CHAPTER 7. OPTIMIZATION STUDY

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7.1 Parameters for Study

Since this project is endowed with such favorable conditions for hydropower development of large scale as abundant water resources and steep river gradient, it is desirable to make the large-scale development plan which meets not only domestic power demand growth in Nepal but also power export. However, as the form of power demand of the importing country side and the method of power export are not cleared yet at present, it is difficult to study in detail the subject of power export. In this study, the development scheme for satisfying domestic power demand only (Case I) is first studied, then, the scheme including some part of future constructions to be required for power export (Case II:1st stage development) is studied and the scheme which also includes all constructions for future power export (Case III:2nd stage development) is finally studied. The summary of each case is described as follows.

Case I: (for domestic power demand only)

Case I is the study on the scheme which meets domestic power demand only. The studies are made for various values of the maximum power discharge, dam height (intake water level) and tailwater level (powerhouse site) which are taken as parameters. The dam height and powerhouse site selected in accordance with the Case I study are again adopted in Cases II and III without repeated examinations, while, the maximum power discharge is still taken as parameter for studies of the succeeding cases.

Case II: (1st stage development for domestic power demand)

As previously stated, it can be expected to further improve the project economy when power export is considered in addition to the primary purpose of constructing the project to cope with domestic power demand. However, the information related to power export on the importing country side is not clear at present. It is anticipated that the time of considerable length will be needed to negotiate for formulation of power export with the importing country and this may cause delay of initiating the construction of the project. It is required to commence the construction of the optimum scheme (Case I) giving priority to domestic power demand for the time being, with simultaneous construction of the structures such as intake, powerhouse, tailrace outlet, etc. which are considered difficult to construct as the future extension. A parameter applied to the examination of Case II is the maximum power discharge only.

Case III: (2nd stage development for power export)

In connection with power export, there are several assumptions involved in the study and accordingly, the results of Case III study will not be considered to be satisfactory enough. However, the study will indicate a certain optimum size of the future extension plan which is partly involved in Case II and also the project economy that will be improved by the said extension plan. The assumptions stated above are as follows.

(i) Timing of starting the 2nd stage development and commissioning time

In this study, the starting time of the second stage development is set at 1994 giving four years for negotiation of power export, fund arrangement, etc. immediately after commencement of the first stage development. The commissioning time is decided taking into account the reasonable construction period for the second stage development.

(ii) Power demand of importing country

As the general features of power demand of the importing country are not known, it is planned in this study that only surplus power is to be exported, giving priority to domestic power demand.

(iii) Unit rate of exported power

The unit rate of US$0.048/kWh is applied to the study.

The major work items involved in the second stage development scheme are the additional works of headrace tunnel, surge tank, penstock, tailrace tunnel, etc. as the civil works and those of turbines, generators, transmission line, etc. as the electric works. Similarly to the study of Case II, only the maximum power discharge is considered as a parameter.

Further, the scope of studies on the civil structures is limited to a certain extent as described in Chapter 6 and the following conditions are also taken into consideration.

(i) Headrace tunnel of single line is designed for Cases I and II, while two headrace tunnels with identical diameter are designed for Case III to flow the two times power discharge of Case II.

(ii) The unit capacity of generator is limited to around 70 MW in order to avoid unfavorable effect on the power system.

The objective of the study in this chapter is solely to find out the optimum scheme and the accuracy as required in the preliminary design is not expected. Therefore, there will be some difference between the figures applied to this study and those finally decided.

Fig. 7-1 indicates the flow chart of optimization study.

7.2 Methodology

7.2.1 General

For economic evaluation of respective cases, net present value (B-C) calculated by means of the Discounted Cash Flow Method is adopted. The period applied to calculation includes 7 years from commencement of construction works to first commissioning of the units No.1 and No.2 and 50 years for operation and maintenance, totalling 57 years. The examples of this method are indicated in Table 7-1 (1), (2), (3).

The discount rate used for calculating present value is 12% being the social opportunity cost of capital in Nepal.

Fig. 7−1 Flow Chart of Optimization Study

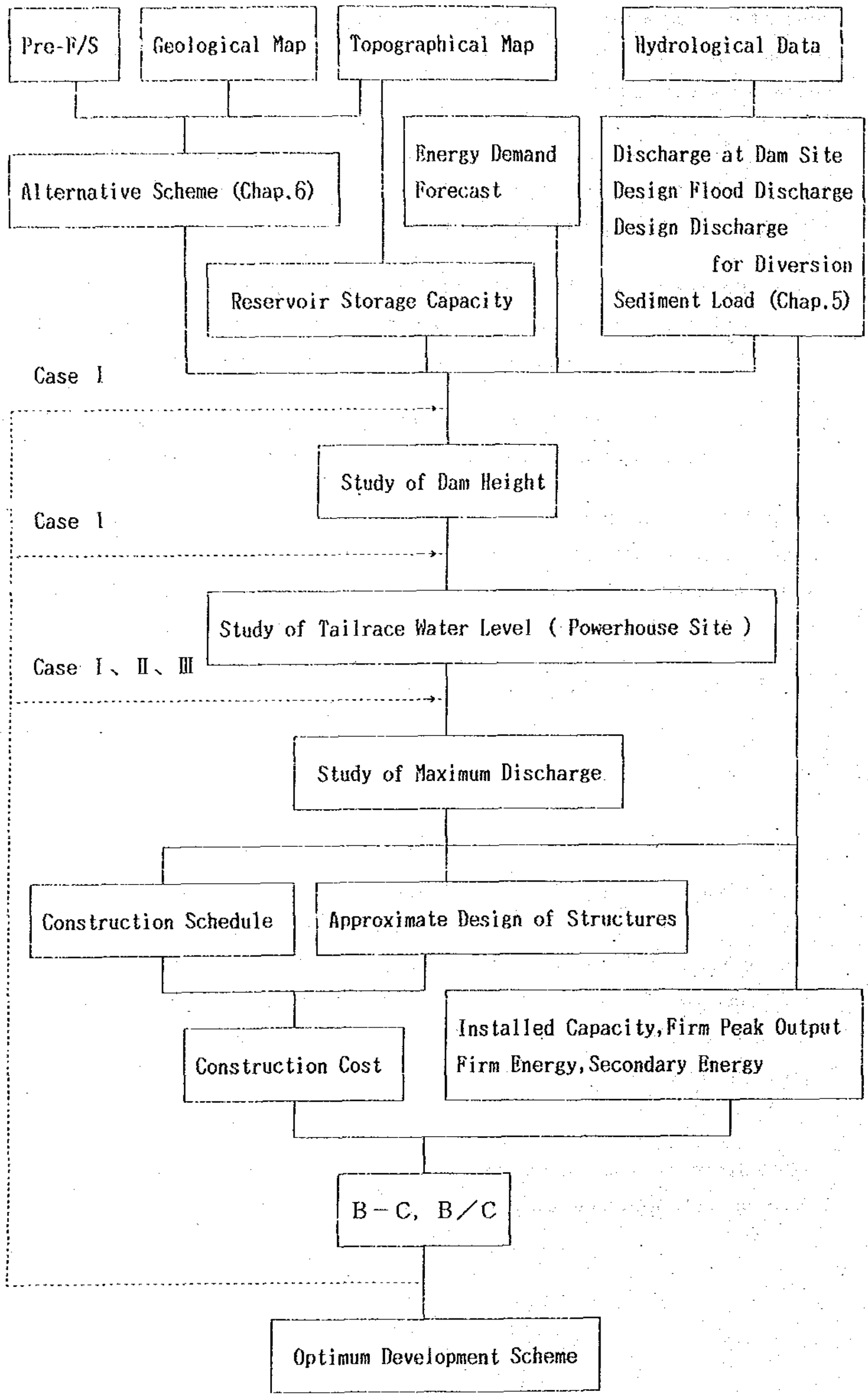


Table 7-1 (1) Discounted Cash Flow Method Case I-80

Discount rate=	12(%)					
B =	242.02		S =	1		
C =	193.17	kW Value	B1=	68 US$/kW	C1= 0.059009402	
B/C=	1.252	kWH Value	B2=	0.063 US$/kWH	C2= 0.047048685	
B-C=	48.85	kWH Value	B3=	0.005 US$/kWH	C3= 0.034799634	UNIT=Million US$

Year	Serial Number	Cost Flow	Discounted Cost Flow	Project Sales			Discounted Benefit Flow			
				Salable Energy (GWH/Yr)	Surplus Energy (GWH/Yr)	Useful Capacity (MW)	Salable Energy	Surplus Energy	Useful Capacity	Total
1987	1	4.81	4.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1988	2	19.57	15.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1989	3	21.57	15.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1990	4	22.77	14.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1991	5	43.60	24.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	6	64.18	32.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1993	7	105.08	47.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1994	8	53.59	21.64	179.00	980.70	52.00	4.55	1.98	1.42	7.96
1995	9	2.56	0.92	256.00	903.70	69.00	5.81	1.62	1.69	9.13
1996	10	2.56	0.82	333.00	826.70	86.10	6.75	1.33	1.88	9.97
1997	11	8.10	2.32	415.00	744.70	104.20	7.51	1.07	2.03	10.62
1998	12	13.70	3.51	500.00	659.70	123.20	8.08	0.84	2.15	11.08
1999	13	9.36	2.14	588.00	1133.60	143.00	8.48	1.29	2.22	12.01
2000	14	3.84	0.78	680.00	1041.60	163.70	8.76	1.06	2.27	12.10
2001	15	3.84	0.70	776.00	945.60	185.40	8.93	0.86	2.30	12.09
2002	16	3.84	0.62	876.00	845.60	201.00	9.00	0.68	2.22	11.92
2003	17	3.84	0.55	980.00	741.60	201.00	8.99	0.54	1.99	11.52
2004	18	3.84	0.49	1089.00	632.60	201.00	8.92	0.41	1.77	11.11
2005	19	3.84	0.44	1201.00	520.60	201.00	8.78	0.30	1.58	10.67
2006	20	3.84	0.39	1318.00	403.60	201.00	8.60	0.20	1.41	10.23
2007	21	3.84	0.35	1440.00	281.60	201.00	8.39	0.13	1.26	9.79
2008	22	3.84	0.31	1567.00	154.60	201.00	8.15	0.06	1.12	9.35
2009	23	3.84	0.28	1699.00	22.60	201.00	7.89	0.00	1.00	8.91
2010	24	3.84	0.25	1721.60	0.00	201.00	7.14	0.00	0.90	8.04
2011	25	3.84	0.22	1721.60	0.00	201.00	6.38	0.00	0.80	7.18
2012	26	3.84	0.20	1721.60	0.00	201.00	5.69	0.00	0.71	6.41
2013	27	3.84	0.18	1721.60	0.00	201.00	5.08	0.00	0.64	5.72
2014	28	3.84	0.16	1721.60	0.00	201.00	4.54	0.00	0.57	5.11
2015	29	3.84	0.14	1721.60	0.00	201.00	4.05	0.00	0.51	4.56
2016	30	3.84	0.12	1721.60	0.00	201.00	3.62	0.00	0.45	4.07
2017	31	3.84	0.11	1721.60	0.00	201.00	3.23	0.00	0.40	3.63
2018	32	3.84	0.10	1721.60	0.00	201.00	2.88	0.00	0.36	3.24
2019	33	3.84	0.09	1721.60	0.00	201.00	2.57	0.00	0.32	2.90
2020	34	3.84	0.08	1721.60	0.00	201.00	2.30	0.00	0.28	2.59
2021	35	3.84	0.07	1721.60	0.00	201.00	2.05	0.00	0.25	2.31
2022	36	3.84	0.06	1721.60	0.00	201.00	1.83	0.00	0.23	2.06
2023	37	3.84	0.05	1721.60	0.00	201.00	1.63	0.00	0.20	1.84
2024	38	3.84	0.05	1721.60	0.00	201.00	1.46	0.00	0.18	1.64
2025	39	3.84	0.04	1721.60	0.00	201.00	1.30	0.00	0.16	1.46
2026	40	3.84	0.04	1721.60	0.00	201.00	1.16	0.00	0.14	1.31
2027	41	3.84	0.03	1721.60	0.00	201.00	1.04	0.00	0.13	1.17
2028	42	3.84	0.03	1721.60	0.00	201.00	0.92	0.00	0.11	1.04
2029	43	3.84	0.02	1721.60	0.00	201.00	0.82	0.00	0.10	0.93
2030	44	3.84	0.02	1721.60	0.00	201.00	0.74	0.00	0.09	0.83
2031	45	3.84	0.02	1721.60	0.00	201.00	0.66	0.00	0.08	0.74
2032	46	3.84	0.02	1721.60	0.00	201.00	0.59	0.00	0.07	0.66
2033	47	3.84	0.01	1721.60	0.00	201.00	0.52	0.00	0.06	0.59
2034	48	3.84	0.01	1721.60	0.00	201.00	0.47	0.00	0.05	0.53
2035	49	3.84	0.01	1721.60	0.00	201.00	0.42	0.00	0.05	0.47
2036	50	3.84	0.01	1721.60	0.00	201.00	0.37	0.00	0.04	0.42
2037	51	3.84	0.01	1721.60	0.00	201.00	0.33	0.00	0.04	0.37
2038	52	3.84	0.01	1721.60	0.00	201.00	0.29	0.00	0.03	0.33
2039	53	3.84	0.00	1721.60	0.00	201.00	0.26	0.00	0.03	0.30
2040	54	3.84	0.00	1721.60	0.00	201.00	0.23	0.00	0.03	0.26
2041	55	3.84	0.00	1721.60	0.00	201.00	0.21	0.00	0.02	0.23
2042	56	3.84	0.00	1721.60	0.00	201.00	0.19	0.00	0.02	0.21
2043	57	3.84	0.00	1721.60	0.00	201.00	0.16	0.00	0.02	0.19
Total		540.41	193.17				192.95	12.44	36.63	242.02

C1: average net cost of useful salable energy and capacity
C2: average net cost of useful salable energy
C3: average net cost of total energy and capacity

Table 7-1 (2) Discounted Cash Flow Method Case II-80

Discount rate= 12(%)
B = 242.02 S = 1
C = 207.05 kW Value B1= 68 US$/kW C1= 0.063543053
B/C= 1.168 kWH Value B2= 0.063 US$/kWH C2= 0.051582336
B-C= 34.96 kWH Value B3= 0.005 US$/kWH C3= 0.037301072 UNIT=Million US$

Year	Serial Number	Cost Flow	Discounted Cost Flow	Project Sales			Discounted Benefit Flow			
				Salable Energy (GWH/Yr)	Surplus Energy (GWH/Yr)	Useful Capacity (MW)	Salable Energy	Surplus Energy	Useful Capacity	Total
1987	1	4.81	4.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1988	2	19.57	15.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1989	3	21.57	15.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1990	4	23.67	15.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1991	5	49.08	27.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	6	72.41	36.68	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1993	7	113.06	51.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1994	8	57.72	23.31	179.00	980.70	52.00	4.55	1.98	1.42	7.96
1995	9	2.71	0.97	256.00	903.70	69.00	5.81	1.62	1.69	9.13
1996	10	2.71	0.87	333.00	826.70	86.10	6.75	1.33	1.88	9.97
1997	11	8.25	2.37	415.00	744.70	104.20	7.51	1.07	2.03	10.62
1998	12	14.06	3.60	500.00	659.70	123.20	8.08	0.84	2.15	11.08
1999	13	9.72	2.22	588.00	1133.60	143.00	8.48	1.29	2.22	12.01
2000	14	4.07	0.83	680.00	1041.60	163.70	8.76	1.06	2.27	12.10
2001	15	4.07	0.74	776.00	945.60	185.40	8.93	0.86	2.30	12.09
2002	16	4.07	0.66	876.00	845.60	201.00	9.00	0.68	2.22	11.92
2003	17	4.07	0.59	980.00	741.60	201.00	8.99	0.54	1.99	11.52
2004	18	4.07	0.52	1089.00	632.60	201.00	8.92	0.41	1.77	11.11
2005	19	4.07	0.47	1201.00	520.60	201.00	8.78	0.30	1.58	10.67
2006	20	4.07	0.42	1318.00	403.60	201.00	8.60	0.20	1.41	10.23
2007	21	4.07	0.37	1440.00	281.60	201.00	8.39	0.13	1.26	9.79
2008	22	4.07	0.33	1567.00	154.60	201.00	8.15	0.06	1.12	9.35
2009	23	4.07	0.30	1699.00	22.60	201.00	7.89	0.00	1.00	8.91
2010	24	4.07	0.26	1721.60	0.00	201.00	7.14	0.00	0.90	8.04
2011	25	4.07	0.23	1721.60	0.00	201.00	6.38	0.00	0.80	7.18
2012	26	4.07	0.21	1721.60	0.00	201.00	5.69	0.00	0.71	6.41
2013	27	4.07	0.19	1721.60	0.00	201.00	5.08	0.00	0.64	5.72
2014	28	4.07	0.17	1721.60	0.00	201.00	4.54	0.00	0.57	5.11
2015	29	4.07	0.15	1721.60	0.00	201.00	4.05	0.00	0.51	4.56
2016	30	4.07	0.13	1721.60	0.00	201.00	3.62	0.00	0.45	4.07
2017	31	4.07	0.12	1721.60	0.00	201.00	3.23	0.00	0.40	3.63
2018	32	4.07	0.10	1721.60	0.00	201.00	2.88	0.00	0.36	3.24
2019	33	4.07	0.09	1721.60	0.00	201.00	2.57	0.00	0.32	2.90
2020	34	4.07	0.08	1721.60	0.00	201.00	2.30	0.00	0.28	2.59
2021	35	4.07	0.07	1721.60	0.00	201.00	2.05	0.00	0.25	2.31
2022	36	4.07	0.06	1721.60	0.00	201.00	1.83	0.00	0.23	2.06
2023	37	4.07	0.06	1721.60	0.00	201.00	1.63	0.00	0.20	1.84
2024	38	4.07	0.05	1721.60	0.00	201.00	1.46	0.00	0.18	1.64
2025	39	4.07	0.04	1721.60	0.00	201.00	1.30	0.00	0.16	1.46
2026	40	4.07	0.04	1721.60	0.00	201.00	1.16	0.00	0.14	1.31
2027	41	4.07	0.03	1721.60	0.00	201.00	1.04	0.00	0.13	1.17
2028	42	4.07	0.03	1721.60	0.00	201.00	0.92	0.00	0.11	1.04
2029	43	4.07	0.03	1721.60	0.00	201.00	0.82	0.00	0.10	0.93
2030	44	4.07	0.02	1721.60	0.00	201.00	0.74	0.00	0.09	0.83
2031	45	4.07	0.02	1721.60	0.00	201.00	0.66	0.00	0.08	0.74
2032	46	4.07	0.02	1721.60	0.00	201.00	0.59	0.00	0.07	0.66
2033	47	4.07	0.01	1721.60	0.00	201.00	0.52	0.00	0.06	0.59
2034	48	4.07	0.01	1721.60	0.00	201.00	0.47	0.00	0.05	0.53
2035	49	4.07	0.01	1721.60	0.00	201.00	0.42	0.00	0.05	0.47
2036	50	4.07	0.01	1721.60	0.00	201.00	0.37	0.00	0.04	0.42
2037	51	4.07	0.01	1721.60	0.00	201.00	0.33	0.00	0.04	0.37
2038	52	4.07	0.01	1721.60	0.00	201.00	0.29	0.00	0.03	0.33
2039	53	4.07	0.01	1721.60	0.00	201.00	0.26	0.00	0.03	0.30
2040	54	4.07	0.00	1721.60	0.00	201.00	0.23	0.00	0.03	0.26
2041	55	4.07	0.00	1721.60	0.00	201.00	0.21	0.00	0.02	0.23
2042	56	4.07	0.00	1721.60	0.00	201.00	0.19	0.00	0.02	0.21
2043	57	4.07	0.00	1721.60	0.00	201.00	0.16	0.00	0.02	0.19
Total		578.42	207.05				192.95	12.44	36.63	242.02

C1: average net cost of useful salable energy and capacity
C2: average net cost of useful salable energy
C3: average net cost of total energy and capacity

Table 7–1 (3) Discounted Cash Flow Method Case III–160

Discount rate= 12 (%)
B = 428.78
C = 245.49
B/C= 1.746
B-C= 183.29

S = 1
kW Value B1= 68 US$/kW
kWh Value B2= 0.063 US$/kWh
kWh Value B3= 0.048 US$/kWh
kWh Value B4= 0.005 US$/kWh

C1= 0.035027288
C2= 0.028022935
C3= 0.029995237

UNIT= Million US$

Year	Serial Number	Cost Flow	Discounted Cost Flow	Project Sales: Salable Domestic Energy (GWh/Yr)	Project Sales: Salable Export Energy (GWh/Yr)	Project Sales: Surplus Energy (GWh/Yr)	Project Sales: Useful Capacity (MW)	Discounted Benefit Flow: Salable Domestic Energy	Discounted Benefit Flow: Salable Export Energy	Discounted Benefit Flow: Surplus Energy	Discounted Benefit Flow: Useful Capacity	Discounted Benefit Flow: Total
1987	1	4.81	4.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1988	2	19.57	15.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1989	3	21.57	15.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1990	4	23.69	15.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1991	5	49.10	27.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1992	6	72.47	36.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1993	7	112.97	51.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1994	8	61.61	24.88	179.00	0.00	980.70	52.00	4.55	0.00	1.98	1.42	7.96
1995	9	11.33	4.08	256.00	0.00	903.70	69.00	5.81	0.00	1.62	1.69	9.13
1996	10	17.16	5.52	333.00	0.00	826.70	86.10	6.75	0.00	1.33	1.88	9.97
1997	11	69.43	19.95	415.00	0.00	744.70	104.20	7.51	0.00	1.07	2.03	10.62
1998	12	46.95	12.05	500.00	0.00	659.70	123.20	8.08	0.00	0.84	2.15	11.08
1999	13	10.65	2.44	588.00	2372.30	0.00	143.00	8.48	26.09	0.00	2.22	36.81
2000	14	5.57	1.13	680.00	2280.30	0.00	163.70	8.76	22.39	0.00	2.27	33.44
2001	15	5.57	1.01	776.00	2184.30	0.00	185.40	8.93	19.15	0.00	2.30	30.38
2002	16	5.57	0.90	876.00	2084.30	0.00	208.30	9.00	16.31	0.00	2.31	27.63
2003	17	5.57	0.81	980.00	1980.30	0.00	232.30	8.99	13.84	0.00	2.30	25.13
2004	18	5.57	0.72	1089.00	1871.30	0.00	257.50	8.92	11.68	0.00	2.27	22.87
2005	19	5.57	0.64	1201.00	1759.30	0.00	283.80	8.78	9.80	0.00	2.24	20.83
2006	20	5.57	0.57	1318.00	1642.30	0.00	311.30	8.60	8.17	0.00	2.19	18.97
2007	21	5.57	0.51	1440.00	1520.30	0.00	340.10	8.39	6.75	0.00	2.14	17.29
2008	22	5.57	0.46	1567.00	1393.30	0.00	354.00	8.15	5.52	0.00	1.98	15.67
2009	23	5.57	0.41	1699.00	1261.30	0.00	354.00	7.89	4.46	0.00	1.77	14.14
2010	24	5.57	0.36	1837.00	1123.30	0.00	354.00	7.62	3.55	0.00	1.58	12.76
2011	25	5.57	0.32	1863.20	1097.10	0.00	354.00	6.90	3.09	0.00	1.41	11.41
2012	26	5.57	0.29	1863.20	1097.10	0.00	354.00	6.16	2.76	0.00	1.26	10.19
2013	27	5.57	0.26	1863.20	1097.10	0.00	354.00	5.50	2.46	0.00	1.12	9.10
2014	28	5.57	0.23	1863.20	1097.10	0.00	354.00	4.91	2.20	0.00	1.00	8.12
2015	29	5.57	0.20	1863.20	1097.10	0.00	354.00	4.38	1.96	0.00	0.89	7.25
2016	30	5.57	0.18	1863.20	1097.10	0.00	354.00	3.91	1.75	0.00	0.80	6.47
2017	31	5.57	0.16	1863.20	1097.10	0.00	354.00	3.49	1.56	0.00	0.71	5.78
2018	32	5.57	0.14	1863.20	1097.10	0.00	354.00	3.12	1.40	0.00	0.64	5.16
2019	33	5.57	0.13	1863.20	1097.10	0.00	354.00	2.78	1.25	0.00	0.57	4.61
2020	34	5.57	0.11	1863.20	1097.10	0.00	354.00	2.48	1.11	0.00	0.51	4.11
2021	35	5.57	0.10	1863.20	1097.10	0.00	354.00	2.22	0.99	0.00	0.45	3.67
2022	36	5.57	0.09	1863.20	1097.10	0.00	354.00	1.98	0.89	0.00	0.40	3.28
2023	37	5.57	0.08	1863.20	1097.10	0.00	354.00	1.77	0.79	0.00	0.36	2.93
2024	38	5.57	0.07	1863.20	1097.10	0.00	354.00	1.58	0.70	0.00	0.32	2.61
2025	39	5.57	0.06	1863.20	1097.10	0.00	354.00	1.41	0.63	0.00	0.28	2.33
2026	40	5.57	0.05	1863.20	1097.10	0.00	354.00	1.26	0.56	0.00	0.25	2.08
2027	41	5.57	0.05	1863.20	1097.10	0.00	354.00	1.12	0.50	0.00	0.23	1.86
2028	42	5.57	0.04	1863.20	1097.10	0.00	354.00	1.00	0.45	0.00	0.20	1.66
2029	43	5.57	0.04	1863.20	1097.10	0.00	354.00	0.89	0.40	0.00	0.18	1.48
2030	44	5.57	0.03	1863.20	1097.10	0.00	354.00	0.80	0.35	0.00	0.16	1.32
2031	45	5.57	0.03	1863.20	1097.10	0.00	354.00	0.71	0.32	0.00	0.14	1.18
2032	46	5.57	0.03	1863.20	1097.10	0.00	354.00	0.63	0.28	0.00	0.13	1.05
2033	47	5.57	0.02	1863.20	1097.10	0.00	354.00	0.57	0.25	0.00	0.11	0.94
2034	48	5.57	0.02	1863.20	1097.10	0.00	354.00	0.50	0.22	0.00	0.10	0.84
2035	49	5.57	0.02	1863.20	1097.10	0.00	354.00	0.45	0.20	0.00	0.09	0.75
2036	50	5.57	0.01	1863.20	1097.10	0.00	354.00	0.40	0.18	0.00	0.08	0.67
2037	51	5.57	0.01	1863.20	1097.10	0.00	354.00	0.36	0.16	0.00	0.07	0.59
2038	52	5.57	0.01	1863.20	1097.10	0.00	354.00	0.32	0.14	0.00	0.06	0.53
2039	53	5.57	0.01	1863.20	1097.10	0.00	354.00	0.28	0.12	0.00	0.05	0.47
2040	54	5.57	0.01	1863.20	1097.10	0.00	354.00	0.25	0.11	0.00	0.05	0.42
2041	55	5.57	0.01	1863.20	1097.10	0.00	354.00	0.23	0.10	0.00	0.04	0.38
2042	56	5.57	0.00	1863.20	1097.10	0.00	354.00	0.20	0.09	0.00	0.04	0.34
2043	57	5.57	0.00	1863.20	1097.10	0.00	354.00	0.18	0.08	0.00	0.03	0.30
Total		766.39	245.49					198.21	175.99	6.85	47.71	428.78

C1: average net cost of useful salable energy and capacity
C2: average net cost of useful salable energy
C3: average net cost of total energy and capacity

7.2.2 Classification of Supply Capacity

For evaluation of quantity and quality of electricity serviceable by the hydroelectric power project, it is required to observe the relation between load demand and supply capacity.

Namely, it is necessary to divide the full supply capacity into two components; salable and surplus ones, corresponding to load demand.

(1) Firm Peak Output (P_F)

As this power plant is capable of daily regulation, the firm output is determined by configuration of daily load curve and daily river discharge, i.e., the firm peak output at the firm discharge is shown by the following equation.

$$P_F = 9.8\eta \cdot He \cdot Q_{LL} \cdot 24hr/Tp$$

η : Total generation efficiency

He : Effective head (m)

Q_{LL}: Firm discharge (m^3/s) 1/

Tp : Equivalent peak duration time (hr) 2/

1/ Firm discharge (Q_{LL})

Based on river discharge (Qd) at the proposed dam site estimated in the previous chapter 5 "Hydrology and Meteorology" and duration curves induced therefrom for 11 years from 1975 to 1985, the average value of river discharge available for 95% of time of a year is adopted as the firm discharge.

$$Q_{LL} = 87\ m^3/s$$

2/ Equivalent peak duration time (Tp)

Based on the power and energy demand forecast described in Chapter 2 and the actual daily load curve recorded in January 1985, the daily load curve at the maximum daily demand in each month is estimated for the years after 1993/94 at which the first commissioning of the project is requested (refer to Fig. 7-2).

Then, the equivalent duration peak time in respective months are calculated in terms of the incremental energy demand in kWh divided by the incremental peak demand in kW. As shown in Table 7-2, the equivalent duration peak time in January corresponding to the annual maximum peak demand is calculated to be 15.78

Table 7–2 Equivalent Peak Duration Time

DAILY PEAK LOAD(MW)

	JUL.	AUG.	SEP.	OCT.	NOV.	DEC.	JAN.	FEB.	MAR.	APR.	MAY.	JUN.
1985	64.9	68.9	67.0	69.9	71.5	74.2	79.7	79.5	77.6	73.7	73.3	71.9
1994	205.	218.	212.	221.	226.	234.	252.	251.	245.	233.	232.	227.
1995	239.	253.	246.	257.	263.	273.	293.	292.	285.	271.	270.	264.
1996	253.	268.	261.	272.	278.	289.	310.	309.	302.	287.	285.	280.
1997	267.	283.	275.	287.	293.	305.	327.	326.	318.	302.	301.	295.
1998	281.	298.	290.	303.	310.	321.	345.	344.	336.	319.	318.	311.
1999	297.	315.	306.	319.	327.	339.	364.	363.	355.	337.	335.	329.
2000	313.	332.	323.	337.	344.	357.	384.	383.	374.	355.	354.	346.
2001	330.	350.	340.	355.	363.	377.	405.	404.	394.	374.	373.	365.
2002	348.	369.	358.	374.	383.	397.	426.	425.	415.	394.	393.	385.

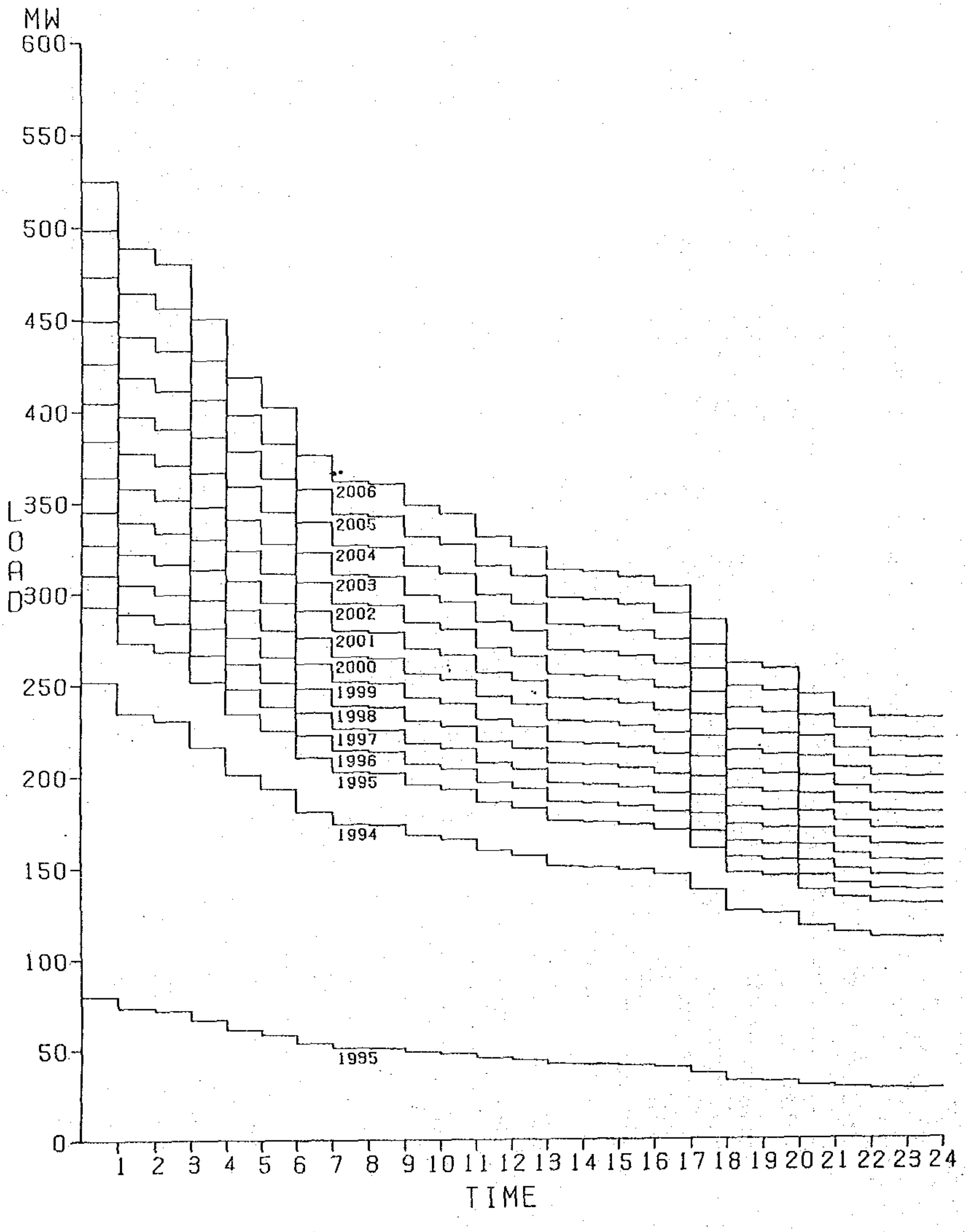
DAILY ENERGY CONSUMPTION(MWH)

	JUL.	AUG.	SEP.	OCT.	NOV.	DEC.	JAN.	FEB.	MAR.	APR.	MAY.	JUN.
1985	830.	871.	819.	832.	902.	1056.	1144.	1110.	1068.	942.	862.	882.
1994	3076.	3184.	3048.	3083.	3268.	3684.	3938.	3843.	3725.	3378.	3162.	3215.
1995	3585.	3711.	3552.	3593.	3808.	4291.	4586.	4477.	4339.	3936.	3685.	3747.
1996	3797.	3929.	3762.	3805.	4032.	4542.	4855.	4739.	4593.	4167.	3902.	3967.
1997	4006.	4146.	3969.	4015.	4255.	4793.	5123.	5000.	4847.	4397.	4117.	4187.
1998	4231.	4378.	4192.	4240.	4493.	5060.	5408.	5279.	5117.	4643.	4348.	4421.
1999	4465.	4620.	4424.	4474.	4741.	5339.	5707.	5570.	5399.	4899.	4588.	4665.
2000	4707.	4871.	4634.	4718.	4998.	5630.	6017.	5873.	5693.	5166.	4837.	4918.
2001	4960.	5133.	4914.	4971.	5267.	5932.	6340.	6189.	5999.	5443.	5097.	5182.
2002	5223.	5405.	5175.	5234.	5546.	6248.	6678.	6518.	6318.	5732.	5367.	5458.

EQUIVALENT PEAK DURATION TIME(HOURS)

	JUL.	AUG.	SEP.	OCT.	NOV.	DEC.	JAN.	FEB.	MAR.	APR.	MAY.	JUN.	AVERAGE
1994													
1995	14.97	15.06	14.82	14.17	14.59	15.56	15.80	15.46	15.35	14.66	13.76	14.38	14.89
1996	15.02	14.90	14.57	14.16	14.69	15.60	15.81	15.45	15.23	14.61	13.96	14.19	14.85
1997	15.00	14.80	14.62	14.12	14.73	15.62	15.80	15.43	15.37	14.77	13.84	14.29	14.87
1998	15.20	14.93	14.67	14.11	14.58	15.82	15.81	15.44	15.30	14.71	13.79	14.36	14.89
1999	15.10	14.80	14.64	14.19	14.58	15.76	15.79	15.42	15.22	14.63	13.84	14.22	14.85
2000	15.10	14.80	14.56	14.09	14.66	15.82	15.75	15.38	15.26	14.66	13.73	14.31	14.84
2001	15.07	14.77	14.58	14.09	14.59	15.72	15.70	15.33	15.26	14.65	13.72	14.25	14.81
2002	15.01	14.71	14.57	14.06	14.51	15.73	15.75	15.37	15.25	14.62	13.70	14.20	14.79
AVERAGE	15.06	14.84	14.63	14.12	14.62	15.70	15.78	15.41	15.28	14.66	13.79	14.27	14.85

Fig. 7-2 Estimated Daily Peak Load Duration Curve at January (1994 to 2006)



hours, while that in the month corresponding to the monthly maximum peak demand is 14.85 hours. Thus, the average value of 15 hours is adopted as the equivalent peak duration time.

(2) Available Energy Production (E_T)

Available energy production is the annual average value of total energy production at the powerhouse calculated based on daily discharges at the dam site for 11 years from 1975 to 1985.

(3) Firm Energy (E_L)

The firm energy is defined to be the energy meeting the domestic demand in Nepal throughout the year. In this case, the power discharge is limited upto the firm discharge stated in (1) above.

(4) Secondary Energy (E_S)

The secondary energy is expressed in terms of the total energy production minus the firm energy.

7.2.3 Classification of Project Sales

(1) Useful Capacity (Puy)

Useful capacity is a part of power to be applied to calculation of kW value for project evaluation. Useful capacity is selected out of incremental power demand of the respective years and firm peak output (P_F) in the same years, whichever is smaller. Namely, useful capacity is, out of the firm peak output, the power being considered consumable as referred to load demand forecast.

(2) Salable Energy

(i) Salable domestic energy (E_{ADy})

For incremental domestic energy demand, firm energy is to be preferentially supplied. The remining energy after deduction of domestic demand from firm energy is considered as surplus energy in the case of "without export".

(ii) Salable export energy (E_{AEy})

Basically, salable export energy defined in this study is the residual of energy production after preferential supply for domestic use. It is not known how the imported energy be consumed by the importing country and accordingly, it is difficult to exactly evaluate the benefit as previously stated.

(3) Surplus Energy (Esy)

(i) Without export (Case I and II)

The residual energy after deduction of domestic energy consumption from annual energy production in the case of "without export".

(ii) With export (Case III)

The residual energy after deductions of domestic energy consumption from annual energy production for the period before generating operation of the equipment to be installed as the second stage development.

Fig. 7-3 indicates the typical chart of capacity and energy defined above.

7.2.4 Calculation of Supply Capacity and Project Sales

Power and energy defined in 7.2.2 and 7.2.3 above are estimated in accordance with the procedure shown in Fig. 7-4 based on the following basic data. Demand and supply balance is examined for the

Fig. 7-3 Typical Chart of Demand and Sales

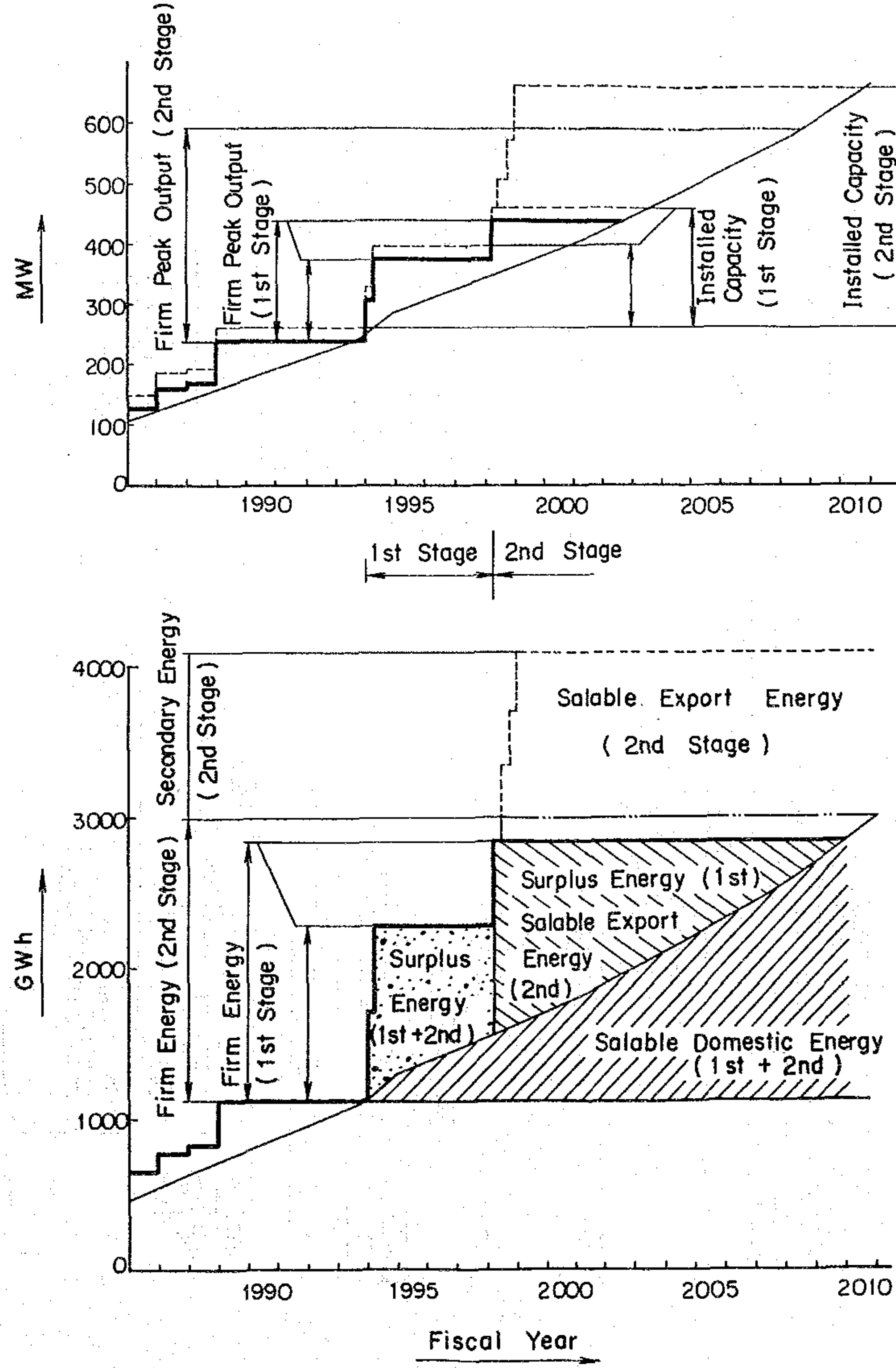
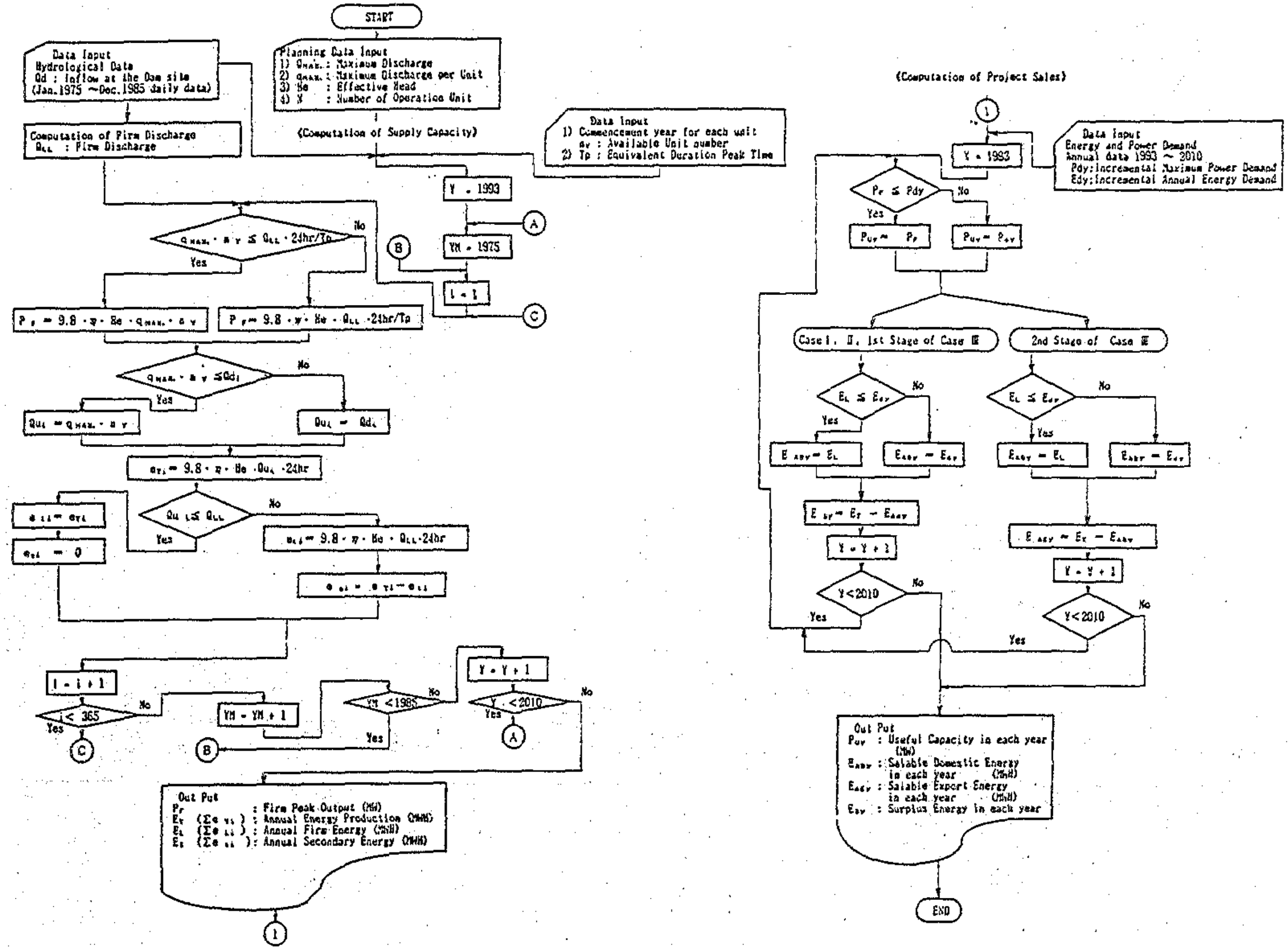


Fig. 7–4 Calculation Procedure of Supply Capacity and Project Sales



period from 1993 to 2010 and all figures at 2010 are also applied to the economical evaluation for further years since they are constant after 2010.

Hydrological data:	Daily discharge record at damsite for 11 years from Jan. 1, 1975 to Dec. 31, 1985 (refer to Chapter 5 : Hydrology and Meteorology)
Power demand forecast:	Power and energy demand from 1993 to 2010 described in Chapter 2.

The examples of the demand and supply balance sheets are shown in Table 7-3 (1), (2).

7.2.5 Benefit Components

In this study, the values of generating components for economic evaluation of the Arun 3 project are quoted from the "Long Run Marginal Costs of Electricity Generation in Nepal" (Report No. 3/2/301284/1/2 Seq. 211 prepared by WERDP in Dec. 1984) wherein the discount rate of 12% is adopted, provided that escalation of 6% per annum is applied to the above in order to coordinate the time with that of estimating construction cost. However, the unit rate expected for power export is used as benefit value.

Value of Generation Components

Generation Capacity	68 US$/kW/yr
Firm Energy	0.063 US$/kWh/yr
Export Energy	0.048 US$/kWh/yr
Surplus Energy	0.005 US$/kWh/yr

7.2.6 Cost

The cost applied to the project evaluation of each alternative plan consists of construction cost and operation and maintenance cost.

Table 7–3 (1) Power/Energy Demand & Sales Case I–80, II–80

Pmax.= 201.0MW N= 3

Year	System Demand				Supply Capacity				Project Sales		
	Total Energy Demand (GWH)	Incremental Energy Demand (GWH)	Total Peak Demand (MW)	Incremental Peak Demand (MW)	Firm Energy (GWH/Yr)	Secondary Energy (GWH/Yr)	Total Energy (GWH/Yr)	Firm Peak Output (MW)	Salable Energy (GWH/Yr)	Surplus Energy (GWH/Yr)	Useful Capacity (MW)
1987	635.0		141.1								
1988	710.0		157.7								
1989	787.0		177.4								
1990	870.0		196.3								
1991	946.0		213.3								
1992	1038.0		233.8								
1993	1128.0		241.0								
1994	1307.0	179.0	293.0	52.0	1159.7	0.0	1159.7	134.0	179.0	980.7	52.0
1995	1384.0	256.0	310.0	69.0	1159.7	0.0	1159.7	134.0	256.0	903.7	69.0
1996	1461.0	333.0	327.1	86.1	1159.7	0.0	1159.7	134.0	333.0	826.7	86.1
1997	1543.0	415.0	345.2	104.2	1159.7	0.0	1159.7	134.0	415.0	744.7	104.2
1998	1628.0	500.0	364.2	123.2	1159.7	0.0	1159.7	134.0	500.0	659.7	123.2
1999	1716.0	588.0	384.0	143.0	1721.6	0.0	1721.6	201.0	588.0	1133.6	143.0
2000	1808.0	680.0	404.7	163.7	1721.6	0.0	1721.6	201.0	680.0	1041.6	163.7
2001	1904.0	776.0	426.4	185.4	1721.6	0.0	1721.6	201.0	776.0	945.6	185.4
2002	2004.0	876.0	449.3	208.3	1721.6	0.0	1721.6	201.0	876.0	845.6	201.0
2003	2108.0	980.0	473.3	232.3	1721.6	0.0	1721.6	201.0	980.0	741.6	201.0
2004	2217.0	1089.0	498.5	257.5	1721.6	0.0	1721.6	201.0	1089.0	632.6	201.0
2005	2329.0	1201.0	524.8	283.8	1721.6	0.0	1721.6	201.0	1201.0	520.6	201.0
2006	2446.0	1318.0	552.3	311.3	1721.6	0.0	1721.6	201.0	1318.0	403.6	201.0
2007	2568.0	1440.0	581.1	340.1	1721.6	0.0	1721.6	201.0	1440.0	281.6	201.0
2008	2695.0	1567.0	611.5	370.5	1721.6	0.0	1721.6	201.0	1567.0	154.6	201.0
2009	2827.0	1699.0	642.5	401.5	1721.6	0.0	1721.6	201.0	1699.0	22.6	201.0
2010	2965.0	1837.0	675.3	434.3	1721.6	0.0	1721.6	201.0	1721.6	0.0	201.0
2011	3109.0	1981.0	709.4	468.4	1721.6	0.0	1721.6	201.0	1721.6	0.0	201.0
2012	3258.0	2130.0	745.0	504.0	1721.6	0.0	1721.6	201.0	1721.6	0.0	201.0
2013	3413.0	2285.0	782.1	541.1	1721.6	0.0	1721.6	201.0	1721.6	0.0	201.0
2014	3574.0	2446.0	820.7	579.7	1721.6	0.0	1721.6	201.0	1721.6	0.0	201.0

Table 7–3 (2) Power/Energy Demand & Sales Case III–160

Pmax.= 402.0MW N= 6

Year	System Demand				Supply Capacity				Project Sales		
	Total Energy Demand (GWH)	Incremental Energy Demand (GWH)	Total Peak Demand (MW)	Incremental Peak Demand (MW)	Firm Energy (GWH/Yr)	Secondary Energy (GWH/Yr)	Total Energy (GWH/Yr)	Firm Peak Output (MW)	Salable Energy (GWH/Yr)	Surplus Energy (GWH/Yr)	Useful Capacity (MW)
1987	635.0		141.1								
1988	710.0		157.7								
1989	787.0		177.4								
1990	870.0		196.3								
1991	946.0		213.3								
1992	1038.0		233.8								
1993	1128.0		241.0								
1994	1307.0	179.0	293.0	52.0	1159.7	0.0	1159.7	134.0	179.0	980.7	52.0
1995	1384.0	256.0	310.0	69.0	1159.7	0.0	1159.7	134.0	256.0	903.7	69.0
1996	1461.0	333.0	327.1	86.1	1159.7	0.0	1159.7	134.0	333.0	826.7	86.1
1997	1543.0	415.0	345.2	104.2	1159.7	0.0	1159.7	134.0	415.0	744.7	104.2
1998	1628.0	500.0	364.2	123.2	1159.7	0.0	1159.7	134.0	500.0	659.7	123.2
1999	1716.0	588.0	384.0	143.0	1863.2	1097.1	2960.3	354.0	588.0	2372.3	143.0
2000	1808.0	680.0	404.7	163.7	1863.2	1097.1	2960.3	354.0	680.0	2280.3	163.7
2001	1904.0	776.0	426.4	185.4	1863.2	1097.1	2960.3	354.0	776.0	2184.3	185.4
2002	2004.0	876.0	449.3	208.3	1863.2	1097.1	2960.3	354.0	876.0	2084.3	208.3
2003	2108.0	980.0	473.3	232.3	1863.2	1097.1	2960.3	354.0	980.0	1980.3	232.3
2004	2217.0	1089.0	498.5	257.5	1863.2	1097.1	2960.3	354.0	1089.0	1871.3	257.5
2005	2329.0	1201.0	524.8	283.8	1863.2	1097.1	2960.3	354.0	1201.0	1759.3	283.8
2006	2446.0	1318.0	552.3	311.3	1863.2	1097.1	2960.3	354.0	1318.0	1642.3	311.3
2007	2568.0	1440.0	581.1	340.1	1863.2	1097.1	2960.3	354.0	1440.0	1520.3	340.1
2008	2695.0	1567.0	611.5	370.5	1863.2	1097.1	2960.3	354.0	1567.0	1393.3	354.0
2009	2827.0	1699.0	642.5	401.5	1863.2	1097.1	2960.3	354.0	1699.0	1261.3	354.0
2010	2965.0	1837.0	675.3	434.3	1863.2	1097.1	2960.3	354.0	1837.0	1123.3	354.0
2011	3109.0	1981.0	709.4	468.4	1863.2	1097.1	2960.3	354.0	1863.2	1097.1	354.0
2012	3258.0	2130.0	745.0	504.0	1863.2	1097.1	2960.3	354.0	1863.2	1097.1	354.0
2013	3413.0	2285.0	782.1	541.1	1863.2	1097.1	2960.3	354.0	1863.2	1097.1	354.0
2014	3574.0	2446.0	820.7	579.7	1863.2	1097.1	2960.3	354.0	1863.2	1097.1	354.0

(1) Construction Cost

The construction cost is estimated at price level on June 1986 and includes those for access road, supporting facilities, civil structures, hydraulic equipment, electrical equipment and transmission line and substation facilities. And the total project cost is estimated adding administration cost including engineering cost and contingency including compensation. Interest during construction and import duties are, however, excluded.

(2) Operation and Maintenance Cost

Operation and maintenance cost is calculated at the following percentage to each work component. However, the required cost for replacing equipment is neglected in this study.

Civil works	1%
Hydromechanical equipment	2%
Electrical equipment	2%
Transmission line and substation facilities	1.5%

(3) Cost

The required cost for each alternative plan and the examples of its annual disbursement are shown in Tables 7-4 (1) and (2), and Tables 7-5 (1), (2) and (3), respectively.

7.3 Analysis

7.3.1 Case I (Domestic Power Demand only)

(1) Maximum Power Discharge

Studies are made for 5 cases corresponding to various maximum power discharges in the range of 60 m^3/s to 100 m^3/s as shown in Table 7-6 (1) and the costs and benefits for various power discharges are shown in Fig. 7-5. The powerhouse site, intake water level and number of headrace tunnels applied to this study are the Pikhuwa site, EL. 840 m and single line, respec-

Table 7–4 (1) Construction Cost (Case I)

	I -60	I -70	I -80	I -90	I -100	I -80-830	I -80-855	I -80-875	I -80-S	I -80-K
Installed Capacity (MW)	149.4	174.9	201	224.8	250.4	193.8	211.2	223.6	149.1	211.8
1. Civil Works 1-1 Access Road	39000	39000	39000	39000	39000	39000	39000	39000	39000	39000
1-2 Preparatory Works	9700	9700	9700	9700	9700	9700	9700	9700	9700	9700
1-3 Diversion & Coffer Dam	10752	10752	10752	10752	10752	10752	10752	10752	10752	10752
1-4 Dam & Spillway	26400	26400	26400	26400	26400	19800	39999	78728	26400	26400
1-5 Intake & Desilting Basin	10200	11600	12632	14450	16000	12632	15532	17675	12632	12632
1-6 Headrace & Surge Tank	32500	36000	38424	43050	46000	38424	38424	38646	24773	40725
1-7 Penstock	2310	2560	2728	3060	3270	2728	2810	3002	2350	4469
1-8 Powerhouse & Switchyard	12510	14150	15769	18430	20520	15769	16242	18356	12532	17744
1-9 Tailrace Tunnel	2830	3140	3345	3750	4000	3345	3345	3345	3345	3345
Sub Total	146202	153302	158750	168592	175642	152150	175804	219204	141484	164767
2. Hydraulic Equipment	7130	7900	8674	9490	10400	8485	9680	10624	7277	13122
3. Electromechanical Facilities	34200	36100	38400	44700	46200	38100	39300	44700	33080	38990
4. Transmission Line & Substation	87500	87500	87500	87500	101400	87500	87500	87500	87500	87500
5. Total Cost (1+2+3+4)	275032	284802	293324	310282	333642	286235	312284	362028	269341	304379
6. Engineering & Administration 5×7.5%	20627	21360	21999	23271	25023	21468	23421	27152	20201	22828
7. Physical Contingency 1×15% + (2+3+4+6)×10%	36876	38281	39470	41785	44649	38378	42361	49878	36028	40959
Grand Total (5+6+7)	332535	344443	354793	375338	403314	346081	378066	439058	325570	368166

Table 7–4 (2) Construction Cost (Case II, III)

	II-60	II-70	II-80	II-90	II-100	III-120	III-140	III-160	III-180	III-200
Installed Capacity (MW)	149.4	174.9	201	224.8	250.4	298.8	349.8	402	449.6	500.8
1. Civil Works 1-1 Access Road	39000	39000	39000	39000	39000	39000	39000	39000	39000	39000
1-2 Preparatory Works	9700	9700	9700	9700	9700	9700	9700	9700	9700	9700
1-3 Diversion & Coffer Dam	10752	10752	10752	10752	10752	10752	10752	10752	10752	10752
1-4 Dam & Spillway	26400	26400	26400	26400	26400	26400	26400	26400	26400	26400
1-5 Intake & Desilting Basin	20400	23200	25263	28900	32000	20400	23200	25263	28900	32000
1-6 Headrace & Surge Tank	32500	36000	38424	43050	46000	65000	72000	76847	86100	92000
1-7 Penstock	3822	4078	4373	5015	5260	6457	6900	7405	8486	8900
1-8 Powerhouse & Switchyard	18210	19541	21467	23702	25254	22765	24372	25920	29398	31272
1-9 Tailrace Tunnel	3747	4092	4365	4928	5282	5036	5500	5860	6624	7100
Sub Total	164531	172763	179744	191447	199648	205510	217824	227147	245360	257124
2. Hydraulic Equipment	7720	8399	9554	10771	12062	12226	13300	15128	17056	19100
3. Electromechanical Facilities	34200	36100	38400	44700	46200	61200	64800	69400	82900	86500
4. Transmission Line & Substation	87500	87500	87500	87500	101400	107000	107000	107000	107000	107000
5. Total Cost (1+2+3+4)	293951	304762	315198	334418	359310	385936	402924	418675	452316	469724
6. Engineering & Administration 5×7.5%	22046	22857	23640	25081	26948	28945	30219	31401	33924	35229
7. Physical Contingency 1×15% + (2+3+4+6)×10%	39826	41400	42871	45522	48608	51764	54206	56365	60892	63352
Grand Total (5+6+7)	355823	369019	381709	405021	434866	466645	487349	506441	547132	568305

Table 7-5 (1) Disbursement Schedule Case I-80

Construction Period T= 13 years
Maximum Output P= 201 MW

Unit: 1,000 US$

	Const.Cost 1,000US$	1 1987	2 1988	3 1989	4 1990	5 1991	6 1992	7 1993	8 1994	9 1995	10 1996	11 1997	12 1998	13 1999	14 2000	15 2001	16 2002	17 2003	18 2004	19 2005	20 2006	21 2007
Installed Capacity (MW)	201	0	0	0	0	0	0	0	134	134	134	134	134	201	201	201	201	201	201	201	201	201
1. Civil Works 1-1 Access Road	39000	3900	13650	13650	3900	3900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1-2 Preparatory Works	9700	0	2231	1697	1940	766	1270	1270	523	0	0	0	0	0	0	0	0	0	0	0	0	0
1-3 Diversion & Coffer Dam	10752	0	0	2150	4300	4300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1-4 Dam & Spillway	26400	0	0	0	2640	7920	7920	5280	2640	0	0	0	0	0	0	0	0	0	0	0	0	0
1-5 Intake & Desilting Basin	12632	0	0	0	0	2526	3789	3789	2526	0	0	0	0	0	0	0	0	0	0	0	0	0
1-6 Headrace & Surge Tank	38424	0	0	0	3842	7684	11527	11527	3842	0	0	0	0	0	0	0	0	0	0	0	0	0
1-7 Penstock	2728	0	0	0	272	818	818	545	272	0	0	0	0	0	0	0	0	0	0	0	0	0
1-8 Powerhouse & Switchyard	15769	0	0	0	1576	3153	4730	4730	788	0	0	0	473	315	0	0	0	0	0	0	0	0
1-9 Tailrace Tunnel	3345	0	0	0	0	669	1672	1003	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub Total	158750	3900	15881	17497	18472	31739	31729	28147	10593	0	0	0	473	315	0	0	0	0	0	0	0	0
2. Hydraulic Equipment	8674	0	0	0	0	867	1734	3469	2602	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Electromechanical Facilities	38400	0	0	0	0	2918	11596	8716	5798	0	0	4684	3763	921	0	0	0	0	0	0	0	0
4. Transmission Line & Substation	87500	0	0	0	0	0	7875	47337	23712	0	0	0	5162	3412	0	0	0	0	0	0	0	0
5. Total Cost (1+2+3+4)	293324	3900	15881	17498	18473	35525	52936	87671	42707	0	0	4685	9399	4649	0	0	0	0	0	0	0	0
6. Engineering & Administration 5×7.5%	21999	293	1191	1312	1385	2664	3970	6575	3203	0	0	351	705	349	0	0	0	0	0	0	0	0
7. Physical Contingency 1×15% + (2+3+4+6)×10%	39470	614	2501	2756	2909	5406	7277	10832	5121	0	0	504	1034	516	0	0	0	0	0	0	0	0
Grand Total (5+6+7)	354793	4807	19573	21566	22767	43595	64183	105078	51031	0	0	5540	11138	5514	0	0	0	0	0	0	0	0
O & M Cost	3841	0	0	0	0	0	0	0	2561	2561	2561	2561	2561	3841	3841	3841	3841	3841	3841	3841	3841	3841
Total (Grand Total + O&M Cost)	358634	4807	19573	21566	22767	43595	64183	105078	53592	2561	2561	8101	13699	9355	3841	3841	3841	3841	3841	3841	3841	3841

Table 7-5 (2) Disbursement Schedule Case II-80

Construction Period T= 13 years
Maximum Output P= 201 MW

Unit: 1,000 US$

	Const. Cost 1,000US$	1 1987	2 1988	3 1989	4 1990	5 1991	6 1992	7 1993	8 1994	9 1995	10 1996	11 1997	12 1998	13 1999	14 2000	15 2001	16 2002	17 2003	18 2004	19 2005	20 2006	21 2007
Installed Capacity (MW)	201	0	0	0	0	0	0	0	134	134	134	134	134	201	201	201	201	201	201	201	201	201
1. Civil Works 1-1 Access Road	39000	3900	13650	13650	3900	3900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1-2 Preparatory Works	9700	0	2231	1697	1940	766	1270	1270	523	0	0	0	0	0	0	0	0	0	0	0	0	0
1-3 Diversion & Coffer Dam	10752	0	0	2150	4300	4300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1-4 Dam & Spillway	26400	0	0	0	2640	7920	7920	5280	2640	0	0	0	0	0	0	0	0	0	0	0	0	0
1-5 Intake & Desilting Basin	25263	0	0	0	0	5052	7578	7578	5052	0	0	0	0	0	0	0	0	0	0	0	0	0
1-6 Headrace & Surge Tank	38424	0	0	0	3842	7684	11527	11527	3842	0	0	0	0	0	0	0	0	0	0	0	0	0
1-7 Penstock	4373	0	0	0	437	1311	1311	874	437	0	0	0	0	0	0	0	0	0	0	0	0	0
1-8 Powerhouse & Switchyard	21467	0	0	0	2146	4293	6440	6440	1073	0	0	0	644	429	0	0	0	0	0	0	0	0
1-9 Tailrace Tunnel	4365	0	0	0	0	873	2182	1309	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sub Total	179744	3900	15881	17497	19207	36102	38231	34281	13569	0	0	0	644	429	0	0	0	0	0	0	0	0
2. Hydraulic Equipment	9554	0	0	0	0	955	1910	3821	2866	0	0	0	0	0	0	0	0	0	0	0	0	0
3. Electromechanical Facilities	38400	0	0	0	0	2918	11596	8716	5798	0	0	4684	3763	921	0	0	0	0	0	0	0	0
4. Transmission Line & Substation	87500	0	0	0	0	0	7875	47337	23712	0	0	0	5162	3412	0	0	0	0	0	0	0	0
5. Total Cost (1+2+3+4)	315198	3900	15881	17498	19207	39977	59614	94157	45947	0	0	4685	9570	4763	0	0	0	0	0	0	0	0
6. Engineering & Administration 5×7.5%	23640	293	1191	1312	1441	2998	4471	7062	3446	0	0	351	718	357	0	0	0	0	0	0	0	0
7. Physical Contingency 1×15% + (2+3+4+6)×10%	42871	614	2501	2756	3025	6103	8320	11836	5618	0	0	504	1061	534	0	0	0	0	0	0	0	0
Grand Total (5+6+7)	381709	4807	19573	21566	23673	49078	72405	113055	55011	0	0	5540	11349	5654	0	0	0	0	0	0	0	0
O & M Cost	4069	0	0	0	0	0	0	0	2713	2713	2713	2713	2713	4069	4069	4069	4069	4069	4069	4069	4069	4069
Total (Grand Total + O&M Cost)	385778	4807	19573	21566	23673	49078	72405	113055	57724	2713	2713	8253	14062	9723	4069	4069	4069	4069	4069	4069	4069	4069

Table 7–5 (3) Disbursement Schedule Case III–160

Construction Period T= 13 years
Maximum Output P= 402 MW

Unit: 1,000 US$

	Const. Cost 1,000US$	1 1987	2 1988	3 1989	4 1990	5 1991	6 1992	7 1993	8 1994	9 1995	10 1996	11 1997	12 1998	13 1999	14 2000	15 2001	16 2002	17 2003	18 2004	19 2005	20 2006	21 2007
Installed Capacity (MW)	402	0	0	0	0	0	0	0	134	134	134	134	134	402	402	402	402	402	402	402	402	402
1. Civil Works 1-1 Access Road	39000	3900	13650	13650	3900	3900	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1-2 Preparatory Works	9700	0	2231	1697	1940	766	1270	1270	523	0	0	0	0	0	0	0	0	0	0	0	0	0
1-3 Diversion & Coffer Dam	10752	0	0	2150	4300	4300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1-4 Dam & Spillway	26400	0	0	0	2640	7920	7920	5280	2640	0	0	0	0	0	0	0	0	0	0	0	0	0
1-5 Intake & Desilting Basin	25263	0	0	0	0	5052	7578	7578	5052	0	0	0	0	0	0	0	0	0	0	0	0	0
1-6 Headrace & Surge Tank	76847	0	0	0	3842	7684	11527	11527	7684	7684	11527	11527	3842	0	0	0	0	0	0	0	0	0
1-7 Penstock	7405	0	0	0	444	1332	1332	888	444	0	888	1184	888	0	0	0	0	0	0	0	0	0
1-8 Powerhouse & Switchyard	25920	0	0	0	2151	4302	6454	6454	1114	0	0	2851	2332	259	0	0	0	0	0	0	0	0
1-9 Tailrace Tunnel	5860	0	0	0	0	867	2168	1300	0	0	0	761	761	0	0	0	0	0	0	0	0	0
Sub Total	227147	3900	15881	17497	19218	36127	38251	34300	17459	7684	12415	16324	7825	259	0	0	0	0	0	0	0	0
2. Hydraulic Equipment	15128	0	0	0	0	953	1906	3812	2859	0	0	3025	2571	0	0	0	0	0	0	0	0	0
3. Electromechanical Facilities	69400	0	0	0	0	2914	11589	8675	5829	0	0	20195	16178	4025	0	0	0	0	0	0	0	0
4. Transmission Line & Substation	107000	0	0	0	0	0	7918	47294	23647	0	0	16906	11235	0	0	0	0	0	0	0	0	0
5. Total Cost (1+2+3+4)	418675	3900	15881	17498	19219	39995	59666	94082	49796	7685	12416	56452	37803	4284	0	0	0	0	0	0	0	0
6. Engineering & Administration 5×7.5%	31401	293	1191	1312	1441	3000	4475	7056	3735	576	931	4234	2835	321	0	0	0	0	0	0	0	0
7. Physical Contingency 1×15% + (2+3+4+6)×10%	56365	614	2501	2756	3027	6106	8327	11829	6226	1210	1955	6885	4455	474	0	0	0	0	0	0	0	0
Grand Total (5+6+7)	506441	4807	19573	21566	23687	49101	72468	112967	59757	9471	15302	67571	45093	5079	0	0	0	0	0	0	0	0
O & M Cost	5567	0	0	0	0	0	0	0	1856	1856	1856	1856	1856	5567	5567	5567	5567	5567	5567	5567	5567	5567
Total (Grand Total + O&M Cost)	512008	4807	19573	21566	23687	49101	72468	112967	61613	11327	17158	69427	46949	10646	5567	5567	5567	5567	5567	5567	5567	5567

tively. Eventually, it is found that the optimum scale will have the maximum power discharge of 80 m^3/s which gives the maximum output of around 200 MW.

As observed in Fig. 7-5, benefit curve is divided roughly into 2 portions, namely, the first portion indicating sharp rise corresponding to increase of power discharge from 0 to 80 m^3/s, and the second portion indicating gentle slope. The sharp rise in the first portion originates from the high kW and kWh values of the firm energy for domestic use.

In general, the benefit curve has a character that the incremental benefit per unit discharge becomes smaller for the larger maximum power discharge. In connection with cost curve, since the major variables are the costs for headrace tunnel and electric equipment and further, the capacity of generating equipment and tunnel diameter vary linearly in proportion to the maximum power discharge, the gradient of cost curve is almost constant with exception that the curve for power discharge of more than 90 m^3/s has different character due to increase of number of units from 3 to 4.

(2) Intake Water Level

Table 7-6 (2) and Fig. 7-6 show the results of analytical study on 4 cases having different dam height, for the power station at the Pikhuwa site as a representative and power discharge of 80 m^3/s. The benefit values are dotted on almost straight lines, while, the cost curve above EL. 840 m becomes steeper than that below EL. 840 m due to additional costs required for dealing with the landslide existing on right bank above EL. 850 m and strengthening of the part crossing the Khoktak Khola of the desanding basin. Referring to the abovementioned benefit and cost curves, the optimum intake water level is set at EL. 840 m.

(3) Powerhouse Site

As shown in Table 7-6 (3) and Fig. 7-7, the comparative study of 3 powerhouse sites: Solakhani, Pikhuwa and Kaguwa sites, is carried out based on the intake water level at EL. 840 m and power discharge of 80 m^3/s. It is observed that the economical situation of the Solakhani site is apparently worse than those of other two downstream sites. As to the comparison of the Pikhuwa site with the Kaguwa site, it is found that the incremental benefit due to additional head at the Kaguwa site is just absorbed by the cost increase attributable to the electrical equipment of larger scale as well as geological disadvantages and further, the net present value (B-C) at the Pikhuwa site is slightly larger than the other one.

Accordingly, the powerhouse site is selected at the Pikhuwa site taking also the geological advantages into consideration.

7.3.2 Case II (1st Stage Development)

On the assumption that the extension works (2nd stage development) required for power export will be executed in the future following those included in Case I, Case II includes a part of the works of the second stage development to be executed in advance. The works to be executed in advance are intake, desanding basin, powerhouse and tailrace outlet which will jeopardize safety of the structures already completed, if these works are executed separately as the second stage development. The parameter applied to this study is the maximum power discharge only, while, the powerhouse site and intake water level are fixed at the Pikhuwa site and EL. 840 m being selected for the optimum development scheme in Case I study.

The results of this study are shown in Table 7-6 (1) and Fig. 7-5 in which the benefit curve is common with Case I and the cost line runs in parallel with that of Case I. Owing to the above, the highest point of net present value (B-C) falls on the line corresponding to the maximum power discharge of 80 m^3/s similarly to Case I. The difference of B-C curves between Cases I and II just corresponds to the advanced execution of the structures for power export. The results of Case II study indicate that this project will be still economically feasible even if the extension plan is suspended after completion of the first stage development due to the problems concerning power export.

7.3.3 Case III (2nd Stage Development)

Since Case III study is made on the basis of various assumptions as stated in 7.1, the benefit and cost induced therefrom involve much of uncertainty. In particular, the amount of power to be exported and its price are the basic elements for estimating the benefit and can be reasonably fixed upon conclusion of negotiation with the importing country. In this study, it is assumed that all surplus power can be exported from the viewpoint of enhancing project economy as much as possible. Comparing Fig. 7-5 with Fig. 7-8, it can be observed that the economical situation of the project in the case of power export is much better than the other. There exists discontinuity of benefit curve between power discharges of 160 m^3/s and 180 m^3/s in Fig. 7-8, and this owes to the fact that the number of unit increases from 6 to 8 due to limited unit capacity resulting in delay of commissioning date of one year.

In other words, this will indicate that the higher project economy can be obtained by the earlier commissioning of unit when power export is considered. Because of discontinuity of benefit curve shown in the said figure, the highest point of net present value (B-C) falls on the line corresponding to the maximum power discharge of 160 m^3/s which is just double amount of the power discharge of 80 m^3/s optimized in the studies of Cases I and II. This is quite advantageous to make the coordinated plans of the first and second stage development schemes.

7.3.4 Optimum Development Scale

Based on the above studies, the stagewise development schemes shown below are selected as the optimum ones which will be applied to the succeeding detailed studies.

	Max. Power Discharge (m³/s)	Max. Output (MW)	Powerhouse Site	Intake Level (m)
1st stage	80	201	Pikhuwa	840
2nd stage	160	402	Pikhuwa	840

Table 7–6 (1) Study of Development Scale (1–4: Maximum Discharge)

CASE	Unit	I - 60	I - 70	I - 80	I - 90	I - 100	II - 60	II - 70	II - 80	II - 90	II - 100
Power House Site	-	Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa
Intake Water Level	m	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0
Max.discharge	m^3/s	60.0	70.0	80.0	90.0	100.0	60.0	70.0	80.0	90.0	100.0
Power Facilities											
Dam Height	m	65	65	65	65	65	65	65	65	65	65
Tunnel D X L X n	m km n	6.3x11.3x1	6.6x11.3x1	7.0x11.3x1	7.4x11.3x1	7.7x11.3x1	6.3x11.3x1	6.6x11.3x1	7.0x11.3x1	7.4x11.3x1	7.7x11.3x1
Penstock Number	n	1~3	1~3	1~3	1~4	1~4	1~3	1~3	1~3	1~4	1~4
Turbine Unit No.	n	3	3	3	4	4	3	3	3	4	4
Power Generating Plan											
Intake Level	m	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0	840.0
Tailrace Level	m	538.0	538.0	538.0	538.0	538.0	538.0	538.0	538.0	538.0	538.0
Effective Head	m	288.0	288.0	288.0	288.0	288.0	288.0	288.0	288.0	288.0	288.0
Max.Discharge	m^3/s	60.0	70.0	80.0	90.0	100.0	60.0	70.0	80.0	90.0	100.0
Installed Capacity	MW	149.4	174.9	201.0	224.8	250.4	149.4	174.9	201.0	224.8	250.4
(p X n)	MW n	(49.8 X 3)	(58.3 X 3)	(67.0 X 3)	(56.2 X 4)	(62.6 X 4)	(49.8 X 3)	(58.3 X 3)	(67.0 X 3)	(56.2 X 4)	(62.6 X 4)
Annual Energy	GWh	1,303.5	1,514.4	1,721.6	1,922.1	2,106.2	1,303.5	1,514.4	1,721.6	1,922.1	2,106.2
Firm Energy	GWh	1,303.5	1,514.4	1,721.6	1,863.2	1,863.2	1,303.5	1,514.4	1,721.6	1,863.2	1,863.2
Secondary Energ.	GWh	0	0	0	58.9	243.0	0	0	0	58.9	243.0
Construction Cost	10^6US$	332.54	344.44	354.79	375.34	403.31	355.82	369.02	381.71	405.02	434.87
Economic Evaluation											
Without Exports											
Present value of B	10^6US$	212.08	228.20	242.02	250.57	254.41	212.08	228.20	224.02	250.57	254.41
Present value of C	10^6US$	183.74	188.88	193.17	202.27	210.45	195.84	201.57	207.05	217.46	226.53
B - C	10^6US$	28.34	39.32	48.85	48.30	43.96	16.24	26.62	34.96	33.10	27.87
B/C	-	1.15	1.21	1.25	1.24	1.21	1.08	1.13	1.17	1.15	1.12
Cost per kwh 1	c /KWh	6.39	6.11	5.90	6.00	6.21	6.83	6.55	6.35	6.48	6.72
Cost per kwh 2	c /KWh	4.15	3.78	3.48	3.46	3.41	4.43	4.03	3.73	3.72	3.67
With Exports											
Present value of B	10^6US$										
Present value of C	10^6US$										
B - C	10^6US$										
B/C	-										
Cost per kwh 1	c /KWh										
Cost per kwh 2	c /KWh										

Cost per kwh 1 : average net cost of useful salable energy and capacity
Cost per kwh 2 : average net cost of total energy and capacity

Table 7-6 (2) Study of Development Scale (2-4: Intake Water Level)

CASE	Unit	I - 80-830	I - 80-840	I - 80-855	I - 80-875
Power House Site		Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa
Intake Water Level	m	830.0	840.0	855.0	875.0
Max.discharge	m^3/s	80.0	80.0	80.0	80.0
Power Facilities					
Dam Height	m	55.0	65.0	80.0	100.0
Tunnel D X L X n	m km n	7.0X11.3X1	7.0X11.3X1	7.0X11.3X1	7.0X11.3X1
Penstock Number	n	1~3	1~3	1~3	1~4
Turbine Unit No.	n	3	3	3	4
Power Generating Plan					
Intake Level	m	830.0	840.0	855.0	875.0
Tailrace Level	m	538.0	538.0	538.0	538.0
Effective Head	m	278.0	288.0	303.0	323.0
Max.Discharge	m^3/s	80.0	80.0	80.0	80.0
Installed Capacity	MW	193.8	201.0	211.2	223.6
(p X n)	MW n	(64.6 x 3)	(67.0 X 3)	(70.4 X 3)	(55.9 X 4)
Annual Energy	GWh	1,661.8	1,721.6	1,811.3	1,930.8
Firm Energy	GWh	1,661.8	1,721.6	1,811.3	1,930.8
Secondary Energ.	GWh	0	0	0	0
Construction Cost	10^6US$	346.08	354.79	378.07	439.06
Economic Evaluation					
Without Exports					
Present value of B	10^6US$	238.07	242.02	247.61	252.63
Present value of C	10^6US$	189.49	193.17	205.53	236.63
B - C	10^6US$	48.58	48.85	42.08	16.00
B/C	-	1.26	1.25	1.20	1.07
Cost per kwh 1	c /KWh	5.88	5.90	6.16	7.02
Cost per kwh 2	c /KWh	3.54	3.48	3.52	4.04
With Exports					
Present value of B	10^6US$				
Present value of C	10^6US$				
B - C	10^6US$				
B/C	-				
Cost per kwh 1	c /KWh				
Cost per kwh 2	c /KWh				

Cost per kwh 1 : average net cost of useful salable energy and capacity
Cost per kwh 2 : average net cost of total energy and capacity

Table 7-6 (3) Study of Development Scale (3-4: Tailrace Water Level)

CASE	Unit	I - 80 - S	I - 80 - P	I - 80 - K
Power House Site		Solakhani	Pikhuwa	Kaguwa
Intake Water Level	m	840.0	840.0	840.0
Max.discharge	m^3/s	80.0	80.0	80.0
Power Facilities				
Dam Height	m	65.0	65.0	65.0
Tunnel D X L X n	m km n	7.0X7.0X1	7.0X11.3X1	7.0X11.6X1
Penstock Number	n	1~3	1~3	1~3
Turbine Unit No.	n	3	3	3
Power Generating Plan				
Intake Level	m	840.0	840.0	840.0
Tailrace Level	m	615.0	538.0	525.0
Effective Head	m	215.0	288.0	303.0
Max.Discharge	m^3/s	80.0	80.0	80.0
Installed Capacity	MW	149.1	201.0	211.8
(p X n)	MW n	(49.7 x 3)	(67.0 X 3)	(70.6 X 3)
Annual Energy	GWh	1,285.2	1,721.6	1,811.3
Firm Energy	GWh	1,285.2	1,721.6	1,811.3
Secondary El	GWh	0	0	0
Construction Cost	10^6US$	325.57	354.79	368.17
Economic Evaluation				
Without Exports				
Present value of B	10^6US$	209.11	242.02	247.67
Present value of C	10^6US$	180.00	193.17	200.12
B - C	10^6US$	29.11	48.85	47.55
B/C	-	1.16	1.25	1.24
Cost per kwh 1	c /KWh	6.34	5.90	5.98
Cost per kwh 2	c /KWh	4.34	3.48	3.43
With Exports				
Present value of B	10^6US$			
Present value of C	10^6US$			
B - C	10^6US$			
B/C	-			
Cost per kwh 1	c /KWh			
Cost per kwh 2	c /KWh			

Table 7–6 (4) Study of Development Scale (4–4: Maximum Discharge)

CASE	Unit	III - 120	III - 140	III - 160	III - 180	III - 200
Power House Site	-	Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa	Pikhuwa
Intake Water Level	m	840.0	840.0	840.0	840.0	840.0
Max.discharge	m^3/s	120.0	140.0	160.0	180.0	200.0
Power Facilities						
Dam Height	m	65	65	65	65	65
Tunnel D X L X n	m km n	6.3x11.3x2	6.6x11.3x2	7.0x11.3x2	7.4x11.3x2	7.7x11.3x2
Penstock Number	n	2~6	2~6	2~6	2~8	2~8
Turbine Unit No.	n	6	6	6	8	8
Power Generating Plan						
Intake Level	m	840.0	840.0	840.0	840.0	840.0
Tailrace Level	m	538.0	538.0	538.0	538.0	538.0
Effective Head	m	288.0	288.0	288.0	288.0	288.0
Max.Discharge	m^3/s	120.0	140.0	160.0	180.0	200.0
Installed Capacity	MW	298.8	349.8	402.0	449.6	500.8
(p X n)	MW n	(49.8 X 6)	(58.3 X 6)	(67.0 X 6)	(56.2 X 8)	(62.6 X 8)
Annual Energy	GWh	2,431.3	2,710.6	2,960.3	3,186.9	3,396.4
Firm Energy	GWh	1,863.2	1,863.2	1,863.2	1,863.2	1,863.2
Secondary Energ.	GWh	568.1	847.4	1,097.1	1,323.7	1,533.2
Construction Cost	10^6US$	466.65	487.35	506.44	547.13	568.31
Economic Evaluation						
Without Exports						
Present value of B	10^6US$					
Present value of C	10^6US$					
B - C	10^6US$					
B/C	-					
Cost per kwh 1	c /KWh					
Cost per kwh 2	c /KWh					
With Exports						
Present value of B	10^6US$	370.42	402.55	428.78	424.16	443.66
Present value of C	10^6US$	229.12	237.72	245.49	260.41	269.03
B - C	10^6US$	141.30	164.82	183.29	163.74	174.63
B/C	-	1.62	1.69	1.75	1.63	1.65
Cost per kwh 1	c /KWh	3.93	3.68	3.50	3.77	3.68
Cost per kwh 2	c /KWh	3.36	3.15	3.00	3.16	3.08

Cost per kwh 1 : average net cost of useful salable energy and capacity
Cost per kwh 2 : average net cost of total energy and capacity

Fig. 7–5 Study for Optimum Development Scale

(Maximum Discharge Case I, II)

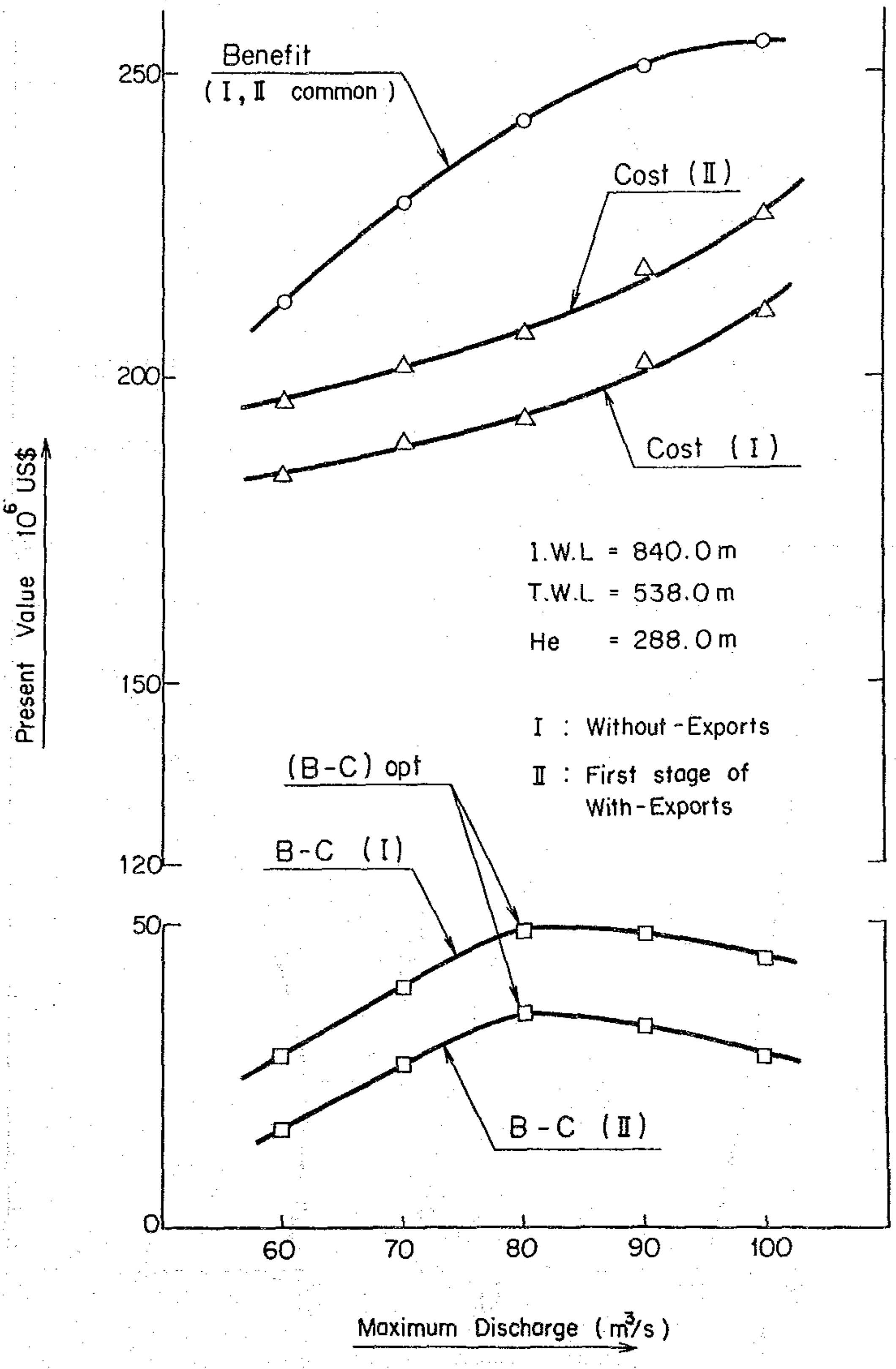


Fig. 7–6 Optimum Intake Water Level

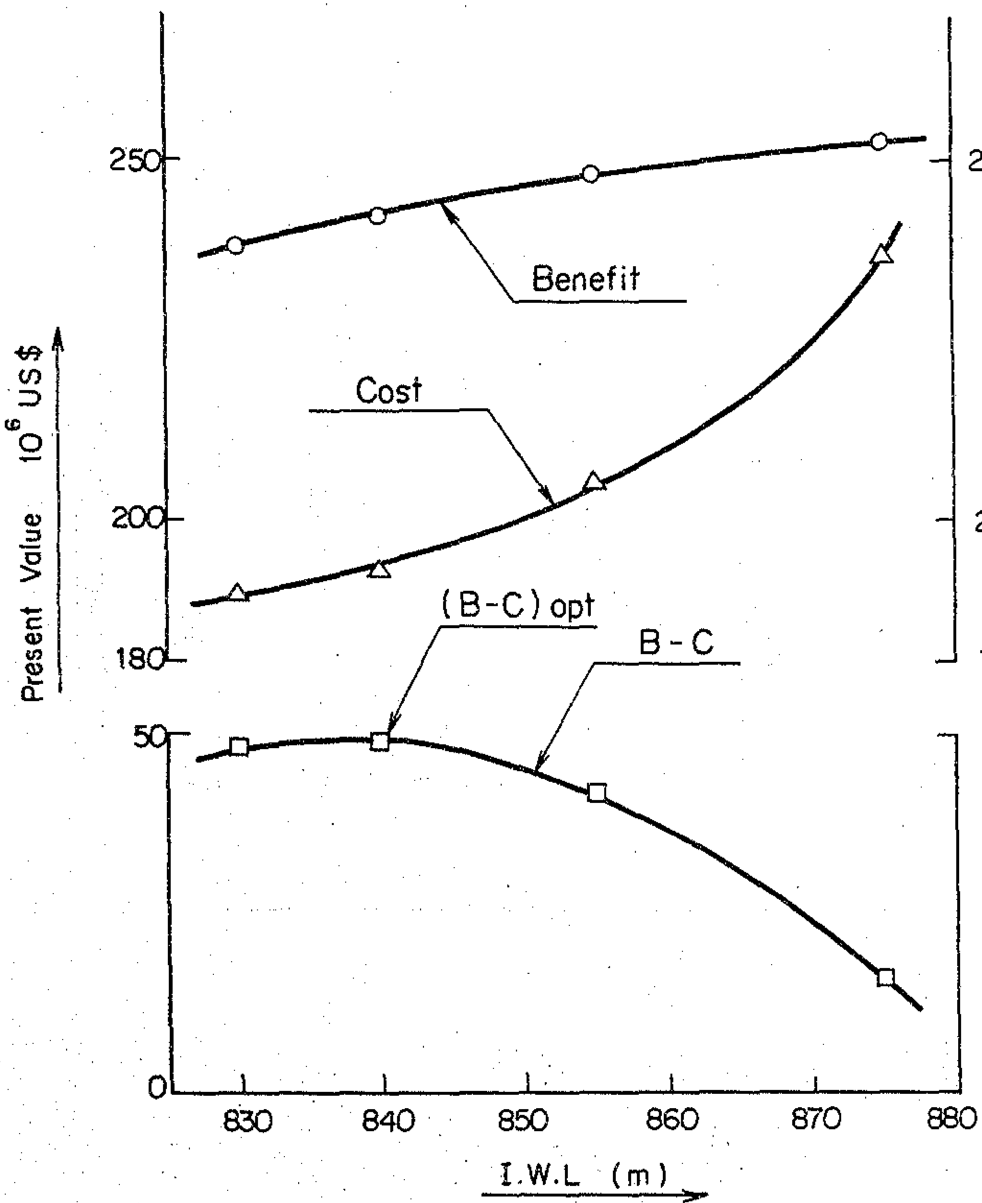


Fig. 7–7 Optimum Power House Site

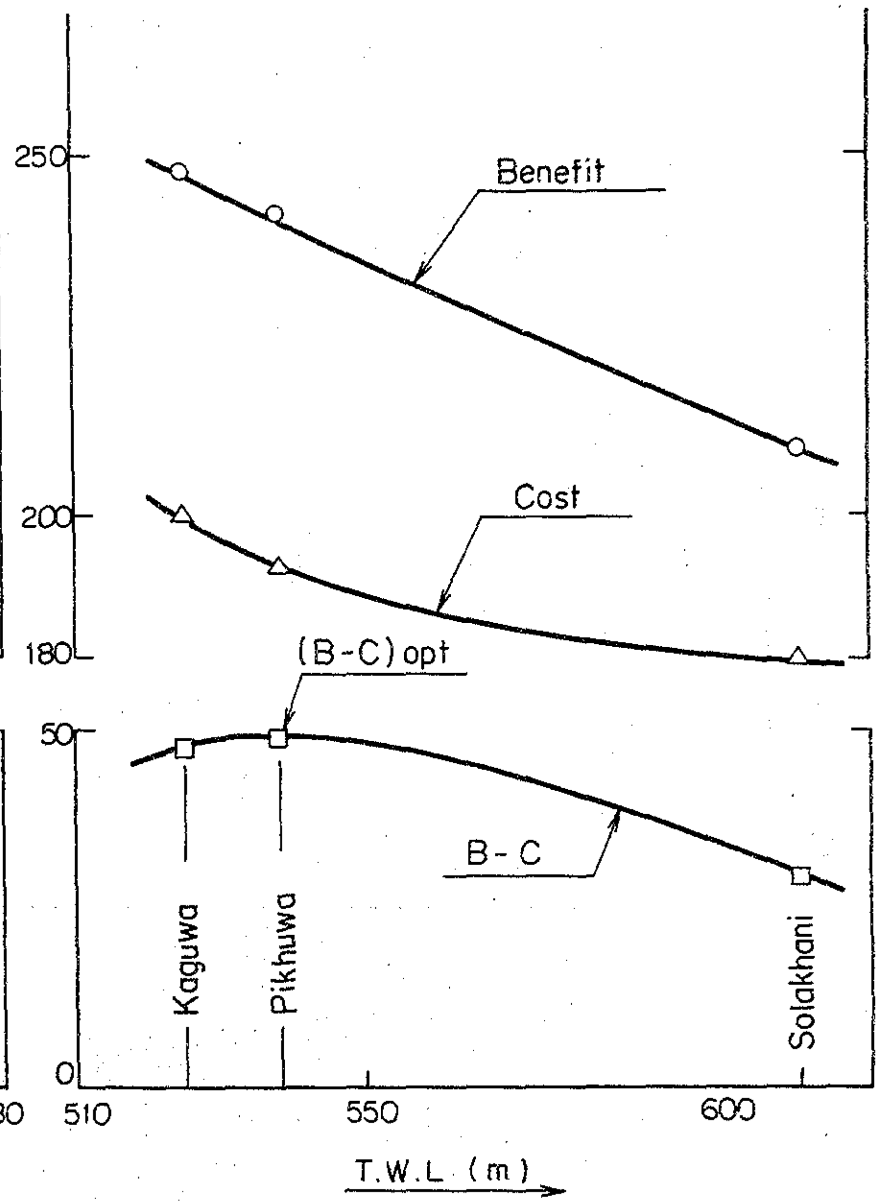
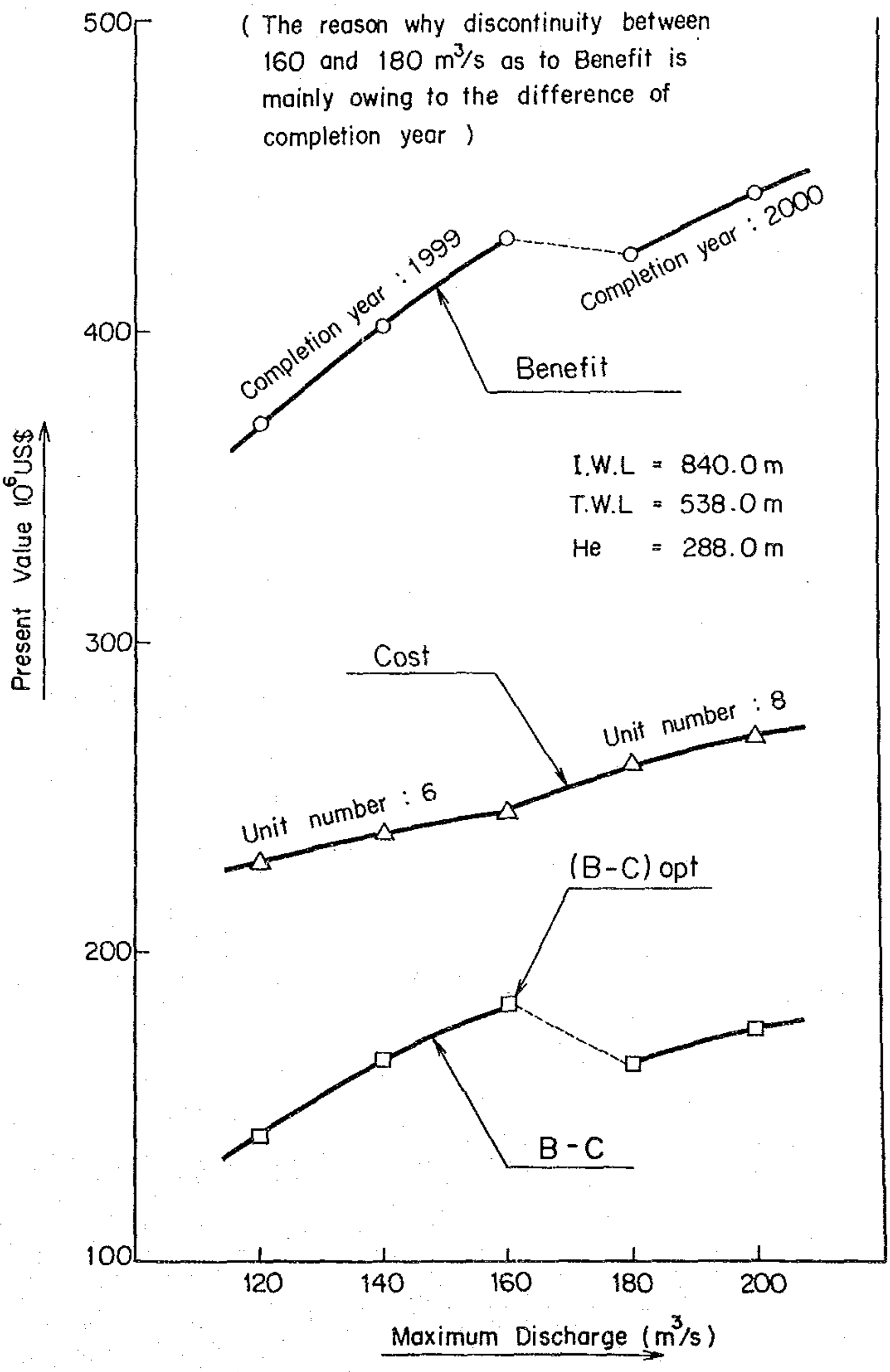


Fig. 7-8 Study for Optimum Development Scale (Maximum Discharge Case III)



CHAPTER 8 . POWER TRANSMISSION AND SUBSTATION SYSTEM PLAN

CHAPTER 8. POWER TRANSMISSION AND SUBSTATION SYSTEM PLAN

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CHAPTER 8. POWER TRANSMISSION AND SUBSTATION SYSTEM PLAN

8.1 Selection of Transmission Pattern

The electric power system of Nepal is made up of a primary system of 132 kV and a secondary system of 66 kV as described in preceding paragraph 2.3.1. The 132 kV transmission network stretches approximately 800 km east-west centerred at Kathmandu with a ring system of 66 kV transmission lines making up the power system around Kathmandu.

The electric power generated at the Arun 3 power station will be consumed mainly at Kathmandu, and via the Dubi substation, at Biratnagar. The load forecasts according to substation are as shown in Table 2-9, Chapter 2.

The power generated at the Arun 3 will be transmitted to Kathmandu by existing 132 kV transmission line between the Hetauda substation and the Dubi substation (presently operated as single circuit, but another circuit is necessary to be added by the time of commissioning of the Arun 3 power station) and 220 kV transmission line to be newly constructed.

With regard to the transmission route from the Arun 3 power station to load areas, the optimum transmission pattern is to be selected out of these applicable from technical and economical point of view.

8.1.1 Utilization of Existing Transmission Lines

In view of project economy, it is preferable to utilize to the utmost extent the existing transmission lines between the Hetauda and the Dubi substations (132 kV, 2 cct including expansion plan of 1 cct) for transmitting power generated at the Arun 3 power station. For power generation of 201 MW (3 units, 67 MW each) after completion of the first stage development of the Arun 3 project, stability analyses for the following two cases are examined to clarify the possibility of transmitting the above power to Kathmandu through the Hetauda substation with the existing 132 kV transmission line (2 cct) without new construction of 220 kV transmission line.

Case 1 : Power transmission (132 kV, 2 cct) from the Arun 3 power station to the Dubi substation

Case 2 : Power transmission (220 kV, 2 cct) from the Arun 3 power station to the Dubi substation and step-down to 132 kV with transformers at the Dubi substation

The results of stability analyses for the above two cases are shown in Figs. 8-2(1) and 8-2(2). The calculation condition is that three units of the Arun 3 power station operate at full output condition (201 MW) and local power distributed from the Dubi substation is 90% of the estimated load, and accordingly in its degree power flow towards Kathmandu is increased more than estimated one. The fault point is 132 kV bus at the Dubi substation and fault clearing-off time is estimated at 150 ms in the both cases. As obviously observed in these drawings, power transmission of 201 MW with the existing 132 kV transmission line (2 cct) only is not applicable due to difficulty in maintaining the system stability. It is, therefore, required to construct 220 kV transmission line (1 cct) for development of the first stage scheme.

8.1.2 Applicable Transmission Patterns

The following four patterns shown in Figs. 8-1(1) and 8-1(2) are taken into account for power transmission from the Arun 3 power station to Kathmandu, with the premise of new construction of 220 kV transmission line. For selecting the optimum transmission pattern, these conceivable patterns are analyzed from technical and economical standpoints for the fiscal years: 2001/02 and 2007/08 at which the transmission and substation facilities constructed as the first stage development (201 MW without power export) and the second stage development (402 MW in total, with power export) respectively will be full loaded to meet the domestic requirements only as referred to Fig. 2-7.

(1) 1st Stage Development

(i) Pattern 1

This patttern is the power transmission from the Arun 3 power station to the Hetauda substation via the Dubi substation, the Dhalkebar switchyard and the Pathalaiya substation.

New transmission line:

Arun 3 P/S - Dubi S/S (220 kV, 2 cct)

Dubi S/S - Dhalkebar S/Y - Pathalaiya S/S (220 kV, 1 cct)

Pathalaiya S/S - Hetauda S/S (132 kV, 1 cct)

New substation:

Pathalaiya S/S

Expanded substation and switchyard:

Dubi S/S, Dhalkebar S/Y, Hetauda S/S

(ii) Pattern 2

This pattern is power transmission from the Arun 3 power station to the Hetauda and the Siuchatar substations via the Dubi substation, the Dhalkebar switchyard and the Pathalaiya substation.

New transmission line:

Arun 3 P/S - Dubi S/S (220 kV, 2 cct)

Dubi S/S - Dhalkebar S/Y - Pathalaiya S/S - Siuchatar S/S (220 kV, 1 cct)

New substation:

Pathalaiya S/S

Expanded substation and switchyard:

Dubi S/S, Dhalkebar S/Y, Siuchatar S/S

(iii) Pattern 3

This pattern consists of a route with 220 kV voltage from the Arun 3 power station to the New Kathmandu substation via the Dubi substation and the Dhalkebar switchyard, connecting the New Kathmandu substation with the Siuchatar and the Balaju substations by 132 kV line, and another route from the Dhalkebar switchyard to the Hetauda substation via the Pathalaiya substation with 220 kV voltage.

New transmission line:

Arun 3 P/S - Dubi S/S (220 kV, 2 cct)
Dubi S/S - Dhalkebar S/Y - New Kathmandu S/S (220 kV, 1 cct)
Dhalkebar S/Y - Pathalaiya S/S (220 kV, 1 cct)
* New Kathmandu S/S - Balaju S/S (132 kV, 1 cct)
* New Kathmandu S/S - Siuchatar S/S (132 kV, 1 cct)

* The costs of the transmission lines in these sections are not included in the feasibility study.

New substation:

Pathalaiya S/S, New Kathmandu S/S

Expanded substation and switchyard:

Dubi S/S, Dhalkebar S/Y

(iv) Pattern 4

This pattern is power transmission with 220 kV voltage from the Arun 3 power station to the Siuchatar substation and the Balaju substation via the Dubi substation, the Dhalkebar switchyard, and the New Kathmandu substation.

New transmission line:

Arun 3 P/S - Dubi S/S (220 kV, 2 cct)
Dubi S/S - Dhalkebar S/Y - New Kathmandu S/S (220 kV, 1 cct)
* New Kathmandu S/S - Siuchatar S/S (132 kV, 1 cct)
* New Kathmandu S/S - Balaju S/S (132 kV, 1 cct)

* The costs of the transmission line in these sections are not included in the feasibility study.

New substation:
New Kathmandu S/S

Expanded substation and switchyard:
Dubi S/S, Dhalkebar S/Y

(2) 2nd Stage Development

The transmission line routes for respective patterns are same as those described in the first stage development above and the following additional transmission lines are to be provided.

(i) Pattern 1

Dubi S/S - Dhalkebar S/Y - Pathalaiya S/S (220 kV, 1 cct)
Pathalaiya S/S - Hetauda S/S (132 kV, 1 cct)

(ii) Pattern 2

Dubi S/S - Dhalkebar S/Y - Pathalaiya S/S - Siuchatar S/S (220 kV, 1 cct)

(iii) Pattern 3

Dubi S/S - Dhalkebar S/Y - New Kathmandu S/S (220 kV, 1 cct)
Dhalkebar S/Y - Pathalaiya S/S (220 kV, 1 cct)

(iv) Pattern 4

Dubi S/S - Dhalkebar S/Y - New Kathmandu S/S (220 kV, 1 cct)

8.1.3 Optimum Pattern

The optimum power transmission pattern is to be selected carrying out technical and economic comparison studies on the beforementioned four patterns.

In selection of the power transmission pattern, the study is first made with the voltage of the new transmission line as 220 kV, while transmission voltage is selected for the optimum transmission pattern so chosen, as described later in paragraph 8.2.

With the details of power system analysis given in the succeeding paragraph 8.6, power flow and power system stability analyses are made for various power transmission patterns as of F.Y. 2001/02 and F.Y. 2007/08 for the first and second stage development, respectively. Power flows for respective patterns are shown in Figs. 8-3(1-1), 8-3(2-1), 8-3(3-1) and 8-3(4-1) for the fiscal year 2001/02 and Figs. 8-3(1-2), 8-3(2-2), 8-3(3-2) and 8-3(4-2) for 2007/08. While, transient generator swing curves are shown in Figs. 8-4(1-1-1), 8-4(1-1-2), 8-4(2-1-1), 8-4(2-1-2), 8-4(3-1-1), 8-4(3-1-2), 8-4(4-1-1), 8-4(4-1-2) and 8-4 (4-1-3) for the fiscal year 2001/02 and Figs. 8-4(1-2), 8-4(2-2), 8-4(3-2), 8-4(4-2-1), 8-4(4-2-2) and 8-4(4-2-3) for 2007/08. According to these calculations, it is found that the stable power transmission of 201 MW and 402 MW generated at the Arun 3 power station as of F.Y. 2001/02 and 2007/08 can be secured for any of the above patterns.

Meanwhile, comparative study on economy of these transmission patterns for F.Y. 2001/2002 and F.Y. 2007/2008 is made as shown in Tables 8-1(1) and 8-1(2) respectively, based on the annual costs as parameters derived from power transmission loss (kW loss), energy transmission loss (kWh loss) and construction costs of transmission lines and substations (switchyard). It should be noted, concerning Table 8-1(1) and Fig. 8-1(1), that cost of transformers to be installed in September, 1998 is included in this study because new transmission line is to be operated at 220 kV in this stage. As for substation (switchyard) equipment, the costs are calculated for these of conventional type. Among these four patterns, the power transmission method categorized as Pattern 4 is found to be the most economical one and Pattern 3 to be the costliest at both points of time. Therefore, Pattern 4 is selected as the optimum one. The features of respective patterns as of F.Y. 2007/08 are as described below, since these at both times are almost the same.

(1) Pattern 1 (Refer to fig. 8-3(1-2))

The specific feature of Pattern 1 is that the electric power from the Arun 3 power station is concentrically received at the Hetauda substation. As shown in Fig. 8-3(1-2), the power received at the Hetauda substation will be approximately 279 MW and power flow amounting to 50 percent of the total demand of 552 MW in whole Nepal (F.Y. 2007/08, excluding transmission line loss) will be concentrated at the existing 132 kV buses of the Hetauda substation. Taking the possible troubles at the Hetauda substation into consideration, it will be necessary to have the power system capable of dispersing excess power flow from the standpoint of securing stable power supply. Therefore, this pattern is not very desirable in view of system reliability.

The construction cost of this pattern is low next to Pattern 4, but the power transmission loss for the entire system will be 39.6 MW which is the biggest of the four patterns. The existing 132 kV and 66 kV transmission lines can be utilized from the Hetauda substation to Kathmandu, but the power flow will be heavy in this section and it will be necessary for the system to be expanded at an early stage. Furthermore, this pattern will require 132 kV, 4 cct between the Hetauda substation and the Pathalaiya substation and it will be difficult to secure space for additional installation of equipment at the Hetauda substation.

(2) Pattern 2 (Refer to Fig. 8-3(2-2))

The specific feature of Pattern 2 is that a ring system will be made up linking the Hetauda, the Pathalaiya and the Siuchatar substations with the existing system. Compared with Pattern 1, it will be more reliable for stable power supply, but the power flow from the 220 kV bus to the 132 kV bus of the Pathalaiya substation will be small at approximately 88 MW, and there is little necessity for new construction of this substation from viewpoint of power system operation. Furthermore, the construction cost will be high next to Pattern 3 and therefore, this pattern is economically disadvantageous.

(3) Pattern 3 (Refer to Fig. 8-3(3-2))

The specific feature of Pattern 3 is that the ring system will be made up linking the Hetauda and the Pathalaiya substations, the Dhalkebar switchyard and the New Kathmandu substaion with the existing system, similarly to Pattern 2.

The construction cost of this pattern is the highest of the four patterns. Power flow from the 220 kV bus to the 132 kV bus of the Pathalaiya substation will be small at about 89 MW, and there will be little merit of new construction of the transmission line between the Dhalkebar switchyard and the Pathalaiya substation.

However, there is the merit that the power transmission loss of the entire system is the smallest of the four patterns.

(4) Pattern 4 (Refer to Fig. 8-3(4-2))

The specific feature of Pattern 4 is that a ring system will be made up linking the Hetauda substation, the Dhalkebar switchyard, the Dubi substation and the New Kathmandu substation with the existing system. Stable power supply is secured with this pattern similarly to Pattern 3. Since the power received at the Hetauda substation will be small at about 71 MW, the influence on the existing system between the Hetauda substation and Kathmandu will be small.

The construction cost will be the lowest of the four patterns, while the power transmission loss of the entire system will be small next to Pattern 3, and this is considered to be the optimum pattern from technical and economical viewpoints.

8.2 Selection of Transmission Line Voltage

8.2.1 Voltage Selection Method

In case of transmitting the electric power of 201 MW (1st stage) and 402 MW (2nd stage) generated at the Arun 3 power station with distance of approximately 400 km, the existing voltage of 132 kV will be too low to maintain the system voltage and power system stability, and it will be necessary to apply a higher level voltage. In selection of a higher level voltage, it will be necessary to take into account the magnitude of demand, distribution of load, transmission distance, harmonization with existing facilities from viewpoints of operation and maintenance, and electric power export as well as examination of the electric power development plan in the future.

Technical and economical comparisons are examined for two voltage levels of 220 kV and 400 kV based on the power system of Pattern 4 selected as the optimum one in the preceding paragraph 8.1. Accordingly, the section of transmission line to be the object of study is 386 km from the Arun 3 power station to the New Kathmandu substation via the Dubi substation and the Dhalkebar switchyard.

8.2.2 Optimum Voltage

The results of power flow analyses (F.Y. 2007/08) for transmission lines of 220 kV and 400 kV are shown in Figs. 8-3(4-2) and 8-3(5). With regard to power system stability analyses, since the voltage level of 220 kV is proven to be stable and there would be stability naturally for 400 kV, power system stability analyses for 400 kV are omitted. The economic comparison of the two voltages is given in Table 8-2. The costs of substation (switchyard) equipment are calculated for conventional type except those for the Arun 3 switchyard.

The results of comparison of the two voltages are described in detail below and since 220 kV is found to be more advantageous judging from the viewpoints of operation and the economics even if another power development plan on the Arun river in the future is taken into account as described later in paragraph 8.2.3, 220 kV is selected as the optimum one.

(1) Comparison of Economic Aspect

A minimum of two circuits is necessary for either voltage level to be selected in order to maintain system stability and supply reliability. Since it would not be practical to adopt single-circuit facilities even for the voltage level of 400 kV, the construction cost for 400 kV will be higher than that for 220 kV by approximately US$56 x 10^6 or US$6.7 x 10^6 in terms of annual cost. Furthermore, with 400 kV, as is described in (2) below, shunt reactor of large capacity will be required to suppress voltage rise, and when the cost therefor is added, the cost will be very high so that a 400 kV transmission line will be considered to be an excessively large facility, and therefore it is reasonable to adopt 220 kV. Although transmission loss for 400 kV is less compared with 220 kV, the latter is more economical from an overall viewpoint including construction cost.

(2) Comparison of Operational Aspect

The line charging capacity of a 400 kV transmission line is a total of 430 MVA for two circuits, and as shown in Fig. 8-3(5) shunt reactor of approximately 250 MVA will be required at the Dhalkebar switchyard even at peak load time. Because of this, switching operation of shunt reactor will be required at all times in accordance with the power flow to maintain system voltage at a suitable level so that complicated system operation will be caused. Further, at off peak load time during night or when performing trial charging of the line, shunt reactor of larger capacity will be needed to suppress voltage rise in the transmission line.

Consequently, adoption of 220 kV is desirable from the operational aspect, and further, from the viewpoints of operation and maintenance in line with the existing facilities having the maximum voltage of 132 kV, 220 kV will be more advantageous.

8.2.3 220 kV Transmission and Future Power Development

The result of power system stability analysis at F.Y. 2007/08 for transmitting the power of 402 MW generated at the Arun 3 power station by 220 kV transmission line is given in Figs. 8-4(4-2-1), 8-4(4-2-2) and 8-4(4-2-3). Judging from the generator swing curve of the Arun 3 power station at fault, it is considered that power flow of at least 100 MW can be added on the 220 kV transmission line from the Arun 3 power station.

Furthermore, even the future power development plans in the vicinity of the Arun 3 power station are considered, 220 kV transmission system will still be competent for carrying the future increase of power, as the power transmission capacity estimated on the basis of power system stability will increase up to 800 MW to 900 MW in total by new construction of 220 kV transmission line (1 cct) between the new power station and the Arun 3 power station and additional construction of the same between the Arun 3 power station and the Dubi substation.

8.3 Construction and Expansion of Substation/Switchyard

The substation and switchyard to be newly constructed or expanded based on the optimum transmission pattern (Pattern 4) selected previously in paragraph 8.1 are as described below.

8.3.1 Expansion of Dubi Substation

The Dubi substation is carrying the largest load in the eastern part of Nepal and is presently supplied with electric power from the Hetauda substation by 132 kV, 1 cct transmission line.

The transmission line from the Arun 3 power station to Kathmandu will first be connected to this Dubi substation for power supply to the area centerred at Biratnagar, while it will be necessary for the Dubi substation to install 220/132 kV transformers for transmission of a part of the power via the Hetauda substation to Kathmandu by the existing 132 kV, 1 cct transmission line and the other 132 kV, 1 cct transmission line being planned by NEA.

Furthermore, it is necessary to install 220 kV switchgear at the Dubi substation for outgoing line to the Dhalkebar switchyard in order to transmit the power to Kathmandu via the Dhalkebar switchyard.

8.3.2 Construction of New Kathmandu Substation

A part of the electric power generated at the Arun 3 power station will be consumed at the Dubi substation, with almost all of the remainder transmitted to Kathmandu. The power flow to the New Kathmandu substation at the time when all of the units of the Arun 3 power station have been commissioned will be approximately 211 MW (Fig. 8-3(4-2)). Since this electric power will be too much for the existing substation in the vicinity of Kathmandu, it will be advantageous from the viewpoint of stable power supply to newly construct a 220/132 kV substation near Kathmandu wherefrom the power is to be transmitted to the existing substations.

In the feasibility study, it is planned to construct a new 220/132 kV substation (tentatively called as New Kathmandu) for power transmission to the Siuchatar and the Balaju substations with a 132 kV, 1 cct transmission line each.

It is necessary to further study on selection of the secondary voltage at the New Kathmandu substation. It seems preferable to adopt the secondary voltage of 66 kV from the viewpoints that (1) the ring system with 66 kV transmission lines is being operated in the Kathmandu area, (2) power supply at 66 kV will be able to be maintained also in the future, (3) large amount of cost for providing 132/66 kV and 132/33 kV transformers is required in the case of adopting the secondary voltage of 132 kV and (4) reactive power loss will increase.
However, the secondary voltage of 132 kV at the New Kathmandu substation is applied in this study in consideration of the future expansion program of transmission and substation network in the Kathmandu area being proceeded by NEA.

8.3.3 Expansion of Dhalkebar Switchyard

Since the length of transmission line from the Arun 3 power station to Kathmandu is approximately 400 km, it will be advantageous to provide intermediate switchyard for maintenance of the transmission line and for securing power system stability. The entire length of approximately 400 km will be divided into lengths of 100 to 150 km for shortening the section of outage during maintenance work or fault.

The site of the switchyard will be located adjacent to the Dhalkebar substation and with this switchyard, the 266 km between the Dubi and the New Kathmandu substations will be divided into sections of 146 km on the Dubi side and 120 km on the New Kathmandu side.

Besides 220 kV switchyard equipment, the switchyard will be provided with shunt reactors to be operated at off peak load time or when the transmission line is to be charged from the Arun 3 power station. The capacity required for shunt reactor will be 25 MVA per circuit of the 220 kV transmission line, a total of 50 MVA for two circuits, and it will be economical to install the shunt reactors in stages.

During the off peak load time, voltage rise of transmission line is to be suppressed by these shunt reactors as well as condenser operation of the Arun 3 power station.

8.4 Development Sequence of Transmission Line and Substation

The construction program for the transmission line, substation and switchyard according to Pattern 4 previously selected as the optimum power transmission pattern in paragraph 8.1 is planned in coordination with the development sequence of the Arun 3 power station. The development sequence is divided into three schedules: Schedule 1 and Schedule 2 corresponding to the first stage development of the project and schedule 3 corresponding to the second stage development, as shown in Table 8-3.

(1) Schedule 1 (F.Y. 1993/1994)

Two units of the Arun 3 power station will have been commissioned at this time (June, 1994, and September, 1994) and the construction program for transmission, substation and switchyard equipment is as shown in Table 8-3.

The output of the Arun 3 power station will be 134 MW (67 MW x 2 units). Since the power transmission will be of small quantity at this stage and system voltage and power system stability can be maintained for the provisional transmission line operation at 132 kV, the transmission line is to be operated at this voltage. The power flows at peak load and off peak load are shown in Figs. 8-5(1) and 8-5(2) respectively, and the transient generator swing curve according to power system stability analysis in Figs. 8-6(1), 8-6(2) and 8-6(3).

For 132 kV operation, 220/132 kV transformers will not be required at this time at the Dubi and the New Kathmandu substations.

As to the number of circuits for the transmission line of 220 kV, two circuits between the Arun 3 power station and the Dubi substation, and one circuit from the Dubi substation to the Dhalkebar switchyard and further to the New Kathmandu substation are to be provided and operated at 132 KV provisionally.

Furthermore, to prevent the system voltage from rising during off peak load time, condenser operation will be done at the Arun 3 power station, and it will be necessary to install shunt reactor of 10 MVA at the Dhalkebar switchyard to be used together with the 7.5 MVA shunt reactor being planned by NEA at the existing Dhalkebar substation.

(2) Schedule 2 (F.Y. 1998/1999)

The unit No. 3 of the Arun 3 power station will have been commissioned at this time (September, 1998) and the output will be a total of 201 MW. The results of power flow analyses during peak load and off peak load times are shown in Figs. 8-5(3) and

8-5(4), respectively. It is required to step up the line voltage to 220 kV for power transmission at this stage. It is also required to provide 220/132 kV transformers with accessories at the Dubi and the New Kathmandu substations by Septmber 1998, though no additional provisions of transmission line and switchgears at the Dhalkebar switchyard are required.

On the other hand, it is scheduled to install the units No.4 to No.6 of the Arun 3 power station in F.Y. 1998/99 for the purpose of power export, making the total installed capacity to be 402 MW. Considering the case that the construction for power export (second stage development) be suspended, power flow and system stability analyses are also examined as shown in Figs. 8-3(4-1), 8-4(4-1-1), 8-4(4-1-2) and 8-4(4-1-3) and it is proved that the above facilities can be used for stable power supply up to F.Y. 2001/02.

Condenser operation will be done at the Arun 3 power station during off peak load time and the total shunt reactor capacity required will be 20 MVA at the Dhalkebar switchyard. Accordingly, additional installation of 10 MVA will be necessary.

(3) Schedule 3 (F.Y. 1998/1999)

At this stage, units No.4 to No.6 of the Arun 3 power station will have been commissioned for power export (No.4 in December 1998, No.5 in March 1999 and No.6 in June 1999) and the total installed capacity will become 402 MW.

The result of studies on possibility of transmitting power of 200 MW for power export in addition to that for domestic demand without additional construction of 220 kV, 1 cct transmission line, is shown in Figs. 8-7(1), 8-7(2) and 8-7(3). Figs. 8-7(1) and 8-7(2) are the cases that the Dubi S/S, the Dhalkebar S/Y and the New Kathmandu S/S are connected with 220 kV, 1 circuit. In case of Fig. 8-7(1), fault is occurred at 220 kV bus of the Arun 3 switchyard and accordingly 220 kV transmission line between the Arun 3 switchyard and the Dubi substation is tripped. In case of Fig. 8-7(2), fault is occurred at 220 kV bus of the Dubi substation and 220 kV transmission line between the Dubi substation and the Dhalkebar switchyard is tripped.

In the meantime, Fig. 8-7(3) is the case that the Dubi S/S, the Dhalkebar S/Y and the New Kathmandu S/S are connected with 220 kV, 2 circuits, in which the fault is occurred at 220 kV bus of the Dubi substation and accordingly the 220 kV transmission line between the Dubi substation and the Dhalkebar switchyard is tripped.

As obviously observed in Fig. 8-7(2), power system stability will not be able to be maintained when the fault is occurred at the Dubi substation in case of the 220 kV, 1 circuit transmission line from the Dubi substation to the New Kathmandu substation via the Dhalkebar switchyard, while it will be possible to maintain the system stability even in the same fault as above in case of the 220 kV, 2 circuits.

It is, threfore, necessary to additionally construct at this stage 220 kV, 1 cct transmission line from the Dubi substation to the New Kathmandu substation through the Dhalkebar switchyard and also to provide the related equipment at these substations and switchyard by December 1998. As described in the succeeding paragraph 8.5, it is conceivable to export the power of 200 MW in view of the results of rough study on system stability analysis, though the matters related to power export shall be further studied in detail.

At the stage of F.Y. 1998/99, the time at which the stability of power supply system of Nepal has to be checked is not the peak load time but the off peak load time after completion of the above transmission and substation facilities. The result of power flow analysis during off peak load time (for domestic demand in Nepal only) is as shown in Fig. 8-5(5) and shunt reactor of 50 MVA at the Dhalkebar switchyard is required.

Further, power system analyses during peak load time in F.Y. 2007/08 with the above transmission and substation facilities are also made and no problems are found. The result of power flow analysis is shown in Fig. 8-3(4-2) and that of power system stability analysis in Figs. 8-4 (4-2-1), 8-4(4-2-2) and 8-4(4-2-3).

With additional construction and 220 kV operation of the transmission line, the capacity of shunt reactors to suppress the system voltage rise has to be also increased, namely, it will be necessary to install the shunt reactor with capacity of 30 MVA additionally (total 25 MVA x 2 cct = 50 MVA) at the Dhalkebar switchyard in order to suppress the voltage rise induced to 220 kV transmission line in the case of line charging by the Arun 3 power station as described later in paragraph 8.6.4. In the meantime, shunt reactors having a total capacity of 50 MVA will be needed during off peak load in combination with condenser operation of the Arun 3 power station.

8.5 Conceptual Study on Power Export

In connection with power export, the following two cases are examined regarding the method of transmitting power to the electric power system of the importing country in accordance with the development sequence of the Arun 3 power station, transmission and substation facilities. Since it is presumed that only the power in excess of domestic demand will be exported, the amount of power export decreases with the growth of domestic load demand and the maximum power of 200 MW can be exported during the period from F.Y. 1998/99 to F.Y. 2001/02 only. Hence, the power system analyses are made at F.Y. 1998/99 and F.Y. 2001/02. The premise for power system analysis is as described later in paragraph 8.6.1.

Case 1: Export of 200 MW by 200 kV, 2 cct transmission lines (F.Y. 1998/99)

Case 2: Export of 200 MW by 220 kV, 2 cct transmission lines (F.Y. 2001/02)

(1) Case 1

The power flow and the transient generator swing curve according to power system stability analysis are shown in Figs. 8-8(1) and

8-7(3)/8-9(1), respectively. If the system voltage of 220 kV can be maintained at the importing country, the stability of the power system of Nepal can be maintained even for a 3-phase line-to-ground fault applied to one of the two circuits of the interconnecting lines.

(2) Case 2

The power flow and the transient generator swing curve according to power system stability analysis are shown in Figs. 8-8(2) and 8-9(2), respectively. In this case also, if the system voltage of 220 kV can be maintained at the importing country, the stability of the power system of Nepal can be maintained even for a 3-phase line-to-ground fault applied to one of the two circuits of the interconnecting lines.

(3) Basic Considerations

In the case of power export of 200 MW by 220 kV transmission line, no instability in generators on the Nepal power supply system will be induced as referred to the results of system stability analysis. However, if the power supply system of importing country is not equipped with complete voltage stabilization capability, there will be possibility of instability in both power supply systems induced from generators on the system of importing country. The amount of power export will naturally be limited to less than 200 MW in such case.

It will be said that, from the standpoint of power system characteristics, the amount of power that can be exported varies depending upon the capability of voltage stabilization of importing country. Consequently, the magnitude of possible power export will not be finalized until the actual situation of power supply system of importing country has been investigated and detailed power system analysis has been made.

8.6 Power System Analysis

The results of power system analysis are of extreme importance for making technical and economical judgements on selection of the transmission pattern, selection of the new voltage to be adopted, etc., for planning the optimum power transmission and substation facilities.

8.6.1 Calculation Condition

(1) Power System Calculation Items

The technical study is carried out based on the following power system calculation results:

- Power flow and voltage calculations
- Power system stability
- Short circuit current
- Transmission line charging capacity

(2) Objective Years of Calculations

The necessary power system calculations are made in accordance with the commissioning dates of the main equipment of the Arun 3 power station indicated below.

No. of Unit	Commissiong Date	Unit Capacity (MW)	Cumulative Output (MW)
No. 1	Jun. 1994	67	67
No. 2	Sep. 1994	67	134
No. 3	Sep. 1998	67	201
No. 4	Dec. 1998	67	268
No. 5	Mar. 1999	67	335
No. 6	Jun. 1999	67	402

(3) Conditions for Power Flow and Voltage Calculations

Power flow and voltage calculations are made based on the operational conditions of electric power facilities as shown below.

System Voltage to be maintained

95 - 105% of rated voltage

Operating voltage of generator

95 - 105% of rated voltage

Operating power factor of generator

Not less than 0.85

Tap ratio of transformer

1.00 ± 0.05 P.U (fixed tap)

1.00 ± 0.10 P.U. (LRT)

Power factor of load

0.9

Load time

At peak load and off peak load

(off peak load ..... 35% of peak load)

Load at each substation

According to Table 2-9, Chapter 2

Base generator for voltage phase angle

Kulekhani-1

In order to maintain the abovementioned system voltage, it is considered to adequately provide static condensers or shunt reactors at substations or switchyard.

(4) Condition for Power System Stability Calculation

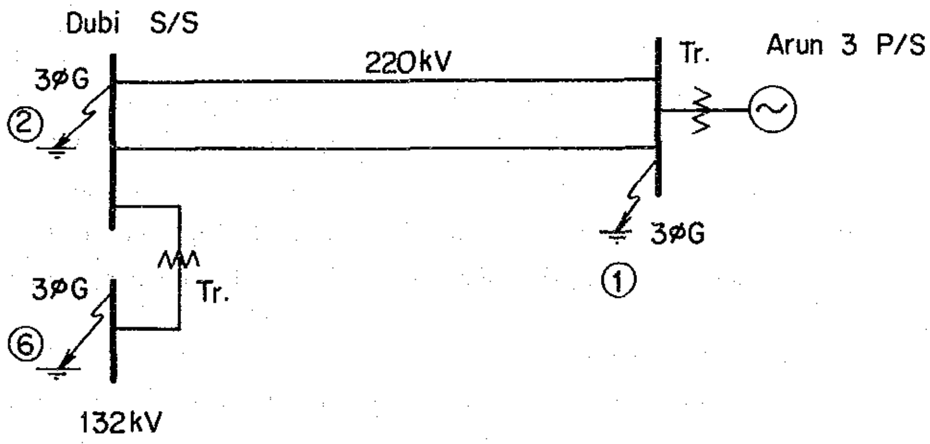
Power system stability calculations are made with the generators of the Arun 3 power station. As to the disturbance on the power system, a 3-phase line-to-ground fault (3ϕG fault) is applied to the transmission line from the Arun 3 power station, and the transient characteristic of generator after clearing off the fault is examined.

The following conditions are added so that the disturbance will inflict a severe impact on the power system.

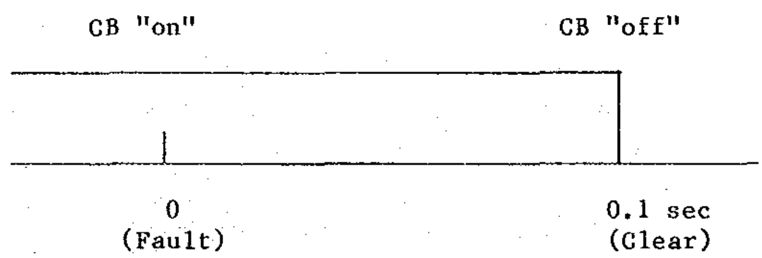
- Fault resistance zero
- Generator AVR (Automatic Voltage Regulator) and turbine governor functions eliminated
- No automatic reclosing of transmission line at fault

The location of disturbance applied and the fault sequence are as shown below, with the fault clearing-off time of 0.1 sec assuming that protective relays will function normally. In order to find out the location of fault which causes the severest effect on the power supply system, stability analyses are made for different locations of fault as shown below.

Location of disturbance application



Fault sequence



(5) Condition for Calculation in Case of Power Export

For exporting the surplus electric power of the Arun 3 power station, power system calculations are carried out assuming the following conditions for electric power system of the importing country.

(i) The length of transmission line from the Dubi substation in Nepal to the substation of the importing country is estimated at 175 km.

(ii) The electric power system of the importing country is simulated as a simple system of a single-generator.

(iii) The capacity of the single-generator system is estimated at 2,500 to 3,000 MVA, corresponding to magnitude of demand forecast of objective area in importing country.

(iv) The short circuit capacity of electric power system of objective area in importing country is estimated at 10 kA.

(6) Condition of Existing System

As it is necessary to expand the electric power facilities of the existing 132 kV and 66 kV systems along with development of the Arun 3 power station, the study is made on the premise expendiently that the facilities below will have been expanded, including expansions being currently planned by NEA.

Transmission Line:

Dhalkebar S/S - Dubi S/S 132 kV, 1 cct —> 2 cct
Siuchatar S/S - Patan S/S, 66 kV, 1 cct —> 2 cct
Balaju S/S - New Chabel S/S, 66 kV, 1 cct —> 2 cct

Substation:

Hetauda S/S, 10 MVA —> 40 MVA
Siuchatar S/S, 80 MVA —> 160 MVA
Balaju S/S, 80 MVA —> 160 MVA

(7) Constants of Electric Power Facilities

The power system impedances used for power system analysis are shown in Fig. 8-10, and generator and transformer constants in Table 8-4. The constants adopted, other than those furnished by NEA, are of standard levels.

As for impedance voltages of transformers, the following standard values on self-capacity basis are adopted, except for the existing transformers:

Voltage (kV)	Impedance voltage (%)
132/66	7.5
220/132, 66	8.5
220/13.8	10.0
132/11, 6.6	8.0

8.6.2 Power Flow/Voltage and System Stability

The results of the analytical calculations have been described in the preceding paragraphs, but are recapitulated below.

<u>Case 1</u> Power system stability calculation for 1st stage development (201 MW) in F.Y. 1998/1999 without construction of 220 kV line from Dubi S/S to New Kathmandu S/S

(a) 132 kV operation from Arun 3 P/S to Dubi S/S .... Fig. 8-2(1)

(b) 220 kV operation from Arun 3 P/S to Dubi S/S .... Fig. 8-2(2)

<u>Case 2</u> Power flow, voltage calculation in F.Y. 2001/2002 for selection of optimum transmission pattern

(a) Transmission Pattern 1 .... Fig. 8-3(1-1)

(b) Transmission Pattern 2 .... Fig. 8-3(2-1)

(c) Transmission Pattern 3 .... Fig. 8-3(3-1)

(d) Transmission Pattern 4 .... Fig. 8-3(4-1)

<u>Case 3</u> Power flow, voltage calculation in F.Y. 2007/2008 for selection of optimum transmission pattern

(a) Transmission Pattern 1 .... Fig. 8-3(1-2)

(b) Transmission Pattern 2 .... Fig. 8-3(2-2)

(c) Transmission Pattern 3 .... Fig. 8-3(3-2)

(d) Transmission Pattern 4 .... Fig. 8-3(4-2)

(e) In case of 400 kV transmission .... Fig. 8-3(5)

<u>Case 4</u> Power system stability calculation in F.Y. 2001/2002 for selection of optimum transmission pattern

(a) Transmission Pattern 1, Fault at Bus 1 .... Fig. 8-4(1-1-1)

(b) Transmission Pattern 1, Fault at Bus 2 .... Fig. 8-4(1-1-2)

(c) Transmission Pattern 2, Fault at Bus 1 .... Fig. 8-4(2-1-1)

(d) Transmission Pattern 2, Fault at Bus 2 .... Fig. 8-4(2-1-2)

(e) Transmission Pattern 3, Fault at Bus 1 .... Fig. 8-4(3-1-1)

(f) Transmission Pattern 3, Fault at Bus 2 .... Fig. 8-4(3-1-2)

(g) Transmission Pattern 4, Fault at Bus 1 .... Fig. 8-4(4-1-1)

(h) Transmission Pattern 4, Fault at Bus 2 .... Fig. 8-4(4-1-2)

(i) Transmission Pattern 4, Fault at Bus 6 .... Fig. 8-4(4-1-3)

Case 5 Power system stability calculation in F.Y. 2007/2008 for selection of optimum transmission pattern

(a) Transmission Pattern 1 .... Fig. 8-4(1-2)

(b) Transmission Pattern 2 .... Fig. 8-4(2-2)

(c) Transmission Pattern 3 .... Fig. 8-4(3-2)

(d) Transmission Pattern 4, Fault at Bus 1 .... Fig. 8-4(4-2-1)

(e) Transmission Pattern 4, Fault at Bus 2 .... Fig. 8-4(4-2-2)

(f) Transmission Pattern 4, Fault at Bus 6 .... Fig. 8-4(4-2-3)

Case 6 Power flow, voltage calculation in F.Y. 1993/1994 (Schedule 1, 2 units of Arun 3 power station commissioned) in case of transmission pattern 4

(a) At peak load time .... Fig. 8-5(1)

(b) At off peak load time .... Fig. 8-5(2)

Case 7 Power flow, voltage calculation in F.Y. 1998/1999 (Schedule 2, 3 units of Arun 3 power station commissioned) in case of transmission pattern 4

(a) At peak load time .... Fig. 8-5(3)

(b) At off peak load time .... Fig. 8-5(4)

Case 8 Power flow, voltage calculations in F.Y. 1998/1999 (Schedule 3, 6 units of Arun 3 power station commissioned for power export) in case of transmission pattern 4

(a) At off peak load time .... Fig. 8-5(5)

Case 9 Power system stability calculation for transmission pattern 4 in F.Y. 1993/1994

(a) Fault at Bus 1 .... Fig. 8-6(1)

(b) Fault at Bus 2 .... Fig. 8-6(2)

(c) Fault at Bus 6 .... Fig. 8-6(3)

Case 10 Power system stability calculation for 200 MW power export in F.Y. 1998/1999

(a) 220 kV, 1 cct transmission,
Fault at Bus 1 .... Fig. 8-7(1)

(b) 220 kV, 1 cct transmission,
Fault at Bus 2 .... Fig. 8-7(2)

(c) 220 kV, 2 cct transmission,
Fault at Bus 2 .... Fig. 8-7(3)

Case 11 Power flow, voltage calculation for 200 MW power export

(a) In F.Y. 1998/1999 .... Fig. 8-8(1)

(b) In F.Y. 2001/2002 .... Fig. 8-8(2)

Case 12 Power system stability calculation for 200 MW power export in case of 220 kV, 2 cct transmission, fault at Bus 1

(a) In F.Y. 1998/1999 .... Fig. 8-9(1)

(b) In F.Y. 2001/2002 .... Fig. 8-9(2)

8.6.3 Short Circuit Current

It is considered that, as referred to Fig. 2-7, the full power generation with six units of the Arun 3 power station will be all consumed by domestic demand of Nepal in F.Y. 2007/08. Hence the 3-phase short circuit current is calculated on the basis of power system in F.Y. 2007/08 as shown in Fig. 8-11. The total capacity of generators in Nepal at this time will be approximately 732 MVA. Transient reactance X_d' is used as generator reactance.

The maximum short circuit currents of substation (switchyard) busses for each voltage level are as follows:

Arun 3 switchyard 220 kV bus	:	4.0 kA
Dubi substation 132 kV bus	:	3.5 kA
Siuchatar substation 132 kV bus	:	4.0 kA

The short circuit current supplied from the Arun 3 power station will be 3.4 kA on a 220 kV basis, but since the Arun 3 power station will be at a great distance from the existing electric power facilities of Nepal, the effects of the short circuit current from the Arun 3 power station on the neighboring substations (switchyard) will be extremely small.

8.6.4 Transmission Line Charging

A study is made for the case of charging the transmission line up to Kathmandu from the Arun 3 power station. The extent of transmission line charging from the Arun 3 power station is considered for the three cases below.

The conditions for the study are that upper limit of substation bus voltage and lower limit of the Arun 3 generator operating voltage will be 102 and 85 percent, respectively and shunt reactor capacities are calculated based on these conditions. For the 132 kV transmission line, it is assumed that the 7.5 MVA shunt reactor being planned by NEA for the existing Dhalkebar substation is also available.

Case 1: 220 kV transmission line from the Arun 3 power station to the New Kathmandu substation via the Dubi substation and the Dhalkebar switchyard

(1) During 132 kV operation (1994 - 1998)
(2) During 220 kV operation (after 1998)

Case 2: 132 kV transmission line from the Arun 3 power station to the Hetauda substation via the existing Dubi and Dhalkebar substations

Case 3: 220 kV transmission line from the Arun 3 power station to the Dubi substation

The results of calculations for bus voltages and reactive power flows in the above cases are shown in Fig. 8-12, according to which the capacities of shunt reactors are as given below. The Dhalkebar switchyard is selected as an appropriate place for provision of shunt reactors since the effects of the shunt reactors will be the greatest at that site. A further condition is that only 1 unit of the Arun 3 power station will be in operation.

Case 1: Dhalkebar S/Y, 25 MVA/cct x 2 cct (total 50 MVA)

Case 2: Existing Dhalkebar S/S, 7.5 MVA (planned by NEA)

Case 3: Unnecessary

According to the above studies, line charging will be possible for any case if a shunt reactor of 25 MVA per one circuit is provided at the Dhalkebar switchyard. And line charging of one circuit from the Arun 3 power station to Kathmandu or Hetauda can be made by means of only one generator operation of the Arun 3 power station.

8.7 Further Study and Investigation

Detailed examinations are made in this feasibility study mainly for the eastern part of the electric power system of Nepal with regard to formulation of a power transmission and substation plan to be developed in accordance with the output of 402 MW from the Arun 3 power station. Since electric power system will be expanded in succession with increase in demand, it will be necessary to make the detailed examinations regarding the expansion plan for the entire electric power system in Nepal at all times. It is also required to study further on power export.

Based on the results of the examinations of the power transmission and substation plan for the Arun 3 project, the subjects which require further investigations and studies are cited below. The topics cited below are on matters which will require much time for study, and therefore, it will be necessary to make such investigations and studies separately from this feasibility study.

8.7.1 Power Facilities around Kathmandu

Kathmandu is the load center of the electric power system in Nepal, and the facilities of the 66 kV substations and 66 kV transmission lines around the city have to be expanded or renewed in step with development of the Arun 3 power station.

As described previously in paragraph 8.1, Pattern 4 is selected in this feasibility study as the optimum power transmission plan. In this case, it will be necessary to construct the New Kathmandu substation and a detailed study on secondary substations to be connected with this New Kathmandu substation will also be needed. It is planned in this study for convenience sake that the New Kathmandu substation will be interconnected with the Balaju and the Siuchatar substations by 132 kV transmission lines, however, studies hereafter of the following points will be required.

- Location for construction of the New Kathmandu substation
- Selection of secondary voltage of the New Kathmandu substation (66 kV or 132 kV)
- Selection of the number of outgoing circuits for secondary transmission lines of the New Kathmandu substation and of interconnecting substations

- Expansion plan for reactive power facilities in surroundings of Kathmandu

8.7.2 Expansion of 132 kV Transmission Line in Western Power System

One of the features of load on the electric power system in Nepal is that the difference between peak load and off peak load is great. According to the present study, the off peak load is about 35 percent of the peak load. Static condensers will be necessary at peak load time to maintain system voltage as seen from the results of power flow analysis, while shunt reactors will be needed at off peak load time. This system characteristic is due not only to the features of the load but also the fact that the length of the transmission line is great.

Particularly, at the section between the Dumkibas substation and the Nepalgunj substation of the western power system, expansion of 132 kV, 2 cct will have effect on maintaining system voltage at peak load time, but voltage will rise at off peak load time. In order to suppress this voltage rise, it will be necessary to increase the capacity of the shunt reactor presently being planned by NEA, or to adopt the measure of shutting down one of the two circuits during off peak load time.

Accordingly, as the demand of the western power system increases, further studies will be required with regard to transmission line expansion plans, shunt reactor capacities, and method of transmission line operation.

It should be noted in the present study, that voltage rise in the case of the power flow calculations at off peak load time is suppressed by reducing the transmission line charging capacity shutting down one of the two circuits between the Dumkibas and the Nepalgunj substations (Figs. 8-5(2), 8-5(4), 8-5(5)).

8.7.3 Expansion of Hetauda Substation

If the power transmission plan is formulated based on Pattern 4 concerning the optimum power transmission pattern as described in paragraph 8.1, the expansion plan of the Hetauda substation by NEA will cause no special problem for the time being.

However, in case a power transmission plan other than Pattern 4 is formulated, especially in case Pattern 1 will be adopted (interconnection with the Hetauda substation by 132 kV, 4 cct via the Pathalaiya substation), the reserve space at the Hetauda substation for 132 kV transmission lines will be insufficient and it will be necessary to review the expansion plan presently contemplated by NEA to match the Arun 3 project development plan.

Expansion will also be required for existing 132 kV and 66 kV transmission line facilities from the Hetauda substation to Kathmandu, furthermore, due attention should be paid to reliability of power system as described in preceding paragraph 8.1.2.

8.7.4 Power Export

With regard to power export, it will be necessary to grasp thoroughly the characteristics of electric power system of the importing country. The principal items of study to facilitate the interconnection with different power systems are the following:

- Control of power flow of the interconnecting lines
- Control of frequency and voltage of the two systems
- Effects of step-out of generator with large capacity
- Operation method of interconnecting lines

In this connection, it is recommended for the study to be made to assure that the two power system is synchronized without problems examining transient and steady-state stability. To do so, governor and exciter characteristics as well as inertia and other constants for principal generating plants in both countries, transmission line and transformer impedances and protective relaying system pertaining to the power systems, etc. are to be investigated. Meanwhile study on asynchronous power system interconnection (HVDC) would be made as an option though the possibility on adoption of such system is less.

Table 8–1 (1) Economic Comparison of Each Transmission Pattern (For F.Y. 2001/2002)

Items \ Pattern	Pattern 1	Pattern 2	Pattern 3	Pattern 4
Transmission Line Length (km) x Number of Circuits	(220kV) 120x2 256x1 (132kV) 30x1	(220kV) 120x2 326x1	(220kV) 120x2 376x1	(220kV) 120x2 266x1
Construction Cost (10^3US$)				
Transmission Line				
Arun 3 P/S - Dubi S/S (120 km, 2 cct)	23,200	23,200	23,200	23,200
Dubi S/S - Dhalkebar S/Y (146 km, 1 cct)	14,800	14,800	14,800	14,800
Dhalkebar S/Y - Pathalaiya S/S (110 km, 1 cct)	11,100	11,100	11,100	-
Pathalaiya S/S - Hetauda S/S (30 km, 1 cct)	1,800	-	-	-
Pathalaiya S/S - Siuchatar S/S (70 km, 1 cct)	-	7,100	-	-
Dhalkebar S/Y - New Kathmandu S/S (120 km, 1 cct)	-	-	12,100	12,100
Sub-total .... (1)	50,900	56,200	61,200	50,100
Substation & Switchyard				
Dubi S/S	11,900	11,900	11,900	11,900
Dhalkebar S/Y	7,500	7,500	8,400	7,500
Pathalaiya S/S	14,600	15,000	14,100	-
Hetauda S/S	1,700	-	-	-
Siuchatar S/S	-	900	-	-
New Kathmandu S/S	-	-	12,500	12,500
Sub-total .... (2)	35,700	35,300	46,900	31,900
Telecommunication .... (3)	4,200	6,500	6,500	5,500
Total (1) + (2) + (3) .... (4)	90,800	98,000	114,600	87,500
Annual Total Construction Cost (10^3US$) ... (5) (Annual Cost Rate 12%)	10,896	11,760	13,752	10,500
Transmission Line Losses				
kW Losses (MW)	14.8	13.5	12.4	12.7
kWh Losses (GWh)	42.1	38.4	35.3	36.2
Annual Cost due to Transmission Line Losses (10^3US$)				
kW Losses .... (6)	1,006	918	843	864
kWh Losses .... (7)	2,652	2,419	2,224	2,281
Total (6) + (7) .... (8)	3,658	3,337	3,067	3,145
Total Annual Cost (10^3US$), (5) + (8)	14,554	15,097	16,819	13,645

Note: (1) Annual energy losses (kWh losses) are calculated taking into account the loss factor (Lr) which is the ratio of average power losses to peak power losses obtained from experimental equation of Buller-Woodrow.

$Lr = 0.3 \times (\text{Annual Load Factor}) + 0.7 \times (\text{Annual Load Factor})^2$, where Annual Load Factor : 0.50

$= 0.325$

(2) Cost for power losses and energy losses
(a) 68 US$/kW (b) 0.063 US$/kWh

Table 8–1 (2) Economic Comparison of Each Transmission Pattern (For F.Y. 2007/2008)

Items \ Pattern	Pattern 1	Pattern 2	Pattern 3	Pattern 4
Transmission Line Length (km) x Number of Circuits	(220kV) 376x2 (132kV) 30x2	(220kV) 446x2	(220kV) 496x2	(220kV) 386x2
Construction Cost (10^3US$)				
Transmission Line				
Arun 3 P/S - Dubi S/S (120 km, 2 cct)	23,200	23,200	23,200	23,200
Dubi S/S - Dhalkebar S/Y (146 km, 2 cct)	18,900	18,900	18,900	18,900
Dhalkebar S/Y - Pathalaiya S/S (110 km, 2 cct)	14,100	14,100	14,100	-
Pathalaiya S/S - Hetauda S/S (30 km, 2 cct)	2,600	-	-	-
Pathalaiya S/S - Siuchatar S/S (70 km, 2 cct)	-	9,000	-	-
Dhalkebar S/Y - New Kathmandu S/S (120 km, 2 cct)	-	-	15,400	15,400
Sub-total .... (1)	58,800	65,200	71,600	57,500
Substation & Switchyard				
Dubi S/S	12,700	12,700	12,700	12,700
Dhalkebar S/Y	10,300	10,300	12,100	10,300
Pathalaiya S/S	18,300	19,100	15,000	-
Hetauda S/S	2,200	-	-	-
Siuchatar S/S	-	1,800	-	-
New Kathmandu S/S	-	-	13,400	15,400
Sub-total .... (2)	43,500	43,900	53,200	38,400
Telecommunication .... (3)	4,200	6,500	6,500	5,500
Total (1) + (2) + (3) .... (4)	106,500	115,600	131,300	101,400
Annual Total Construction Cost (10^3US$) ... (5) (Annual Cost Rate 12%)	12,780	13,872	15,756	12,168
Transmission Line Losses				
kW Losses (MW)	39.6	36.0	31.5	33.3
kWh Losses (GWh)	112.7	102.5	89.7	94.8
Annual Cost due to Transmission Line Losses (10^3US$)				
kW Losses .... (6)	2,693	2,448	2,142	2,264
kWh Losses .... (7)	7,100	6,458	5,651	5,972
Total (6) + (7) .... (8)	9,793	8,906	7,793	8,236
Total Annual Cost (10^3US$), (5) + (8)	22,573	22,778	23,549	20,404

Table 8-2 Economic Comparison between 220 kV and 400 kV Substation/Switchyard and Transmission Line Facilities

	220 kV	400 kV
Transmission Line Length (km) x Number of Circuits	386 x 2	386 x 2
Construction Cost (10^3US$)		
Transmission Line		
Arun 3 S/Y - Dubi S/S (120 km)	23,200	24,100
Dubi S/S - Dhalkebar S/Y (146 km)	18,900	29,300
Dhalkebar S/Y - New Kathmandu S/S (120 km)	15,400	24,100
Sub-total .... (1)	57,500	77,500
Substation & Switchyard		
Arun 3 S/Y	14,900	30,200
Dubi S/S	12,700	19,900
Dhalkebar S/Y	10,300	16,400
New Kathmandu S/S	15,400	22,500
Sub-total .... (2)	53,300	89,000
Telecommunication .... (3)	5,500	5,500
Total (1) + (2) + (3) .... (4)	116,300	172,000
Annual Total Construction Cost .. (5) (Annual Cost Rate 12%)	13,956	20,640
Transmission Line Losses		
kW Losses (MW)	33.3	15.5
kWh Losses (GWh)	94.8	44.1
Annual Cost due to Transmission Line Losses (10^3US$)		
kW Losses .... (6)	2,264	1,054
kWh Losses .... (7)	5,972	2,778
Total (6) + (7) .... (8)	8,236	3,832
Total Annual Cost (5) + (8)	22,192	24,472

Note: (1) Annual energy losses (kWh losses) are calculated taking into account the loss factor (Lr) which is the ratio of average power losses to peak power losses obtained from experimental equation of Buller-Woodrow.
$Lr = 0.3 \times (\text{Annual Load Factor}) + 0.7 \times (\text{Annual Load Factor})^2$
Annual Load Factor : 0.5

(2) Cost for power losses and energy losses
(a) 68 US$/kW/year (b) 0.063 US$/kWh

(3) Cost of shunt reactor required for 400 kV transmission system is excluded.

Table 8–3 Development Sequence of Transmission Line and Substation

Arun 3 Power Station	1st Stage (No.1-No.3)		2nd Stage (No.4-No.6)	
Transmission Line and Substation	Schedule 1 (Jun. 1994)	Schedule 2 (Sep. 1998)	Schedule 3 (Dec. 1998)	Entire Facilities
Transmission Line				
Arun 3 S/Y - Dubi S/S	220 kV, 2 Circuits (Operation 132 kV)	- (Operation 220 kV)	- (Operation 220 kV)	220 kV, 2 Circuits
Dubi S/S - Dhalkebar S/Y	220 kV, 1 Circuit (Operation 132 kV)	- (Operation 220 kV)	220 kV, 1 Circuit (Operation 220 kV)	220 kV, 2 Circuits
Dhalkebar S/Y - New Kathmandu S/S	220 kV, 1 Circuit (Operation 132 kV)	- (Operation 220 kV)	220 kV, 1 Circuit (Operation 220 kV)	220 kV, 2 Circuits
* New Kathmandu S/S - Existing S/S	132 kV, 2 Circuits	-	-	132 kV, 2 Circuits
Substation & Switchyard				
Dubi S/S	220 kV, 2 Circuits for Incoming 220 kV, 1 Circuit for Outgoing (Operation 132 kV)	- Transformer 220/132 kV 70 MVA, 3 units (Operation 220 kV)	- 220 kV, 1 Circuit for Outgoing (Operation 220 kV)	220 kV, 2 Circuits for Incoming 220 kV, 2 Circuits for Outgoing Transformer, 70 MVA x 3
Dhalkebar S/Y	220 KV, 1 Circuit for Incoming 220 kV, 1 Circuit for Outgoing Shunt Reactor 10 MVA (Operation 132 kV)	- - Shunt Reactor 10 MVA (Operation 220 kV)	220 kV, 1 Circuit for Incoming 220 kV, 1 Circuit for Outgoing Shunt Reactor 30 MVA (Operation 220 kV)	220 kV, 2 Circuits for Incoming 220 kV, 2 Circuits for Outgoing Shunt Reactor, 25 MVA x 2
New Kathmandu S/S	220 kV, 1 Circuit for Incoming - (Operation 132 kV) *132 kV, 2 Circuits for Outgoing	- Transformer 220/132 kV, 100 MVA 2 units (Operation 220 kV) -	220 kV, 1 Circuit for Incoming Transformer 220/132 kV, 100 MVA, 1 Unit (Operation 220 kV) -	220 kV, 2 Circuits for Incoming Transformer, 100 MVA x 3 *132 kV, 2 Circuits for Outgoing

* Construction costs of 132 kV transmission lines for interconnection between New Kathmandu S/S and existing substations of Siuchatar and Balaju are not included in this Feasibility Study.

Table 8–4 Generator and Transformer Data

Power Station	Generator						Transformer		
	Installed Capacity (MW)	Total Capacity (MVA)	Xd (%)	Xd' (%)	Xq (%)	H (kW-sec/KVA)	Total Capacity (MVA)	Voltage (kV)	Xt (%)
Arun 3	400	474	100	30	60	3.75	480	220/13.8	10.0
Kulekhani-1	60	70.59	100	26	60	1.99	70	66/11	7.25
Kulekhani-2	32	37.65	100	28	60	2.00	37	132/11	8.4
Sunkosi	10.05	11.82	100	30	60	2.16	12.6	66/6.3	7.97
Devighat	14.1	17.63	100	28	60	2.40	18.9	66/11	6.97
Trisuli	21	26.25	100	34.3	60	3.55	22.5	66/6.6	8.4
Marsyangdi	66	73.33	100	28	60	2.53	81	66/6.6	8.0
Gandak	15	17.65	100	39	60	1.08	20	132/6.6	8.4
Substation									
New Kathmandu							300	220/66	8.5
Dubi							210	220/132	8.5
Hetauda							40	132/66	7.35
Siuchatar							120	132/66	7.5
Balaju							120	132/66	7.5

(Note) Xd : Direct-axis synchronous reactance
Xd': Direct-axis transient reactance
Xq : Quadrature-axis synchronous reactance
H : Inertia constant
Xt : Impedance voltage

Fig. 8–1 (1) Conceivable Transmission Pattern (1st Stage)