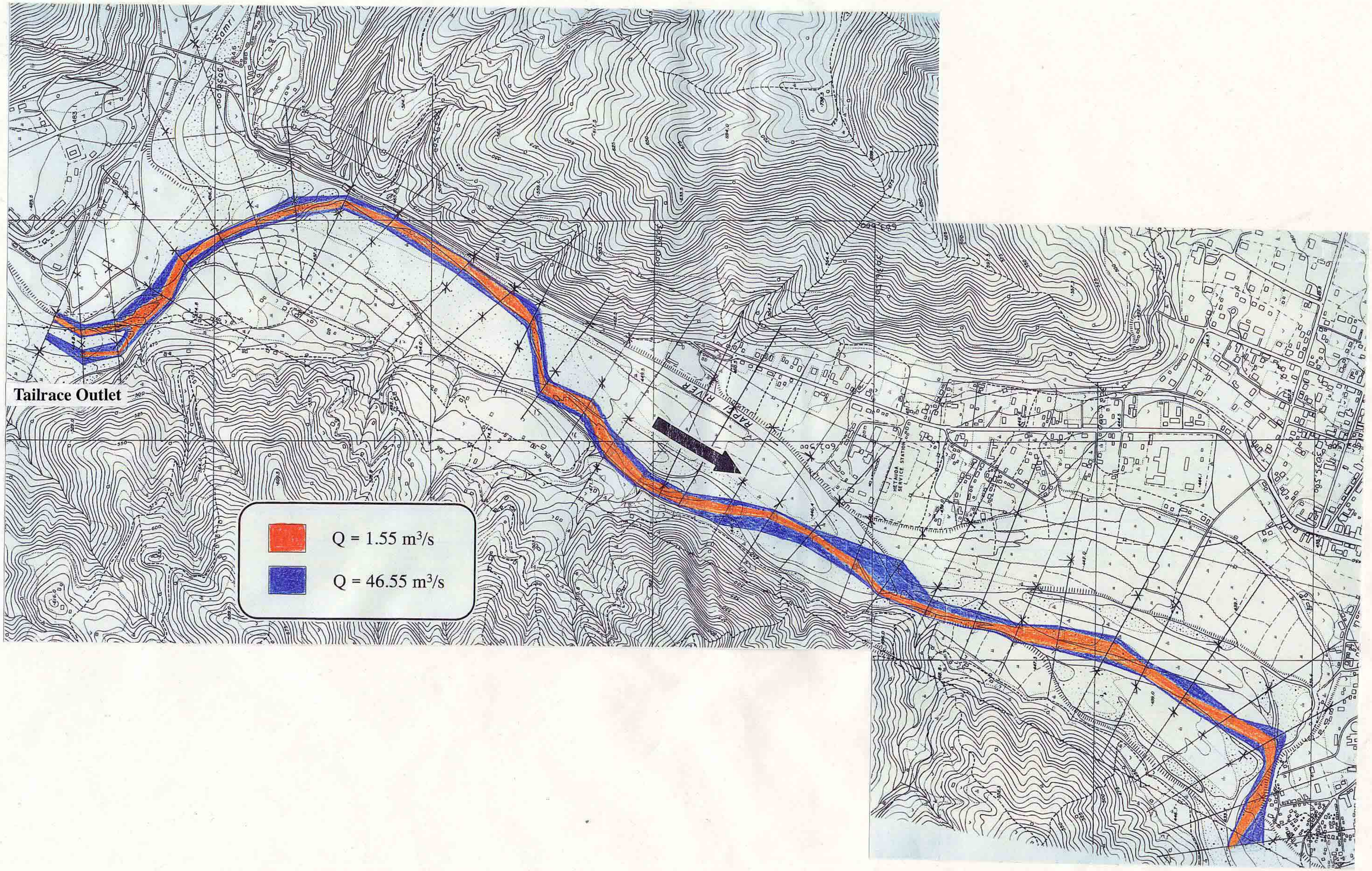


THE UPGRADING FEASIBILITY STUDY ON THE DEVELOPMENT OF THE KULEKHANI III HYDROPOWER PROJECT IN THE KINGDOM OF NEPAL

JAPAN INTERNATIONAL COOPERATION AGENCY

Figure 4.4.2
Affected Area of the Rapti River at Peak Discharge from Tailrace Outlet

Chapter 5

CHAPTER 5 POWER SURVEY

5.1 Present Power Sector

5.1.1 Institution of Power Sector

Any private company can enter the power business in Nepal by obtaining a license from His Majesty's Government of Nepal (HMG/N) under the Electricity Act, 2049 enacted in 1992. All the power businesses in Nepal are regulated by this act. Besides that, foreign capital can be invested for hydropower development in Nepal under the Foreign Investment and Technology Transfer Act, 1992 and Hydropower Development Policy, 1992.

Outline of the Electricity Act is mentioned below.

- No person shall be entitled to conduct survey, generation, transmission or distribution of electricity without obtaining license under this Act.
- Provided that no license shall be required to be obtained by a national or a corporate body for the generation, transmission or distribution of electricity up to 1000 kW and for conducting necessary survey thereof. Before generating, transmitting or distributing hydroelectricity of the capacity ranging from 100 kW to 1000 kW, information to that effect shall be given to the prescribed officer in a manner as prescribed.
- A person or corporate body, who desires to conduct survey, generation, transmission or distribution of electricity, shall be required to submit an application to the prescribed officer along with the economic, technical and environmental study report and with other prescribed particulars on the relevant subject.
- In case a licensee desires to sell or otherwise transfer its license, it shall be required to obtain the approval from the prescribed officer.
- The term of license to be issued for the survey of electricity may be of five years in maximum, and that for generation, transmission and distribution of electricity may be of 50 years in maximum.
- In case a license has been issued to any person or corporate body for the distribution of electricity in any area in accordance with this Act, no license shall be issued to any other person or corporate body for the distribution of electricity in the same area for the whole term of such license.
- HMG/N may enter into agreement with the licensee for bulk purchase of electricity, guarantee for the necessary capital to be invested or other financial and technical matters.
- The licensee has to pay royalty to HMG/N for commercial operation as follows:

	for fist 15 years	after first 15 years
1000 kW or less	non	non
hydro-electricity greater than 1000 kW	- NRs100/kW installed capacity/annum - 2 % of energy sales	- NRs1000/kW installed capacity/annum - 10 % of energy sales

Source: Electricity Act, 2049

Facilities related to income tax are as follows.

	for first 10 years	after 10 up to 15 years	after 15 years
Hydro-electricity generation transmission or distribution up to 1000 kW	none	none	none
Licensee for hydro-electricity generation transmission or distribution	none	none	*)lessened by 10 % than the corporate income tax levied pursuant to the prevailing law
Licensee for hydro-electricity transmission or distribution	none	lessened by 10 % than the corporate income tax levied pursuant to the prevailing law	lessened by 10 % than the corporate income tax levied pursuant to the prevailing law
*) Present corporate income is 25 % as of December 2001, then being lessened by 10 % means 25 x 0.9 = 22.5 %.			

Source: Electricity Act, 2049

- In principle HMG/N shall fix electricity charges and the licensee shall not be entitled to realize electricity tariff.
- Notwithstanding the above, one who distributes electricity in isolation of the National Grid shall be entitled to fix the electricity tariff.

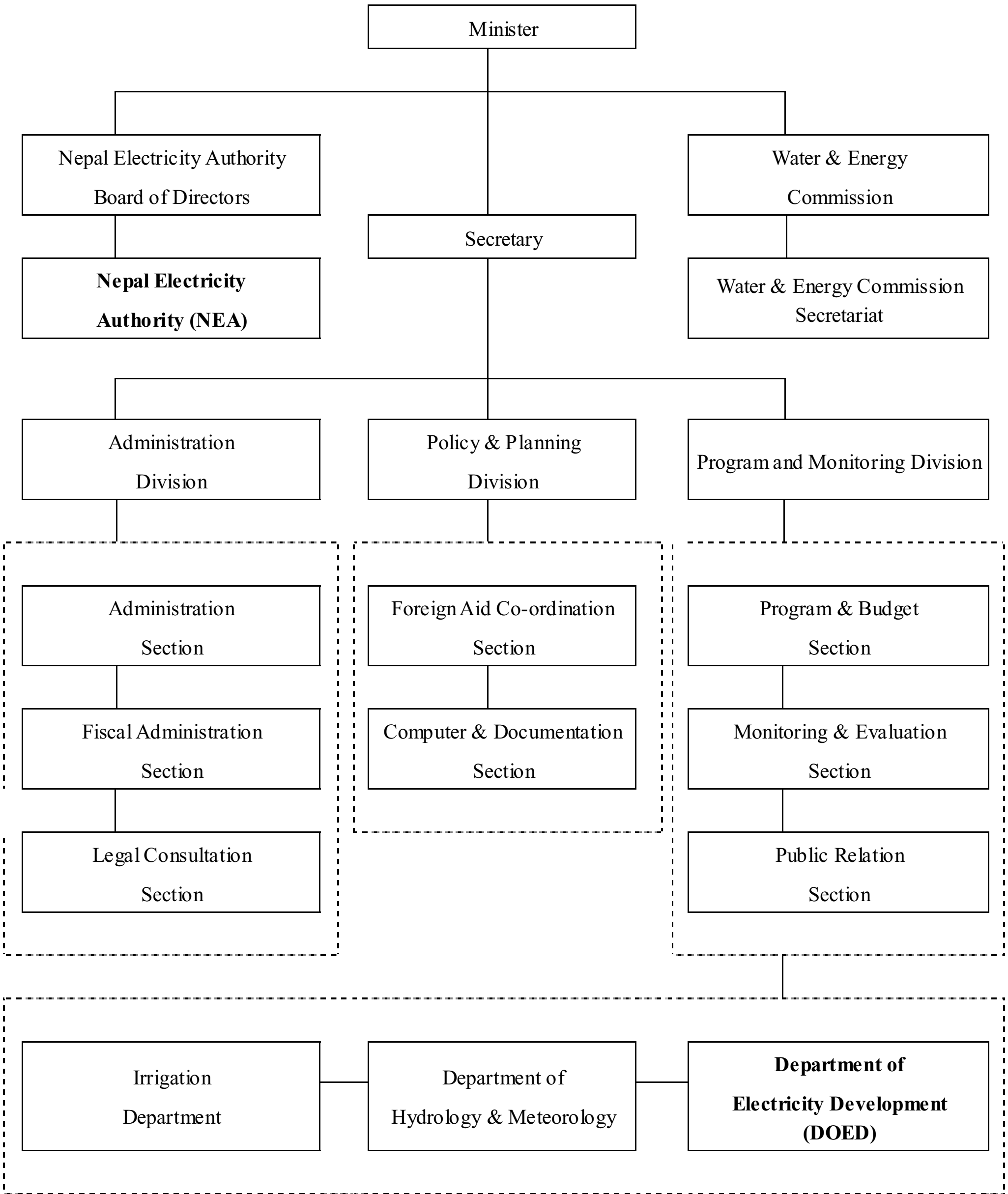
As mentioned above, institution of power sector is constituted to encourage newcomers to enter power business, especially for small hydropower businesses up to 1000 kW it is strongly encouraged by exemption of royalties and income taxes. Besides licensees can fix electricity tariff by themselves if they distribute electricity in isolation of the National Grid. This treatment tends to promote rural electrification, which is surely important in Nepal considering the current electrification ration of 15 % of the country. However, as common understanding it is difficult to get profit from rural electrification in any developing country. Nepal is no exception. Also few newcomers have entered the business of rural electrification

Generation is the most practical way to enter power business on a commercial basis from the viewpoint of profitability and operation. Independent Power Producers (IPPs) have already started their businesses of hydropower generation in Nepal. No royalty is required for the generation other than hydro-generation such as solar and wind, however there are no facilities to collect income tax on their businesses.

5.1.2 Organization of Power Sector

Ministry of Water Resources (MOWR) administrates the power business in Nepal under the Electricity Act.

The organization chart of MOWR is indicated below.



Organization Chart of MOWR

Department of Electricity Development (DOED is in the position to deal with the actual administrative work of power business in MOWR.

The center player of power business in Nepal is Nepal Electricity Authority (NEA) even though any private company can enter this business field. NEA is a wholly government-owned enterprise under the control of MOWR and its business covers planning, construction, operation and maintenance for generation, transmission, substation and distribution facilities, and sale of electricity to the consumers. NEA was established in 1985 as an amalgamation of Electricity Department (ED), Nepal Electricity Corporation (NEC) and other related departments under the NEA Act (1984).

NEA's responsibilities mentioned in the NEA Act are to recommend the policies of electricity supply to HMG/N, to recommend, determine and realize tariff structure for electricity consumption with prior approval of HMG/N, to arrange for training and study so as to produce skilled manpower in power sector, and others. On the other hand, the major mandates of NEA are to collect electricity tariff from the consumers, borrow from foreign government or international agencies with prior approval of HMG/N and to exchange power with foreign countries.

The organization of NEA is shown in Figure 5.1.1.

NEA has been reforming its organization and management aiming at being a financially self-sustainable enterprise on a commercial basis with cost-effective operations. As a part of the reforms, NEA introduced the Profit Center concept to 15 distribution offices out of NEA's 56 in total distribution offices for the profit management by designated office itself, loss reduction and providing consumer-oriented services. Six distribution offices became the profit centers in 2001 and the remaining nine distribution offices became the same in 2002.

The following table shows the six profit centers with their revenue and number of consumers in percentage to those of NEA's total values, and distribution losses.

6 Profit Center

Profit Center Branch	% of revenue of NEA's Total	% of Consumer of NEA's Total	% of Loss
Kathmandu Central	12.34	5.65	12.09
Lalitpur	3.51	4.01	41.07
Biratnagar	6.09	2.23	16.78
Birgunj	7.15	3.96	33.41
Pokhara	3.96	4.06	11.52
Nepalgunj	1.98	2.24	12.65
Total	35.03	22.15	

Source: NEA FY 2000/01 A Year in Review

The nine distribution offices which became profit centers in 2002 are of Kathmandu East, Kathmandu West, Bhaktapur, Hetauda, Bharatpur, Janakpur, Dharan, Butwal and Bhairahawa.

Global tide of power sector is toward deregulation and privatization. Management and operation of NEA is in the same tide and NEA continues to make effort to establish sound financial structure as mentioned earlier. Besides NEA is actively encouraging private companies to enter the power generation business and keeping the plan to split distribution sector as independent organization from NEA in the future. However, NEA will still possess the National Grid and the system control facilities and function as government-owned enterprise in the long term future - like 20 or 30 years - in order to take responsibility for reliable and stable power supply in Nepal.

5.1.3 Power Development Policy

The power development policy of NEA is shown below.

(1) Development of hydropower generation
(2) Power exchange with India
(3) Development of storage type and large scale hydropower generation
(4) Promotion of rural electrification

With the background of abundant hydropower potential in Nepal, NEA has the policy to develop that potential as power sources. Present generation expansion plan doesn't include thermal power generation. The advantage of thermal power generation is that seasons or climates don't affect its generating capacity. In Nepal, thermal power generation supplements the decrease in the output of hydropower generation, which increases the reliability of power supply in the National Grid. However, Nepal is not active enough to introduce thermal power generation from the viewpoint of power security because there are no fossil fuel resources like oil or coal in Nepal, which are wholly imported. Besides that, growing interest in conservation of global environment by depressing carbon dioxide is also the background of passivity of NEA for introducing thermal power generation.

The import of power from India, where the prime power source is thermal, has been effective as a manner to increase the reliability of power supply. Although the current ceiling value of power exchange with India is 50 MW, the ceiling is planned to be increased to 150 MW in the future considering power export to India in the wet season.

As a measure increasing the power supply reliability, increased capacity of storage type hydropower generation like Kulekhani III is effective, then high priority is given to the development plan of Kulekhani III in NEA's generation expansion plan.

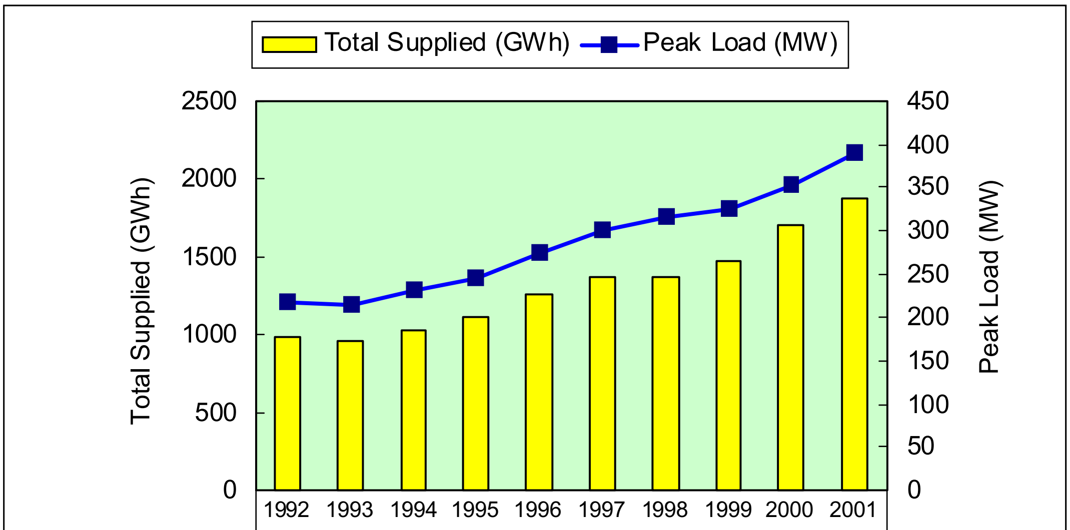
As a future view, NEA plans to develop large hydro generation, ensure the generating capacity beyond the internal consumption even in the dry season, increase the reliability of power supply by these means, and also to obtain a profit by selling surplus energy to India.

NEA gives high priority to rural electrification in the power developing policy observing the current electrification ratio of 15 %. It is planned to actively apply small hydropower generation to the isolated areas as well as grid extension for rural electrification; grid extension is difficult in mountainous areas.

5.1.4 Power Balance

As the final figures after the audit in FY2001/02 A YEAR IN REVIEW of NEA, the total energy supplied, total sales of energy and peak demand in the fiscal year (FY) 2001 are 1868 GWh, 1707 GWh and 391 MW, respectively. The ratio of energy purchased from India against total supplied is 12 %, and in the same manner the ratio of energy purchased from IPP is 27 %. The ratio of energy generated by thermal (diesel) power stations against the whole energy generated in the country including IPP is 1.7 %. The remaining energy is generated by hydropower stations. Looking at the demand side, the number of domestic consumers account for 95.7 % of the total number of consumers and the sales of energy by the domestic consumers comes to 37.6 %. The number of consumers categorized as industry is small at 2.3 %. However the sales to industry consumers account for 38.0 %, slightly larger than that of domestic consumers.

The demand and supply of the National Grid from FY1971 is indicated in Table 5.1.1. The whole energy supplied in a year and the peak demand from FY1992 to FY2001 are shown below.



	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Total Supplied (GWh)	981	963	1031	1118	1262	1369	1373	1475	1701	1868
Peak Load (MW)	216	214	231	244	275	300	317	326	352	391

Source: NEA FY 2001/02 A Year in Review

Energy Supplied and Peak Load from FY1992 to FY2001

The average annual growth rates of energy supplied and peak load are 7.41 % and 6.82 %, respectively.

5.1.5 Power Tariff

The tariff rates of NEA have been revised four times since 1993 and the latest tariff rates as of August 2002 became effective in September 2001. The present tariff structure consists of 11 categories and the time of day rates was introduced in 1998 for the consumers receiving high voltage (66 kV and above) and medium voltage (33 kV and 11 kV).

The present power tariff structure is shown in Table 5.1.2 and Table 5.1.3 indicates the record of revisions of power tariff rates for domestic, industry, commercial and non-commercial consumers.

The present power tariff rates is at a high enough level considering the economic and price level in the country; World Bank and Asian Development Bank have long advised NEA to increase power tariff rates for efficient management . For example, referring to the energy charge of domestic consumers, it is NRs9.9/kWh, which corresponds to Yen16/kWh at exchange rate of NRs1.0=Yen1.62, if the consumption exceeds 250 kWh.

The average power tariff rate calculated from dividing total revenue by total sold energy increased 4.5 times from 1991 to 2001.

Average Power Tariff Rate form FY1991 to FY2001

FY	91	92	93	94	95	96	97	98	99	00	01
NRs/kWh	1.40	1.98	2.59	3.38	4.10	4.15	4.96	5.05	5.01	5.70	6.23

Source: NEA internal data and NEA FY 2001/02 A Year in Review

5.2 Present Power System and Development Plan

5.2.1 Existing Power System

The source of the existing power system in Nepal is hydro generation and the system voltages are 132 kV and 66 kV for transmission. The voltages of distribution system are 33 kV and 11 kV as high tension lines and 400/230 V as low tension lines. The frequency of the system is 50 Hz. Most high tension distribution lines are 11 kV, however, in the rural areas, a 33 kV distribution system is also applied widely. The voltage level of 11 kV is not enough to transmit the power for such a long distance in rural areas as demand points are much scattered widely.

The National Grid consists of the trunk line, which is laid east to west in Terai plain, and some branch lines extending to northern mountain areas from the trunk line. The system diagram of National Grid is shown in Figure 5.2.1.

Grid extension to the northern mountain areas is economically difficult in many cases, so there are many small isolated power supply systems with mini or micro hydropower stations. In western areas there are two power supply systems with photovoltaic power generation. Wind generation system had been installed however there is no system now in operational condition.

5.2.2 Existing Generation and Transmission Facilities

Referring to the existing generation facilities as of June 2002, the capacity of hydropower generation including IPP's property is 527.7 MW, the same of thermal generation is 56.8 MW, and then total is 584.5 MW according to NEA A Year in Review FY2001/02. As most power stations are run-of-river type, they cannot generate the full rated capacities in the dry season when peak demand comes out. Although the generating capacity available at the peak time in dry season varies dependent on river flow conditions, it is estimated to be 323 MW totally in Nepal. The peak demand of FY2001/02 came out on December 12, 2001 and the total generation at this time was 415 MW. By this figure deducting 72 MW of generation by one unit operation of the Kali Gandaki-A, it might be said that the estimated capacity at peak time is consistent with the actual capacity.

The existing generation facilities connected to the National Grid as of July 2002 are indicated in Table 5.2.1.

The existing transmission lines and the capacities of substation transformers of the National Grid including 33 kV system is shown in the next table.

Transmission Lines of National Grid

Voltage (kV)	Circuit	Route Length (km)
132	single	1,132.00
132	double	412.10
66	single	231.46
66	double	161.30
66 & 132	double	22.00
66	four	3.37
33	single	2,362.00

Source: NEA FY 2001/02 A Year in Review

Capacity of Substation Transformers of National Grid

Voltage (kV)	Transformer Capacity (MVA)
132/11	28.50
132/33	220.00
132/66	220.10
66/11	324.00
66/33	25.00

Source: NEA FY 2001/02 A Year in Review

5.2.3 Activities of Independent Power Producers

Independent Power Producers (IPPs) have activated their businesses after the Electricity Act was enacted. Four IPPs are generating power at present and four IPPs are constructing power stations; all hydropower stations.

Activities of IPP

No.	Plant Name	Installed Capacity (MW)	Promoter's Name	Year In Service
Existing				
1	Andi Khola	5.1	Butwal Power Company	1991
2	Jhimruk	12.3	Butwal Power Company	1994
3	Khimti Khola	60.0	Himal Power Limited	2000
4	Upper Bhote Koshi	36.0	Bhote Koshi Power Co.	2000
Under Construction				(scheduled)
5	Chilime	20.0	Chilime Hydropower Co. Ltd.	2002
6	Indrawati	7.5	National Hydropower Pvt. Ltd.	2003
7	Upper Modi	14.0	Jaitech	2003
8	Pilwa Khola	3.0	Arun Valley Hydropower Development Co., Pvt. Ltd.	2003

Source: NEA FY 2001/02 A Year in Review and NEA's Internal Data

The situation of licenses that have been given for power businesses and surveys are shown in Table 5.2.2. According to the table, it is found that 62 licenses have been given; out of them, Upper Modi (SN: C.16) is already under construction.

5.2.4 Generation Expansion Plan

(1) Generation Expansion Plan of ADB's Master Plan Study

The latest generation expansion plan with overall study and examination is Power System Master Plan for Nepal[1] ("ADB Master Plan" afterward) which was prepared in 1998 with financial assistance by Asian Development Bank (ADB). ADB Master Plan formulates generation expansion plan for 15 years after the expected completion year of Kali Gandaki A, that is to say FY[2]2003 to FY2017 with least cost method.

ADB Master Plan formulated the following four scenarios as generation expansion plan.

---

[1] Power System Master Plan for Nepal, Generation Expansion Plan Final Report, Financed by ADB, Norconsult International A.S. , August 1998

[2] Fiscal year of Nepal starts from middle of July and ends at the middle of July in the next year.

1) The Hydro and Thermal Scenario
2) The Hydropower Only Scenario
3) The Hydropower Only Scenario (Flexible Plan)
4) The Hydropower Only with High Demand Scenario

ADB Master Plan prepared four demand forecasts: medium growth, low growth and two kinds of high growth (medium-high and high). The scenarios “1)” to “3)” out of the above four generation expansion plans are formulated based on medium growth demand forecast and the scenario “4)” is based on high growth (medium-high) demand forecast.

The necessity of thermal generation of scenario “1)” is to cover the peak demand in the dry season; the annual peak demand comes out and the output capacity of hydropower generation declines as well in this season. The scenario “2)” is the plan to introduce Kulekhani III with capacity of 12 MW in FY2005, seven years earlier than the scenario “1)”, Upper Karnali in FY2007, one year earlier than the same, and Arun 3 in FY2011, two years earlier as same, and to make the thermal generation unnecessary with the increased hydro capacity and to encourage export of power to India. Regarding the project cost, the scenario “1)” is cheapest, however, if the income of power export is considered, the scenario “2)” becomes cheaper than the scenario “1)”. Besides that, taking into account the fact that fuel oil would have to be imported for thermal generation and Nepal aims to self-support the energy in the future, ADB Master Plan recommends the scenario “2)”.

The scenario “3)” is the plan to introduce small and medium scale hydropower stations at an earlier stage based on the scenario “2)” supposing that the completions of large scale hydropower stations, Upper Karnali and Arun 3, are delayed respectively. This is a flexible and realistic plan because the small and medium scale hydropower projects are easier to proceed with than large-scale projects. The scenario “4)” is the plan to correspond with high growth (medium-high) demand forecast.

The scenario “2)” is shown below with the peak demand forecast, project cost and others quoted from ADB Master Plan as they are.

Generation Expansion Plan of ADB Master Plan

FY	Projects	Project Type	Project Capacity (MW) *)	Total System Capacity (MW) *)	Peak Load (MW) *)	Reserve Margin (MW) *)
2002				504	432	72
2003	Middle Marsyangdi	PROR	61	504	464	40
2004	Khimti Khola II **)	PROR	27	565	505	60
2005	Kulekhani III	PROR	12	629	549	80
2006	Likhu-4	PROR	44	641	594	47
2007	Upper Karnali	PROR	300	685	642	43
2008				985	692	293
2009				985	742	243
2010				974	799	175
2011	Arun 3	PROR	402	950	860	90
2012				1352	924	428
2013				1352	992	360
2014				1352	1063	289
2015				1352	1139	213
2016	Chameliya	PROR	30	1352	1219	133
2017				1382	1304	78
PV of total costs excluding export revenues:				751.3 mill. USD		
PV of total costs including export revenues:				586.4 mill. USD		
Present value of total investments:				840.6 mill. USD		

*) In driest season February/March
**) Construction of Khimti II increases the peaking capacity of Khimti I.
"PROR": peaking Run-of-river plant
Source: Generation Expansion Plan Final Report, August 1998

(2) Generation Expansion Plan of NEA

The final report of generation expansion plan by ADB Master Plan was completed in August 1998. At that time the following seven power stations were under construction with the schedule to be completed by January 2001. The completion of these power stations in time was the precondition of the generation expansion plan of ADB Master Plan.

1) Ilam (Puwa Khola)
2) Modi Khola
3) Chilime
4) Khimti Khola
5) Kali Gandaki A
6) Upper Bhotekoshi
7) Indrawati

Some of the projects are, however, behind schedule. As of November 2002, the two power stations of Chilime and Indrawati have not yet been completed.

In this circumstance, NEA updated the generation expansion plan. The latest generation expansion plan of NEA as of August 2002 is given below.

Generation Expansion Plan of NEA

FY	Projects	Installed Capacity (MW)	Peaking Capacity (MW)	Average Energy (GWh/yr)	Comments
2002	Kali Gandaki A	144	144	791	Completed
	Syange	0.1	0.06	1	IPP, PPA signed
2003	Chilime	20	20	101	IPP, Under Construction
	Indrawati	7.5	3	37	IPP, Under Construction
	Daram Khola	5	5	33	IPP, PPA signed
	Piluwa Khola	3	2	18	IPP, Under Construction
	Chaku Khola	0.91	0.9	7	IPP, PPA signed
2004	Pheme	0.95	0.9	8	IPP, PPA signed
	Upper Modi	14	8	89.6	IPP, Under Construction
	Khudi	3.5	2.2	25	IPP, PPA signed
2005	Mailung	5	4.3	37	IPP, PPA signed
	Middle Marsyangdi	70	70	393	NEA, Under Construction
2006	-	-			-
2007	Langtang	10	10	78	IPP, PPA signed
	Chameliya	30	30	196	NEA Planned
	Kulekhani III	42	42	50	NEA, Planned
	Khimti II	27	27	157	NEA, joint venture
2008	Rahughat	27	6	165	Private
	Kabeli-A	30	15	162	Private
2009	Upper Karnali	300	300	2133	NEA joint venture
2010	-	-			-
2011	-	-			-
2012	-	-			-

Source: NEA Corporate Development Plan

Compared with ADB Master Plan, although the policy to develop only hydropower stations has not changed, most of the projects have been delayed. Middle Marsyangdi has been postponed for two years, Khimti Khola II for three years, Kulekhani III for two years and Upper Karnali for two years. The plan of NEA shows the projects only up to FY2009. In this plan Arun 3 and Likhu-4 are not included.

The generation expansion plan of NEA tries to encourage small hydropower stations by IPP to be introduced instead of putting off the major hydropower stations. However, as a short range prospect, power shortage to the peak demand may come up in FY2005 even after the completion of Middle Marsyangdi, considering the precondition of ADB Master Plan, which is that Kali Gandaki A, Chilime and Indrawati are supposed to be completed by January 2001.

5.2.5 Transmission Expansion and Other Plan

The expansion plan of transmission lines[3] is also prepared in the ADB Master Plan. This transmission expansion plan is formulated consistent with the generation expansion plan. NEA, however, is updating the transmission expansion plan because the generation expansion plan in the ADB Master Plan is delayed and does not reflect the actual situation.

The major components of the latest transmission expansion plan as of August 2002 are indicated below.

Transmission Expansion Plan of NEA

FY	Project	cct	Remarks
2003	132 kV Hetauda - Dhalkebar second circuit on existing tower	-	under construction by NEA
2003	132 kV Butwal - Bardhghat second circuit on existing tower	-	under construction by NEA
2004	132 kV Butwal - Aanandnagar (India), Nepal side only	2	Committed by ADB
2004	132 kV Pathalaiya - Parwanipur (Birgunj Corridor)	2	
2005	66 kV Teku – K3 underground transmission line and K3 substation	2	Basic design study has been conducted by JICA
2005	132 kV Thankot - Budhanilkantha	1	Thankot - Bhakutapur section with single circuit string on double circuit tower, committed by ADB
2005	132 kV Middle Marsyangdi - (Dumre) - Damauli	2	Middle Marsyangdi - (Dumre) 2cct - Marsyangdi under construcion by KfW, (Dumre)-Damauli by NEA
2006	132 kV Birgunj - Motihari (India), Nepal side only	1	Single circuit string on double circuit tower,
2006	132 kV Dhalkebar - Sitamadhi (India), Nepal side only	1	Single circuit string on double circuit tower, going to request WB
2006	132 kV Khimti - Dhalkebar	1	going to request WB
2006	66 kV Kulekhani III - Hetauda	2	by NEA

[3] Transmission System Master Plan Final Report, August 1998

The points of the plan are efficient use of the power generated by Kali Gandaki A, strengthening power exchange with India and reinforcement of power supply in Kathmandu.

The activities and development plans of other donors, not limited to transmission systems, are mentioned by donors below.

(1) ADB

The loan agreement for transmission and distribution lines, and rural electrification was signed on July 13, 2000. This is the co-finance of US$50 million from ADB and US$10 million from OPEC fund. Although the agreement was signed, the loan has not yet been effective as of December 2001 for the reason that the condition for the loan such as financial strength and loss reduction is not cleared.

The components of the project are shown below.

Project Components of Co-finance Loan by ADB and OPEC

Project Title: Transmission Distribution and Rural Electrification Project
(ADB 8th Power Project)

1. Rural Electrification
2. Distribution System for Isolated Power Project
3. Distribution System Reinforcement
4. Transmission Development
    (i) Thankot - Bhaktapur 132 kV Transmission Line, double circuit with single circuit string
    (ii) New 132 kV Thakot switching station, New 132/11 kV Harisidhi substation and Expansion of Patan, Balaju, Bhaktapur and Chabel substation
    (iii) Butwal – Anandnagar (India) 132 kV Transmission Line, Nepal side only
5. Computerizing Billing System for 15 Distribution Consumer Service Branch Offices (Profit Center)

(2) World Bank

NEA is planning to apply the loan of World Bank to the project of transmission lines and rural electrification.

The component of the candidate projects for the World Bank loan is shown below.

Component of Candidate Projects for World Bank Loan

1. Project Title: Power Development Project132 kV Khimti – Dhalkebar
2. Power Exchange Links
   (i) Dhalkebar – Sitamarhi (India) 132 kV single circuit T/L, Nepal side only
3. High Voltage Spare Parts and Protection Equipment
4. Rural Electrification and Distribution System Reinforcement
   (i) Lalitpur district
   (ii) Bhaktapur district
   (iii) Kabhre district
   (iv) Rural Electrification for Nuwakot district
5. Technical Assistance

(3) Other Donors

DANIDA of Denmark, KfW of Germany, SIDA of Sweden, KOICA of Korea and USAID of USA are active in the power sector.

The projects and activities of these donors are shown below.

Projects and Activities of Other Donors

DANIDA (The Danish Agency for Development Assistance)

1. Kaiali – Kanchanpur Rural Electrification;
   Review of detail design stage

KfW (German development bank)

1. Middle Marsyangdi Hydropower Project
2. Load Dispatching Center Master Station in Siuchatar Substation;
   under construction under grant aid program

SIDA (Swedish International Cooperation Agency)

1. Rural Electrification;
   opting to undertake a rural electrification project in several districts of the far-west and mid-west development regions.

KOICA (Korea International Cooperation Agency)

1. Chameliya Hydropower Project;
   Detailed design and preparation of tender document is being carried out under grant aid program.

USAID (The United States Agency for International Development)

1. Energy Partnership Program;
   The program is sponsored by USAID and managed by the United States Energy Association (USEA) for the formation of partnerships between utilities in the USA.

5.3 Power Demand Forecast

5.3.1 Review of NEA's Demand Forecast

NEA prepared the demand forecast from FY2002 through FY2020 as the latest version estimating annual energy and peak demand. If the forecasted value is defined specifically, the values are at the sending end of the power stations connected to the National Grid. Regarding the power sales to India, only small scale and committed supply to areas in India across the border are incorporated in the forecast. The average annual growth rate of annual energy demand from 2002 through 2020 is 7.50 % and in the same manner the average annual growth rate of peak demand is 7.93 %.

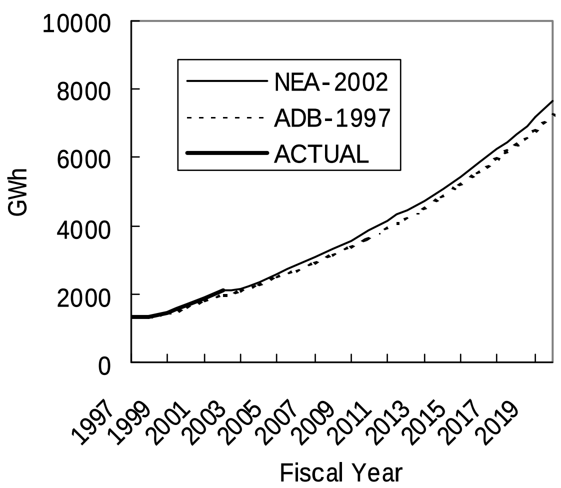
The same methodology of the demand forecast of ADB Master Plan[4] is applied to NEA' demand forecast.

The demand forecast of NEA, the one of ADB Master Plan (FY1998 - FY2020) and the actual record of demand from 1997 through 2002 are indicated in following table and graph.

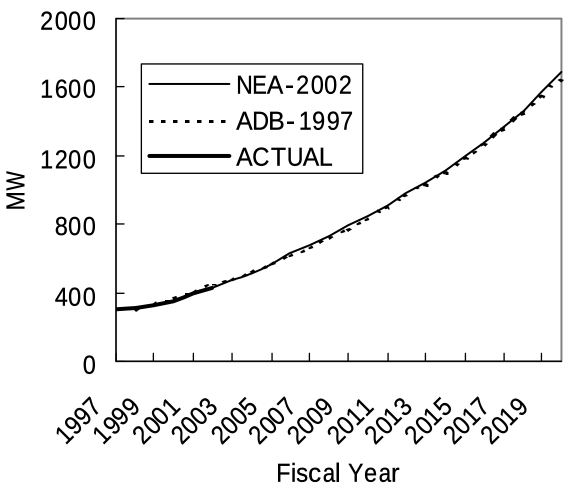
[4] Power System Master Plan for Nepal, Load Forecast Final Report, Financed by ADB, Norconsultant International A.S., December 1997

Comparison of Demand Forecast

FY	Annual Energy Demand NEA-2002 GWh/yr.	Annual Energy Demand ADB-1997 GWh/yr.	Annual Energy Demand ACTUAL GWh/yr.	Annual Peak Demand NEA-2002 MW	Annual Peak Demand ADB-1997 MW	Annual Peak Demand ACTUAL MW
1997			1369			300
1998		1349	1373		308	317
1999		1478	1475		337	325
2000		1617	1701		369	352
2001		1788	1868		408	391
2002	2088	1967	2088	426	449	426
2003	2149	2110		472	482	
2004	2354	2300		517	525	
2005	2598	2502		570	571	
2006	2850	2702		625	617	
2007	3094	2922		679	667	
2008	3343	3150		734	719	
2009	3591	3377		788	771	
2010	3855	3637		846	830	
2011	4135	3914		908	894	
2012	4434	4205		974	960	
2013	4753	4514		1044	1031	
2014	5093	4840		1118	1105	
2015	5456	5185		1198	1184	
2016	5843	5550		1283	1267	
2017	6255	5937		1373	1355	
2018	6696	6347		1470	1449	
2019	7166	6782		1573	1548	
2020	7668	7244		1683	1654	



Annual Energy



Annual Peak

5.3.2 Power Exchange

Nepal currently exchanges power with India. Peak demand occurs in winter in Nepal and in summer in India. The generating capacity of Nepal increases in the summer wet season because the major power source is hydropower. In India, constant generating power can be obtained throughout the year and is not affected by the seasons because the major power source is thermal power. The power exchange is considered to be beneficial for both countries[5] from the viewpoint of optimal power allocation.

The power exchange between the countries under the present contractual agreement has taken place since the India-Nepal Power Exchange Committee was established and the first meeting was held in 1992 at New Delhi. The ceiling power exchange level decided by the committee was 50 MW. The exchange takes place on an as available basis when there is a surplus of power. NEA, however, tries to continue the committed supply to certain locations of India across the border from the viewpoint of regional efficiency of power supply and goodwill between the countries. At present the power exchange takes place at around 11 locations by 33 kV and 11 kV distribution lines, and at two locations (Gandak and Duhabi) by 132 kV transmission lines. In addition to the above power exchange, Nepal has the right to receive annual 70 GWh to a maximum of 16 MW of power from the Tanakpur power station in India, which utilizes the water of the Mahakali river: border river, under the Tanakpur Treaty.

The following table shows the record of power exchange from FY1993 through FY2002.

Power Exchange Record for Past 10 Years

FY	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Import (GWh)	82	103	114	73	154	210	232	232	227	238
Export (GWh)	46	51	39	87	100	67	64	95	126	143

Source: NEA A Year in Review 2000/01 & 1998/99

For exchange in both directions, the following tariff schedule has been in effect since January 1996.

- Supply at 33 kV : Indian Rs1.67/kWh (January 1996)
- Annual escalation : 8.5 %
- Supply at 11 kV : a surcharge of 7.5 % on the 33 kV rate
- Supply at 132 kV : a rebate of 7.5 % on the 33 kV rate

According to the above, the tariff for power exchange at 132 kV in the year 2002 is calculated to be IRs2.52/kWh, which corresponds US ¢ 5.28/kWh (IRs1.0=US ¢ 2.095).

[5] To be specific, the contracting partners for power exchange are Bihar and Uttar Pradesh State Electricity Boards (BSEB, UPSEB).

A raising of the ceiling for power exchange from 50 MW to 150 MW level was proposed by Nepal in the 3rd India-Nepal Power Exchange Committee meeting. This proposal is intended to increase the export of surplus power in the wet season. After the discussion in various India-Nepal Power Exchange Committee meetings, it was decided in principle that the exchange level would be increased from 50 MW to 150 MW in the 6th committee meeting held in January 2001. However, this ceiling level will become effective around the year 2003 or 2004 after completion of the following three transmission line projects that aim to enhance the exchange capacity.

- Butwal (Nepal) － Anandnagar(Uttar Pradesh)
- Birgunji (Nepal) － Motihari (Bihar)
- Dhalkebar (Nepal) － Sitamadhi(Bihar)

5.3.3 Losses

The power losses of around 30 % early in the 1980s came down to around 25 % in the 1990s. It can be said that this is the result of various loss reduction programs that NEA executed.

Record of Power Losses from Year 1982 through 2002

FY	1982	1984	1986	1988	1990	1992	1994	1996	1998	2000	2002
Losses (%)	31.0	33.3	29.5	26.0	29.2	24.8	26.6	25.8	23.4	25.4	24.6

Power losses can be divided into two categories: non-technical and technical losses. Reduction of technical losses is available by enhancing transmission capacity or installing capacitors to improve power factor. Non-technical losses arise from inaccurate or tampered-with meters and connections, unrecorded consumers, and pilferage. In order to reduce non-technical losses, a statutory approach is required.

NEA is planning to achieve a 20 % level of power losses by around FY2005, especially concentrating their effort on the reduction of non-technical losses. Enactment of the Electricity Theft Act, which was approved in the Parliament in October 2001, has made punishment of theft of power possible.

While quantification of non-technical losses is difficult, rough estimates place the figure at around 12 %. As the amount of theft is usually high in developing countries, reducing non-technical losses through the Electricity Theft Act to 20 %, and later to 18 %, seems to be possible by FY2005.

5.3.4 Energy Demand Forecast

In this Section, the annual energy demand is forecasted by reviewing NEA's demand forecast. Based on the results of this review, peak demand is forecasted in Section 5.3.8.

(1) Methodology

In this study the same methodology as NEA's demand forecast is applied. NEA adopted the methodology from the ADB Master Plan with the only change being to update parameters. There was no particular problem in the methodology found when reviewing NEA's demand forecast. Following NEA's methodology, the demand forecast of this study is formulated by updating the parameters and data, and replacing data with more appropriate values if necessary.

In the demand forecast of NEA, three models were prepared for each consumer category.

1) Domestic Sector

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

where,

D_t	=	Electricity consumption in period t
ΔP_t	=	Change in price of electricity in period t
ΔCPI_t	=	Change in 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) Industrial, Commercial, and Other Sectors

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

Where,

$D_{t,i}$	=	Electricity consumption by sector i in period t
$\Delta P_{t,i}$	=	Change in price of electricity for sector i in period t
ΔCPI_t	=	Change in consumer price index in period t
$a_{t,i}$	=	GDP growth rate for sector i in period t
b_i	=	GDP elasticity for electricity for sector i
c_i	=	Price elasticity for electricity for sector i
$\Delta L_{t,i}$	=	Large new projects in sector i in period t

3) Irrigation Sector

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

Where,

D_t	=	Electricity consumption of 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 in period t

(2) Domestic Demand

NEA's demand forecast places the following preconditions.

- Demand of FY2002 (Base Year) : 576.5 GWh (actual record)
- Annual change in price of electricity in real terms ($\Delta P_t / \Delta CPI_t$) : 104.5 % (FY2001 - 2003)
  100.0 % (FY2004 - 2020)
- New consumers connected : 88,676 (record of FY2001)
  100,000 (FY2002 - 2020)
- Real income growth rate : 3.8 % (GDP / capita growth)
- Income elasticity for electricity : 1.4 (FY2001 - 2008)
  1.3 (FY2009 - 2020)
- Price elasticity for electricity for households: - 0.4
- Average consumption for new consumers, period t:
  350 kWh/connection (FY2001 - 2003)
  325 kWh/connection (FY2004 - 2008)
  300 kWh/connection (FY2009 - 2020)

The annual average increases of the power tariff in real terms of 4.5 % up to FY2003 and 0.0 % after that are practical considering the past tariff increases frequently conducted and the current tariff level which is already high enough mentioned in Section 5.1.5.

New connections of 100,000 consumers per annum are within the realms of possibility considering the fact that actual new connection in FY2002 was recorded as 127,093 and the power development policy of NEA attaches great importance to rural electrification.

Real income (GDP/Capita) growth rate of 3.8 % is reasonable as mentioned in Section 2.6.

Regarding the income elasticity and price elasticity, although there is no specific information available for Nepal, the applied values seem to be reasonable with reference to the values usually applied for developing countries.

Annual average consumption for new consumers is set to reduce over time. This kind of arrangement is based on the assumption that the wealthier families can connect their houses to the grid faster, which is considered to be rational. Referring to the applied value of 350 kWh/year, this translates into 40 W of annual average consumption. As lighting seems to be the major load, the period for consuming electricity is 8 hours, then the average consumption during 8 hours is calculated to 120 W, which corresponds to the capacity of two bulbs. This value is considered reasonable for the consumption of the average house in rural areas.

As a result of the review mentioned above, the applied data and indicators for NEA's demand forecast are considered reasonable and so these values are adopted in the demand forecast of this study.

Table 5.3.1 shows the result of the domestic demand forecast.

(3) Industrial Demand

NEA's demand forecast places the following preconditions.

- Demand of FY2002 (Base Year) : 597.0 GWh (actual record)
- Annual change in price of electricity in real terms ($\Delta P_t / \Delta CPI_t$) : 104.5 % (FY2001 - 2003)
  100.0 % (FY2004 - 2020)
- GDP growth rate for the industrial sector : 7.3 %
- GDP elasticity for electricity for the industrial sector :
  1.2 (FY2001 - 2008)
  1.1 (FY2009 - 2020)
- Price elasticity of electricity for the industrial sector : -0.3

In addition to the above, the projected demand from large new projects is estimated as shown below, based on the information of the Nepal Industrial Development Corporation.

Expected Large New Projects

Industry	Capacity	Commencement Year
1. Argakhachi	10 MW	FY2003
2. Surkhet	12 MW	FY2004
3. Salyan	8 MW	FY2004
Total	30 MW	

The annual average increase in power tariff is considered reasonable for the same reasons mentioned in the analysis of domestic demand.

A GDP growth rate of 7.3 % in real terms is examined in Section 2.6, and is considered reasonable.

The values applied for GDP elasticity and price elasticity for the industrial sector are considered reasonable for the same reason as mentioned for the domestic demand forecast.

The large new projects are based on the national development plan for industries, and the considered to be realistic.

As a result of the review mentioned above, the applied data and indicators for NEA's demand forecast are considered reasonable and these values are adopted in the demand forecast of this study.

Table 5.3.2 shows the result of industrial demand forecast.

(4) Commercial Demand

NEA's demand forecast places the following preconditions.

- Demand of FY2002 (Base Year) : 95.5 GWh (actual record)
- Annual change in price of electricity in real terms ($\Delta P_t / \Delta CPI_t$) : 104.5 % (FY2001 - 2003)
  100.0 % (FY2004 - 2020)
- GDP growth rate for commercial sector: 6.5 %
- GDP elasticity of electricity for commercial sector :
  1.3 (FY2001 - 2008)
  1.2 (FY2009 - 2020)
- Price elasticity of electricity for commercial sector : -0.4

The annual average increase in power tariff is considered reasonable as well, as mentioned for domestic demand.

The GDP growth rate of 6.5 % in real terms is examined in Section 2.6, and is considered reasonable.

The values applied for GDP elasticity and price elasticity for the commercial sector are considered reasonable for the same reason as for the domestic demand forecast.

As a result of the review mentioned above, the applied data and indicators for NEA's demand forecast are considered reasonable and these values are adopted in the demand forecast of this study.

Table 5.3.3 shows the result of the industrial demand forecast.

(5) Other Demand

The other demand includes mostly the load from public facilities such as government offices, streetlights and temples. NEA's demand forecast applied the following preconditions.

- Demand of FY2002 (Base Year) : 131.4 GWh (actual record)
- Annual change in price of electricity in real terms ($\Delta P_t / \Delta CPI_t$) : 104.5 % (FY2001 - 2003)
  100.0 % (FY2004 - 2020)
- GDP growth rate for other sector : 5.5 %
- GDP elasticity of electricity for the other sector :
  1.2 (FY2001 - 2008)
  1.1 (FY2009 - 2020)
- Price elasticity of electricity for the commercial sector : 0.0

With the same results of review as obtained for the commercial sector, the applied data and indicators for the other sector demand forecast of NEA are considered reasonable, so these values are also adopted in the demand forecast of this study.

Table 5.3.4 shows the result of other demand forecast.

(6) Irrigation Demand

NEA's demand forecast places the following preconditions.

- Demand of FY2002 (Base Year) : 31.2 GWh (actual record)
- Annual growth rate of existing demand: 1.4 %

In addition to the above demand growth, the load of deep and shallow tube-well pumps is incorporated in the demand forecast as new demand. This new demand reflects the Agriculture Perspective Plan (APP) formulated under the Ninth Five Year Plan. The APP calls for an average of 24,000 hectares of land to be added to the groundwater-irrigated area. Out of that area, it is planned that 22,000 hectares will be turned over to shallow tube-well irrigation and 2,000 hectares to deep tube-well irrigation. According to the Ground Water Development Project of the Department of Irrigation, there is a target to add 8,800 shallow and 50 deep tube-wells per annum.

The demand forecast incorporates the irrigation pumps of those tube-wells assuming that about 20 % of the shallow tube-wells and all of the deep tube-wells are run by electrical energy. The capacities of electrical pumps are 2.6 kW for shallow tube-wells and 22.38 kW for deep tube-wells, and the pumps are assumed to run around 800 hours for shallow tube-wells and 500 hours for deep tube-wells.

The annual growth rate of existing demand of 1.4 % is similar to the actual growth rate recorded from 1991 to 1999 and so is considered reasonable. It is rational to count irrigation pumps from the execution of the Ground Water Development Project as new load.

Therefore, the applied data and conditions of the NEA forecast are adopted in the demand forecast of this study.

Table 5.3.5 shows the result of the irrigation demand forecast.

(7) Power Export to India

As mentioned in Section 5.3.2, NEA endeavors to continue the committed supply across the border to certain locations in India. This demand is incorporated in the demand forecast and based on the actual demand of 142.9 GWh recorded in FY2002, an 8 % annual growth rate is applied.

This 8 % growth rate is almost the same as the growth rate of domestic demand, and is thus considered reasonable. The amount of power export will be over 571 GWh in FY2020 with an 8 % of annual growth rate. In case of the power exchange ceiling becoming 150 MW, the amount of export energy possible is calculated as 657 GWh with a 50 % load factor. The estimated export amount 571 GWh is in the possible amount.

Therefore, the applied data and condition of NEA's demand forecast are considered reasonable and are adopted in the demand forecast of this study.

Table 5.3.6 shows the calculated demand forecast for power export to India.

(8) Losses

The forecasted values of demand in the preceding sections represent values at the consumer ends. In order to convert the values into those at the supply end of power stations, a power loss rate is required. The actual power loss rate in FY2002 is calculated as 24.6 %. In NEA's demand forecast, a value of 22 % is applied to FY2003, that decreases 1 % every year until it reaches 18 %, which is then applied up to FY2020.

This assumption is considered achievable as mentioned in Section 5.3.3. Therefore, these values are adopted in the demand forecast of this study.

(9) Energy Demand Forecast

From the review on the demand forecast stated above, NEA's energy demand forecast is considered to be applicable to this study. However, when recalculation was done with the same data, parameters and conditions, there was a small discrepancy with the figures stated in A YEAR IN REVIEW FY2001/02 of NEA; the energy demand at FY2020 in A YEAR IN REVIEW FY2001/02 is 1.7 % lower than the recalculated value. This study adopts the recalculated values resulting in a higher demand.

Table 5.3.7 shows the result of energy demand forecast.

(10) High and Low Demand Forecast

High and low demand forecasts were calculated based on the demand forecast worked out through the above steps (base case). The condition of the high demand forecast is to apply 20 % higher values against the values adopted to the base case demand forecast; the values are the real income growth rate for domestic demand and each corresponding GDP growth rates for industrial, commercial and other demand forecast. In the same manner, 20 % lower values against the base case demand forecast are applied for the low demand forecast.

The results of high and low demand forecasts are indicated in the Attachment A5.1 and A5.2, respectively.

5.3.5 Demand Side Management

Demand Side Management (DSM) is the effective tool to restrain the peak demand in the morning and evening.

The DSM that NEA actually applies is a differential tariff rates for peak and off-peak time in a day (Time-of-Day Tariff Rates). The tariff rates are selected to be high at the peak time and lower at the off-peak time. This difference of rates usually moves the peak demand to the off-peak time. The time-of-day tariff rates system was introduced in November 1998. However, no study or survey has been executed to quantitatively evaluate the effect of the introduced tariff rates. A remarkable effect might not be found, since the targeted consumers are only the heavier power consumers that are connected to 11 kV or higher.

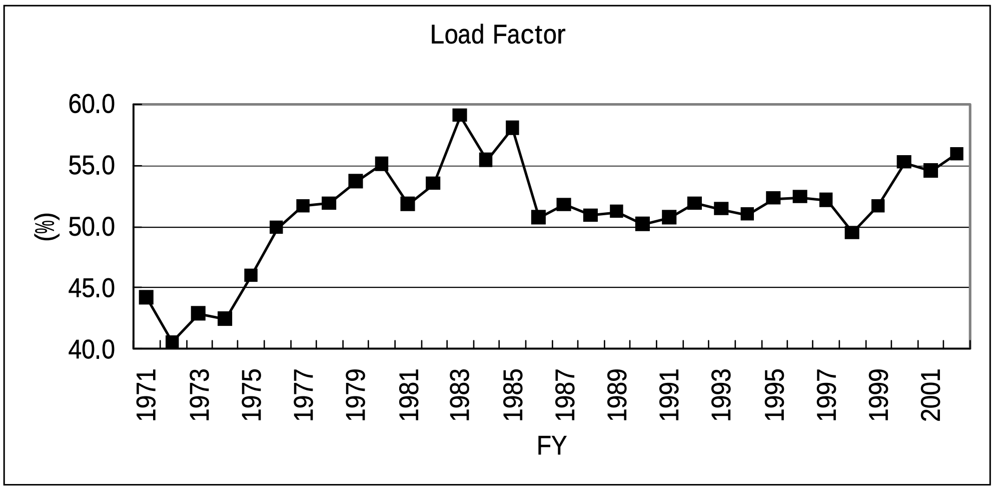
The peak demand in the winter season seems to be created by domestic consumers for the most part. Applying the above time-of-day tariff rates to domestic consumers is worth considering. However, for the time being NEA has no plan to introduce the rates to domestic consumers. The primary reason why NEA has no plan to introduce the time-of-day tariff rates is that investment in new energy meters, which are required for introducing the tariff rates, is a huge financial load for NEA. The investment in installation of new energy meters is surely heavy because domestic consumers cover 95 % of the total number of consumers. Secondly NEA considers that the load of domestic consumers at the peak time is mostly lighting, and this load cannot be shifted to the off-peak time. The heaters and water heaters that consume off-peak power at midnight, and are widely used in Europe or Japan, are effective for DSM. However, such heaters have not been introduced in Nepal, and possession of a water heater is limited to large income earners in Nepal. Considering these matters, the introduction of the time-of-day tariff rates to domestic consumers requires a large investment, but a large DSM effect seems not to be expected.

From the above consideration, it is supposed that there is only a small possibility to lower the peak demand by DSM even in the future. Therefore, the effect of DSM to lower the peak demand is not incorporated in the demand forecast of this study.

5.3.6 Load Factor

NEA's demand forecast applies 52 % as a load factor[6].

The trend in the load factor from FY1971 through FY2002 is indicated in the following graph.



Trend of Load Factor from FY1971 through FY2002 (Source: NEA)

6 Annual Load Factor = (average annual demand) / (annual peak demand)

The load factor varied between 50 % and 52 % from the later 1980s to 1999. It rose to 55 % in FY2001 and to 56 % in FY2002. These high load factors are introduced by load shedding due to the power deficit in the years in which the peak load was suppressed, with a resultant increase in the load factor. Scheduled load shedding has been conducted due to continuous power deficits since the later 1980s, not only in the past two years. Therefore, the potential peak load seems to be higher than the recorded peak load, which means that the load factor tends to be lower if load shedding is cancelled by an increase in the supply capacity.

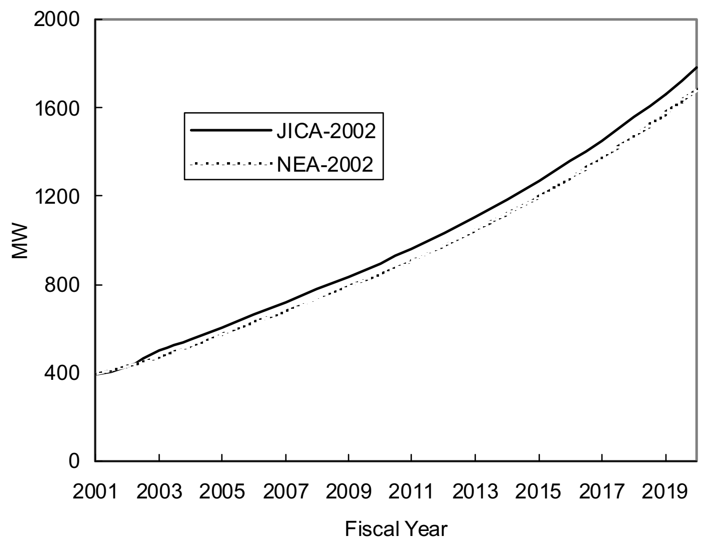
From the above consideration, 50 % is adopted for the load factor in the demand forecast of this study.

5.3.7 Peak Demand Forecast

With the annual energy demand estimated in Section 5.3.4, and the annual load factor decided in Section 5.3.6, the annual peak demand is calculated. The annual average growth rate of the peak demand up to FY2020 is 8.3 %.

The peak demand forecast is shown in the following table and graph compared with NEA's forecast.

FY	Annual Peak Demand	
	NEA-2002 MW	JICA-2002 MW
2001	391	391
2002	426	426
2003	472	502
2004	517	549
2005	570	606
2006	625	664
2007	679	720
2008	734	778
2009	788	835
2010	846	896
2011	908	962
2012	974	1031
2013	1044	1105
2014	1118	1184
2015	1198	1268
2016	1283	1357
2017	1373	1453
2018	1470	1555
2019	1573	1664
2020	1683	1781



Note: Data in FY2001 and FY2002 are actual

.Comparison of Peak Demand Forecast

The result of demand forecast including energy demand is shown in Table 5.3.7.

5.3.8 Demand and Supply Balance

Demand and supply balance was examined using the results of the demand forecast and generation expansion plan of NEA mentioned in Section 5.2.4.

The energy balances with and without the Kulekhani III power station are indicated in Tables 5.3.8 and 5.3.9, respectively. Figure 5.3.1 shows these as graph. The Kulekhani III project is included as a peak power station with a capacity of 42 MW. As the annual available energy produced by the Kulekhani III power station is small, the presence of the Kulekhani III does not much affect the energy balance. Both of the cases: with and without Kulekhani III, indicate that there is no deficit up to FY2017 if the generation expansion plan of NEA proceeds well as scheduled. The result is same even if the demand increases along the high demand forecast. However, it is noted that NEA's expansion plan shows the schedule only up to the introduction of the Upper Karnali power station in FY2009.

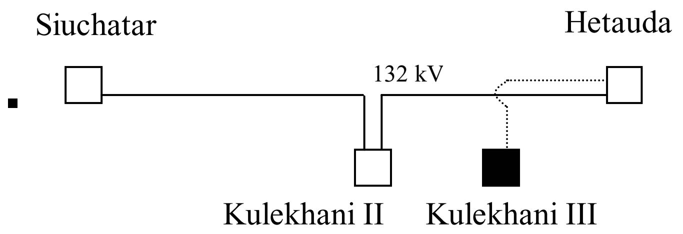
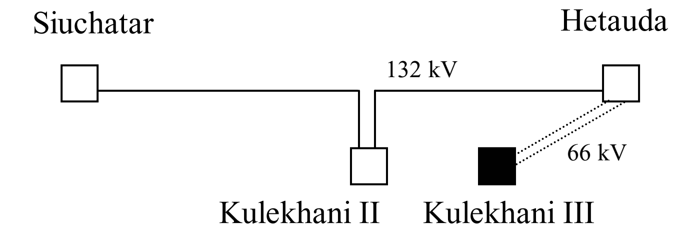
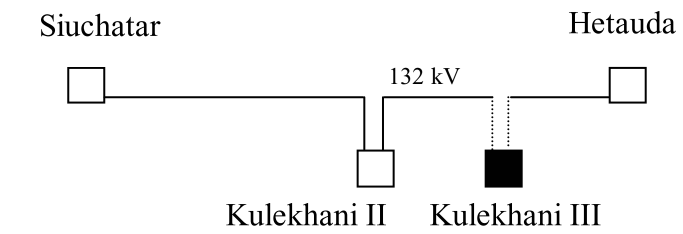
The balances of power capacity with and without Kulekhani III are indicated in Table 5.3.10 and 5.3.11, respectively. Figure 5.3.2 shows these as graph. The power deficit is predicted in FY2004, FY2005 in both cases of with and without Kulekhani III and in FY2009 in case of without Kulekhani III. Besides that, as no project is scheduled after Upper Karnali, there will be a capacity deficit after FY2014. If Upper Karnali fails to be completed in the scheduled time, continuous power deficit appears from FY2010.

5.4 Transmission Line for the Kulekhani III Hydropower Project

For transmission lines to connect Kulekhani III to the National Grid, there are three alternative plans; a plan indicated in the Kulekhani III FS report of NEA, a plan presented in the transmission expansion plan of NEA, and a plan recommended by the JICA Study team.

The features of these plans are as indicated below.

Transmission Line Plans

	**(1) NEA FS Plan** Connect to Hetauda S/S utilizing spare circuit (not strung) of the existing 132 kV Siuchatar – Hetauda line
	**(2) NEA T/L Expansion Plan** Connect to Hetauda S/S with new 66 kV double circuit line
	**(3) JICA Plan** Loop-in loop-out connection with existing 132 kV Hetauda – Siuchatar line

The above three plans were evaluated on the three factors of system reliability, ease of construction including land acquisition, and construction cost.

In terms of system reliability, Plan (2) is superior, the next is Plan (3) and Plan (1) is inferior to those. Regarding ease of construction, Plan (1) and Plan (3) are ranked at the same level, and Plan (2) is inferior to those with the necessity of environmental impact assessment and land acquisition for the new transmission line. Regarding construction cost, Plan (3) is cheapest, the next is Plan (1) and Plan (2) is most expensive.

As a result of evaluation on the system reliability, ease of construction, and cost, this study recommends Plan (3) for Kulekhani III hydropower project as the appropriate plan of transmission line. Though it is not included in the project, it is recommended to string the second circuit of the existing Hetauda – Siuchatar line before completion of the Kulekhani III project in order to increase the system reliability.

5.5 Operation and Maintenance Program of the Existing Hydropower Stations

The organization, budgetary arrangements, and staff training arrangements in the major existing hydropower stations of NEA are outlined as follows:

5.5.1 Organization for operation and maintenance

The existing structure of the power stations is under the control of the Operation and Maintenance Department of Generation in Kathmandu, as introduced in the Clause 5.2, except for the Kali Gandaki A hydropower station.

Typical organization charts (i.e., for Kulekhani I, Kulekhani I, Marsyangdi and Kaligandaki A hydropower stations) are shown in Figure 5.5.1 through 5.5.4, in which the number of staff are indicated for each of the four power stations and summarized as follows:

Kulekhani I	Kulekhani II	Marsyangdi	Kali Gandaki A
PS Manager: 1	PS Manager: 1	PS Manager: 1	PS Manager: 1 (w/assistant:2)
Operation Section 1+(2)	Electrical Section 1+(1)	Electrical Section 1+(2)	Electrical Section 1+(4)
Maintenance Section 2+(2)	Mechanical Section 2+(0)	Mechanical Section 1+(3)	Mechanical Section 1+(5)
Civil Section for Powerhouse 1+(0)	Civil Work Section 1+(0)	Civil Work Section 1+(3)	Civil Work Section 1+(2)
Civil Section for Dam 1+(0)			
Account Section 1+(2)	Administration Section incl. account, etc. (2)	Account Section incl. store 1+(5)	Account Section incl. store 1+(1)
Administration Section 1+(0)		Administration Section 1+(1)	Administration Section 1+(2)
Total =14	Total =8	Total =20	Total =20

Note: 1st figure-Section chief/Assist. Manager
2nd figure-Engineer/Supervisor/Assist. Officer/Accountant as key staff.

In general, the organization adopted is similar in each power station, though section-wise or administration-wise organization is adopted respectively.

The Operation Section, which is responsible for the control of plants, power generation, and operation of river control equipment, adopts four shifts operation with 2-day rotation.

Because of its remote location, a Civil Section has been established for the Kulekhani I dam, and this section is responsible for operation of intake gates, spillway gates, valves, and so on, including maintenance work of Kulekhani dam, Chakhel dam and Sim intake dam.

Daily operation for power generation is performed under instruction from the Load Dispatching Center (LDC) in Kathmandu. Meter/indicator readings are regularly recorded on the station log sheets and reported to the LDC by the operators every hour around the clock and every half hour during the peak load time in Kulekhani I and Kulekhani II hydropower stations.

The Maintenance Section is responsible for inspection and maintenance of electrical and mechanical equipment/facilities, for which both electrical and mechanical staff are assigned.

The Administration Section is responsible for management of accounts, stores and non-technical matters in general.

It seems that the total number of operators and maintenance staff, including superintendents and labor, is between 30 and 55 for power stations of a scale of 100 MW. As seen in Figures 5.5.1a~d, Kulekhani I and Kali Gandaki A hydropower stations seem to have a larger number of staff considering maintenance labor force and a remotely located dams of storage type for Kulekhani I, Marsyangdi and larger scale of Kali Gandaki A, in view of employment structure in Nepal.

5.5.2 Budgetary Arrangement for operation and maintenance

The latest six-year budget and expenditure for operation and maintenance are tabulated in Table 5.5.1, in which all expenditures are shown only local currency (LC) but foreign currency (FC).

Therefore, the budget seems mainly to be used for procurement of small parts and repairing electric and mechanical equipment, civil improvement works, distribution lines, etc. to take up periodical and/or occasional maintenance.

To procure spare parts, consumables, apparatus and components that are not available in Nepal, the FC portion appears to be budgeted as the occasion demands, judging from the past allotment of FC portion. However, the yearly budget does not seem enough for procurement of necessary spare parts and consumables for a major overhaul every 10 years to keep the plant in good condition. For this purpose, there are two methods: NEA can deposit the FC so that overhaul work can be performed every 10 years, including procurement and supervisory services from the manufacturer. The second approach is for NEA to ask for economical assistance in the foreign aid program on a grant or loan basis, though this will depend upon the policy of the country concerned.

5.5.3 Training of NEA staff for operation and maintenance

A training center was established in Kathmandu in 1991. At this centre, NEA's employees are continuously trained in the following programs:

- basic technical knowledge of electricity;
- operation and programming of computers;
- erection and maintenance of medium and low voltage lines; and

- operation and maintenance of diesel power stations.

However, there is no training center for operation and maintenance of hydropower plants at present.

In case of Kulekhani I and Kulekhani II hydropower stations, instruction programs for operation and maintenance were performed by the equipment supply contractors within the framework of the contracts. The operation and maintenance staff seem to have been well trained and gained experienced in the overhaul of powerhouse equipment for both Kulekhani I and Kulekhani II hydropower stations in 1994, when the manufacturer's supervisor only gave necessary instructions and advice and performed tests after reassembly.

Similarly to Kulekhani I and II hydropower stations, commissioning of Marsyangdi hydropower stations also seems to have programmed training in the framework of the equipment contracts, not only on-site but also in the contractor's country. The operation and maintenance staffs seem well trained and experienced. However, overhaul is yet to be performed even though 13 years have passed since commissioning.

Site inspection of the existing hydropower stations indicated that there are no problems with ordinary operation and maintenance works, such as routine operation and ordinary periodical inspections. Maintenance works are also performed smoothly by the stationed staff. However, it appears that there is limited capacity to perform works that require dismantling of hydropower equipment for overhaul, i.e., annual inspection and overhaul. These tasks are dependent on experienced staff. The reasons for the limited capacity in this area appears to be as follows:

- staff seem to have been well trained for assembly during the construction of the hydropower plant, but are inexperienced in dismantling works as there has been no chance so to do, e.g., at Modi Khola hydropower station;
- well trained and experienced staff are often periodically transferred, e.g., Kulekhani I and Kulekhani II hydropower stations; and
- well trained experienced staff commonly do not wish to work in the remote locations of the power plants for a long period due to the unattractive wage structure;

In case of Kali Gandaki A hydropower station, training programs similar to those for Marsyangdi hydropower station have been planned and proposed by NEA in the framework of the existing contracts. It seems that these programs may be realized so far as JBIC and the ADB have no objections to its necessity. NEA also considers that the total number of personnel to be assigned for Kali Gandaki A hydropower station includes some staff to be deployed to other power stations after being well trained.

5.5.4 Power Generation Performance

The features of the major existing power plants are shown in Table 5.5.2. All power plants except Kulekhani I and Kulekhani II hydropower stations are run-of river type. Marsyangdi and Kaligandaki A hydropower stations are also operable as peak load period plants with at maximum 3 to 6 hours daily settling basin capacity. Only Kulekhani I hydropower station is a storage (reservoir) type with seasonal regulating capacity to supply the power for part of the peak loads in the Central Nepal Power System (CNPS), especially in the winter (dry season).

Kulekhani II utilizes the outflow from Kulekhani I so as to operate along with Kulekhani I as a peak load power plant.

The annual firm energy, average generated energy, peak power and plant factor of each power station for the latest 6 years are tabulated in Table 5.5.2.

5.5.5 Maintenance Works

The history of maintenance works at each major existing power station is shown in Table 5.5.3 and the present status of maintenance observations and measures in Table 5.5.4.

Ordinary inspection and maintenance of the plants (daily, weekly and monthly) are performed and recorded by maintenance staff stationed at the power stations as specified in the Operation and Maintenance Manual. Less frequent major inspections (annual and overhaul) were performed by the maintenance staff for Kulekhani I and Kulekhani II hydropower station in 1994 under the manufacture's supervision, including correcting equipment problems, as shown in Table 5.5.4.

Now, NEA has prepared a 2nd overhaul plan for Kulekhani I and Kulekhani II hydropower station to enable the routine maintenance work in 2004, in which disaster prevention works appear to have been included, with financial assistance from the foreign aid program.

In the case of Marsyangdi hydropower station, each turbine runner has been repaired every three years since 1992 due to heavy sand-erosion. However, overhaul of the generators has yet to be performed even though 13 years have passed since installation.

Kali Gandaki A hydropower station commenced commercial operation in April, 2002, and the organization and training program are recently established. It is expected that through the training program the operation and maintenance staff will be well trained in how to manage plans, working schedules and staffing, inspection, dismantling/assembling work, etc. (as mentioned in Section 5.5.3).

Present problems or troubles in Kaligandaki A hydropower station, as shown in Table 5.5.4, will be settled in the frameworks of the contracts.

5.5.6 Recommendation on Administration of Maintenance

At present, NEA has a large amount of manpower stationed at each plant for operation and maintenance. The number of staff is considerably larger (approx. 110~150 personnel) than usually assigned to plants of similar scale in developed countries (approx. 30~50 personnel except for labor for large-scale overhaul). This is mainly because NEA does not have a separate maintenance company to maintain the equipment of all the plants, as maintenance is required.

Now, NEA has more than 10 major hydropower stations. To increase efficiency and improve the economics of maintenance, and to reduce the number of staff in the plants, it would be desirable for NEA to establish a maintenance company within NEA itself. The company could be formed from a combination of well-trained expert power plant engineers and the skilled staff (level 2 to level 5) who currently work at and maintain all the major hydropower stations.

It is also recommended that an efficiency evaluation system such as that employed in Marsyangdi power station be adopted with reasonable salary and allowances, and that staff sometimes receive training programs for hydropower plants. The timing of staff movements also needs to be considered more carefully so as to keep excellent maintenance staff at the various power plants:

Regarding maintenance of civil works, a similar company may be appropriate. It would also be comprised of well-trained experts and engineers including civil engineering design along with expertise for maintenance of heavy equipment.

Twenty and fifteen years have passed since commissioning of the Kulekhani I and II hydropower station. As mentioned in the Section 5.5.5, both power stations are to overhaul. After commissioning of Kaligandaki A Hydropower Project, the energy is surplus during the rainy season for a few years. Taking advantage of this opportunity of surplus power, it is recommended that the overhaul at the both power station could be carried out by applying loan from donor countries. Occasions of the trouble of the generating equipment can be decreased by this overhaul. As a result, a series of the Kulekhani power stations including the Kulekhani III hydropower stations can be operated without any interruption and effectively utilize the water from the Kulekhani reservoir.

TABLES

Chapter 5

Table 5.1.1 Demand and supply of National Grid from Fiscal Year 1971

Fiscal Year	Sales				Self	Total		System		Total		Peak		System	Est,Load
	Nepal	Growth	Export	Total	Consump	Energy Consumption		Losses		Supplied		Load		Load Factor	Shedding
	(GWh)	Rate %	(GWh)	(GWh)	(GWh)	(GWh)	Growth %	(GWh)	Rate %	(GWh)	Growth %	(MW)	Growth %	%	(GWh)
	1	2	3	4		6	7	8	9	10	11	12	13	14	15
				1+3	5	4+5		10-4	8*100/10					10/(12*8.760)	
1971	39.2			39.2	1.7	40.9		20.8	34.7	60.0		15.5		44.2	
1972	49.8	27.0		49.8	1.8	51.6	26.2	25.1	33.5	74.9	24.8	21.1	36.1	40.5	
1973	59.9	20.3	2.3	62.2	1.8	64.0	24.0	30.2	32.7	92.4	23.4	24.6	16.6	42.9	
1974	71.4	19.2	3.7	75.1	1.8	76.9	20.2	35.7	32.2	110.8	19.9	29.8	21.1	42.4	
1975	84.9	18.9	4.6	89.5	2.3	91.8	19.4	39.3	30.5	128.8	16.2	32.0	7.4	45.9	
1976	104.6	23.2	5.9	110.5	2.3	112.8	22.9	42.4	27.7	152.9	18.7	35.0	9.4	49.9	
1977	116.2	11.1	6.1	122.3	2.5	124.8	10.6	45.1	26.9	167.4	9.5	37.0	5.7	51.6	
1978	126.5	8.9	6.0	132.5	3.0	135.5	8.6	53.7	28.8	186.2	11.2	41.0	10.8	51.8	
1979	143.5	13.4	6.2	149.7	4.2	153.9	13.6	61.7	29.2	211.4	13.5	45.0	9.8	53.6	
1980	156.5	9.1	5.2	161.7	4.5	166.2	8.0	65.0	28.7	226.7	7.2	47.0	4.4	55.1	
1981	156.6	0.1	3.8	160.4	4.5	164.9	-0.8	66.6	29.3	227.0	0.1	50.0	6.4	51.8	
1982	175.5	12.1	7.4	182.9	4.8	187.7	13.8	82.3	31.0	265.2	16.8	56.6	13.2	53.5	
1983	220.8	25.8	8.9	229.7	5.0	234.7	25.0	111.6	32.7	341.3	28.7	66.0	16.6	59.0	
1984	235.7	6.7	10.3	246.0	5.5	251.5	7.2	122.6	33.3	368.6	8.0	76.0	15.2	55.4	
1985	288.0	22.2	10.6	298.6	5.8	304.4	21.0	106.0	26.2	404.6	9.8	79.7	4.9	58.0	
1986	323.0	12.2	21.5	344.5	6.1	350.6	15.2	144.0	29.5	488.5	20.7	110.0	38.0	50.7	
1987	381.0	18.0	20.5	401.5	8.8	410.3	17.0	169.5	29.7	571.0	16.9	126.0	14.5	51.7	
1988	449.1	17.9	16.1	465.2	7.3	472.5	15.2	163.3	26.0	628.5	10.1	141.0	11.9	50.9	
1989	478.5	6.5	17.6	496.1	8.8	504.9	6.9	176.2	26.2	672.3	7.0	150.0	6.4	51.2	
1990	524.7	9.7	23.3	548.0	7.5	555.5	10.0	225.8	29.2	773.8	15.1	176.0	17.3	50.2	
1991	588.8	12.2	80.6	669.4	6.0	675.4	21.6	236.9	26.1	906.3	17.1	204.0	15.9	50.7	
1992	651.9	10.7	85.4	737.3	4.5	741.8	9.8	243.8	24.8	981.1	8.3	216.0	5.9	51.9	17
1993	663.8	1.8	46.1	709.9	3.0	712.9	-3.9	253.4	26.3	963.3	-1.8	214.0	-0.9	51.4	65
1994	706.0	6.4	50.5	756.5	2.1	758.6	6.4	274.4	26.6	1030.9	7.0	231.0	7.9	50.9	55
1995	785.0	11.2	39.5	824.5	2.9	827.4	9.1	293.0	26.2	1117.5	8.4	244.0	5.6	52.3	21.3
1996	850.0	8.3	87.0	937.0	3.9	940.9	13.7	325.0	25.8	1262.0	12.9	275.0	12.7	52.4	0
1997	910.0	7.1	100.0	1010.0	16.8	1026.8	9.1	359.0	26.2	1369.0	8.5	300.0	9.1	52.1	11.5
1998	984.0	8.1	67.4	1051.4	19.9	1071.3	4.3	321.8	*23.4*	1373.2	0.3	317.0	5.7	49.4	25.97
1999	1049.4	6.6	64.2	1113.6	23.6	1137.2	6.1	361.4	*24.5*	1475.0	7.4	326.0	2.8	51.6	24.08
2000	1174.3	11.9	95.0	1269.3	25.5	1294.8	13.9	432.2	*25.4*	1701.5	15.4	352.0	8.0	55.2	18.26
2001	1281.1	9.1	126.0	1407.1	29.8	1436.9	11.0	461.3	*24.7*	1868.4	9.8	391.0	11.1	54.5	20.47
Average Annual Growth Rates (%)															
1981 to 2001		11.1					11.4				11.1		10.8		
1991 to 2001		8.1					7.8				7.5		6.7		
1996 to 2001		8.6					8.8				8.2		7.3		

** Losses Incluces self consumption also*

Table 5.1.2 Power Tariff Rates

(Effective from the Billing of September 17, 2001)

1: DOMESTIC CONSUMERS			
A. Minimum Monthly Charge:	***Minimum Charge***	***Exempt***	
METER CAPACITY	***(NRs.)***	***(kWh)***	
Upto 5 ampere	80.00	20.00	
15 ampere	299.00	50.00	
30 ampere	664.00	100.00	
60 ampere	1394.00	200.00	
Three phase supply	3244.00	400.00	
B. Energy charge:			
Upto 20 units	Rs. 4.00 per unit		
21 - 250 units	Rs. 7.30 per unit		
Over 250 units	Rs. 9.90 per unit		
2: TEMPLES			
Energy charge	Rs. 5.10	per unit	
3: STREET LIGHTS			
A. With Meter	Rs. 5.10	per unit	
B. Without Meter	Rs. 1860.00	per kVA	
4: TEMPORARY SUPPLY			
Energy Charge	Rs. 13.50	per unit	
5: COMMUNITY WHOLESALE CONSUMER			
Energy Charge	Rs. 3.50	per unit	
6: INDUSTRIAL			
	Monthly Demand Charge	*Energy Charge*	
	(Rs./kVA)	*(Rs./unit)*	
A. Low Voltage (400/230 volt)			
a) Rural and Cottage	45.00	5.45	
b) Small Industry	90.00	6.60	
B. Medium voltage (11kV)	190.00	5.90	
C. Medium voltage (33kV)	190.00	5.80	
D. High voltage (66 kV and above)	175.00	4.60	
7: COMMERCIAL			
A. Low voltage (400/230 volt)	225.00	7.70	
B. Medium voltage (11 kV)	216.00	7.60	
C. Medium voltage (33 kV)	216.00	7.40	
8: NON-COMMERCIAL			
A. Low voltage (400/230 volt)	160.00	8.25	
B. Medium voltage (11 kV)	180.00	7.90	
C. Medium voltage (33 kV)	180.00	7.80	
9: IRRIGATION			
A. Low voltage (400/230 volt)	-	3.60	
B. Medium voltage (11 kV)	47.00	3.50	
C. Medium voltage (33 kV)	47.00	3.45	
10: WATER SUPPLY			
A. Low voltage (400/230 volt)	140.00	4.30	
B. Medium voltage (11 kV)	150.00	4.15	
C. Medium voltage (33 kV)	150.00	4.00	
11: TRANSPORT			
A. Medium voltage (11 kV)	180.00	4.30	
B. Medium voltage (33 kV)	180.00	4.25	

TIME OF DAY (TOD) TARIFF RATES

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

Note : a) If demand meter reads kilowatts (kW) then kVA = kW/0.8
b) 10% discount in the total bill amount will be given to the HMG/N approved Industrial District
c) 25% discount in the total bill amount will be given to HMG Hospitals and Health Center (except residential complex)

Source: Nepal Electricity Authority (FY2000/01) A Year in Review

Table 5.1.3 Record of Power Tariff Revision

CATEGORY A : DOMESTIC CONSUMERS									
		Effective March 14, 1993		**Effective May 14, 1996**		**Effective November 17, 1999**		**Effective August 17, 2001**	
A.1	Minimum Monthly Charges:	**Minimum Charge**	**Exempt**	**Minimum Charge**	**Exempt**	**Minimum Charge**	**Exempt**	**Minimum Charge**	**Exempt**
	METER CAPACITY	(NRs.)	(KWh)	(NRs.)	(KWh)	(NRs.)	(KWh)	(NRs.)	(KWh)
	Upto 5 ampere	50.00	20	60.00	20	78.00	20	80.00	20
	6 - 30 ampere	130.00	40	160.00	40	208.00	40		
	15 ampere							299.00	50
	30 ampere							664.00	100
	31 - 60 ampere	290.00	80	360.00	80	468.00	80		
	60 ampere							1394.00	200
	Three phase supply	770.00	200	960.00	200	1248.00	200	3244.00	400
A.2	Energy charge:								
	Upto 20 units	Rs.2.50 per unit		Rs.3.00 per unit		Rs.3.90 per unit		Rs.4.00 per unit	
	21 - 250 units	Rs.4.00 per unit		Rs.5.00 per unit		Rs.6.50 per unit		Rs.7.30 per unit	
	Over 251 units	Rs.6.20 per unit		Rs.7.75 per unit		Rs.9.25 per unit		Rs.9.90 per unit	
CATEGORY B : INDUSTRIAL									
	Sub-category	Demand fee	Energy charge	Demand fee	Energy charge	Demand fee	Energy charge	Demand fee	Energy charge
		(Rs. / KVA)	(Rs. / Unit)	(Rs. / KVA)	(Rs. / Unit)	(Rs. / KVA)	(Rs. / Unit)	(Rs. / KVA)	(Rs. / Unit)
B.1	Low voltage (400/230 volt)								
	Rural and cottage	16.00	3.30	20.00	4.00	25.00	5.00	45.00	5.45
	Small Industry	32.00	4.00	40.00	4.90	50.00	6.10	90.00	6.60
B.2	Medium voltage (11 & 33 KV)	72.00	3.50	84.00	4.40	105.00	5.50		
	Medium voltage (11KV)							190.00	5.90
	Medium voltage (33KV)							190.00	5.80
B.3	High voltage (>66 KV)	64.00	2.80	78.00	3.50	95.00	4.35	175.00	4.60
CATEGORY C : COMMERCIAL									
C.1	Low voltage	88.00	4.70	100.00	5.80	125.00	7.25	225.00	7.70
C.2	Medium voltage	80.00	4.60	96.00	5.70	120.00	7.10		
	Medium voltage (11 KV)							216.00	7.60
	Medium voltage (33 KV)							216.00	7.40
CATEGORY D : NON-OMMERCIAL									
D.1	Low voltage	56.00	4.70	68.00	5.80	88.00	7.50	160.00	8.25
D.2	Medium voltage	64.00	4.60	76.00	5.70	98.00	7.40		
	Medium voltage (11 KV)							180.00	7.90
	Medium voltage (33 KV)							180.00	7.80

Note: If demand meter reads kilowatts (KW) : KVA = KW/0.8. A reduction of 10% in the designated Industrial Districts for 2001.

1. 10% discount in the total bill amount will be given for the Industrial Customs in HMG/N approved Industrial Districts.
2. 25% discount in the total bill amount will be given for HMG Hospitals and Health Centre (except residential complex).

Compiled by Research and Information Division of FNCCI from Nepal Electricity Authority.

Source: Nepal and the world statistical profile 2001

Table 5.2.1 Existing Generation Facilities of National Grid

as of July 2002

No	Plant Name	Plant Type	Year in Service	Installed Capacity (MW)	Peaking Capacity (MW)	Average Energy (GWh/yr)
	Hydro Power Plant					
1	Trisuli	ROR	1967(96)	24.5	19.0	277
2	Devighat	ROR	1984(96)	14.1	13.0	*
3	Sunkoshi	ROR	1972	10.0	6.0	66
4	Gandak	ROR	1979	15.0	10.0	53
5	Kulekhani I	ST	1982	60.0	60.0	169
6	Kulekhani II	ST	1986	32.0	32.0	85
7	Marshangdi	PROR	1989	69.0	69.0	462
8	Andhi Khola	ROR	1991	5.1	4.0	38
9	Jhimruk	ROR	1994	12.3	7.0	81
10	Ilam (Puwa Khola)	ROR	1999	6.2	2.0	41
11	Khimti Khola	ROR	2000	60.0	34.0	353
12	Upper Bhote Koshi	ROR	2000	36.0	25.0	250
13	Modi Khola	ROR	2000	14.0	6.0	87
14	Kali Gandaki-A	PROR	2002	144.0	144.0	791
15	Small Hydros	ROR	-	5.0	4.0	26
	Total of Hydro Power Plant			507.2	435.0	2,779
	Thermal Power Plant					
15	Biratnagar	DG		1.0	1.0	
16	Hetauda	DG	1983	9.0	8.0	
17	Marsyangdi	DG	1989	2.3	1.0	
18	Duhabi	MF	1992	39.0	22.0	
	Total of Thermal Power Plant			51.3	32.0	
	Total of Existing Power Plant			558.5	467.0	2,779

Notes

1) * : Average energy of Devighat is included in Trisuli

2) Peaking Capacity means the available capacity at peak time in dry season.

Abbreviation

ROR: Run-of-River

PROR: Peaking Run-of-River; plants which have ability of daily regulation

ST: Storage; plants which have ability of annual regulation

DG: Diesel Generator

MF: Multi-fuel

Source: NEA

Table 5.2.2 Licenses Given for Power Business and Survey

SN	Project Name	District	VDC/Municipality	Capacity (MW)	Month / Year of Licence	Promoter's Name
A.	**Licences for Electricity Generation, Transmission and Distribution Projects**					
1.	Andhi Khola	Syangja	Jagratadevi	5.1	Apr 1995	Butwal Power Company
2.	Jhimruk Khola	Pyuthan	Ramdi	12.0	Jan 1996	Butwal Power Company
3.	Janakpur Cigarette Factry	Janakpur	Janakpur	1.9	Jan 2001	Janakpur Cigrette Factory
B.	**Licences for Electricity Generation**					
1.	Upper Bhote Koshi	Sindhupalchowk	Tatopani	36.0	Nov 1996	Bhote Koshi Power Company
2.	Chilime	Rasuwa	Chilime	20.0	Aug 1997	Chilime Hydropower Co. Pvt. Ltd.
3.	Indrawati -III	Sindhupalchowk	Jyamire	5.0	Mar 1998	National Hydropower Company Pvt. Ltd.
4.	Khimti - I	Ramechhap	Sahare, Shama	60.0	Feb 1995	Himal Power Limited
5.	Piluwa Khola	Sankhuwasabha	Chainpur	3.0	Aug 2000	Arun Valley Hydropower Development Co. Pvt. Ltd.
C.	**Licence for Survey**					
1.	Seti - 3	Sankhuwasabha	Chainpur	107.0	Aug 1998	SMEC Development PtY Ltd.
2.	Siswa Khola	Taplejung	Tawethok	53.0	Jun 1998	East Consult Pvt. Ltd.
3.	West Seti	Doti	Doti	750.0	Sep 1994	SMEC Development PtY Ltd.
4.	Daram Khola	Baglung	Baglung	3.0	Jul 1996	The Gorkha Engineering and Services Int'l Pvt. Ltd.
5.	Bayu Shakti	--	--	100.0	Jun 1995	AMIYAM Int'l Pvt. Ltd.
6.	Nyagdi	Lamjung	--	2.8	Feb 1999	Lamjung Bidyut Bikas Company
7.	Indrawati -III	Sindhupalchowk	Jyamire	4.3	Feb 1995	National Hydropower Co. Ltd.
8.	Kali Gandaki	Nawalparasi	Kohthar	660.0	Nov 1998	SMEC Development PtY Ltd.
9.	Middle Bhote Koshi	Sindhupalchock	--	120.0	Jun 1998	Panda and Harya
10.	Middle Marsyangdi	Lamjung	Badipur	42.0	Apr 1995	Algonqueen Power Corporates Inc.
11.	Tamakoshi - 3	Dolakha	--	123.0	Apr 1996	Indsheel
12.	Piluwa Khola	Sankhuwasabha	--	2.4	Apr 1999	Arun Valley Hydropower Development Co. Pvt. Ltd.
13.	Chameliyagad	Darchula	Shikhar	30.0	Jul 1999	NEA and NIDC
14.	Idrawati I	Sindhupalchowk	--	5.1	Feb 1995	National Hydropower Company Ltd.
15.	Rolwaling	Dolakha	--	25.0	Feb 1999	Dr. Christihe Ae Uller
16.	Upper Modi	Kaski	Dansingh	20.0	May 1999	Jaitech
17.	Uper Marsyangdi	Lamjung	Daman Dada	43.0	Apr 1995	Mathiwas International
18.	Upper Marsyangdi 'A'	Lamjung	Baman Dada	43.0	Apr 1999	Sagarmatha Power Co.
19.	Badigaad	Gulmi	Rimuwa	5.2	May 2000	Butwal Power Company
20.	Naugadgaad	Darchula	Dithala	1.8	Jan 1999	Malikarjun Power Co. Pvt. Ltd.
21.	Lower Modi Khola	Parbat	Tilahar	20.0	Jul 1998	Manang Trade Links
22.	Thulo Dhunga	Solukhumbu	--	24.7	Jun 1998	Thulo Dhunga Jal Bidyut Co.
23.	Khudi Khola	Lamjung	--	1.5	Sep 1999	Khudi Hydropower Ltd.
24.	Madi River I	Kaski	Lekhanth	10.0	Dec 1998	Annapurna Group Pvt. Ltd.
25.	Trishuli Khola	Rasuwa	Dhunche	3.0	Mar 1998	Annapurna Group Pvt. Ltd.
26.	Khoranga Khola	Terhathum	Tamfula	2.0	Aug 1999	Khoranga Khola Hydropower Dev. Co., Pvt. Ltd.
27.	Belkhu Khola	Dhading	--	2.6	Feb 2000	Manu Trade Links
28.	Upper Myagdi	Myagdi	--	6.0	Mar 2000	Millennium Hydropower Company Pvt. Ltd.
29.	Dordi Khola	Lumjung	Nauthar	8.5	May 2000	Alliance Power Nepal Pvt. Ltd.
30.	Melung Khola	Rasuwa	Haku	4.0	Apr 2000	Molnia Powers Pvt. Ltd.
31.	Liping Khola	Sindhulpalchowk	Tatopani	1.5	May 2000	Mansarovar Powers Pvt. Ltd.
32.	Balephi Khola	Sindhupalchowk	--	15.0	May 2000	Water Resource Consult
33.	Langtang	Rasuwa	Syaphru	5.0	Apr 2000	Kantipur Hydropower Pvt. Ltd.
34.	Sunkoshi Small	Sindhupalchowk	Chikati	1.2	Apr 2000	Sanima Hydropower Pvt. Ltd.
35.	Hew Khola	Panchthar	Phidim	4.0	Aug 2000	Hewa River Power Development Co. Pvt. Ltd.
36.	Upper Madi	Kaski	Nagargun	19.2	Aug 2000	Madi Power Pvt. Ltd.
37.	Thopal Khola	Dhading	Kumpur	1.1	Oct 2000	Neha Engineering and Consultancy Pvt. Ltd.
38.	Lower Myagdi Khola	--	Tatopani	25.5	Jan 2001	Nect Centre Pvt. Ltd. Him Consult
39.	Rosi Khola - 2	--	Gaganpani	8.0	Jan 2001	Molnea Power Pvt. Ltd.
40.	Sunaiyagaad	Baitadi	Sakar	4.6	Aug 2000	Jayant Chand
41.	Middle Modi	Kaski	Lumle	13.0	Nov 2000	Continental Power Development Pvt. Ltd.
42.	Tandi Khola	Nuwakot	Samundrataar	4.2	Aug 2000	EXEM International Pvt. Ltd.
43.	Khimti - 2	Ramechhap	Dolkha	25.0	Jun 1994	Himal Power Limited
44.	Khimti - 2	Remechhap	Dolkha	27.0	Nov 2000	Statecraft International
45.	Mylup Khola	Ilam	Danabari	60.0	Dec 2000	Sanima Hydropower Pvt. Ltd.
46.	Upper Trishuli - 2	Rasuwa	Dhunche	300.0	Nov 2000	Pacific Hydro
47.	Likhu - 4	Okhaldhunga	Pokli	51.0	Nov 2000	Pacific Hydro
48.	Lower Arun	Sankhuwasabha	Mulpani	308.0	Nov 2000	Was Power
49.	Upper Marsyandgi	Lumjung	Dhermu	121.0	Dec 2000	Bha Tech
50.	Molung Khola	--	Lamidanda	2.5	Dec 2000	Eastern Power Co., Pvt. Ltd.
51.	Ridi Khola	--	Ruru	1.6	Dec 2000	Ridi Hydropower Development Co. Pvt. Ltd.
52.	Maya Khola	Sankhuwasabha	Mamling	3.0	Jan 2001	Makalu Hydropower Development Co., Pvt. Ltd.
53.	Upper Seti Khola I	Kaski	Puranchaur	3.0	Jan 2001	Seti Hydropower Development Co. Pvt. Ltd.
54.	Upper Seti Khola II	Kaski	Puranchaur	5.0	Jan 2001	Kaski Hydropower Development Co. Pvt. Ltd.
55.	Madi Khola	Kaski	Rivan	3.0	Feb 2001	Gandaki Hydropower Development Co. Pvt. Ltd.
56.	Lower Indrawati	Sindhupalchowk	Duwachaur	4.5	Feb 2001	Nation Hydropower Co. Pvt. Ltd.
57.	Bijaypur Khola I	Kaski	Pokhara	2.0	Feb 2001	Bhagwati Hydropower Co. Pvt. Ltd.
58.	Bijaypur Khola II	Kaski	Pokhara	2.0	Feb 2001	Bindhabasini Hydropower Co. Pvt. Ltd.
59.	Kotre Khola	Kaski	Lekhanth	2.0	Feb 2001	Machapuchhre Hydropower Co., Pvt. Ltd.
60.	Manahari Khola	Makawanpur	Bharta	4.0	Feb 2001	Mount Hydropower Co. Pvt. Ltd.
61.	Rigdi Khola	Chitwan	Kabilas	1.5	Mar 2001	Niltara W&E Pvt. Ltd.
62.	Upper Karnali	Achham	Syalghat	300.0	Mar 2001	Elsee NEA Hydro Electric

Source : Nepal and The World A Statistical Profile 2001

Table 5.3.1 Domestic Load Forecast

FY	New Consumers	Total Consumers	Domestic Load (GWh) *)	Electrification Ratio (%)
2001	69,993	713,307	524.1	16%
2002	127,093	840,400	576.5	19%
2003	100,000	940,400	637.1	21%
2004	100,000	1,040,400	705.7	23%
2005	100,000	1,140,400	776.6	24%
2006	100,000	1,240,400	851.2	26%
2007	100,000	1,340,400	929.9	27%
2008	100,000	1,440,400	1,012.7	29%
2009	100,000	1,540,400	1,094.8	30%
2010	100,000	1,640,400	1,179.6	31%
2011	100,000	1,740,400	1,268.7	33%
2012	100,000	1,840,400	1,362.1	34%
2013	100,000	1,940,400	1,460.1	35%
2014	100,000	2,040,400	1,563.0	36%
2015	100,000	2,140,400	1,670.9	37%
2016	100,000	2,240,400	1,784.2	38%
2017	100,000	2,340,400	1,903.1	39%
2018	100,000	2,440,400	2,027.8	40%
2019	100,000	2,540,400	2,158.7	40%
2020	100,000	2,640,400	2,296.1	41%

Average annual growth: *8.1%*

**) 2001 & 2002 = actual*

Assumptions:

No. of new consumers	*Ceiling in number of new connections p.a.:*		*100,000*
	2001-2003	*2004 - 2008*	*2009 - 2020*
Average kWh pr. new connection	*350*	*325*	*300*
GDP / capita growth (%)	*3.8*	*3.8*	*3.8*
Income elasticity	*1.4*	*1.4*	*1.3*
Price elasticity	*-0.4*	*-0.4*	*-0.4*
Tariff increase (%)	*4.5*	*0*	*0*

Average household size: 5.4 persons

(All growth rates in real terms)

Table 5.3.2 Industrial Load Forecast

FY	Normal Industrial Load (GWh) *)	Surkhet	Arghakhach	Salyan	Total large Industrial Load (GWh)	Total Industrial Load (GWh)
2001	526.3	0.0	0.0	0.0	0.0	526.3
2002	597.0	0.0	0.0	0.0	0.0	597.0
2003	640.8	0.0	4.6	0.0	4.6	645.4
2004	696.9	8.1	18.5	4.6	31.2	728.1
2005	758.0	32.4	32.4	18.5	83.3	841.2
2006	824.4	56.7	46.3	32.4	135.3	959.6
2007	896.6	80.9	46.3	46.3	173.4	1,070.0
2008	975.1	80.9	46.3	46.3	173.4	1,148.6
2009	1,053.4	80.9	46.3	46.3	173.4	1,226.9
2010	1,138.0	80.9	46.3	46.3	173.4	1,311.5
2011	1,229.4	80.9	46.3	46.3	173.4	1,402.8
2012	1,328.1	80.9	46.3	46.3	173.4	1,501.6
2013	1,434.8	80.9	46.3	46.3	173.4	1,608.2
2014	1,550.0	80.9	46.3	46.3	173.4	1,723.4
2015	1,674.4	80.9	46.3	46.3	173.4	1,847.9
2016	1,808.9	80.9	46.3	46.3	173.4	1,982.3
2017	1,954.1	80.9	46.3	46.3	173.4	2,127.6
2018	2,111.0	80.9	46.3	46.3	173.4	2,284.5
2019	2,280.6	80.9	46.3	46.3	173.4	2,454.0
2020	2,463.7	80.9	46.3	46.3	173.4	2,637.1

Average annual growth: *8.9%*

**) 2001 & 2002 = actual*

Assumptions:	*2001-2003*	*2004 - 2008*	*2009 - 2020*
Ind.GDP Growth (%)	*7.3*	*7.3*	*7.3*
Elasticity of GDP	*1.2*	*1.2*	*1.1*
Price elasticity	*-0.3*	*-0.3*	*-0.3*
Tariff Increase (%)	*4.5*	*0*	*0*

(All growth rates in real terms)

Table 5.3.3 Commercial Load Forecast

FY	Commercial Load GWh *)
2001	95.2
2002	95.5
2003	101.8
2004	110.4
2005	119.7
2006	129.8
2007	140.8
2008	152.7
2009	164.6
2010	177.4
2011	191.2
2012	206.2
2013	222.2
2014	239.6
2015	258.3
2016	278.4
2017	300.1
2018	323.5
2019	348.8
2020	376.0

Average annual growth: *7.5%*

**) 2001 & 2002 = actual*

Assumptions:	*2001-2003*	*2004 - 2008*	*2009 - 2020*
GDP Growth (%)	*6.5*	*6.5*	*6.5*
Elasticity of GDP	*1.3*	*1.3*	*1.2*
Price elasticity	*-0.4*	*-0.4*	*-0.4*
Tariff Increase (%)	*4.5*	*0*	*0*

Table 5.3.4 Other Load Forecast

FY	Other Load GWh *)
2001	120.7
2002	131.4
2003	140.1
2004	149.3
2005	159.2
2006	169.7
2007	180.9
2008	192.8
2009	204.5
2010	216.9
2011	230.0
2012	243.9
2013	258.6
2014	274.3
2015	290.9
2016	308.5
2017	327.1
2018	346.9
2019	367.9
2020	390.2

Average annual growth : *6.4%*

**) 2001 & 2002 = actual*

Assumptions:	*2001-2003*	*2004 - 2008*	*2009 - 2020*
GDP Growth (%)	*5.5*	*5.5*	*5.5*
Elasticity of GDP	*1.2*	*1.2*	*1.1*
Price elasticity	*0*	*0*	*0*
Tariff Increase (%)	*4.5*	*0*	*0*

(All growth rates in real terms)

Table 5.3.5 Irrigation Load forecast

FY	Irrigation Load GWh *)	New Load GWh	Total Irr Load GWh
2001	28.9		28.9
2002	31.2		31.2
2003	31.6	4.2	35.9
2004	36.3	4.2	40.5
2005	41.1	4.2	45.3
2006	45.9	4.2	50.1
2007	50.7	4.2	55.0
2008	55.7	4.2	59.9
2009	60.7	4.2	64.9
2010	65.8	4.2	70.0
2011	70.9	4.2	75.2
2012	76.2	4.2	80.4
2013	81.5	4.2	85.7
2014	86.8	4.2	91.1
2015	92.3	4.2	96.5
2016	97.8	4.2	102.1
2017	103.4	4.2	107.7
2018	109.1	4.2	113.3
2019	114.9	4.2	119.1
2020	120.7	4.2	124.9

Average annual growth: *8.0%*

**) 2001 & 2002 = actual*

Average annual growth rate for existing load (1991-99) *1.4%*

Table 5.3.6 Export Load Forecast

FY	Export Load GWh *)
2001	128.4
2002	142.9
2003	154.3
2004	166.7
2005	180.0
2006	194.4
2007	210.0
2008	226.8
2009	244.9
2010	264.5
2011	285.7
2012	308.5
2013	333.2
2014	359.8
2015	388.6
2016	419.7
2017	453.3
2018	489.6
2019	528.7
2020	571.0

Average annual growth: *8.2%*

**) 2001 & 2002 = actual*

Table 5.3.7 Energy and Peak Demand Forecasts (Base Case)

FY	Energy Demand (GWh) Domestic	Industrial	Commer-cial	Irrigation	Other	Total Nepal	Export	Total	Growth (%)	Losses (%)	Total Requirement	Load Factor (%)	Peak Load (MW)
2001	524.1	526.3	95.2	28.9	120.7	1,295.2	128.4	1,423.6	-	*23.8*	1,868.4	*54.5*	391.0
2002	576.5	597.0	95.5	31.2	131.4	1,431.6	142.9	1,574.5	*10.6*	*24.6*	2,087.6	*55.9*	426.0
2003	637.1	645.4	101.8	35.9	140.1	1,560.2	154.3	1,714.5	*8.9*	*22.0*	2,198.1	*50.0*	501.9
2004	705.7	728.1	110.4	40.5	149.3	1,734.0	166.7	1,900.7	*10.9*	*21.0*	2,406.0	*50.0*	549.3
2005	776.6	841.2	119.7	45.3	159.2	1,941.9	180.0	2,121.9	*11.6*	*20.0*	2,652.4	*50.0*	605.6
2006	851.2	959.6	129.8	50.1	169.7	2,160.5	194.4	2,354.9	*11.0*	*19.0*	2,907.3	*50.0*	663.8
2007	929.9	1,070.0	140.8	55.0	180.9	2,376.5	210.0	2,586.5	*9.8*	*18.0*	3,154.3	*50.0*	720.2
2008	1,012.7	1,148.6	152.7	59.9	192.8	2,566.7	226.8	2,793.5	*8.0*	*18.0*	3,406.7	*50.0*	777.8
2009	1,094.8	1,226.9	164.6	64.9	204.5	2,755.7	244.9	3,000.6	*7.4*	*18.0*	3,659.2	*50.0*	835.4
2010	1,179.6	1,311.5	177.4	70.0	216.9	2,955.4	264.5	3,219.9	*7.3*	*18.0*	3,926.7	*50.0*	896.5
2011	1,268.7	1,402.8	191.2	75.2	230.0	3,167.9	285.7	3,453.5	*7.3*	*18.0*	4,211.6	*50.0*	961.6
2012	1,362.1	1,501.6	206.2	80.4	243.9	3,394.1	308.5	3,702.6	*7.2*	*18.0*	4,515.3	*50.0*	1,030.9
2013	1,460.1	1,608.2	222.2	85.7	258.6	3,634.9	333.2	3,968.1	*7.2*	*18.0*	4,839.1	*50.0*	1,104.8
2014	1,563.0	1,723.4	239.6	91.1	274.3	3,891.3	359.8	4,251.2	*7.1*	*18.0*	5,184.3	*50.0*	1,183.6
2015	1,670.9	1,847.9	258.3	96.5	290.9	4,164.5	388.6	4,553.1	*7.1*	*18.0*	5,552.6	*50.0*	1,267.7
2016	1,784.2	1,982.3	278.4	102.1	308.5	4,455.5	419.7	4,875.2	*7.1*	*18.0*	5,945.4	*50.0*	1,357.4
2017	1,903.1	2,127.6	300.1	107.7	327.1	4,765.6	453.3	5,218.9	*7.0*	*18.0*	6,364.5	*50.0*	1,453.1
2018	2,027.8	2,284.5	323.5	113.3	346.9	5,096.1	489.6	5,585.7	*7.0*	*18.0*	6,811.8	*50.0*	1,555.2
2019	2,158.7	2,454.0	348.8	119.1	367.9	5,448.6	528.7	5,977.3	*7.0*	*18.0*	7,289.4	*50.0*	1,664.2
2020	2,296.1	2,637.1	376.0	124.9	390.2	5,824.4	571.0	6,395.4	*7.0*	*18.0*	7,799.3	*50.0*	1,780.7
I	*8.1%*	*8.9%*	*7.5%*	*8.0%*	*6.4%*	*8.2%*		*8.2%*			*7.8%*		*8.3%*
II	*9.4%*	*10.7%*	*7.2%*	*10.3%*	*6.7%*	*9.6%*		*9.5%*			*8.6%*		*9.7%*
III	*6.9%*	*7.2%*	*7.8%*	*6.0%*	*6.1%*	*7.0%*		*7.1%*			*7.1%*		*7.1%*

I *Average annual growth over forecast period 2001 to 2020*

II *Average annual growth for years 2001 to 2010*

III *Average annual growth for years 20 10 to 20 2 0*

Notes: *2001 & 2002 figures are actuals corrected for load shedding.*

Losses: targeted to reach 18% in stages through loss reductions, part of which are converted to sales.

Load factor: constant at 50%

Table 5.3.8 Energy Balance (with Kulekhani III)

with Kulekhani 3 in 2007

No	Plant Name	Plant Type	Year in Service FY	Installed Capacity (MW)	Average Energy (GWh/yr)	FY 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Trisuli	ROR	1967(96)	24.5	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0
2	Devighat	ROR	1984(96)	14.1	*																				
3	Sunkoshi	ROR	1972	10.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
4	Gandak	ROR	1979	15.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0
5	Kulekhani I	ST	1982	60.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
6	Kulekhani II	ST	1986	32.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
7	Marshangdi	PROR	1989	69.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0
8	Andhi Khola	ROR	1991	5.1	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
9	Jhimruk	ROR	1994	12.3	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
10	Ilam (Puwa Khola)	ROR	1999	6.2	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0
11	Khimti Khola	ROR	2000	60.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0
12	Upper Bhote Koshi	ROR	2000	36.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
13	Modi Khola	ROR	2000	14.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0
14	Small Hydros	ROR	-	5.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
15	Biratnagar	DG		1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Hetauda	DG	1983	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Marsyangdi	DG	1989	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Duhabi	MF	1992	39.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Kali Gandaki-A	PROR	2002	144.0	791.0			791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0
20	Syange	ROR	2002	0.1	1.0			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
21	Chilime	PROR	2003	20.0	101.0				101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
22	Indrawati	ROR	2003	7.5	37.0				37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
23	Daram Khola	PROR	2003	5.0	33.0				33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
24	Piluwa Khola	PROR	2003	3.0	18.0				18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
25	Chaku Khola	PROR	2003	0.9	7.0				7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
26	Pheme	PROR	2004	1.0	8.0					8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
27	Upper Modi	ROR	2004	14.0	89.6					89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6
28	Khudi	PROR	2004	3.5	25.0					25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
29	Mailung	PROR	2005	5.0	37.0						37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
30	Middle Marsyangdi	PROR	2005	70.0	393.0						393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0
31	Langtang	PROR	2007	10.0	78.0								78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0
32	Chameliya	PROR	2007	30.0	196.0								196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0
33	Kulekhani III	ST	2007	42.0	50.0								50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
34	Khimti-2	PROR	2007	27.0	157.0								157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0
35	Rahughat	ROR	2008	27.0	165.0									165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
36	Kabeli-A	ROR	2008	30.0	162.0									162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0
37	Upper Karnali-A	PROR	2009	300.0	2133.0										2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0
(a)	Total Generation			(GWh/Year)		1988	1988	2780	2976	3099	3529	3529	4010	4337	6470	6470	6470	6470	6470	6470	6470	6470	6470	6470	6470
(b1)	Forecasted Demand (Base Case)			(GWh/Year)		1868.4	2087.6	2198.1	2406	2652.4	2907.3	3154.3	3406.7	3659.2	3926.7	4211.6	4515.3	4839.1	5184.3	5552.6	5945.4	6364.5	6811.8	7289.4	7799.3
(c)	Balance (Generation－Demand)			(GWh/Year)		120	-100	582	570	446	621	374	603	677	2543	2258	1954	1630	1285	917	524	105	-342	-820	-1330
(b2)	Forecasted Demand (High Case)			(GWh/Year)		1868	2088	2224	2461	2741	3035	3326	3631	3939	4270	4627	5012	5427	5875	6359	6882	7447	8057	8717	9430
(b3)	Forecasted Demand (Low Case)			(GWh/Year)		1868	2088	2173	2352	2566	2785	2992	3197	3401	3614	3839	4075	4324	4587	4864	5157	5465	5791	6134	6497

Notes

1) * : Average energy of Devighat is included in Trisuli

2) New power stations supply their full annual energy from the following year of in service.

Abbreviation

- ROR: Run-of-River
- PROR: Peaking Run-of-River; plants which have ability of daily regulation
- ST: Storage; plants which have ability of annual regulation
- DG: Diesel Generator
- MF: Multi-fuel Diesel Generator

Table 5.3.9 Energy Balance (without Kulekhani III)

No	Plant Name	Plant Type	Year in Service FY	Installed Capacity (MW)	Average Energy (GWh/yr)	FY 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Trisuli	ROR	1967(96)	24.5	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0	277.0
2	Devighat	ROR	1984(96)	14.1	*																				
3	Sunkoshi	ROR	1972	10.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
4	Gandak	ROR	1979	15.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0
5	Kulekhani I	ST	1982	60.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0	169.0
6	Kulekhani II	ST	1986	32.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
7	Marshangdi	PROR	1989	69.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0	462.0
8	Andhi Khola	ROR	1991	5.1	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
9	Jhimruk	ROR	1994	12.3	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
10	Ilam (Puwa Khola)	ROR	1999	6.2	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0
11	Khimti Khola	ROR	2000	60.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0	353.0
12	Upper Bhote Koshi	ROR	2000	36.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
13	Modi Khola	ROR	2000	14.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0
14	Small Hydros	ROR	-	5.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
15	Biratnagar	DG		1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Hetauda	DG	1983	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Marsyangdi	DG	1989	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	Duhabi	MF	1992	39.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
19	Kali Gandaki-A	PROR	2002	144.0	791.0			791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0	791.0
20	Syange	ROR	2002	0.1	1.0			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
21	Chilime	PROR	2003	20.0	101.0				101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0	101.0
22	Indrawati	ROR	2003	7.5	37.0				37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
23	Daram Khola	PROR	2003	5.0	33.0				33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0	33.0
24	Piluwa Khola	PROR	2003	3.0	18.0				18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
25	Chaku Khola	PROR	2003	0.9	7.0				7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
26	Pheme	PROR	2004	1.0	8.0					8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
27	Upper Modi	ROR	2004	14.0	89.6					89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6
28	Khudi	PROR	2004	3.5	25.0					25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
29	Mailung	PROR	2005	5.0	37.0							37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
30	Middle Marsyangdi	PROR	2005	70.0	393.0						393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0	393.0
31	Langtang	PROR	2007	10.0	78.0								78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0	78.0
32	Chameliya	PROR	2007	30.0	196.0								196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0	196.0
33	Kulekhani III	ST	2007	42.0									0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Khimti-2	PROR	2007	27.0	157.0								157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0	157.0
35	Rahughat	ROR	2008	27.0	165.0									165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0	165.0
36	Kabeli-A	ROR	2008	30.0	162.0									162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0	162.0
37	Upper Karnali-A	PROR	2009	300.0	2133.0										2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0	2133.0
(a)	Total Generation			(GWh/Year)		1988	1988	2780	2976	3099	3529	3529	3960	4287	6420	6420	6420	6420	6420	6420	6420	6420	6420	6420	6420
(b1)	Forecasted Demand (Base Case)			(GWh/Year)		1868.4	2087.6	2198.1	2406	2652.4	2907.3	3154.3	3406.7	3659.2	3926.7	4211.6	4515.3	4839.1	5184.3	5552.6	5945.4	6364.5	6811.8	7289.4	7799.3
(c)	Balance (Generation－Demand)			(GWh/Year)		120	-100	582	570	446	621	374	553	627	2493	2208	1904	1580	1235	867	474	55	-392	-870	-1380
(b2)	Forecasted Demand (High Case)			(GWh/Year)		1868	2088	2224	2461	2741	3035	3326	3631	3939	4270	4627	5012	5427	5875	6359	6882	7447	8057	8717	9430
(b3)	Forecasted Demand (Low Case)			(GWh/Year)		1868	2088	2173	2352	2566	2785	2992	3197	3401	3614	3839	4075	4324	4587	4864	5157	5465	5791	6134	6497

Notes

1) * : Average energy of Devighat is included in Trisuli

2) New power stations supply their full annual energy from the following year of in service.

Abbreviation

ROR: Run-of-River

PROR: Peaking Run-of-River; plants which have ability of daily regulation

ST: Storage; plants which have ability of annual regulation

Table 5.3.10 Capacity Balance (with Kulekhani III)

with Kulekhani 3 in 2007

No	Plant Name	Plant Type	Year in Service FY	Installed Capacity (MW)	Peaking Capacity (MW)	FY 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Trisuli	ROR	1967(96)	24.5	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
2	Devighat	ROR	1984(96)	14.1	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
3	Sunkoshi	ROR	1972	10.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
4	Gandak	ROR	1979	15.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
5	Kulekhani I	ST	1982	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
6	Kulekhani II	ST	1986	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
7	Marshangdi	PROR	1989	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0
8	Andhi Khola	ROR	1991	5.1	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
9	Jhimruk	ROR	1994	12.3	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
10	Ilam (Puwa Khola)	ROR	1999	6.2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
11	Khimti Khola	ROR	2000	60.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
12	Upper Bhote Koshi	ROR	2000	36.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
13	Modi Khola	ROR	2000	14.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
14	Small Hydros	ROR	-	5.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
15	Biratnagar	DG		1.0	1.0	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Hetauda	DG	1983	9.0	8.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Marsyangdi	DG	1989	2.3	1.0	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0
18	Duhabi	MF	1992	39.0	22.0	21.5	22.0	19.5	19.5	19.5	19.5	19.5	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	0.0	0.0	0.0
19	Kali Gandaki-A	PROR	2002	144.0	144.0			144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0
20	Syange	ROR	2002	0.1	0.1			0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
21	Chilime	PROR	2003	20.0	20.0				20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
22	Indrawati	ROR	2003	7.5	3.0				3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
23	Daram Khola	PROR	2003	5.0	5.0				5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
24	Piluwa Khola	PROR	2003	3.0	2.0				2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
25	Chaku Khola	PROR	2003	0.9	0.9				0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
26	Pheme	PROR	2004	1.0	0.9					0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
27	Upper Modi	ROR	2004	14.0	8.0					8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
28	Khudi	PROR	2004	3.5	2.2					2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
29	Mailung	PROR	2005	5.0	4.3						4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
30	Middle Marsyangdi	PROR	2005	70.0	70.0						70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
31	Langtang	PROR	2007	10.0	10.0								10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
32	Chameliya	PROR	2007	30.0	30.0								30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
33	Kulekhani-3	ST	2007	42.0	42.0								42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
34	Khimti-2	PROR	2007	27.0	53.0 *								53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0
35	Rahughat	ROR	2008	27.0	6.0									6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
36	Kabeli-A	ROR	2008	30.0	15.0									15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
37	Upper Karnali-A	PROR	2009	300.0	300.0										300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
	Import from India				50/150	50	50	50	50	50	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
(a)	Total Peaking Capacity			(MW)		367	367	509	540	551	725	725	853	871	1171	1171	1171	1171	1171	1170	1170	1170	1157	1157	1157
(b1)	Forecasted Peak Load (Base Case)			(MW)		391	426	502	549	606	664	720	778	835	896	962	1031	1104.8	1183.6	1267.7	1357.4	1453.1	1555.2	1664.2	1780.7
(c)	Reserve Margin		(a) - (b1)	(MW)		-24	-59	7	-10	-55	61	5	76	36	275	210	140	66	-12	-97	-187	-283	-398	-507	-623
(d)	Ratio of Reserve Margin		(c) / (b1)	(%)		-6.1	-13.8	1.4	-1.7	-9.1	9.2	0.7	9.7	4.3	30.6	21.8	13.6	6.0	-1.1	-7.7	-13.8	-19.5	-25.6	-30.5	-35.0
(b2)	Forecasted Peak Load (High Case)			(MW)		391	426	508	562	626	693	759	829	899	975	1056	1144	1239	1341	1452	1571	1700	1839	1990	2153
(b3)	Forecasted Peak Load (Low Case)			(MW)		391	426	496	537	586	636	683	730	777	825	876	930	987	1047	1111	1177	1248	1322	1400	1483

Notes

1) * : Construction of Khimti-2 increases the peaking capacity of Khimti-1 to 60 MW

2) Power supply at annual peak time of each new power station starts from the following year of in service, respectively.

Abbreviation

- ROR: Run-of-River
- PROR: Peaking Run-of-River; plants which have ability of daily regulation
- ST: Storage; plants which have ability of annual regulation
- DG: Diesel Generator
- MF: Multi-fuel Diesel Generator

Table 5.3.11 Capacity Balance (without Kulekhani III)

No	Plant Name	Plant Type	Year in Service FY	Installed Capacity (MW)	Peaking Capacity (MW)	FY 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Trisuli	ROR	1967(96)	24.5	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
2	Devighat	ROR	1984(96)	14.1	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
3	Sunkoshi	ROR	1972	10.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
4	Gandak	ROR	1979	15.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
5	Kulekhani I	ST	1982	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
6	Kulekhani II	ST	1986	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
7	Marshangdi	PROR	1989	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0	69.0
8	Andhi Khola	ROR	1991	5.1	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
9	Jhimruk	ROR	1994	12.3	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
10	Ilam (Puwa Khola)	ROR	1999	6.2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
11	Khimti Khola	ROR	2000	60.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
12	Upper Bhote Koshi	ROR	2000	36.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
13	Modi Khola	ROR	2000	14.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
14	Small Hydros	ROR	-	5.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
15	Biratnagar	DG		1.0	1.0	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
16	Hetauda	DG	1983	9.0	8.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	Marsyangdi	DG	1989	2.3	1.0	1.0	1.0	1.0	1.0	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.0	0.0	0.0	0.0	0.0	0.0
18	Duhabi	MF	1992	39.0	22.0	21.5	22.0	19.5	19.5	19.5	19.5	19.5	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	0.0	0.0	0.0
19	Kali Gandaki-A	PROR	2002	144.0	144.0			144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0	144.0
20	Syange	ROR	2002	0.1	0.1			0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
21	Chilime	PROR	2003	20.0	20.0				20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
22	Indrawati	ROR	2003	7.5	3.0				3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
23	Daram Khola	PROR	2003	5.0	5.0				5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
24	Piluwa Khola	PROR	2003	3.0	2.0				2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
25	Chaku Khola	PROR	2003	0.9	0.9				0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
26	Pheme	PROR	2004	1.0	0.9					0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
27	Upper Modi	ROR	2004	14.0	8.0					8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
28	Khudi	PROR	2004	3.5	2.2					2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
29	Mailung	PROR	2005	5.0	4.3						4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
30	Middle Marsyangdi	PROR	2005	70.0	70.0						70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
31	Langtang	PROR	2007	10.0	10.0								10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
32	Chameliya	PROR	2007	30.0	30.0								30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
33	Kulekhani-3	ST	2007	42.0	0.0								0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
34	Khimti-2	PROR	2007	27.0	53.0 *								53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0	53.0
35	Rahughat	ROR	2008	27.0	6.0									6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
36	Kabeli-A	ROR	2008	30.0	15.0									15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
37	Upper Karnali-A	PROR	2009	300.0	300.0										300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
	Import from India				50/150	50	50	50	50	50	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
(a)	Total Peaking Capacity			(MW)		367	367	509	540	551	725	725	811	829	1129	1129	1129	1129	1129	1128	1128	1128	1115	1115	1115
(b1)	Forecasted Peak Load (Base Case)			(MW)		391	426	502	549	606	664	720	778	835	896	962	1031	1105	1184	1268	1357	1453	1555	1664	1781
(c)	Reserve Margin			(MW)		-24	-59	7	-10	-55	61	5	34	-6	233	168	98	24	-54	-139	-229	-325	-440	-549	-665
(d)	Ratio of Reserve Margin			(%)	(c) / (b)	-6.1	-13.8	1.4	-1.7	-9.1	9.2	0.7	4.3	-0.8	26.0	17.4	9.5	2.2	-4.6	-11.0	-16.9	-22.3	-28.3	-33.0	-37.4
(b2)	Forecasted Peak Load (High Case)			(MW)		391	426	508	562	626	693	759	829	899	975	1056	1144	1239	1341	1452	1571	1700	1839	1990	2153
(b3)	Forecasted Peak Load (Low Case)			(MW)		391	426	496	537	586	636	683	730	777	825	876	930	987	1047	1111	1177	1248	1322	1400	1483

Notes

1) * : Construction of Khimti-2 increases the peaking capacity of Khimti-1 to 60 MW

2) Power supply at annual peak time of each new power station starts from the following year of in service, respectively.

Abbreviation

ROR: Run-of-River

PROR: Peaking Run-of-River; plants which have ability of daily regulation

ST: Storage; plants which have ability of annual regulation

DG: Diesel Generator

MF: Multi-fuel Diesel Generator

Table 5.5.1 Summary of Budget Allocation for Operation and Maintenance in the Existing Power Stations

(in thousand N.Rs.)

Nepalese Year (AD)	Kulekhani − 1					Kulekhani − 2				
	Operation	Maintenance			Grand Total	Operation	Maintenance			Grand Total
		E/M	Civil	Total			E/M	Civil	Total	
2053/54 (96/97)	9,991	1,221	4,672	5,893	15,884	6,189	904	3,494	4,398	10,587
2054/55 (97/98)	14,035	1,178	4,534	5,712	19,747	7,665	520	3,505	4,025	11,690
2055/56 (98/99)	13,198	1,350	4,500	5,850	19,048	6,899	610	3,000	3,610	10,509
2056/57 (99/00)	15,250	951	4,298	5,249	20,499	7,678	386	4,121	4,507	12,185
2057/58 (00/01)	20,593	1,099	4,039	5,138	25,731	10,651	843	5,047	5,890	16,541
2058/59 (01/02)	21,863	1,719	4,752	6,471	28,334	12,276	3,035	4,730	7,765	20,041
Annual increase in terms of NRs					12.3%					13.6%

Nepalese Year (AD)	Marsyangdi					Kali Gandaki A				
	Operation	Maintenance			Grand Total	Operation	Maintenance			Grand Total
		E/M	Civil	Total			E/M	Civil	Total	
2053/54 (96/97)					21,197					
2054/55 (97/98)					41,908					
2055/56 (98/99)					34,874					
2056/57 (99/00)					46,881					
2057/58 (00/01)					39,952					
2058/59 (01/02)					44,567	−	−	−	−	−
Annual increase in terms of NRs					16.0%					

Note:
(1) Quoted from NEA's Budget Allocation
(2) Nepalese fiscal year starts on approx. July 15.
(3) Kali Gandaki A is preparing O & M budget at present

O & M Budget Converted to US Dollar

(in US$.)

Nepalese Year (AD)	Kulekhani − 1					Kulekhani − 2					Exchange Rate (NRs/US$)
	Operation	Maintenance			Grand Total	Operation	Maintenance			Grand Total	
		E/M	Civil	Total			E/M	Civil	Total		
2053/54 (96/97)	176,233	21,537	82,410	103,948	280,181	109,169	15,946	61,631	77,577	186,746	56.692
2054/55 (97/98)	241,941	20,307	78,159	98,466	340,407	132,132	8,964	60,421	69,385	201,517	58.010
2055/56 (98/99)	200,042	20,462	68,207	88,669	288,711	104,568	9,246	45,471	54,717	159,285	65.976
2056/57 (99/00)	223,479	13,936	62,985	76,921	300,400	112,516	5,657	60,391	66,047	178,564	68.239
2057/58 (00/01)	289,659	15,458	56,812	72,271	361,929	149,816	11,858	70,991	82,848	232,664	71.094
2058/59 (01/02)	291,658	22,932	63,393	86,325	377,983	163,765	40,488	63,099	103,587	267,352	74.961
Annual increase in terms of US$					6.2%					7.4%	5.7%

Nepalese Year (AD)	Marsyangdi					Kali Gandaki A					Exchange Rate (NRs/US$)
	Operation	Maintenance			Grand Total	Operation	Maintenance			Grand Total	
		E/M	Civil	Total			E/M	Civil	Total		
2053/54 (96/97)					373,894						56.692
2054/55 (97/98)					722,433						58.010
2055/56 (98/99)					528,588						65.976
2056/57 (99/00)					692,889						68.239
2057/58 (00/01)					665,064						71.094
2058/59 (01/02)					630,755	−	−	−	−	−	74.961
Annual increase in terms of US$					11.0%						5.7%

Note: Exchange rates are quoted from IMF data.

Table 5.5.2 Features of Major Existing Power Stations in Nepal

(as of E/October., 2002)

Name	Installed Capacity (kW)	No. of Unit	Type of Power Station	Type of Power–house	Hydraulic Turbine				A.C. Shyncronous Generator				Year of Completion	Firm/Ave. Energy (GWh)	Average Energy (GWh)	Average Plant Factor (%)	Peak Load at LDC (MW)
					Output (kW)	D. Head (m)	Discharge (m^3/s)	Type	Capacity (kVA)	Speed (rpm)	PF	Voltage (kV)					
															(96~01)	(96~01)	(12/12/'01)
1. Trishuli	21,000	7	ROR	SF	3,500	54.0	45.3	HF	3,750	500	0.80	6.3	1967	23.2	136.2	74.1	21.0
2. Sunkosi	10,050	3	ROR	SF	3,530	30.5	39.9	VF	*3,940*	300	0.85	6.3	1972	114.6	56.8	64.5	9.0
3. Gandak	15,000	3	ROR	SF	5,600	6.1	311.5	Bulb	*5,880*	107	0.85	6.6	1979	56.7	28.4	21.6	4.0
4. Kulekhani I	60,000	2	ST	UG	31,000	614.0	13.1	VP	35,000	600	0.85	11	1982	154.7	176.1	33.5	60.5
7. Devighat	14,100	3	ROR	SF	5,030	40.0	45.3	VF	*5,875*	333	0.80	6.6	1984	89.7	94.7	76.7	14.1
6. Kulekhani II	32,000	2	ST	SF	16,000	310.0	13.3	VF	18,800	750	0.85	6.6	1986	95.0	83.9	29.9	30.0
7. Marshangdi	75,000	3	PROR	Semi.UG	23,000~ max.26,000	90.5~ 95.0	96.0	VF	30,000	300	0.85	11	Dec. 1989	312.0 (462.5)	443.3	67.5	74.6
8. Modi Khola	14,800	2	ROR	SF	7,260	67.0	25.0	VF	8,260	429	0.90	6.6	Dec. 2000	(92.5)	24.1	18.6	–
9. Khimti Khola (*)	60,000	5	ROR	UG	*12,600	**670.0	2.21	HP	14,200	750	0.86	10.5	Feb. 2000	(350.0)	372.7	70.9	43.0
10. BhoteKosi (*)	45,000	2	ROR	SF	22,000	134.0	18.4	VF	25,000	429	0.90	11	Jan. 2001	(246.0)	121.2	30.8	27.0
11. Kali Gandaki "A"	144,000	3	PROR	SF	48,000	115.0	141.0	VF	56,500	300	0.85	13.8	June 2002	(842.0)	–	–	–

(): Average

Note:

1. Power stations marked with asterisks (*) are owned by other power companys than NEA..
   Then, NEA has purchased their elctricity according to the contract.
2. In Khimti Khola intake structure was destroyed in October, 2002. without damage of powerhouse. Then operation could continue with about half capacity of generation in dry season, but compelled to discontinue in flood season.
3. Italic firgures show estimated capacities.
4. Figure marked with asterisk (*) is estimated from generator capacity.
5. D. Head marked with asterisk (**) seems max. head.
6. Abbreviations adopted herein are as follows:

ROR	:	Run-of-River
PROR	:	Peaking ROR
ST	:	Storage (reservoir) type
SF	:	Surface Type
UG	:	Underground Type
Semi.UG	:	Semi-UG type
HF	:	Horizontal shaft typeFrancis
VF	:	Vertical shaft type Francis
Bulb	:	Horizontal shaft typeBulb
HP	:	Horizontal shaft type Pelton
VP	:	Vertical shaft type Pelton
PF	:	Power factor

Table 5.5.3 History of Maintenance Works

History of maintenance works in each major existing power station is shown below:

1) KL-1

- Commercial operation starts in 1982
- Generator excitation system was modified from static excitation to brushless excitation in 1990 to eliminate earthing fault on the generator circuit due to carbon dust and oil vapour adhered on the rotor coils;
- Flood disaster in July 1993 damaged penstock lines, riverside stores, etc. and forthwith restored;
- 1^{st} Overhaul of powerhouse equipment was performed by NEA staff in July 1994, which included procurement of spare parts and supervision from the manufacturer with the grant assistance of GOJ (JICA);
- Improvement of communication between dam site and powerhouse, including telemetering of reservoir water level indication;
- Improvement of Intake to sloping intake structure in 1997 under disaster project.

2) KL-2

- Commercial operation starts in 1986
- Flood disaster in 1993 damaged Mandu intake weir and rehabilitation works under disaster project in 1995;
- Overhaul of powerhouse equipment was performed by NEA staff in 1994, which included procurement of spare parts and supervision from the manufacturer with the grant assistance of GOJ (JICA), along with KL-1 at the same time.

3) Marsyangdi

- Commercial operation starts in 1989
- Repair of each turbine runner due to abrasion in every three years since 1992 (every one unit per year).
- Overhaul of powerhouse equipment is yet to be performed up to now (13 years passed).

4) Kali Gandaki A

- Commercial operation starts in mid 2002, and then no history of maintenance;
- Final inspection of cavitation pitting (during 8,000 hours operation) is to be made after dismantling of turbine runner at the expiry of performance guarantees in the contract Lot-5, namely in April 2003 at earliest.

Table 5.5.4 Present Status of Maintenance Observed and Measures

Description	KL-1	KL-2	Marsyangdi	Kali Gandak "A"
1. Civil work maintenance				
a. Inspection roads	Found damaged due to landslides and partially repaired by manpower except big collapse	- same as left -	Not found	Not found
b. Sediment in reservoir, settling basin, weir or check dam,	Reported sediment in reservoir and two weirs	Reported sediment in check dam and starting to remove it	Reported sediment in settling basin and drain b a installed sand pump.	Reported sediment in tailrace and drain by a installed sand pump
c. Mechnical maintenance in dam/weir such as gates, valves, etc.	Spillway gates are operated manually. Emergency DG is out of order. Hollow jet valve is out of order.	None.	Reported eroded intake gate sill plate. and repaired with high tension steel plates	None.
Present troubles or problems	Reported no oil, grease, fuel, battery for maintenance	Not reported	Not reported except above.	Not reported
d. Heavy equipment maintenance	Not inspected, but reported to have shifted to Hetauda Workshop. Recommend to keep minimum number of H.E. at site during monsoon	- same as left-	Not inspected	Not inspected
2. Powerhouse equipment maintenance				
a. General inspection	Observed clean and well maintained	- same as left -	- same as left -	- same as left -
b. Present troubles or problems	Temporary repaired stator windings (No.1 unit) is to be repaired at overhaul and exciter ammeters don't indicate correctly	Automatic operation does not work in No.2 unit governor and urgently required to replace with digital type because of no production of spare parts for ananlog one Observed water leakage from guide vanes Observed no repair-shop equipment and reported to shift to Hetauda Workshop	Repaired turbine runner by metal spray one unit every year due to heavy abrasion by sand Observed heavily eroded wearing ring (unit No.1) and now repaired by welding and machining at NHE Butwal recently Reported damage of 132 kV lightning arresters and cause is unknown	Reported some troubles in three inlet vales, fast clogging of shaft seal strainer during wet season. Reported problem in control system of No.2 unit (power supply for PLC (Programmable Logic Controller). (The above are in guarantee and taken up under the contract)

Attachment A5.1 Energy and Peak Demand Forecasts (High Case)

FY	Energy Demand (GWh)												
	Domestic	Industrial	Commer-cial	Irrigation	Other	Total Nepal	Export	Total	Growth (%)	Losses (%)	Total Requirement	Load Factor (%)	Peak Load (MW)
2001	524.1	526.3	95.2	28.9	120.7	1,295.2	128.4	1,423.6	-	*23.8*	1,868.4	*54.5*	391.0
2002	576.5	597.0	95.5	31.2	131.4	1,431.6	142.9	1,574.5	*10.6*	*24.6*	2,087.6	*55.9*	426.0
2003	643.3	655.7	103.3	35.9	141.8	1,580.1	154.3	1,734.4	*10.2*	*22.0*	2,223.6	*50.0*	507.7
2004	719.3	750.8	113.8	40.5	153.0	1,777.5	166.7	1,944.1	*12.1*	*21.0*	2,460.9	*50.0*	561.9
2005	798.7	878.4	125.4	45.3	165.2	2,013.0	180.0	2,193.0	*12.8*	*20.0*	2,741.3	*50.0*	625.9
2006	883.3	1,014.1	138.1	50.1	178.2	2,263.8	194.4	2,458.2	*12.1*	*19.0*	3,034.8	*50.0*	692.9
2007	973.2	1,144.6	152.1	55.0	192.4	2,517.2	210.0	2,727.2	*10.9*	*18.0*	3,325.8	*50.0*	759.3
2008	1,068.9	1,246.7	167.5	59.9	207.6	2,750.6	226.8	2,977.3	*9.2*	*18.0*	3,630.9	*50.0*	829.0
2009	1,164.4	1,350.1	183.2	64.9	222.7	2,985.3	244.9	3,230.2	*8.5*	*18.0*	3,939.3	*50.0*	899.4
2010	1,264.4	1,463.5	200.3	70.0	238.8	3,237.0	264.5	3,501.5	*8.4*	*18.0*	4,270.1	*50.0*	974.9
2011	1,370.2	1,587.8	219.1	75.2	256.2	3,508.4	285.7	3,794.1	*8.4*	*18.0*	4,626.9	*50.0*	1,056.4
2012	1,482.3	1,724.1	239.6	80.4	274.8	3,801.1	308.5	4,109.7	*8.3*	*18.0*	5,011.8	*50.0*	1,144.2
2013	1,601.1	1,873.5	262.0	85.7	294.7	4,117.0	333.2	4,450.2	*8.3*	*18.0*	5,427.1	*50.0*	1,239.1
2014	1,726.9	2,037.3	286.5	91.1	316.1	4,457.9	359.8	4,817.8	*8.3*	*18.0*	5,875.3	*50.0*	1,341.4
2015	1,860.1	2,216.9	313.4	96.5	339.1	4,826.0	388.6	5,214.6	*8.2*	*18.0*	6,359.3	*50.0*	1,451.9
2016	2,001.3	2,413.8	342.7	102.1	363.7	5,223.5	419.7	5,643.3	*8.2*	*18.0*	6,882.0	*50.0*	1,571.2
2017	2,150.8	2,629.7	374.8	107.7	390.1	5,653.0	453.3	6,106.3	*8.2*	*18.0*	7,446.7	*50.0*	1,700.2
2018	2,309.2	2,866.4	409.8	113.3	418.4	6,117.2	489.6	6,606.7	*8.2*	*18.0*	8,057.0	*50.0*	1,839.5
2019	2,477.0	3,125.9	448.2	119.1	448.8	6,618.9	528.7	7,147.7	*8.2*	*18.0*	8,716.7	*50.0*	1,990.1
2020	2,654.7	3,410.4	490.2	124.9	481.3	7,161.5	571.0	7,732.6	*8.2*	*18.0*	9,430.0	*50.0*	2,153.0
I	*8.9%*	*10.3%*	*9.0%*	*8.0%*	*7.6%*	*9.4%*		*9.3%*			*8.9%*		*9.4%*
II	*10.3%*	*12.0%*	*8.6%*	*10.3%*	*7.9%*	*10.7%*		*10.5%*			*9.6%*		*10.7%*
III	*7.7%*	*8.8%*	*9.4%*	*6.0%*	*7.3%*	*8.3%*		*8.2%*			*8.2%*		*8.2%*

I *Average annual growth over forecast period 2001 to 2020*

II *Average annual growth for years 2001 to 2010*

III *Average annual growth for years 2010 to 2020*

Notes: *2001 & 2002 figures are actuals corrected for load shedding.*

Losses: targeted to reach 18% in stages through loss reductions, part of which are converted to sales.

Load factor: constant at 50%

Attachment A5.2 Energy and Peak Demand Forecasts (Low Case)

	Energy Demand (GWh)												
FY	Domestic	Industrial	Commer-cial	Irrigation	Other	Total Nepal	Export	Total	Growth (%)	Losses (%)	Total Requirement	Load Factor (%)	Peak Load (MW)
2001	524.1	526.3	95.2	28.9	120.7	1,295.2	128.4	1,423.6	-	*23.8*	1,868.4	*54.5*	391.0
2002	576.5	597.0	95.5	31.2	131.4	1,431.6	142.9	1,574.5	*10.6*	*24.6*	2,087.6	*55.9*	426.0
2003	630.8	635.1	100.2	35.9	138.3	1,540.3	154.3	1,694.6	*7.6*	*22.0*	2,172.6	*50.0*	496.0
2004	692.2	705.9	106.9	40.5	145.6	1,691.2	166.7	1,857.9	*9.6*	*21.0*	2,351.7	*50.0*	536.9
2005	754.8	805.2	114.2	45.3	153.3	1,872.8	180.0	2,052.8	*10.5*	*20.0*	2,566.0	*50.0*	585.8
2006	820.1	907.8	121.9	50.1	161.4	2,061.4	194.4	2,255.8	*9.9*	*19.0*	2,784.9	*50.0*	635.8
2007	888.2	1,000.1	130.1	55.0	170.0	2,243.4	210.0	2,453.4	*8.8*	*18.0*	2,991.9	*50.0*	683.1
2008	959.2	1,058.0	138.9	59.9	178.9	2,395.0	226.8	2,621.8	*6.9*	*18.0*	3,197.3	*50.0*	730.0
2009	1,029.0	1,114.9	147.6	64.9	187.6	2,544.0	244.9	2,788.9	*6.4*	*18.0*	3,401.1	*50.0*	776.5
2010	1,100.3	1,175.3	156.8	70.0	196.7	2,699.1	264.5	2,963.6	*6.3*	*18.0*	3,614.2	*50.0*	825.2
2011	1,174.4	1,239.7	166.6	75.2	206.2	2,862.0	285.7	3,147.7	*6.2*	*18.0*	3,838.6	*50.0*	876.4
2012	1,251.4	1,308.2	177.0	80.4	216.2	3,033.1	308.5	3,341.6	*6.2*	*18.0*	4,075.2	*50.0*	930.4
2013	1,331.4	1,381.1	188.0	85.7	226.6	3,212.9	333.2	3,546.1	*6.1*	*18.0*	4,324.5	*50.0*	987.3
2014	1,414.6	1,458.7	199.8	91.1	237.6	3,401.7	359.8	3,761.6	*6.1*	*18.0*	4,587.3	*50.0*	1,047.3
2015	1,501.1	1,541.2	212.2	96.5	249.1	3,600.2	388.6	3,988.8	*6.0*	*18.0*	4,864.4	*50.0*	1,110.6
2016	1,591.0	1,629.1	225.5	102.1	261.1	3,808.8	419.7	4,228.5	*6.0*	*18.0*	5,156.8	*50.0*	1,177.3
2017	1,684.5	1,722.6	239.6	107.7	273.8	4,028.1	453.3	4,481.4	*6.0*	*18.0*	5,465.1	*50.0*	1,247.7
2018	1,781.7	1,822.1	254.5	113.3	287.0	4,258.7	489.6	4,748.2	*6.0*	*18.0*	5,790.5	*50.0*	1,322.0
2019	1,882.7	1,928.0	270.4	119.1	300.9	4,501.1	528.7	5,029.9	*5.9*	*18.0*	6,134.0	*50.0*	1,400.5
2020	1,987.7	2,040.7	287.3	124.9	315.5	4,756.1	571.0	5,327.1	*5.9*	*18.0*	6,496.5	*50.0*	1,483.2
I	*7.3%*	*7.4%*	*6.0%*	*8.0%*	*5.2%*	*7.1%*		*7.2%*			*6.8%*		*7.3%*
II	*8.6%*	*9.3%*	*5.7%*	*10.3%*	*5.6%*	*8.5%*		*8.5%*			*7.6%*		*8.7%*
III	*6.1%*	*5.7%*	*6.2%*	*6.0%*	*4.8%*	*5.8%*		*6.0%*			*6.0%*		*6.0%*

I *Average annual growth over forecast period 2001 to 2020*

II *Average annual growth for years 2001 to 2010*

III *Average annual growth for years 2010 to 2020*

Notes: **2001 & 2002 figures are actuals corrected for load shedding.*

**Losses: targeted to reach 18% in stages through loss reductions, part of which are converted to sales.*

**Load factor: constant at 50%*