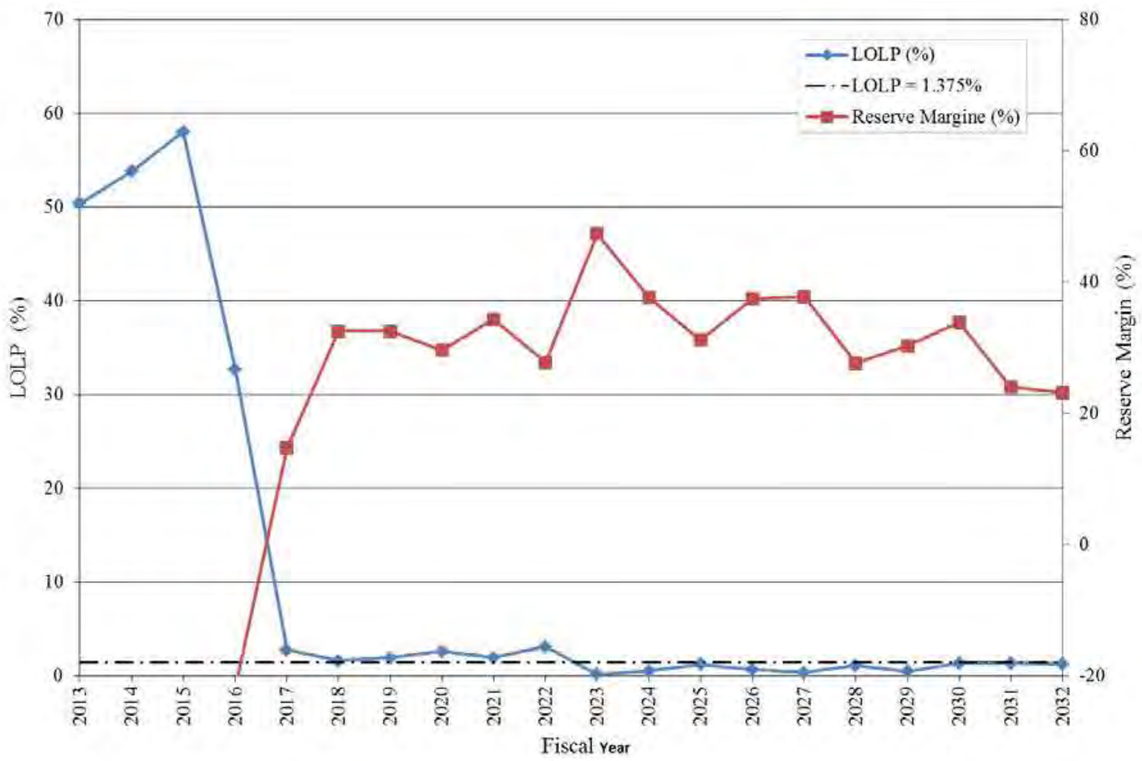

Figure 8.11.2-4 LOLP and Reserve Margin (Base Case)

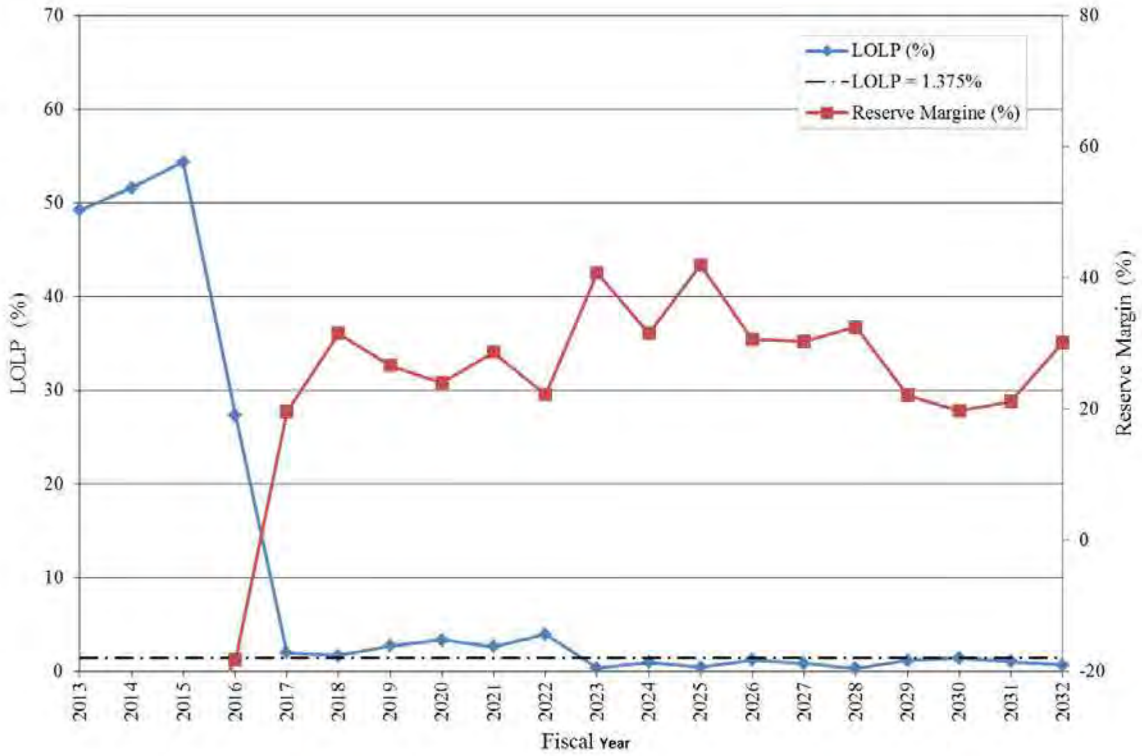

Figure 8.11.2-5 LOLP and Reserve Margin (High Case)

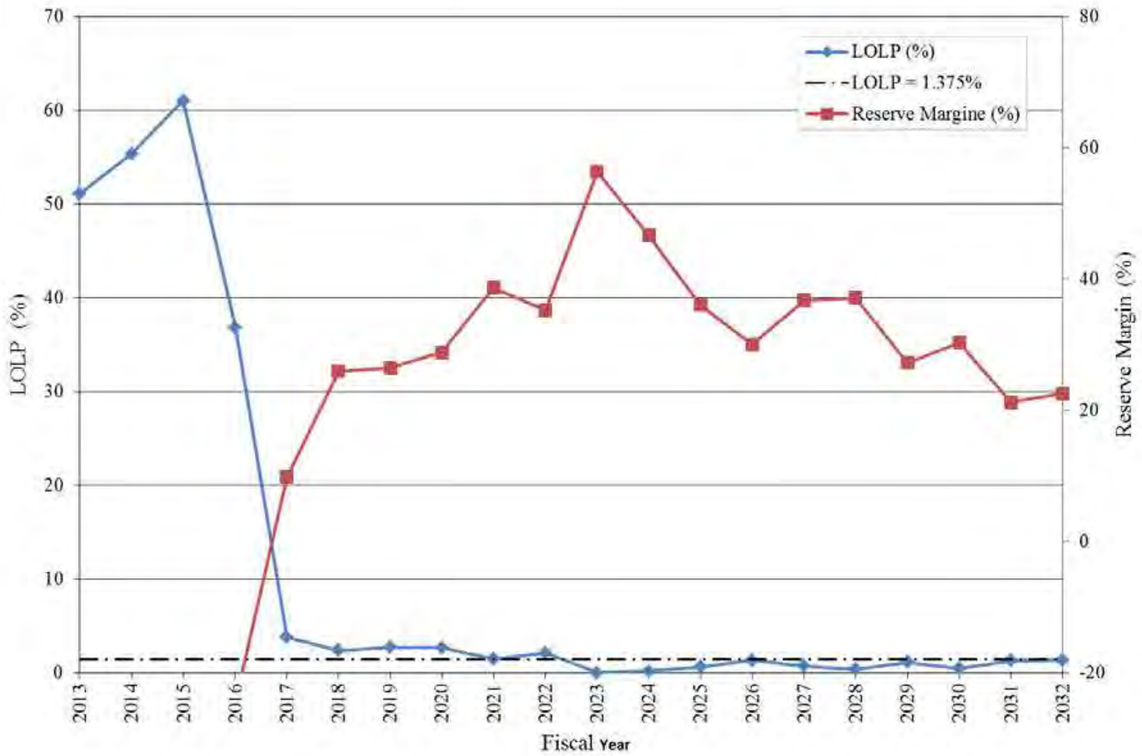

Figure 8.11.2-6 LOLP and Reserve Margin (Low Case)

Chapter 9

Development Plan of Storage-type Hydroelectric Power Projects

Chapter 9 Development Plan of Storage-type Hydroelectric Power Projects

9.1 Storage-type Hydroelectric Power Projects to be Implemented

In the power development plan described in Chapter 8, the total installed capacity of hydroelectric power projects (including an increment in imports from India) that start commercial operation in the 20 years from FY2012/13 to FY 2031/32 is 4,256 MW for the base case of demand forecast, 5,317 MW for the high case, and 3,807 MW for the low case. The total installed capacity of storage-type hydroelectric power projects is 1,993 MW for the base case, 3,154 MW for the high case, and 1,644 MW for the low case.

Table 9.1-1 shows the storage-type hydroelectric power projects to be implemented.

Table 9.1-1 Storage-type Projects to be Implemented

Project	Capacity (MW)	Commissioning Year (FY)			Remarks
		Base Case	High Case	Low Case	
Kulekhani No. 3	14	2015/16	2015/16	2015/16	Under construction
Tanahu	140	2020/21	2020/21	2020/21	LA has been concluded.
Budhi Gandaki	600	2022/23	2022/23	2022/23	DD is ongoing.
Dudh Koshi	300	2026/27	2026/27	2027/28	
Nalsyau Gad	410	2028/29	2027/28	2029/30	
Andhi Khola	180	2029/30	2029/30	2031/32	
Chera-1	149	2031/32	2029/30	----	
Madi	200	2031/32	2030/31	----	
Naumure	245	----	2030/31	----	
Sun Koshi No. 3	536	----	2031/32	----	
Lower Badigad	380	----	2031/32	----	
Total Capacity	----	1,993 MW	3,154 MW	1,644 MW	

In all cases, the Dudh Koshi, the Nalsyau Gad, and the Andhi Khola projects are implemented in addition to the Kulekhani No. 3, the Tanahu, and the Budhi Gandaki projects that are now under construction or in preparation of construction.

For the base case of the demand forecast, the Dudh Koshi HPP (300 MW) is put into operation in FY2026/27, followed by the Nalsyau Gad HPP (410 MW) in FY2028/29 and the Andhi Khola HPP (180 MW) in FY2029/30. Then the Chera-1 HPP (149 MW) and the Madi HPP (200 MW) are put into operation in FY2031/32.

For the high case, the Nalsyau Gad and the Madi HPPs are put into operation one year earlier than those for the base case, and the Chera-1 HPP is put into operation two years earlier. In addition to these HPPs, the Naumure HPP (245 MW) is put into operation in FY2030/31, and the Sun Koshi No. 3 (536 MW) and the Lower Badigad (380 MW) HPPs are also put into operation in FY2031/32.

For the low case, the Dudh Koshi and the Nalsyau Gad HPPs are put into operation one year later than those for the base case, and commissioning of the Andhi Khola HPP is two years later than that for the base case. The Chera-1 and other HPPs are not put into operation in and before FY2031/32, the last year of the power development plan.

Table 9.1-2 shows the earliest possible years of commissioning and the commissioning years in the power development plan for each case of power demand forecast.

Table 9.1-2 Commissioning Year of Commercial Operation

Base Case										
Project	Capacity (MW)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Dudh Koshi	300	P	→	→	G					
Nalsyau Gad	410	P	→	→	→	→	G			
Andhi Khola	180			P	→	→	→	G		
Chera-1	149					P	→	→	→	G
Madi	200					P	→	→	→	G
(Naumure)	245									
(Sun Koshi No. 3)	536									
(Lower Badigad)	380									

High Case										
Project	Capacity (MW)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Dudh Koshi	300	P	→	→	G					
Nalsyau Gad	410	P	→	→	→	G				
Andhi Khola	180			P	→	→	→	G		
Chera-1	149					P	→	G		
Madi	200					P	→	→	G	
Naumure	245					P	→	→	G	
Sun Koshi No. 3	536						P	→	→	G
Lower Badigad	380						P	→	→	G

Low Case										
Project	Capacity (MW)	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
Dudh Koshi	300	P	→	→	→	G				
Nalsyau Gad	410	P	→	→	→	→	→	G		
Andhi Khola	180			P	→	→	→	→	→	G
(Chera-1)	149									
(Madi)	200									
(Naumure)	245									
(Sun Koshi No. 3)	536									
(Lower Badigad)	380									

P: The earliest possible commissioning year.
G: The commissioning year in the generation expansion plan.

9.2 Investment Necessary to Develop Proposed Storage-type Hydropower Projects

Table 9.2-1 indicates the estimated net cash flow or necessary amount of funds for the base case of the demand forecast during the master plan period. In addition to the funds indicated in the table, additional financial resources to complete hydroelectric power projects currently under construction and ROR-type hydroelectric power projects to be constructed after FY 2018/19 shall be needed to meet the power demand forecasted. In this section, analyses of the Budhi Gandaki project that has a high probability to be constructed but sources and methods of financing has not determined is also conducted.

During the period of the 20-year master plan (i.e. from FY2012/13 to 2031/32), the total of US$ 4,209 million (interest during construction and price contingency are excluded) is needed for the base case to finance construction of the six (6) proposed storage-type hydroelectric power projects listed in Table 9.1-1 other than the Kulekhani No. 3 and Tanahu projects. It is assumed that US$ 3,367 million (80% of the total cost) is to be financed from the foreign capital market and the remaining US$ 842 million is to be financed from the domestic capital market. As shown in Table 9.2-1, the largest cash flow will be US$ 429 million (US$ 343 million and US$ 86 million to be obtained from foreign and domestic capital markets, respectively) in FY2025/26 needed to finance the construction of storage-type hydroelectric power projects. These cash flow requirements should be considered to be large with respect to the size of Nepal's current GDP (approximately US$ 10 billion), and borrowing from the foreign capital market must be considered. Due to the small size of the domestic capital market, obtaining funds in the range of US$ 16 million to US$ 86 million in each year for the period of 14 years from the market must require the assurance of high returns to the funds obtained. The total amount of investment required for the high case for the implementation of nine (9) projects is US$ 7,149 million, and for the low case for the implementation of four (4) projects is US$ 3,257 million.

Table 9.2-1 Net Cash Flow of the Base Case during the Master Plan Period

	Serial no.	Fiscal year	Net cash flow (Million USD at FY2012 price)																	
			Budhi Gandaki			Dudh Koshi			Nalsyau Gad			Andhi Khola			Chera-1			Madi		
			Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)
Twenty-year master plan period	1	2012/13																		
	2	2013/14																		
	3	2014/15																		
	4	2015/16	63	16	78															
	5	2016/17	63	16	78															
	6	2017/18	72	18	90															
	7	2018/19	152	38	190	46	12	58												
	8	2019/20	197	49	246	52	13	65												
	9	2020/21	197	49	246	50	13	63	39	10	49									
	10	2021/22	152	38	190	110	27	137	44	11	55									
	11	2022/23				109	27	136	42	11	53									
	12	2023/24				182	46	228	93	23	116									
	13	2024/25				94	24	118	92	23	115	42	11	53	18	5	23	31	8	39
	14	2025/26				55	14	69	154	38	192	85	21	106	18	5	23	31	8	39
	15	2026/27							80	20	100	106	26	132	33	8	41	34	8	42
	16	2027/28							47	12	58	106	26	132	65	16	81	67	17	84
	17	2028/29										85	21	106	81	20	102	84	21	105
	18	2029/30													81	20	102	84	21	105
	19	2030/31													65	16	81	67	17	84
	20	2031/32																		
Total			895	224	1,118	698	175	873	590	147	737	423	106	529	362	90	452	400	100	499

	Serial no.	Fiscal year	Net cash flow (Million USD at FY2012 price)											
			Naumure			Sun Koshi No.3			Lower Badigad			Total		
			Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)	Debt financing (IDC excluded)	Equity financing	Total cost (cash flow basis)
Twenty-year master plan period	1	2012/13												
	2	2013/14												
	3	2014/15												
	4	2015/16										63	16	78
	5	2016/17										63	16	78
	6	2017/18										72	18	90
	7	2018/19										198	50	248
	8	2019/20										248	62	311
	9	2020/21										286	72	358
	10	2021/22										305	76	382
	11	2022/23										151	38	189
	12	2023/24										275	69	343
	13	2024/25										278	69	347
	14	2025/26										343	86	429
	15	2026/27										252	63	315
	16	2027/28										285	71	356
	17	2028/29										250	63	313
	18	2029/30										166	41	207
	19	2030/31										133	33	166
	20	2031/32												
Total												3,367	842	4,209

Note: The cost of Budhi Gandaki project was estimated in 1984 in the pre-FS and modified by the Study Team to the 2012 price.

9.3 Analysis of Possible Project Investment Options

The financial internal rate of return (FIRR) or returns to equity investment of each proposed storage-type hydroelectric power project and case-wise FIRR of the base case, high case and low case scenarios were estimated. Based on the obtained values of FIRRs, possible project investment options with funds obtained from public or private sources were also discussed. The economic internal rate of return (EIRR) of each proposed project and case-wise EIRRs of the scenarios were estimated and compared to examine the expected economic impacts of the project and scenarios.

9.3.1 Establishment of Economic and Financial Analyses Frameworks

Construction of storage-type hydroelectric power generation facilities requires a large financial investment. In order to finance the storage-type hydroelectric power projects, particularly by raising private funds, the project should be attractive in terms of its expected financial returns. Political and social risks associated with the projects should also be sufficiently low to promote such investment decisions by private investors. To examine possible investment options of the base case, high case and low case scenarios, the relationships between returns to equity and power prices of each scenario need to be examined. In this section, the framework of financial analysis at a power price of 12 Rs/kWh is introduced. The framework forms the base of the simulation analysis introduced in the later section for the identification of the power price range within which FIRRs become sufficiently large to attract private investment. The framework of EIRR calculation at a power price of 12 Rs/kWh is also introduced in this section. The framework is used to conduct simulation analysis introduced in the next section to examine the expected magnitude of economy-wide impact of the three scenarios.

To conduct financial analysis of the scenarios, cash flows and FIRRs of proposed storage-type hydroelectric power projects are calculated. Furthermore, these cash flows are aggregated for the calculation of FIRR of each scenario. Table 9.3.1-1 and Table 9.3.1-2 present the FIRRs and EIRRs of the base case at the power price of 12 Rs/kWh. It is also assumed that 80% of the project cost is financed by borrowing at an annual interest rate of 8%, and the remaining 20% of the cost is obtained through equity financing with returns (FIRR) calculated for a 25-year repayment period of borrowing. The interest rate of a loan provided to the industrial sector by the banking sector in 2011 in Nepal was in the rage of 8.0% to 13.5%. In this case, the investment to the power sector in Nepal is considered to be a low risk investment, and therefore, borrowing at 8% interest rate for the project should be reasonable. The assumptions regarding generation capacities of the proposed projects, construction costs without interest during the construction and price contingency, and wet and dry season sellable energy necessary to calculate the returns to equity (FIRR) are shown in Table 9.3.2-1. The calculation of a return to equity (FIRR) for each case is performed for the period of 41 years in which 25-year repayment of all borrowings by 6 projects will be completed. The return to equity (FIRR) for a case is calculated using the aggregated cash flows of all 6 projects included in the case.

As shown in Table 9.3.1-2, the EIRR for each project is calculated for the project period of 50 years. For the determination of EIRR for a case, the EIRR calculation period was set for 61 years within which the 50-year project periods of all the projects in the case can be included.

Table 9.3.1-1 Net Cash Flow and FIRR of Each Project (Base Case) at 8% Interest Rate and 12 Rs/kWh

	Serial no.	Fiscal year	Net cash flow (Million USD at FY2012 price)									
			Budhi Gandaki	Dudh Koshi	Nalsyau Gad	Andhi Khola	Chera-1	Madi	Naumure	Sun Koshi	Lower Badigad	Base Case (All project total)
Twenty-year master plan period	1	2012/13										
	2	2013/14										
	3	2014/15										
	4	2015/16	**-16**									-16
	5	2016/17	**-16**									-16
	6	2017/18	**-18**									-18
	7	2018/19	**-38**	**-12**								-50
	8	2019/20	**-49**	**-13**								-62
	9	2020/21	**-49**	**-13**	**-10**							-72
	10	2021/22	**-38**	**-27**	**-11**							-76
	11	2022/23	183	**-27**	**-11**							145
	12	2023/24	182	**-46**	**-23**							114
	13	2024/25	182	**-24**	**-23**	**-11**	**-5**	**-8**				113
	14	2025/26	182	**-14**	**-38**	**-21**	**-5**	**-8**				96
	15	2026/27	181	134	**-20**	**-26**	**-8**	**-8**				253
	16	2027/28	181	134	**-12**	**-26**	**-16**	**-17**				244
	17	2028/29	180	134	86	**-21**	**-20**	**-21**				338
	18	2029/30	180	133	86	30	**-20**	**-21**				388
	19	2030/31	179	133	86	30	**-16**	**-17**				396
	20	2031/32	84	133	86	30	26	28				386
	21	2032/33	178	132	85	30	26	27				479
	22	2033/34	178	132	85	30	26	27				477
	23	2034/35	177	132	85	29	25	27				476
	24	2035/36	176	120	85	29	25	27				463
	25	2036/37	175	131	84	29	25	27				471
	26	2037/38	147	130	72	29	25	27				430
	27	2038/39	146	130	83	19	25	26				429
	28	2039/40	145	129	83	28	25	26				436
	29	2040/41	143	128	82	28	18	18				418
	30	2041/42	47	108	82	28	24	26				314
	31	2042/43	140	107	81	27	24	25				405
	32	2043/44	138	106	65	27	24	25				386
	33	2044/45	137	105	64	19	23	25				374
	34	2045/46	135	93	63	19	23	24				358
	35	2046/47	**133**	103	62	18	16	17				350
	36	2047/48	235	102	50	18	16	16				437
	37	2048/49	234	100	60	8	15	16				434
	38	2049/50	234	99	59	17	15	15				439
	39	2050/51	233	**97**	58	16	8	7				419
	40	2051/52	137	182	56	15	14	14				419
	41	2052/53	232	182	**55**	14	13	13				510
	42	2053/54	231	182	127	**13**	13	12				578
	43	2054/55	231	181	126	60	12	12				622
	44	2055/56	230	170	126	60	**11**	**11**				607
Total			3,685	2,814	1,699	475	406	420				12,891
FIRR period												
From (year)			2015/16	2018/19	2020/21	2024/25	2024/25	2024/25				2015/16
To (year)			2046/47	2050/51	2052/53	2053/54	2055/56	2055/56				2055/56
Duration (years)			32	33	33	30	32	32				41
FIRR			35.0%	30.0%	25.8%	19.1%	17.8%	16.8%				32.2%

Note: 1) Years with negative values in bold letters indicate the construction period of each project.

2) Years with underlined bold letter indicate the last year of the FIRR period (25 years) for an individual project's FIRR calculation.

Table 9.3.1-2 Net Benefit and EIRR of Each Project (Base Case) at 8% Interest Rate and 12 Rs/kWh

	Serial no.	Fiscal year	Net benefit (Million USD at FY2012 price)									
			Budhi Gandaki	Dudh Koshi	Nalsyau Gad	Andhi Khola	Chera-1	Madi	Naumure	Sun Koshi No.3	Lower Badigad	Base Case (All project total)
Twenty-year master plan period	1	2012/13										
	2	2013/14										
	3	2014/15										
	4	2015/16	**-77**									-77
	5	2016/17	**-77**									-77
	6	2017/18	**-88**									-88
	7	2018/19	**-186**	**-56**								-243
	8	2019/20	**-241**	**-63**								-304
	9	2020/21	**-241**	**-62**	**-48**							-350
	10	2021/22	**-186**	**-134**	**-53**							-374
	11	2022/23	340	**-133**	**-52**							154
	12	2023/24	340	**-223**	**-113**							3
	13	2024/25	340	**-115**	**-113**	**-52**	**-22**	**-38**				-1
	14	2025/26	340	**-68**	**-189**	**-104**	**-22**	**-38**				-81
	15	2026/27	340	259	**-98**	**-130**	**-40**	**-41**				290
	16	2027/28	340	259	**-57**	**-130**	**-80**	**-83**				249
	17	2028/29	340	259	184	**-104**	**-100**	**-103**				475
	18	2029/30	340	259	184	85	**-100**	**-103**				664
	19	2030/31	340	259	184	85	**-80**	**-83**				705
	20	2031/32	218	259	184	85	74	82				902
	21	2032/33	340	259	184	85	74	82				1,023
	22	2033/34	340	259	184	85	74	82				1,023
	23	2034/35	340	259	184	85	74	82				1,023
	24	2035/36	340	245	184	85	74	82				1,009
	25	2036/37	340	259	184	85	74	82				1,023
	26	2037/38	340	259	169	85	74	82				1,009
	27	2038/39	340	259	184	73	74	82				1,011
	28	2039/40	340	259	184	85	74	82				1,023
	29	2040/41	340	259	184	85	66	72				1,005
	30	2041/42	218	259	184	85	74	82				902
	31	2042/43	340	259	184	85	74	82				1,023
	32	2043/44	340	259	184	85	74	82				1,023
	33	2044/45	340	259	184	85	74	82				1,023
	34	2045/46	340	245	184	85	74	82				1,009
	35	2046/47	340	259	184	85	74	82				1,023
	36	2047/48	340	259	169	85	74	82				1,009
	37	2048/49	340	259	184	73	74	82				1,011
	38	2049/50	340	259	184	85	74	82				1,023
	39	2050/51	340	259	184	85	66	72				1,005
	40	2051/52	218	259	184	85	74	82				902
	41	2052/53	340	259	184	85	74	82				1,023
	42	2053/54	340	259	184	85	74	82				1,023
	43	2054/55	340	259	184	85	74	82				1,023
	44	2055/56	340	245	184	85	74	82				1,009
	45	2056/57	340	259	184	85	74	82				1,023
	46	2057/58	340	259	169	85	74	82				1,009
	47	2058/59	340	259	184	73	74	82				1,011
	48	2059/60	340	259	184	85	74	82				1,023
	49	2060/61	340	259	184	85	66	72				1,005
	50	2061/62	218	259	184	85	74	82				902
	51	2062/63	340	259	184	85	74	82				1,023
	52	2063/64	340	259	184	85	74	82				1,023
	53	2064/65	**340**	259	184	85	74	82				1,023
	54	2065/66	340	245	184	85	74	82				1,009
	55	2066/67	340	259	184	85	74	82				1,023
	56	2067/68	340	**259**	169	85	74	82				1,009
	57	2068/69	340	259	184	73	74	82				1,011
	58	2069/70	340	259	**184**	85	74	82				1,023
	59	2070/71	340	259	184	85	66	72				1,005
	60	2071/72	218	259	184	85	74	82				902
	61	2072/73	340	259	184	85	74	82				1,023
	62	2073/74	340	259	184	**85**	**74**	**82**				1,023
	63	2074/75	340	259	184	85	74	82				1,023
	64	2075/76	340	245	184	85	74	82				1,009
Total			13,018	9,950	6,934	3,278	2,713	2,982				46,129
EIRR period												
From (year)			2015/16	2018/19	2020/21	2024/25	2024/25	2024/25				2015/16
To (year)			2064/65	2067/68	2069/70	2073/74	2073/74	2073/74				2075/76
Duration (years)			50	50	50	50	50	50				61
EIRR			19.4%	17.6%	15.6%	13.0%	12.6%	12.3%				17.5%

Note: 1) Years with negative values in bold letters indicate the construction period of each project.

2) Years with underlined bold letter indicate the last year of the EIRR period (50 years) for an individual project's EIRR calculation.

9.3.2 Analysis of Power Prices and Economic Internal Rate of Return

(1) Project-wise Economic Analysis

Table 9.3.2-1 and Table 9.3.2-2 show the results of project-wise EIRR calculation assuming that the interest rate of borrowing is 8% and 1%, respectively. Among the proposed projects, Budhi Gandaki and Dudh Koshi show the highest EIRR, whereas Madi shows the lowest EIRR indicating it has the least economic impact generated per unit amount of investment. Because EIRR is not sensitive to values of interest rates of loans but is sensitive to power prices, the EIRRs at the interest rates of 8% and 1% are almost identical when the power prices of the two interest regimes are the same.

Table 9.3.2-1 Summary of Project-wise EIRR with 8% of Interest on Long-term Debt

Project name	Insta-lled capa-city	Project (economic) cost	Saleable energy			Interest on long term debt	EIRR						Power price at 12% EIRR
			Dry season	Wet season	Total		Average power price for dry and wet season (Rs/kWh)						
							6Rs	8Rs	10Rs	12Rs	14Rs	16Rs	
	(MW)			(GWh)		(%)	(%)	(%)	(%)	(%)	(%)	(%)	(Rs/kWh)
NEA Project													
Budhi Gandaki	600	1,096,032	500	2,000	2,500	8.0%	10.9%	14.1%	16.9%	19.4%	21.7%	23.7%	6.64
Promising Projects													
Dudh Koshi	300	855,063	523	1,386	1,910	8.0%	10.3%	13.1%	15.5%	17.6%	19.5%	21.2%	7.17
Nalsyau Gad	410	722,645	515	853	1,367	8.0%	8.9%	11.4%	13.7%	15.6%	17.4%	19.1%	8.48
Andhi Khola	180	518,506	137	512	649	8.0%	6.3%	8.8%	11.0%	13.0%	14.9%	16.7%	11.00
Chara-1	149	443,041	121	443	563	8.0%	6.2%	8.6%	10.7%	12.6%	14.3%	16.0%	11.36
Madi	200	489,471	171	450	621	8.0%	6.0%	8.4%	10.4%	12.3%	14.0%	15.5%	11.69
Naumure	245	713,409	310	848	1,158	8.0%	8.1%	10.8%	13.1%	15.2%	17.1%	18.9%	9.04
Sun Koshi No.3	536	1,263,494	336	1,548	1,884	8.0%	7.0%	9.3%	11.3%	13.1%	14.7%	16.2%	10.74
Lower Badigad	380	904,241	355	1,011	1,366	8.0%	7.0%	9.4%	11.4%	13.2%	14.9%	16.4%	10.61

Table 9.3.2-2 Summary of Project-wise EIRR with 1% of Interest on Long-term Debt

Project name	Insta-lled capa-city	Project (economic) cost	Saleable energy			Interest on long term debt	EIRR						Power price at 6% FIRR
			Dry season	Wet season	Total		Average power price for dry and wet season (Rs/kWh)						
							3Rs	4Rs	5Rs	6Rs	7Rs	8Rs	
	(MW)			(GWh)		(%)	(%)	(%)	(%)	(%)	(%)	(%)	(Rs/kWh)
NEA Project													
Budhi Gandaki	600	1,096,032	500	2,000	2,500	1.0%	4.8%	7.2%	9.2%	11.0%	12.7%	14.2%	3.49
Promising Projects													
Dudh Koshi	300	855,063	523	1,386	1,910	1.0%	5.0%	7.1%	8.9%	10.5%	11.9%	13.2%	3.45
Nalsyau Gad	410	722,645	515	853	1,367	1.0%	3.9%	5.9%	7.5%	9.0%	10.3%	11.6%	4.08
Andhi Khola	180	518,506	137	512	649	1.0%	1.5%	3.4%	5.0%	6.4%	7.7%	8.9%	5.71
Chara-1	149	443,041	121	443	563	1.0%	1.5%	3.4%	5.0%	6.3%	7.6%	8.7%	5.76
Madi	200	489,471	171	450	621	1.0%	1.5%	3.3%	4.9%	6.2%	7.4%	8.5%	5.85
Naumure	245	713,409	310	848	1,158	1.0%	3.0%	5.0%	6.7%	8.2%	9.6%	10.9%	4.56
Sun Koshi No.3	536	1,263,494	336	1,548	1,884	1.0%	2.4%	4.2%	5.8%	7.1%	8.3%	9.4%	5.16
Lower Badigad	380	904,241	355	1,011	1,366	1.0%	2.4%	4.3%	5.9%	7.2%	8.4%	9.5%	5.11

(2) Case-wise Economic Analysis

Table 9.3.2-3 and Table 9.3.2-4 show results of case-wise EIRR calculation assuming that the interest rate of borrowing is 8% and 1%, respectively. At the same power price the difference in the EIRR values of the base case, high case and low case is not large. The high case with the largest number of projects (9 projects) and largest investment cost shows the lowest EIRR, and the low case with the smallest number of projects (4 projects) with the smallest investment cost shows the highest EIRR. Because EIRR is not sensitive to values of interest rates of loans but is sensitive to power prices, the EIRRs of each case at the interest rates of 8% and 1% are almost identical when the power prices of the two interest regimes are the same.

Table 9.3.2-3 Summary of Case-wise EIRR with 8% of Interest on Long-term Debt

Case	Interest on long-term debt (%)	EIRR						Power price at 12% EIRR (Rs/kWh)
		Average power price for dry and wet season (Rs/kWh)						
		6Rs (%)	8Rs (%)	10Rs (%)	12Rs (%)	14Rs (%)	16Rs (%)	
Base Case	8.0%	9.5%	12.5%	15.1%	17.5%	19.7%	21.7%	7.64
High Case	8.0%	8.8%	11.6%	14.1%	16.4%	18.6%	20.5%	8.29
Low Case	8.0%	10.1%	13.1%	15.8%	18.2%	20.4%	22.4%	7.22

Table 9.3.2-4 Summary of Case-wise EIRR with 1% of Interest on Long-term Debt

Case	Interest on long-term debt (%)	EIRR						Power price at 6% EIRR (Rs/kWh)
		Average power price for dry and wet season (Rs/kWh)						
		3Rs (%)	4Rs (%)	5Rs (%)	6Rs (%)	7Rs (%)	8Rs (%)	
Base Case	1.0%	4.1%	6.2%	8.0%	9.7%	11.2%	12.6%	3.89
High Case	1.0%	3.6%	5.6%	7.4%	8.9%	10.4%	11.7%	4.20
Low Case	1.0%	4.6%	6.7%	8.6%	10.2%	11.8%	13.2%	3.65

9.3.3 Analysis of Power Prices and FIRR - Examination of Private Sector Investment

As indicated in the previous section, the construction of storage-type hydroelectric power generation facilities requires a large financial investment. In order to finance the storage-type hydroelectric power projects by raising private funds, the projects should be attractive in terms of their expected financial returns. Political and social risks associated with the projects should also be sufficiently low to promote such investment by private investors. To examine possible investment options and financial resource mobilization, the relationships between returns to equity and power prices are examined. A simulation analysis is applied to identify the power price range within which FIRRs become sufficiently large to attract private investment.

For financial analysis, it is assumed that storage-type hydroelectric power generation facilities are constructed by an IPP established separately from NEA, and that generated electricity by the IPP is to be sold to NEA. For the calculation of returns to equity financing (i.e. FIRR) it is assumed that 80% of the project cost is financed by borrowing at annual interest rate of 8%, and the remaining 20% of the cost is covered by the equity financing.

Table 9.3.3-1 and Table 9.3.3-2 present results of financial analyses by cases and FIRRs at power prices of 6 Rs/kWh, 8 Rs/kWh, 10 Rs/kWh, 12 Rs/kWh, 14 Rs/kWh, and 16 Rs/kWh. The power prices at 12% FIRR are also indicated in these tables. Because the range of interest rates of time deposits for the period of more than two years is in a range of 5.0% to 12.5% as of 2011, and a return of equity expected by investors can be assumed at 12%.

Table 9.3.3-1 Summary of Project-wise FIRR with 8% Interest on Long-term Debt

Project name	Installed capacity (MW)	Project (financial) cost ('000 USD)	Saleable energy (GWh) Dry season	Wet season	Annual Total	Interest on long-term (%)	Return on equity (FIRR) Average power price for dry and wet season (Rs/kWh) 6Rs (%)	8Rs (%)	10Rs (%)	12Rs (%)	14Rs (%)	16Rs (%)	Power price at 12% FIRR (Rs/kWh)
NEA Project													
Budhi Gandaki	600	1,118,400	500	2,000	2,500	8.0%	11.4%	22.6%	29.6%	35.0%	39.5%	33.2%	6.08
Promising Projects													
Dudh Koshi	300	872,513	523	1,386	1,910	8.0%	9.5%	19.4%	25.4%	30.0%	33.8%	36.9%	6.38
Nalsyau Gad	410	737,393	515	853	1,367	8.0%	n.a.	14.0%	20.9%	25.8%	29.7%	32.9%	7.58
Andhi Khola	180	529,088	137	512	649	8.0%	n.a.	n.a.	11.2%	19.1%	24.9%	29.8%	10.18
Chara-1	149	452,083	121	443	563	8.0%	n.a.	n.a.	10.4%	17.8%	23.1%	27.4%	10.36
Madi	200	499,460	171	450	621	8.0%	n.a.	n.a.	9.3%	16.8%	21.9%	26.0%	10.61
Naumure	245	727,968	310	848	1,158	8.0%	n.a.	10.9%	19.4%	25.3%	29.9%	33.8%	8.21
Sun Koshi No.3	536	1,289,280	336	1,548	1,884	8.0%	n.a.	1.6%	13.6%	19.4%	23.7%	27.1%	9.57
Lower Badigad	380	922,695	355	1,011	1,366	8.0%	n.a.	2.9%	14.1%	19.8%	24.0%	27.4%	9.45

Note: 1) n.a. (not applicable) means that the FIRR cannot be calculated due to negative net present values.

The results indicate that large-scale projects with high investment costs tend to have large salable electricity energy and they yield high FIRR even though power prices are relatively low. The financial analysis of the NEA presented in the next section indicates that the NEA's average purchase price of electricity from IPPs in FY2010/11 is 9.21 Rs/kWh at the 2012 constant price. As shown in Table 9.3.3-1, even prices lower than the 2011 purchase price exhibit better than those of the cut-off FIRR of 12% for some projects. For example, Budhi Gandaki, Dudh Koshi and Nalsyau Gad projects exhibit rates of return to equity (FIRR) of 22.6%, 19.4%, and 14.0% at the price of 8 Rs/kWh, respectively. At the 12% cut-off FIRR value for investment, wholesale power prices of the projects become 6.08 Rs/kWh, 6.38 Rs/kWh, and 7.58 Rs/kWh for the Budhi Gandaki, Dudh Koshi, and Nalsyau Gad projects, respectively. These prices are significantly lower than the FY2010/11 average purchase price of the NEA, and therefore these projects should be considered attractive for investors as long as the NEA purchases power at the 2011 purchase price.

As shown in the financial analysis of the NEA presented in the next section, the appropriate power purchase price is estimated to be 5.18 Rs/kWh at the 2012 constant price. To maintain the NEA's financially viability, the NEA needs to purchase power from IPPs at a price less than or equal to 5.18 Rs/kWh. In this case, FIRRs of the all projects concerned become less than 12% and are not attractive for private sector investment.

Table 9.3.3-2 Summary of FIRR of the Cases with 8% Interest on Long-term Debt

Case	Interest on long-term debt (%)	Return on equity (FIRR) Average power price for dry and wet season (Rs/kWh) 6Rs (%)	8Rs (%)	10Rs (%)	12Rs (%)	14Rs (%)	16Rs (%)	Power price at 12% FIRR (Rs/kWh)
Base Case	8.0%	5.6%	18.7%	26.5%	32.2%	36.8%	40.8%	6.79
High Case	8.0%	-0.6%	16.7%	25.5%	31.8%	36.7%	40.9%	7.24
Low Case	8.0%	8.9%	20.4%	27.7%	33.2%	37.8%	41.6%	6.42

Table 9.3.3-2 shows a summary of FIRR of the three cases with 8% interest on long-term debt. The low case shows the highest FIRR followed by the base case, and the high case shows the lowest FIRR

values. The highest development cost is incurred by the high case scenario which shows the smallest FIRR, whereas the low case requires the smallest development cost but shows the highest FIRR. However, the differences of FIRR among the three cases are relatively small. Because 12% of FIRR is considered to be a cut-off value of investment decision-making, wholesale power prices should be charged by IPPs becomes in the range of 6.42 Rs/kWh - 7.24 Rs/kWh. Since this range is lower than the NEA's FY2010/11 purchase price of 9.21 Rs/kWh at the 2012 price, all three cases should attract private sector investment.

However, as analyzed in the next section, this high purchase price is the major cause of the NEA incurring financial loss, and it should be adjusted accordingly. The analysis suggested that an appropriate power purchase price is 5.18 Rs/kWh at the 2012 constant price, and that with this price the calculated FIRRs of all the cases become less than 12% indicating private investment to the power development to be unattractive.

In order to promote implementation of the medium- to long-term hydroelectric power development with active participation of IPPs and private sector investment, the establishment of a stable and good investment environment is the key to achieve such hydroelectric power development. If the risk of changes in feasibility and profitability of planned hydroelectric power projects is high because of a volatile socioeconomic and political environment, the investment to hydroelectric power development projects can be high risk, discouraging such investment. It can be said that the NEA's high power purchase price offered to IPPs is a mechanism to transfer such risks borne by IPPs to NEA where government support can be obtained as a last resort. IPPs also try to reduce risks by selecting relatively small ROR-type hydroelectric power projects with a short construction period. Although hydroelectric power development by IPPs should be promoted further, the development only by IPPs will not be able to address the insufficient power supply and high cost of the electricity supply. Therefore, the development of storage-type hydroelectric power projects, though its cost is high, should also be considered for implementation.

Based on the above discussions, the following policy measures need to be considered to address risks associated with the hydropower development by IPPs.

1) To determine appropriate wholesale prices by a fully distributed cost method to secure a reasonable level of profit of IPPs.
2) To provide long-term and low-interest loans to IPPs to reduce financial costs for the provision of power with a low price.
3) To promote private sector investment to hydroelectric power development through the reduction of investment risk by securing access to the large power market in India. In this case, the establishment of a bilateral agreement between India and Nepal should be considered to reduce political and economic risks.

9.3.4 Analysis of Power Prices and FIRR - Examination of Public Sector Investment

In the previous section, 80% of the construction cost including interest during the construction period is assumed to be financed by borrowing from commercial banks at the annual interest rate of 8%. In this section, the 80% of the construction cost is assumed to be financed by low interest loans obtained from public institutions such as government banks, bilateral and multilateral development partners and banks in order to lower prices of electricity and/or to increase returns to equity (FIRR). However, it should be appropriate to lower prices of electricity to achieve fair and wide distribution of economic benefit and welfare rather than to increase returns to equity due to the public nature of the low cost loans. In this section, possibility of the NEA to implement hydroelectric power development projects including large storage-type hydroelectric power project by mobilizing low-cost government and donor resources will be examined.

<Examination of cost and retail price of electricity>

NEA generates electricity by itself and purchases electricity from IPPs and the Indian electricity market. Based on the balance sheet and profit and loss statement in the annual report FY2010/2011, the unit cost of electricity and retail price at delivery point are calculated and presented in Table 9.3.4-1. In FY2010/11, the NEA generated 2,096 GWh by its own generation facilities and purchased 1,733 GWh from IPPs and the Indian market. The total of 3,829 GWh of electric energy was secured by the NEA at generation and purchase points. On the other hand, the total of 2,728 GWh of energy was distributed at distribution points indicating a very high system loss of approximately 28%.

Table 9.3.4-1 Cost and Price Analysis of Power Generation and Purchase by the NEA in FY2010/11

Items	Unit	NEA generation	NEA power purchase	NEA system all
I. Electric energy				
Electric energy generated				
a) Hydro generation	GWh	2,122.08		2,122.08
b) Thermal generation	GWh	3.40		3.40
c) Self consumption	GWh	29.30		29.30
d) Total (a+b-c)	GWh	2,096.18		2,096.18
Electric energy purchased				
e) India	GWh		694.05	694.05
f) Nepal (internal)	GWh		1,038.84	1,038.84
g) Total	GWh		1,732.89	1,732.89
Electric energy for sale (or sold)				
h) Electric energy generated and purchased (d+g)	GWh	2,096.18	1,732.89	3,829.07
i) System loss	%	28.55	28.55	28.55
j) System loss including self consumption	%	28.77	28.77	28.77
k) System loss energy (h*j)	GWh	602.98	498.47	1,101.45
l) Electricity for sale (h-k)	GWh	1,493.20	1,234.42	2,727.62
II. Cost of generation, purchase, transmission, and distribution				
Cost at generation				
m) Generation expenses	Million Rs	929.56		929.56
n) Royalty	Million Rs	854.76		854.76
o) Total	Million Rs	1,784.32		1,784.32
Cost of purchase				
p) Purchase expenses	Million Rs		10,493.74	10,493.74
q) Total	Million Rs		10,493.74	10,493.74
Cost of transmission and distribution				
r) Operating expenses				
Transmission expenses	Million Rs	189.39	156.57	345.96
Distribution expenses	Million Rs	1,644.60	1,359.58	3,004.18
Administration expenses	Million Rs	474.49	392.25	866.74
Depreciation expenses	Million Rs	1,659.47	1,371.86	3,031.33
Deferred revenue expenditure	Million Rs	177.19	146.49	323.68
Sub-total	Million Rs	4,145.14	3,426.75	7,571.89
s) Other expenses				
Interest on long-term loans	Million Rs	1,967.50	1,626.51	3,594.01
Foreign exchange losses	Million Rs	46.54	38.47	85.01
Provision for employee benefits	Million Rs	1,034.66	855.35	1,890.01
Street light dues written off	Million Rs	0.00	0.00	0.00
Sub-total	Million Rs	3,048.70	2,520.33	5,569.03
t) Total	Million Rs	7,193.84	5,947.08	13,140.92
Cost total				
u) Cost total (o+q+t)	Million Rs	8,978.16	16,440.82	25,418.98
III. Sale of electricity				
v) Net sale of electricity	Million Rs	9,824.78	8,122.04	17,946.82
w) Income form other services	Million Rs			1,382.94
x) Total	Million Rs	9,824.78	8,122.04	19,329.76
IV. Profit or loss				
y) Profit or loss (x-u)	Million Rs	846.61	-8,318.77	-6,089.22
V. Unit cost and prices at sales				
z) Unit cost of generation and purchase ((o+q)/l)	Rs/kWh	1.19	8.50	4.50
aa) Unit cost of operation expenses (r/l)	Rs/kWh	2.78	2.78	2.78
ab) Unit cost of other expenses (s/l)	Rs/kWh	2.04	2.04	2.04
ac) Total unit cost (z+ab+ac)	Rs/kWh	6.01	13.32	9.32
VI. Average sale price				
ad) Average sale price (v/l)	Rs/kWh	6.58	6.58	6.58

The unit cost per kWh at the distribution point is calculated in order to compare the unit cost with the retail price of electricity at the distribution point. The generation cost of electricity by the NEA’s own facilities and cost of power purchase are different, whereas the cost of transmission and distribution is identical regardless of the methods of electricity generation or purchase.

In FY2010/11, the NEA reported a loss of Rs 6,089 million. Including incomes other than the sale of electricity, the total income from electricity business is reported to be Rs 17,947 million. The total cost of the same year amounts to Rs 25,414 million, which resulted in the total loss of Rs 7,472 million. The primary reason of this large loss occurring every year since early 2000s is the high power purchase price and low retail price. The high system loss also contributes to the high cost and subsequent loss of profit.

The average retail price of electricity in FY2010/11 is 6.58 Rs/kWh, whereas the cost of electricity generated by the NEA’s facilities is 6.01 Rs/kWh. In this case, the NEA is able to make profit. The cost of 6.01 Rs/kWh consists of the cost of generation at 1.19 Rs/kWh, the cost of operation at 2.78 Rs/kWh which includes the cost of transmission, distribution, administration, and depreciation, and the cost of interest payment and welfare at 2.04 Rs/kWh. The total cost of electricity purchased is 13.32 Rs/kWh which is high and causes the NEA's financial loss. The total cost of electricity purchased includes the cost of purchase at 8.50 Rs/kWh, and other cost components are the same as cost of electricity generated by the NEA. The results of this cost analysis revealed that the NEA’s loss comes from the fact that the loss caused by the high power purchase price and low retail price cannot be offset by the profit generated by sale of electricity generated by the NEA’s own facilities. This also reflected in the fact that the average cost of electricity generation and purchase cost is 9.32 Rs/kWh and the average retail price is 6.58 Rs/kWh indicating a loss of 2.72 Rs/kWh per unit sale of electricity.

<Examination of NEA generation and power purchase at the breakeven point>

From the estimated unit costs of NEA generation and power purchase, the average retail electricity price, and energy demand determined by the base case, NEA generation and power purchase portfolios at the breakeven point are calculated and shown in Table 9.3.4-2. In FY2010/11, for example, actual NEA generation is 1,493 GWh (corresponding load capacity is 279 MW), and required NEA generation at the breakeven point is 2,516 GWh (corresponding load capacity is 471 MW). To reach the breakeven point, NEA generation should be increased by 1,023 GWh. On the other hand, the actual power purchase of 1,234 GWh must be reduced to 212 GWh to reach the breakeven point. In terms of load capacity, the NEA needs an additional 191 MW capacity whereas IPPs have an excess capacity of 191 MW in FY2010/11.

Assuming that the cost structure of NEA in FY2010/11 will remain the same in the future, NEA generation and power purchase at the breakeven point in FY2018/19 and 2031/32 are calculated (see Table 9.3.4-2). In the calculations, generation costs of ROR-type facilities and storage-type facilities are considered equal. Applying the results of the base case demand forecast, the FY2018/19 electricity price is set at 12 Rs/kWh and demand at the supply point is at 5,669 GWh (equivalent to supply energy of 7,176 GWh and generation capacity of 1,575 MW both at the generation point). By the same token, the 2032 electricity price is set at 12 Rs/kWh and demand at the supply point is set at 16,179 GWh (equivalent to supply energy of 19,493 GWh and generation capacity of 4,279 MW both at the generation point) for the calculation of breakeven NEA generation and power purchase.

In FY2018/19 at breakeven point, NEA generation becomes 1,023 GWh, which is 470 GWh less than NEA generation in FY2010/11. On the other hand, power purchase in FY2018/19 becomes 4,646 GWh, showing a significant increase from the 2011 power purchase. This is because the increase in retail electricity price from 6.58 Rs/kWh to 12.00 Rs/kWh results in a decrease in loss caused by the power purchase which can be offset by a lesser amount of profit drawn from the NEA generation. It means that a lesser amount of low-cost NEA generation is required to offset the loss. These results indicate that by expanding low-cost NEA generation, a larger quantity of electricity can be supplied to the power market at a lower retail price in order for the power sector to contribute to the economic growth of Nepal. Lowering the retail electricity price from 12 Rs/kWh to 10 Rs/kWh requires NEA generation of 2,575 GWh, requiring an increase of 1,082 GWh from the NEA generation in FY2010/11. The increase requires additional NEA generation capacity of 436 MW. By the same token, lowering the retail price from 12 Rs/kWh to 10 Rs/kWh in FY2031/32 requires additional NEA generation of 5,856 GWh, which also requires an increase of NEA's generation capacity by 1,665 MW from the capacity in FY2010/11.

Table 9.3.4-2 Results of Breakeven Point Analysis (at 2011 prices)

Breakeven simulation parameters and electrical energy sources / Cases				Sale of electrical energy by sources			Required generation capacity				
	Unit cost of NEA generation	Unit cost of power purchase	Average sale price	Total	Generated by NEA	Purchased by NEA	System losses	System load factor	Total	Generated by NEA	Purchased by NEA
	(Rs/ kWh)	(Rs/ kWh)	(Rs/ kWh)	(GWh)	(GWh)	(GWh)	(%)	(%)	(MW)	(MW)	(MW)
	a	b	c	d=e+f	e[*1]	f	g	h	i=j+k	j	k
1. Cases in FY2010/11											
Case 1-1: Actual sale in FY2010/11	6.01	13.32	6.58	2,728	1,493	1,234	29%	86%	510	279	231
Case 1-2: Breakeven in FY2010/11	6.01	13.32	6.58	2,728	2,516	212	29%	86%	510	471	40
Difference between Cases 1-1 and 1-2					1,023	-1,023				191	-191
2. Breakeven cases in FY2018/19											
Case 2-1: Breakeven in FY2018/19 at 12Rs/kWh	6.01	13.32	12.00	5,669	1,023	4,646	21%	52%	1,575	284	1,291
Difference between Cases 1-1 and 2-1			5.42	2,941	-470	3,411			1,065	5	1,060
Case 2-2: Breakeven in FY2018/19 at 10Rs/kWh	6.01	13.32	10.00	5,669	2,575	3,094	21%	52%	1,575	716	860
Difference between Cases 1-1 and 2-2			3.42	2,941	1,082	1,859			1,065	436	629
3. Break even case in FY2031/32											
Case 3-1: Breakeven in FY2031/32 at 10Rs/kWh	6.01	13.32	10.00	16,179	7,349	8,830	17%	52%	4,279	1,944	2,335
Difference between Cases 1-1 and 3-1			3.42	13,451	5,856	7,595			3,769	1,665	2,105

Note: 1) For calculation of breakeven point $e = d \times (c - b) / (a - b)$.

<Expansion of NEA generation capacity by the government's investment and concessionary loans>

The above analysis relies on the assumption that the cost of NEA generation is low and 6.01 Rs/kWh at the sale point. To expand this low cost NEA generation, construction of additional generation facilities with the government's investment and concessionary loans from the ODA is assumed. Based on this assumption, a financial analysis is conducted to examine the relationship between retail price of electricity and returns to equity (FIRR). The results of the analysis are presented in Table 9.3.4-3. Eighty percent of the construction costs including interest during the construction is assumed to be financed by concessionary loans with an interest rate of 1% and a repayment period of 25 years, and the rest of the construction costs are assumed to be financed by the government's equity investment to NEA, to which returns to equity (FIRR) are calculated. Since the cost of NEA generation at the sale point in FY2010/11 is 6.01 Rs/kWh, FIRRs of the assumed electricity prices around the cost are calculated. Because the holder of the equity is the government, prices of electricity at 6% of return to the equity (FIRR), which is about half of the commercial rate of return (12%), are calculated.

The FY2010/11 cost of NEA generation 6.01 Rs/kWh at the sale point includes transmission and distribution costs. However, because the above model used to derive FIRR and power prices at 6% FIRR does not consider the transmission and distribution cost of 1.23 Rs/kWh, for the sake of analysis the cost of electricity at 4.78 Rs/kWh at the generation point (derived by subtracting 1.23 Rs/kWh from the cost of NEA generation 6.01 Rs/kWh at the sale point) is used as the threshold value. In order to interpret the results shown in Table 9.3.4-3, the threshold value of 4.78 Rs/kWh expressed in 2011 prices is adjusted to the 2012 constant price of 5.18 Rs/kWh by recognizing the 8.3% increase in the consumer price index from 2011 to 2012. Storage-type hydroelectric power projects which show more than 6% FIRR, even though their cost of electricity at the wholesale point is lower than this threshold value (i.e. 5.18 Rs/kWh at the 2012 constant price) are given higher priority for development with the government's investment and concessionary loans.

Based on the results shown in Table 9.3.4-3, the highest priority is given to Dudh Koshi project (3.13 Rs/kWh) followed by Budhi Gandaki project (3.31 Rs/kWh), Nalsyau Gad project (3,77 Rs/kWh), Naumure project (4.23 Rs/kWh), Lower Badigad project (4.66 Rs/kWh), and Sun Koshi No. 3 project (4.90 Rs/kWh).

Table 9.3.4-3 Summary of Project-wise FIRR with 1% Interest on Long-term Debt

Project name	Insta-lled capa-(MW)	Project (financial) cost ('000 USD)	Saleable energy Dry sea-son (GWh)	Wet sea-son (GWh)	Total (GWh)	Inte-rest on long- (%)	Return on equity (FIRR) Average power price for dry and wet season (Rs/kWh) 3Rs (%)	4Rs (%)	5Rs (%)	6Rs (%)	7Rs (%)	8Rs (%)	Power price at 6% FIRR (Rs/kWh)
NEA Project													
Budhi Gandaki	600	1,118,400	500	2,000	2,500	1.0%	1.1%	12.4%	18.3%	22.8%	26.5%	29.7%	3.31
Promising Projects													
Dudh Koshi	300	872,513	523	1,386	1,910	1.0%	4.7%	12.1%	16.9%	20.5%	23.6%	26.2%	3.13
Nalsyau Gad	410	737,393	515	853	1,367	1.0%	n.a.	7.8%	13.2%	17.1%	20.2%	22.9%	3.77
Andhi Khola	180	529,088	137	512	649	1.0%	n.a.	n.a.	2.6%	9.2%	13.7%	17.4%	5.45
Chara-1	149	452,083	121	443	563	1.0%	n.a.	n.a.	3.4%	9.3%	13.4%	16.8%	5.38
Madi	200	499,460	171	450	621	1.0%	n.a.	n.a.	2.8%	8.9%	12.9%	16.1%	5.46
Naumure	245	727,968	310	848	1,158	1.0%	n.a.	4.1%	10.8%	15.4%	19.1%	22.2%	4.23
Sun Koshi No.3	536	1,289,280	336	1,548	1,884	1.0%	n.a.	-0.3%	7.7%	12.1%	15.4%	18.2%	4.71
Lower Badigad	380	922,695	355	1,011	1,366	1.0%	n.a.	0.3%	8.0%	12.4%	15.7%	18.4%	4.66

Note: n.a. (not applicable) means that FIRR cannot be calculated due to negative net present values.

The base case-, high case- and low case-wise results of the analysis to determine suitable scenarios for addressing the electricity demand increase by mobilizing the government's investment and concessionary loans are shown in Table 9.3.4-4. Considering the threshold value for 6% FIRR is 5.18 Rs/kWh at the 2012 constant price, and the costs of NEA generation at the generation point for all cases are within the range of 3.32 Rs/kWh to 3.79 Rs/kWh, all cases are considered to be appropriate for implementation by the government's investment and concessionary loans.

Table 9.3.4-4 Summary of FIRR of the Cases with 1% Interest on Long-term Debt

Case	Interest on long-term debt (%)	Return on equity (FIRR) Average power price for dry and wet season (Rs/kWh)						Power price at 6% FIRR (Rs/kWh)
		3Rs (%)	4Rs (%)	5Rs (%)	6Rs (%)	7Rs (%)	8Rs (%)	
Base Case	1.0%	0.0%	9.6%	15.6%	20.2%	24.0%	27.2%	3.54
High Case	1.0%	-4.1%	7.7%	14.2%	19.1%	23.1%	26.6%	3.79
Low Case	1.0%	2.7%	11.2%	16.8%	21.3%	24.9%	28.1%	3.32

Financial analyses are conducted with respect to the electricity price, returns to equity (FIRR), interest rate of loan, cost of generation, and possibility of mobilization of investment and loans from private and public sectors for hydroelectric power development. Storage-type hydroelectric power projects and the cases showing high returns to equity (FIRR) and being able to pay a high interest rate comparable to commercial rates should attract private sector investors. However, the high returns and interest rates likely result in a negative impact on the country's economic growth. Because the functions of the power sector have the nature of the public sector, endeavoring for stable, reliable, and low cost supply of electricity needs to be achieved with a high priority. Therefore, the NEA should implement storage-type hydroelectric power projects by mobilizing the government's investment and concessionary loans to secure stable, reliable, and fairly priced electricity.

The financial analysis of the NEA's business identified a number of management issues: 1) high system loss significantly contributes to the high cost of electricity delivery, 2) having high electricity purchase prices and low sale price schedules incurs large financial loss and is financially not feasible, and 3) high cost of rural electrification. Therefore, it is recommended that the current efforts of organizational reforms and improvement of management and business efficiency must be continued and strengthened.

Regarding the sector-wide perspective, strong political will to improve policy and market environment of the power sector is needed. The market distortions stemmed from, for example, the unmatched price schedules of IPP generated electricity and the NEA's retail price schedule is a serious concern. Establishment of a competitive wholesale power market should be considered in order to reduce the wholesale price to a reasonable level. Adjustment of the retail price should also be considered to determine a reasonable retail price schedule to secure the NEA's financial soundness and further investment for its core businesses.