

ISLAMIC REPUBLIC OF PAKISTAN
Water and Power Development Authority (WAPDA)

**PREPARATORY SURVEY
FOR
MANGLA HYDRO POWER STATION
REHABILITATION AND ENHANCEMENT
PROJECT
IN
PAKISTAN**

Final Report

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**JAPAN INTERNATIONAL COOPERATION AGENCY
(JICA)**

**NIPPON KOEI CO., LTD.
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ABBREVIATIONS

AC	Alternating Current	GM	General Manager
ADB	Asia Development Bank	GOP	Government of Pakistan
AEDB	Alternative Energy Development Board	HESCO	Hyderabad Electrical Supply Company
AJK	Azad Jammu Kashmir	HR & A	Human Resources and Administration
AVR	Automatic Voltage Regulator	IEE	Initial Environmental Examination
BCL	Bamangwato Concessions Ltd.	I&P Dept.	Irrigation and Power Development
BOD	Biochemical Oxygen Demand	I&P	Insurance & Pensions
BOP	Balance of Plant	IESCO	Islamabad Electrical Supply Company
BPS	Basic Pay Scales	IPB	Isolated Phase Bus
BS	British Standard	IPC	Interim Payment Certificate
C&M	Coordination & Monitoring	IPP	Independent Power Producer
CDO	Central Design Office	IRSA	Indus River System Authority
CDWP	Central Development Working Party	JBIC	Japan Bank for International Cooperation
CCC	Central Contract Cell	JICA	Japan International Cooperation Agency
CDM	Clean Development Mechanism	JPY	Japanese Yen
CE	Chief Engineer	KESC	Karachi Electric Supply Company
CER	Certified Emission Reductions	KFW	Kreditanstalt für Wiederaufbau
CIF	Cost, Freight and Insurance	L/A	Loan Agreement
CS	Consultancy Services	LA & R	Land Acquisition and Resettlement
CM	Carrier Management	LC	Local Currency
CPPA	Central Power Purchase Agency	LCC	Life Cycle Cost
CRBC	Chashma Right Bank Canal	L/C	Letter of Credit
CRR	Chief Resident Representative	LEA	Law Enforcing Agencies
CWE	China International Water and Electric Corporation	LESCO	Lahore Electrical Supply Company
DC	Direct Current	M&S	Monitoring and Surveillance
DG	Director General	MOI	Ministry of Interior
DISCO	Distribution Company	MoWP	Ministry of Water and Power
DSO	Dam Safety Organization	MS	Medical Services
ECNEC	Executive Committee of National Council	MEPCO	Multan Electrical Power Company
EIA	Environmental Impact Assessment	MTDF	Medium Term Development
EIRR	Economic Internal Rate of Return	NAP	Northern Area Project
EOI	Expression of Interest	NCS	Pakistan National Conservation Strategy
EPA	Environmental Protection Agency	NEPRA	National Electric Power Regulatory Authority
EPD	Environmental Protection Department	NEQS	National Environmental Quality Standard
FC	Foreign Currency	NJHEPC	Neelum Jehlum Hydro Power Project Company
FESCO	Faisalabad Electrical Supply Company	NOC	Non Objection Certificate
FIRR	Financial Internal Rate of Return	NPCC	National Power Control Center
FNPV	Financial Net Present Value	NPSEP	National Power System Expansion Plan
FS	Feasibility Study	NPV	Net Present Value
FY	Fiscal Year starting on 1 st July ending on 30 th June in Pakistan	NTDC	National Transmission and Dispatch Company
GBHP	Ghazi Barotha Hydropower Project	O&M	Operation and Maintenance
GCB	Gas Circuit Breaker	ODA	Official Development Assistance
GENCO	Generation Company		
GEPCO	Gujranwala Electrical Power Company		
GHG	Greenhouse Gas		

O.E	Operation Engineer	SCADA	Supervisory Control and Data Acquisition
OJT	On-the-job Training		
P&D	Planning and Design	SCF	Standard Conversion Factor
Pak-EPA	Pakistan Environmental Protection Agency	SSG	Speed Signal Generator
PAEC	Pakistan Atomic Energy Commission	SOPs	Standard Operation Procedures
PC	Personnel Computer	STEP	Special Terms for Economic Partnership
PC-1	Planning Commission Form 1	T&D	Transmission and Distribution lines
PC-2	Planning Commission Form 2	TESCO	Tribal area Electric Supply Company
PCB	Poly Chlorinated Biphenyl	TDP	Tarbela Dam Project
PEC	Pakistan Engineering Council	TDS	Total Dissolved Solid
PEPC	Pakistan Environmental Protection Council	TOR	Terms of Reference
PEPA	Pakistan Environmental Protection Act	TS	Technical Services
PEPCO	Pakistan Electric Power Company	USD	United States Dollars
PESCO	Peshawar Electrical Supply Company	UPS	Uninterruptible Power Supply
PF	Power Factor	VAT	Value Added Tax
PLC	Programmable Logic Controller	WASC	WAPDA Administrated Staff College
PM	Project Manager	WAPDA	Water and Power Development Authority
PMU	Project Management Unit	WEA	WAPDA Engineering Academy
PMOs	Principle Medical Offices	WRPO	Water Resources Planning Organization
PPIB	Private Power Infrastructure Board	WSB	WAPDA Sports Board
PRS	Pakistan Rupees	WUA	Water User Association
PSO	Principal Staff Officer	WUC	Water Use Chares
QBS	Quality Based Selection	XLPE	Cross-Linked Polyethylene Insulation
QCBS	Quality and Cost Based Selection		
QESCO	Quetta Electrical Supply Company		
RAP	Resettlement Action Plan		
R.E.	Resident Engineer		
RTD	Resistance Temperature Detectors		

UNITS

Length

mm	Millimeter
cm	Centimeter
m	Meter
km	Kilometer
in	Inch (=25.4 mm)
ft	Feet (=305 mm)

Extent

cm ²	Square-centimeter
m ²	Square-meter
km ²	Square-kilometer
ha	Hectares
AF	Acre Feet (=1,233.5 m ³)

Volume

cm ³	Cubic-centimeter
m ³	Cubic-meter
Nm ³	Normal cubic-meters at 0°C and at 1 barometric pressure
gal	Gallon (=3.78 L)

Weight

g	Grams
kg	Kilograms
mg	Milligram
ton	Metric ton

Pressure

cft	Cubic feet sec (=0.0283 m ³ /s)
psi	Pounds Per Square Inch (=0.0703 kg/cm ²)

Time

sec.	Seconds
min.	Minutes
hr.	Hours

Temperature

°C	Degree Celsius
----	----------------

Currency

USD	United State Dollars
JPY	Japanese Yen
PRs	Pakistan Rupees

Electric

V	Volts (Joule/coulomb)
kV	Kilo volts
A	Amperes (Coulomb/second)
kA	Kilo amperes
W	Watts (active power) (J/s: Joule/second)
kW	Kilo watts
MW	Mega watts
Wh	Watt-hours
kWh	Kilo watt-hours
MWh	Mega watt-hours
GWh	Giga watt-hours
VA	Volt-amperes (apparent power)
kVA	Kilo volt-amperes
MVA	Mega volt-amperes
BHP	British Horse Power (=745.7 W)

Speed of Turbine/Generator
min⁻¹

Frequency

Hz hertz

FINAL REPORT
for
The Preparatory Survey for Mangla Hydro Power Station
Rehabilitation and Enhancement Project
in Pakistan

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EXECUTIVE SUMMARY

E1. Objectives

The Survey aimed at enhancing the maturity of the Project appropriate for Japanese ODA loan financing and searching for the possibility of applying the Special Terms for Economic Partnership (STEP) condition to the Project.

The Survey was carried out as a supplemental survey to the feasibility study (hereinafter referred to as “the F/S”) conducted by Water and Power Development Authority of the country (hereinafter referred to as “WAPDA”) in June to December 2011.

E2. Recommendation in the F/S Report

The F/S report concluded that Alternative 1A (1,310MW total) is recommended since it satisfies all objectives from the scope of works. Alternative 1A also has the highest NPV, BCR, EIRR, and FIRR.

Table E-1 Expected Increase in Energy Output by Up-gradation/Refurbishment

Alternative	Unit Rating	Description
1A	Up-gradation to 1,310 MW in total Units 1-6: 135 MW Units 9-10: 135 MW Units 7-8: 115 MW (no change)	<u>Turbine</u> - Replacement of turbine runner (same as Alternative 0) <u>Generator with higher capacity</u> - Replacement of core and winding for generator (Units 1-6, 9-10) - New static digital excitation system <u>Others</u> - New power transformer and IPB

Source: Feasibility Study for Up-gradation and Refurbishment of Generating Units of Mangla Power Station, December 2011

E3. Recommendation of Rehabilitation and Enhancement Scenarios

Based on the maximum turbine output, the Survey Team recommended the rehabilitation and enhancement concept of the Project as follows:

(1) Main recommendation by the Survey Team is:

- 1) Generator's Capacity: Enhancement up to 180 MVA/unit from the existing 125 MVA/unit
- 2) Output: Enhancement up to 144 MW/unit with 0.8 power factor

(2) Main difference compared with the F/S report is that the Survey Team's idea does not include modification of the existing concrete foundation of turbines and generators.

Meanwhile, in the F/S report, it is recommended to rehabilitate and enhance the generator for upgrade up to 135 MW per unit at PF 0.8 (rated capacity is 169 MVA).

As the result of review on 144MW and 135MW, it reveals that the generator's output of 144MW per unit is more advantageous than 135MW at the average annual power generation. However, in case of 144 MW, the expected number of days which would be reached the maximum output of 1,266MW (4 units enhancement) and 1,324MW (6 units enhancement) is limited to 65 days and 54 days respectively due to the restriction of water resources which are stored to Mangla Dam. Thereby, the average plant factor of 144MW, which is defined as the ratio of the average power load of a power plant to its rated capacity, is lower than 135MW.

It means that the generator's output with 135 MW is more advantageous in respect of a cost benefit compared to 144MW, and it can be said that economical efficiency in case of 135MW is higher than 144MW.

Therefore, the Survey Team also can recommend the rehabilitation and enhancement concept with generator's output of 135 MW per unit with 0.8 power factor in accordance with the recommendation in the F/S report.

E4. Study on Possibility of Formulating the Project as STEP Loan

The Japanese products of water turbine generator have superiority from the viewpoint of "Reliability of Equipment", however, there is no remarkable distinction of technical aspects between the Japanese manufacturers and the overseas ones. Therefore, it seems have a low potential for the formulating the Project as STEP loan.

E5. Operation and Effect Indicators

Table E-2 shows operation and effect indicators to measure the quantitative effects of the Project including target values at the time after completion of the Project.

Table E-2 Operation and Effect Indicators

Indicators	Present Conditions in 2012	Target	
		Scenario-A (for 4 units) The target year is 2021	Scenario-B (for 6 units) The target year is 2023
Maximum output	1,150 [MW]	1,230 [MW]	1,270 [MW]
Average annual power generation	2,753[GWh] (for 4 units)	3,232 [GWh]	-
	4,130[GWh] (for 6 units)	-	4,848 [GWh]
Average plant factor	49.6 [%]	60.6 [%]	59.2 [%]
Increase in the earnings of WAPDA	3,242 [PRs Mil/year] (for 4 units)	3,807 [PRs Mil/year]	-
	4,864 [PRs Mil/year] (for 6 units)	-	5,710 [PRs Mil/year]
Contribution to the reduction of carbon dioxide	-	1,334,527 [t-CO2/year]	1,383,118 [t-CO2/year]

Note: The figures of power generation and earnings are based on those of financial analysis.

Source: Prepared by the Survey Team

E6. Conclusions

The scenarios for rehabilitation and enhancement project of Mangla Power Station with enhanced generator's output 135 MW are summarized in Table E-3.

Table E-3 Summary of Recommended Scenarios

Scenarios	Subject Unit	No. of Units of Stoppage	Project Cost		Economic IRR	Financial IRR
			General Untied Japanese ODA	Climate Change Program		
Scenario-A1	Units 1-4 (4 units)	Double units	USD 294.2 mil. (JPY 23,800 mil.)	USD 284.3 mil. (JPY 23,002 mil.)	19.0 %	5.7 %
Scenario-A2		Single unit	USD 303.6 mil. (JPY 24,563 mil.)	USD 292.7 mil. (JPY 23,680 mil.)	17.9 %	5.4 %
Scenario-B1	Units 1-6 (6 units)	Double units	USD 495.2 mil. (JPY 40,059 mil.)	USD 476.3 mil. (JPY 38,534 mil.)	17.9 %	4.8 %
Scenario-B2		Single unit	USD 519.6 mil. (JPY 42,032 mil.)	USD 496.0 mil. (JPY 40,128 mil.)	16.4 %	4.4 %

Note: Scenario-A1, which is the rehabilitation and enhancement of four (4) units with double unit stoppage

Scenario-A2, which is the rehabilitation and enhancement of four (4) units with single unit stoppage

Scenario-B1, which is the rehabilitation and enhancement of six (6) units with double unit stoppage

Scenario-B2, which is the rehabilitation and enhancement of six (6) units with single unit stoppage

Source: Prepared by the Survey Team

CHAPTER 1
INTRODUCTION

CHAPTER 1 INTRODUCTION

1.1 Background of the Survey

1.1.1 Present Situation of Power Supply and Demand

In the Islamic Republic of Pakistan (hereinafter referred to as “the country”), the power demand has increased at about 10.3% per annum in the past ten years along with the economic growth rate of the country. However, the power supply did not catch up with the power demand which continue to increase year after year. About 6,105 MW power supply-demand gap was recorded in the summer of 2011. Under these circumstances, the people of the country have to brace the planned power outage for about eight hours daily on the average. The planned power outage has caused difficulties in people’s lives and derailed the development of agriculture which depends on irrigation. The industries have also suffered great economic losses due to power outage causing unemployment in the country and high production cost of finished products. Therefore, the closing of the supply-demand gap in power sector is urgently required.

1.1.2 Political Measures on Energy Sector and Development Plan

The Vision 2030 and the Medium Term Development Framework (MTDF) 2005-2010, are the forefront policies of the country which formulated energy policies, namely, i. developing power sources through the use of local resources such as hydropower, coal, and natural gas, ii. promoting power generation through public private partnership, iii. promoting privatization of all power sectors, and iv. reducing power system losses. In addition, the government has announced its energy policy on power supply. It is envisioned that power supply will increase to 20,000 MW by 2020, where the 6,000 MW is expected to come from hydropower generation.

1.1.3 Aid Program by Government of Japan

According to the assistance program of the Government of Japan (GOJ) in February 2005, GOJ has set high-ranked targets in the aid program to the country for the "construction of a sustainable society and its progression". In addition, the GOJ has also cited three directionalities for the assistance strategy, which are: i. developing a strong market economy, ii. ensuring human security and human development, and iii. providing a well-balanced development of the community and the economy. The Mangla Hydro Power Station

Rehabilitation and Enhancement Project (hereinafter referred to as “the Project”)¹ is positioned as part of expanding and upgrading the economic infrastructure in support to the activation of the market economy and reduction of poverty in pursuant to the directionalities mentioned above.

1.1.4 Objective of the Project

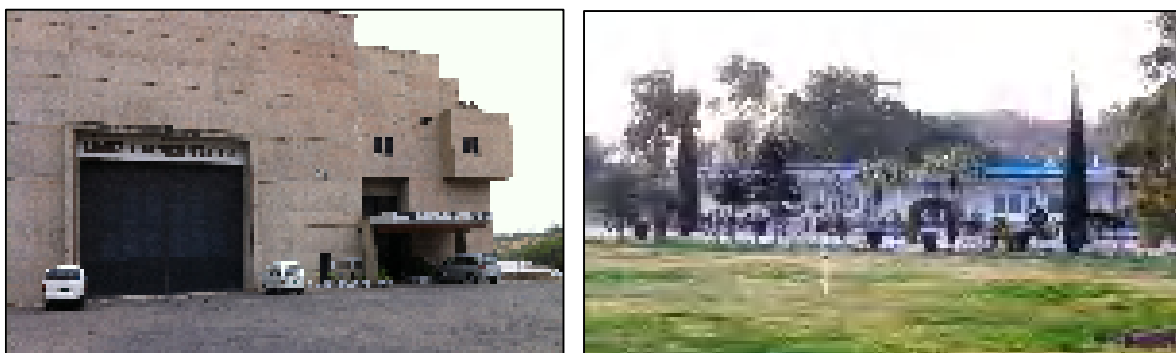
The Project is consistent with the above-mentioned strategies aimed to upgrade the energy sector and development plan of the country. The Survey Team will collect basic information related to the Project and analyze it for the formulation of a project under Japanese ODA Loan. The objective of the Project is to contribute in the improvement of the present power supply situation in the country through the rehabilitation and enhancement of aged power generating equipment like the water turbines, generators, and ancillary equipment in the Mangla Hydro Power Station.

1.2 Objective of the Survey

1.2.1 Objective of the Survey

The Survey aimed at enhancing the maturity of the Project appropriate for Japanese ODA Loan financing and searching for the possibility of applying the Special Terms for Economic Partnership (STEP) condition to the Project.

The Survey was carried out as a supplemental survey to the feasibility study (hereinafter referred to as “the F/S”) conducted by Water and Power Development Authority of the country (hereinafter referred to as “WAPDA”) in June to December 2011.



Source: Prepared by the Survey Team

Photo 1-1 Mangla Hydro Power Station and Guest House

¹ The Project is recognized by the Water and Power Development Authority (WAPDA) and the Government of Pakistan as the “Up-gradation and Refurbishment of Generating Units of Mangla Power Station”.

1.2.2 Objective Area of the Survey

The Mangla Hydro Power Station is located in Azad Jammu Kashmir, Pakistan. The power station and related dam are situated in a place called Mangla on the Jhelum River, lying in Azad Jammu and Kashmir (District Mirpur), located about 30 km upstream of Jhelum City (120 km from Capital Islamabad).

The related reservoir of the dam lies in Azad Jammu and Kashmir (AJK) and the Punjab Province (Districts Jhelum and Rawalpindi). The boundary between AJK and Punjab passes through the center of the Jhelum River. The power station and dam stand in AJK side, which lies on the left bank side of Jhelum River, and the Punjab side is located on the right bank of the river. A fairly good network of paved roads exists in and around the project area.



Source: Central Intelligence Agency

Source: Google

Figure 1-1 Location Map

1.2.3 Scope of Work of the Preparatory Survey

- (1) Field Site Survey
 - 1) To identify the current status and issues of the power sector in the country;
 - 2) To confirm the current situation of Mangla Hydro Power Station and identify the issues concerned;
 - 3) To confirm the necessity of the Project; and
 - 4) To review and confirm the structure of the Project.

- (2) Estimation of the Project Costs
 - 1) To review and estimate the total project cost including financial plan with funding arrangements;
 - 2) To review and assess the future operation and maintenance (O&M) costs; and
 - 3) To propose the estimation of annual fund requirements under the Japanese ODA Loan scheme.

- (3) Composition of the Project Components
 - 1) To compose several project components;
 - 2) To propose an implementation schedule;
 - 3) To suggest a time-bound action plan; and
 - 4) To suggest the procurement packages and technical specifications to meet the STEP conditions.

- (4) Elaboration of Project Implementation and O&M Plan
 - 1) To propose the institutional framework for the project implementation, including procurement and disbursement.
 - 2) To propose the institutional framework for O&M.

- (5) Review of Environmental and Social Consideration
 - 1) To review and confirm the environmental and social considerations based on “JICA Guidelines for Environmental and Social Considerations”.
 - 2) To conduct a climate change mitigation analysis to identify/collect quantitative data needed to compute greenhouse gas (GHG) emissions and to estimate the reduction in emission of GHG of the Project.

- (6) Confirmation of the Project Effect
 - 1) To propose the operation and effect indicators such as baseline data and target value method of data acquisition.
 - 2) To calculate the financial internal rate of return (FIRR) and the economic internal rate of return (EIRR).

- (7) Draft of the Project Implementation Program and Project Status Report (PSR)

1.3 Basic Concept

1.3.1 Project Planning Based on the F/S Report Prepared by WAPDA

The Survey was stated as a supplemental to the F/S carried by WAPDA in June to December 2011. The work procedure of the Survey for project planning is as follows.

(1) Step 1

The Survey Team studied the outline of the Project based on the F/S report prepared by WAPDA and the relevant existing documents owned by WAPDA.

(2) Step 2

The Survey Team collected the operation records, accident/malfunction records, and maintenance records for the Mangla Hydro Power Station from WAPDA, and carried out site investigation to assess the degree of deterioration of the power generating equipment through visual check and by simple inspection, without stopping the operation of the generating equipment.

(3) Step 3

The Survey Team listed all of the items of power generating equipment which were evaluated for rehabilitation and enhancement. Based on the results of Step 1 and Step 2 mentioned above, the listed items of power generating equipment were reviewed, keeping in view the following points:

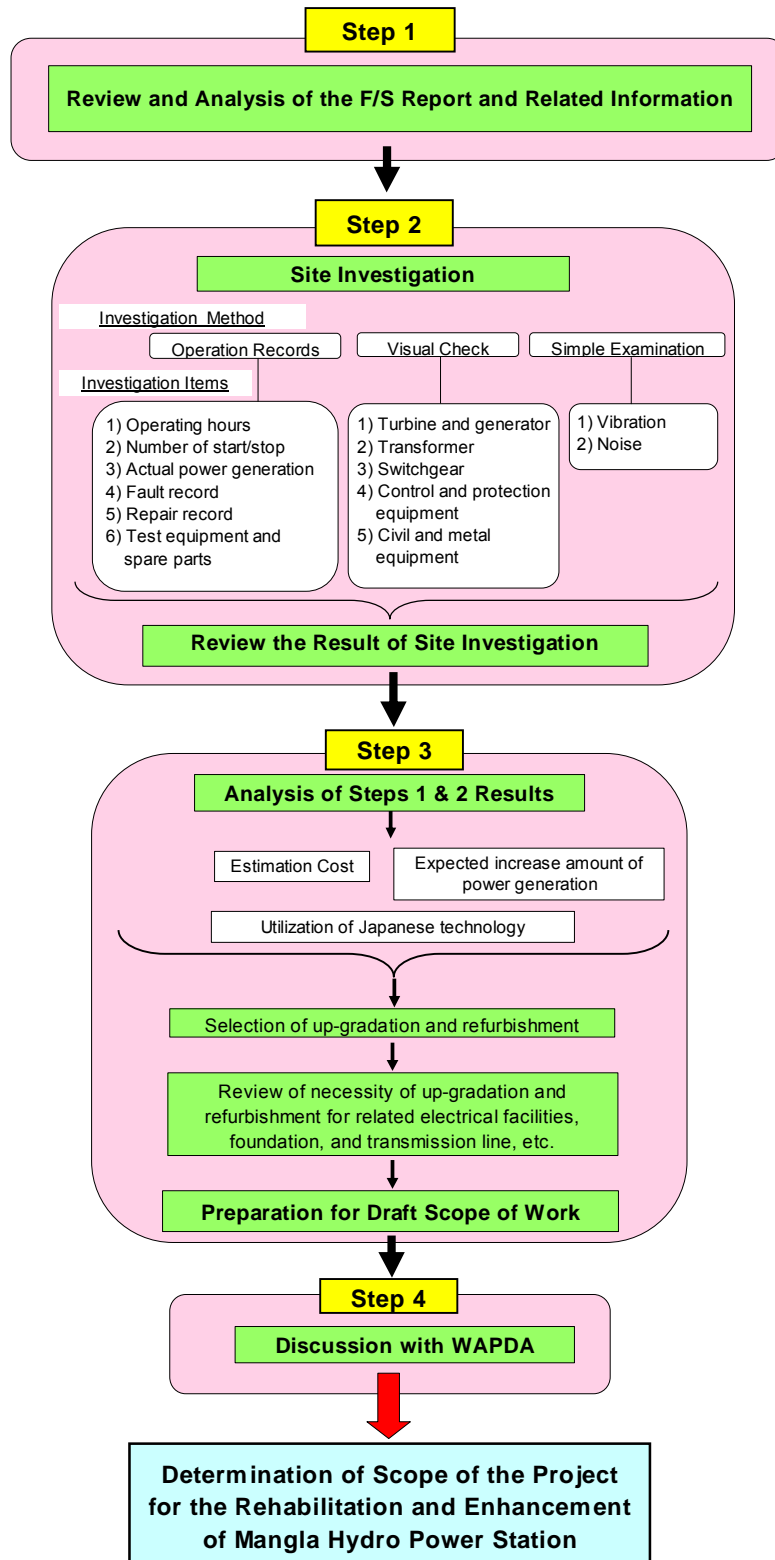
- 1) Expected increase in energy through the rehabilitation and enhancement project;
- 2) Estimated project cost; and
- 3) Possibility of utilization of Japanese technology.

The Survey Team reviewed the necessity of the rehabilitation or enhancement of other facilities such as concrete foundations of the equipment, substation and switching station inside power station, and transmission lines along with the existing power generating facilities and equipment, which are expected to increase the supply of energy.

The Survey Team made a draft scope of work of the project based on the result of the reviews.

(4) Step 4

The Survey Team discussed the draft scope of work of the project with WAPDA and later finalized it.



Source: Prepared by the Survey Team

Figure 1-2 Work Procedure of the Survey

1.3.2 Project Planning aiming for STEP Project Utilizing Japanese Technology

The Survey was implemented aiming to formulate the Project for STEP yen loans. The guideline published by the Ministry of Foreign Affairs of Japan stipulates the following conditions in applying for STEP yen loans:

(1) Procurement Condition

The borrowing country should procure the equipment manufactured in Japan which cost more than 30% of the total contract amount of the project.

(2) Contractor's Condition

The main contractor of the project should be a Japanese firm incorporated and registered under the laws of Japan. In case of a consortium, it should consists of a Japanese firm and a foreign firm, where the Japanese firm shall be the consortium leader.

Adding to the above, the condition cited below is applied to the Project and other project components such as hydropower generation, dam, tunnel, port and harbor, and sewer.

As for the portion of the project which is expected to utilize the Japanese superior technology during construction, the service cost shall be included in the calculation of Japanese procurement portion as well as the equipment cost.

1.3.3 Latest Status of the F/S

The F/S for the Project on the refurbishment and up-gradation of the Mangla Power Station was conducted by the MWH and NESPAK (Consultants JV) as per advice of WAPDA. The F/S was completed in December 2011. According to the information of WAPDA, starting of June 2012, the present status of the Project is as follows:

- 1) PC-I for up-gradation and refurbishment of generating units of Mangla Power Station has been preparing by WAPDA.
- 2) WAPDA has requested the Consultants JV to prepare the detailed design and tender documents for up-gradation and refurbishment for all 10 units. The works of detailed design (tender stage) of turbine, generator, excitation system, governor, and instrumentation are to be completed on 31 August 2012. The works of detailed design of power station cranes and lifting devices, intake, tunnels, bifurcations, draft tube gates, turbine inlet valves, and cooling water system are to be completed by the end of December 2012.

CHAPTER 2

BASIC DATA AND INFORMATION

CHAPTER 2 BASIC DATA AND INFORMATION

2.1 Power Sector's Issues

2.1.1 Annual Power Supply and Demand Gap

As of March 2012, the total installed capacity of Pakistan through all resources was around 21,527 MW. However, rapid demand growth and insufficient generation development created a gap between supply and demand resulting to significant load shedding.

Table 2-1 below shows the level of power shortage in recent years from zero power shortage in 2003 to almost 23% in 2010.

Table 2-1 Power Shortage Level between National Sale and National Demand

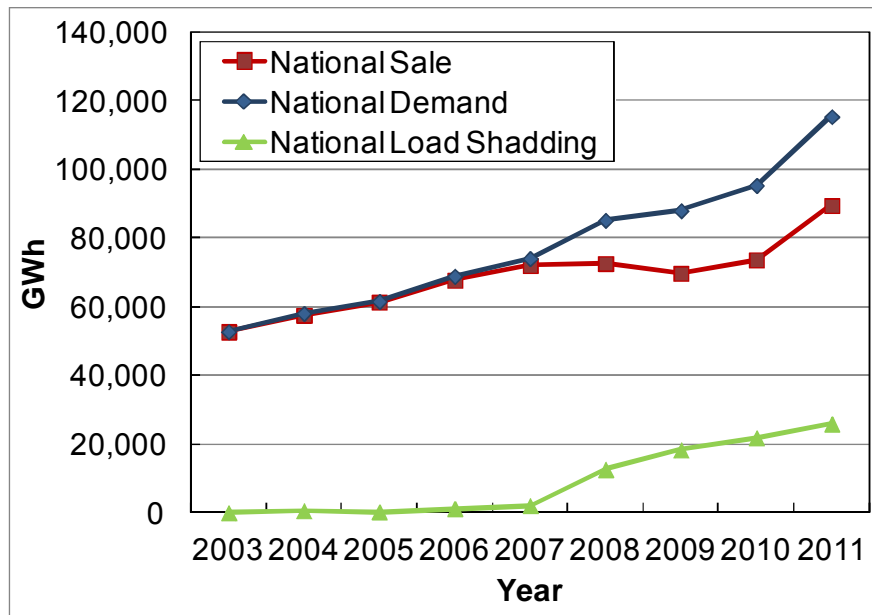
Year	National Sale ¹ [GWh]	National Demand [GWh]	National Power Shortage [GWh]	Power Shortage Rate [%]
2003	52,661	52,661	-	0.0
2004	57,467	57,986	520	0.9
2005	61,247	61,512	265	0.4
2006	67,608	68,815	1,208	1.8
2007	71,947	73,982	2,040	2.8
2008	72,518	85,096	12,578	14.8
2009	69,668	87,890	18,222	20.7
2010	73,595	95,238	21,821	22.9
2011	89,402	115,247	25,845	22.4

Source: Power System Statistic 35th Edition and National Power Control Center

The annual power demand and supply gap which started in 2004 created a slight increase up to 2.8% in 2007. The gap then abruptly increased to 14.8% in 2008 and further increased to 22.9% in 2010.

The trend graph for the national sale and national demand are shown in Figure 2-1.

¹ Peak generation power is a maximum generating power on hourly average in the year.



Source: Prepared by the Survey Team based on the data in Table 2-1

Figure 2-1 Trend Graph for National Sale and National Demand

2.1.2 Peak Generation and Peak Demand Gap

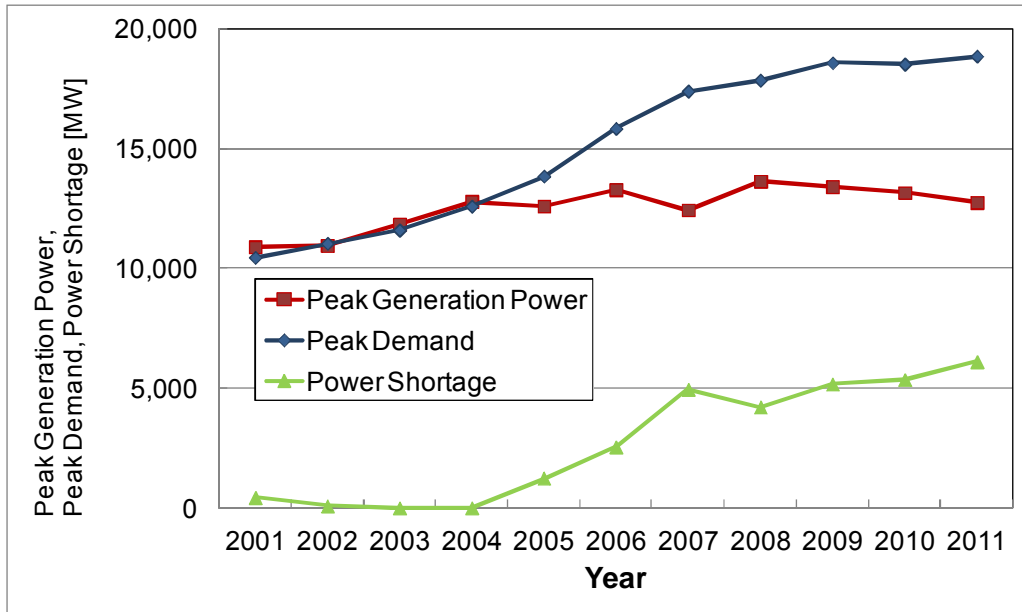
The peak demand increased rapidly at 62.6% in eight years from 2003 to 2011. On the contrary, peak generation power increased only at 7.8%, which caused a huge gap between generation and demand as shown in Table 2-2 and Figure 2-2.

During the survey conducted in May 2012, the scheduled outage of power was for 12 hours in urban areas and 18 hours in rural areas.

Table 2-2 Power Shortage Levels between Peak Generation Power and Peak Demand

Year	Peak Generation Power [MW]	Peak Demand [MW]	Power Shortage [MW]	Power Shortage Rate [%]
2001	10,894	10,459	435	4.2
2002	10,958	11,044	86	0.8
2003	11,834	11,598	-236	-2.0
2004	12,792	12,595	-197	-1.6
2005	12,600	13,847	1,247	9.0
2006	13,292	15,838	2,546	16.1
2007	12,442	17,398	4,956	28.5
2008	13,637	17,852	4,215	23.6
2009	13,413	18,583	5,170	27.8
2010	13,163	18,521	5,358	28.9
2011	12,755	18,860	6,105	32.4

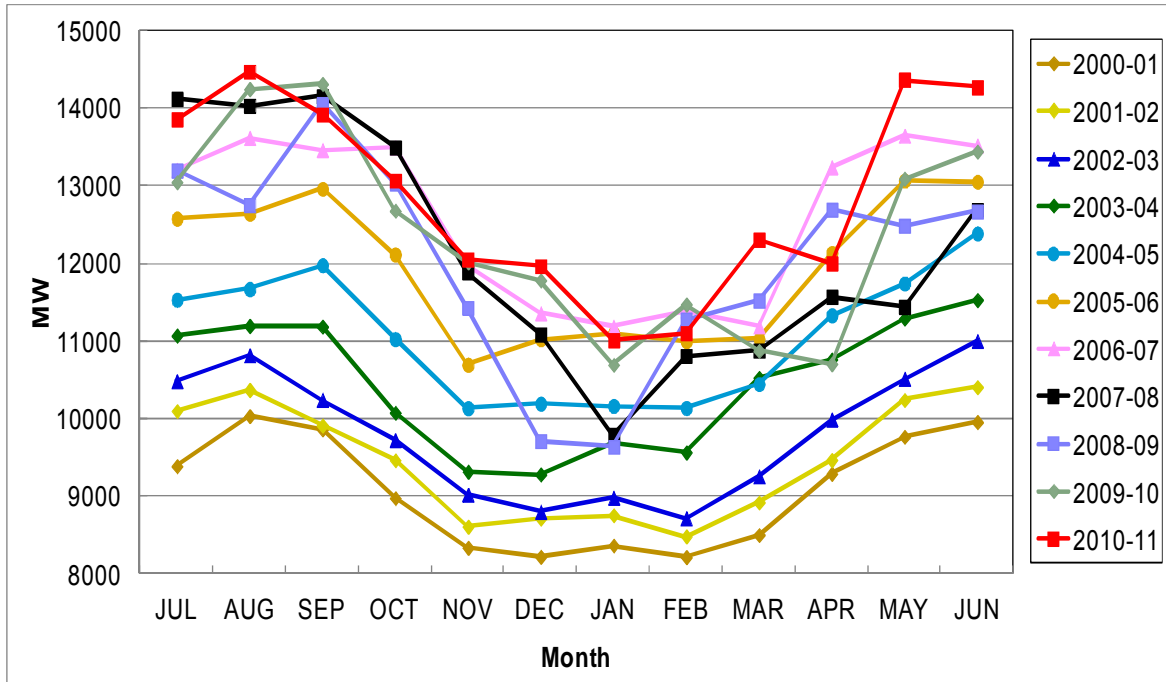
Source: Presentation Documents for Participants in the 10th SMC of National Institute of Management, Karachi



Source: Prepared by the Survey Team based on the data in Table 2-2

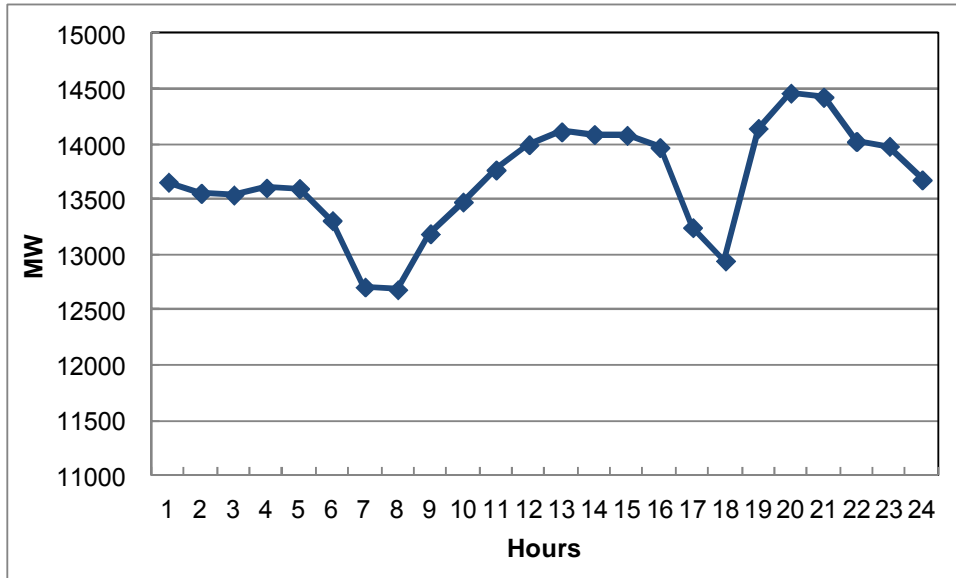
Figure 2-2 Trend in the Peak Generation Power and Peak Demand

The monthly peak demand for the ten-year period from 2000 to 2010 and the load curve peak demand on August 30, 2011, which recorded the highest peak demand in 2011, are shown in Figure 2-3 and Figure 2-4 respectively.



Source: NTDC Yearly System Operation Data, 2012

Figure 2-3 Monthly Peak Demand for the Past 10 Years



Source: NTDC Yearly System Operation Data, 2012

Figure 2-4 Load Curve of Peak Demand on August 30, 2011

2.2 National Power System Expansion Plan

2.2.1 Objective of National Power System Expansion Plan (NPSEP)

In order to address this gap, the National Transmission and Dispatch Company (NTDC) of Pakistan developed a National Power System Expansion Plan (NPSEP).

The objective is to provide a plan for the development of hydro-electric, thermal, nuclear, and renewable energy resources to meet the expected load up to the year 2030. Given the chronic and ever increasing power shortage, the need for an expansion plan was recognized as an urgent matter. This plan was prepared during the period from December 1, 2010 to May 31, 2011.

2.2.2 Scope of National Power System Expansion Plan (NPSEP)

The scope of the NPSEP is to determine new generation facilities and transmission reinforcements required to meet future load growth using the latest available data. Based on the review of the load forecast (prepared by NTDC and reviewed by SNC-Lavalin), the least cost generation expansion plan was prepared, taking into consideration the government policies, environmental considerations, and fuel constraints. An indicative transmission plan to evacuate power was developed using the generation expansion plan in 2030 and the network reinforcement requirements for the distribution company (DISCO) in 2020. These generation and transmission plans were the key inputs in developing the financial plan and the annual revenue requirements to build and operate the system. The investments required by each

DISCO to effectively reduce losses and optimize their systems were also calculated but did not form part of the overall investment requirements in the NPSEP.

2.3 Generation Planning

2.3.1 Strategic Consideration of National Power System Expansion Plan (NPSEP)

In order to develop an effective generation plan to meet the power demand of the country, NPSEP was prepared for both strategic considerations and constraints faced by Pakistan.

Table 2-3 Policy Statements

Title of Policy	Statement of Policy
Policy for Power Generation Projects Year 2002	<ul style="list-style-type: none"> - To provide sufficient capacity for power generation at the least cost, and to avoid capacity shortfalls. - To encourage and ensure exploitation of indigenous resources, which include renewable energy resources. - To attune to safeguarding the environment.
The Natural Gas Allocation and Management Policy 2005	<ul style="list-style-type: none"> - Power plants would get gas supply after meeting the requirements of domestic, commercial, fertilizer, and industrial sectors.
The Policy for Development of Renewable Energy for Power Generation 2006	<ul style="list-style-type: none"> - Increase the deployment of renewable energy (defined as wind, solar and small hydro –less than 50 MW) technologies so that renewable energy provides a minimum of 9,700 MW by 2030.

Source: National Power System Expansion Plan 2011–2030 Main Report

Table 2-4 Constraint and Solutions

	Description
Constraint	<ul style="list-style-type: none"> - Pakistan faces several constraints as it strives to meet its current and expected power demand. Perhaps the most significant constraint is the scarcity of capital, which has affected not only the power sector but also the development of other infrastructure critical to power sector development.
Short-term Solution	<ul style="list-style-type: none"> - In the short-term, the main focus has been in the reduction of load shedding and its focus has often taken the attention away from an optimum long-term growth strategy. It is accepted that it will probably take several years for the target reliability level of 1% loss of load probability to be achieved. - The short-term focus is the rehabilitation of existing plants, on demand side management, and implementation of fast-track projects to reduce load shedding.
Long-term Solution	<ul style="list-style-type: none"> - It is assumed that the country's policy will continue to focus on the

	<p>development of indigenous resources, particularly Tharparkar coal and hydro projects, as well as increasing the use of renewable resources and keeping power tariffs at affordable level.</p> <p>- Also barring major gas discoveries, the country's policy of allocating gas will remain unchanged and future gas based power generation will be based on imported gas or LNG.</p>
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Source: National Power System Expansion Plan 2011–2030 Main Report

2.3.2 Existing Installed Capacity of Power Generation Plants

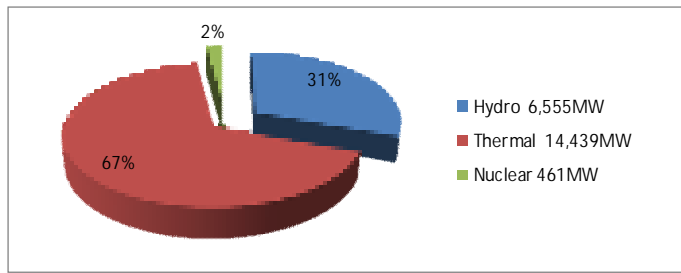
The total installed capacity of existing hydro and thermal generation units in the country including the Karachi Electric Supply Company (KESC) system and independent power producers (IPPs) was about 21,527 MW, as of March 2012. However, due to seasonal variation of water inflow for hydro plants and the capacity de-rating for thermal units, the dependable capacity for the systems was estimated at 15,259 MW during winter. The installed capacity of hydro plants was about 31%, thermal capacity was 67% and nuclear capacity was less than 2%. The total installed capacity from IPPs was about 38% of the total installed capacity. The breakdown is shown in Table 2-5 and Figure 2-3.

Table 2-5 Summary of Existing Power Plants

Type of Plant	Owner	Installed Capacity ² (MW) A	Capacity in Winter (MW) B	Ratio B / A
Hydro Plant	WAPDA	6,516	2,308	35.4%
	IPPs	111	111	100%
	<i>Sub-Total Hydro</i>	<i>6,627</i>	<i>2,419</i>	<i>(36.5%)</i>
Thermal Plant	-	-	De-rated Capacity (MW) B	-
	PEPCO	4,829	3,580	74.1%
	IPPs for PEPCO	7,475	6,909	92.4%
	Rental for PEPCO	113	113	100%
	KESCO	1,655	1,463	88.4%
	IPPs for KESCO	367	353	96.2%
	<i>Sub-Total Thermal</i>	<i>14,439</i>	<i>12,418</i>	<i>(86.0%)</i>
Nuclear Plant	for PEPCO	325	300	92.3%
	for KESC	136	122	89.7%
	<i>Sub-Total Nuclear</i>	<i>461</i>	<i>422</i>	<i>(91.5%)</i>
Total		21,527	15,259	70.9%

Source: National Power System Expansion Plan 2011-2030

² The installed capacity in Table 2-13 is the total MW of operational generating plants in the country, as of March 2012.



Source: National Power System Expansion Plan 2011-2030

Figure 2-5 Installed Capacity of Power Plants

2.3.3 Existing Hydropower Plants

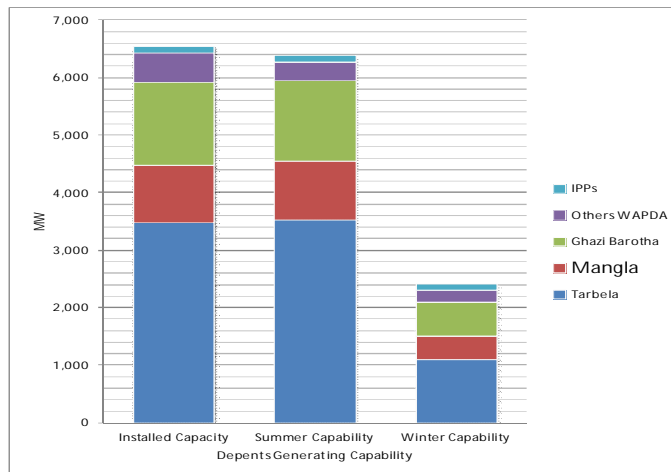
Existing hydropower plants (HPP), as of March 2012, are listed in Table 2-6. The installed capacity including IPP's hydropower stations was 6627 MW, as of March 2012. However, due to the seasonal variation of inflow, the capability of generation during summer and winter seasons were 6,445 MW or 97% of installed capacity, and 2419 MW or 37% of installed capacity, respectively.

Table 2-6 Summary of Existing Hydropower Plants

Owner	No.	Name of Power Station	Installed Capacity (MW)	Capability (MW)		
				Summer	Winter	Win/Sum
WAPDA	1	Tarbela	3,478	3,521	1,101	31.3%
	2	Ghazi Barotha	1,450	1,405	580	41.3%
	3	Mangla	1,000	1,014	409	40.3%
	4	Warsak	234	171	145	84.8%
	5	Chashma Low Head	184	91	48	52.7%
	6	Khan Khwar *1	72	68	5	7.4%
	7	Small Hydros	89	64	20	31.3 %
		<i>Sub-Total WAPDA</i>	6,516	6,334	2,308	36.4%
IPPs	8	Jagran	30	30	30	100%
	9	Malakand-III	81	81	81	100%
		<i>Sub-Total IPP</i>	111	111	111	100%
Total			6,627	6,445	2,419	37.5%

Source: National Power System Expansion Plan 2011-2030/ *1 Khan Khwar HPP, which started operation in November 2010, was added by the Survey Team based on the information given by WAPDA.

At present, Mangla HPP is the third largest hydropower station in Pakistan, which contributes 15.1% of the hydropower installed capacity, and produces 15.7% and 16.9% of generating capability during summer and winter respectively, as illustrated in Figure 2-4.



Source: National Power System Expansion Plan 2011-2030

*1 Khan Khwar HPP, which started operation in November 2010, was added by the Survey Team based on the information given by WAPDA

Figure 2-6 Role of Mangla HPP in Existing Hydro Plants



Source: Presentation Documents on the Role of Hydropower in Addressing the Energy Crisis, WAPDA

Photo 2-1 Tarbela Dam Powerhouse



Source: Presentation Documents on the Role of Hydropower in Addressing the Energy Crisis, WAPDA

Photo 2-2 Ghazi Barotha Dam Powerhouse and Spillway

2.3.4 Future Planning of Hydropower Plants to be commissioned by 2020

"Vision Statement for Accelerated Development of Pakistan's Power Sector for Sustained Economic Growth" at the Energy Summit held at Islamabad in May 2010. The "Vision" includes a "20,000 MW addition by 2020 programme" which targets installation of 20,000 MW of capacity in addition to the presently installed capacity. The "20,000 MW addition by 2020 programme" comprises 6,000 MW of hydro, 6,000 MW of coal (mainly by domestic production), 5,000 MW of gas, 1,000 MW of naphtha and other indigenous fuels and the remaining 2,000 MW from alternative energy resources, specifically solar and wind.

The future planning of hydropower plants to be commissioned by 2020 is shown in Table 2-7.

It is expected to be commissioned 18 hydropower plants (6,654 MW in total) by 2020.

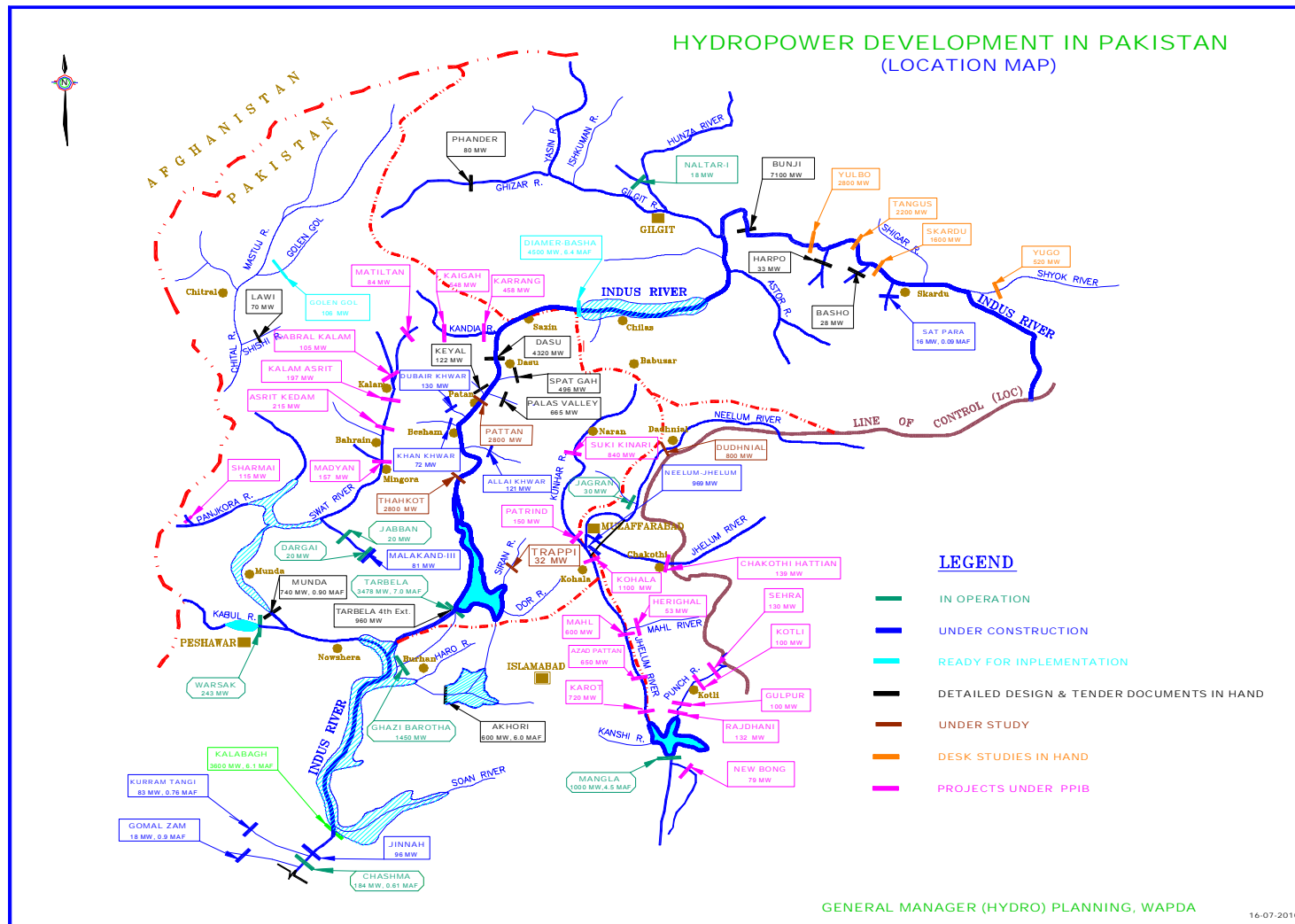
Table 2-7 Future Planning of Hydropower Plants by 2020

Owner	Components	Installed Capacity (MW)	Expected Commissioning Year
WAPDA	Mangla Dam Raising	644 (GWh)	-
	Allai Khwar	121	Oct. 2012
	Duber Khwar	130	Mar. 2013
	Jinnah Barrage	96	Dec. 2012
	Satpara Dama	17.4	Feb. 2013
	Gomal Zam	17.4	Jan. 2013
	Neelum Jhelum	969	Oct. 2015
	Kurram Tangi	83	Dec. 2015
	Golen Gol Chitral	106	Feb. 2015
	Kurram Tangi – Fata	84	2015
	Tarbela 4 th Extension	1,410	2017
	Kohala AJK	1,100	2020
	Dasu	2,160	2020
	Keyal Khwar	122	2018
	Phandar	80	2018
	Basho	40	2017
	Harpo	34.5	2017
	<i>Sub-Total</i>	1,432	-
IPP	New Bong Escape	84	2013-14
	Total	6,654	-

Source: Hydel Development Department of WAPDA

The Mangla Hydro Power Station is also listed in the Committed Hydro Plant remarked with installed capacity not increased, annual generating power of 644 GWh being increased due to the increased water storage capacity by the dam raising.

The preparatory survey's aim was not only for rehabilitation but also for the enhancement of the installed capacity. Figure 2-7 presents the hydropower development in Pakistan.



Source: Presentation Documents on the Role of Hydropower in Addressing the Energy Crisis, WAPDA

Figure 2-7 Hydropower Development in Pakistan

2.4 Power Sector Environment

2.4.1 Current Structure of Power Sector

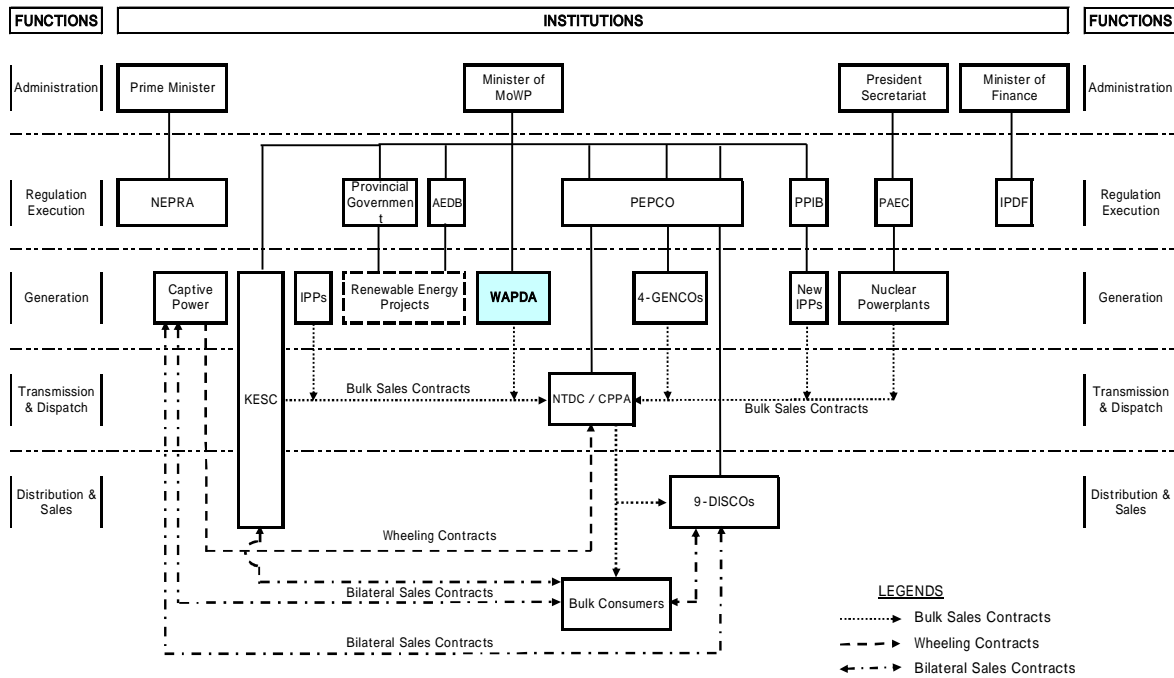
Formerly, the power sector in Pakistan was primarily managed by WAPDA, which was established in 1958. WAPDA, which has been split into two companies in 1998, provided services throughout the country except for Karachi and its adjoining areas. These areas were served by the Karachi Electric Supply Company (KESC), which was established in 1913. In addition, the Pakistan Atomic Energy Commission (PAEC) established in 1956, has been responsible for all aspects of nuclear power generation working under the President Secretariat.

In 1998, the Government of Pakistan (GOP) established the National Electricity Regulatory Authority (NEPRA) to regulate all aspects of the power sector, including tariff-determination. Later, the GOP divided WAPDA into a new WAPDA and the Pakistan Electric Power Company (PEPCO). The new WAPDA is responsible for developing and operating water resources, including hydro-power. While PEPCO is responsible for the operation and maintenance of public-sector thermal plants and transmission and distribution network. PEPCO takes care of and provided technical support to its 14 corporate entities, including four thermal power generation companies (GENCOs), nine distribution companies (DISCOs) and the National Transmission and Power Dispatch Company (NTDC), which controls power transmission from all generating stations including independent power producers (IPPs).

PEPCO also acts as the Central Power Purchase Agency (CPPA), the country's sole electricity procurement agency.

In addition, the GOP established the Private Power and Infrastructure Board (PPIB) in 1994 to provide a one-stop service to power-sector investors interested in developing power generation projects and related infrastructure. The GOP also established the Alternative Energy Development Board (AEDB) in 2003 as an autonomous body to promote and facilitate the exploitation of renewable energy resources in Pakistan to achieve government targets for renewable energy development.

The schematic diagram of the power sector in the country is shown in Figure 2-8.



Source: Modified by the Survey Team based on WAPDA's information

Figure 2-8 Schematic Diagram of Power Sector in Pakistan

2.4.2 Status of WAPDA in the Government

WAPDA was established through a parliamentary enactment in February 1958 for an integrated and rapid development and maintenance of water and power resources of the country. Since October 2007, WAPDA has been divided into two distinct entities, i.e., WAPDA and PEPCO. WAPDA was made responsible for water and hydropower development, whereas PEPCO was vested with the responsibility of thermal power generation, transmission, distribution, and billing.

WAPDA is now fully responsible for the development, operation, and maintenance of hydropower and water sector projects.

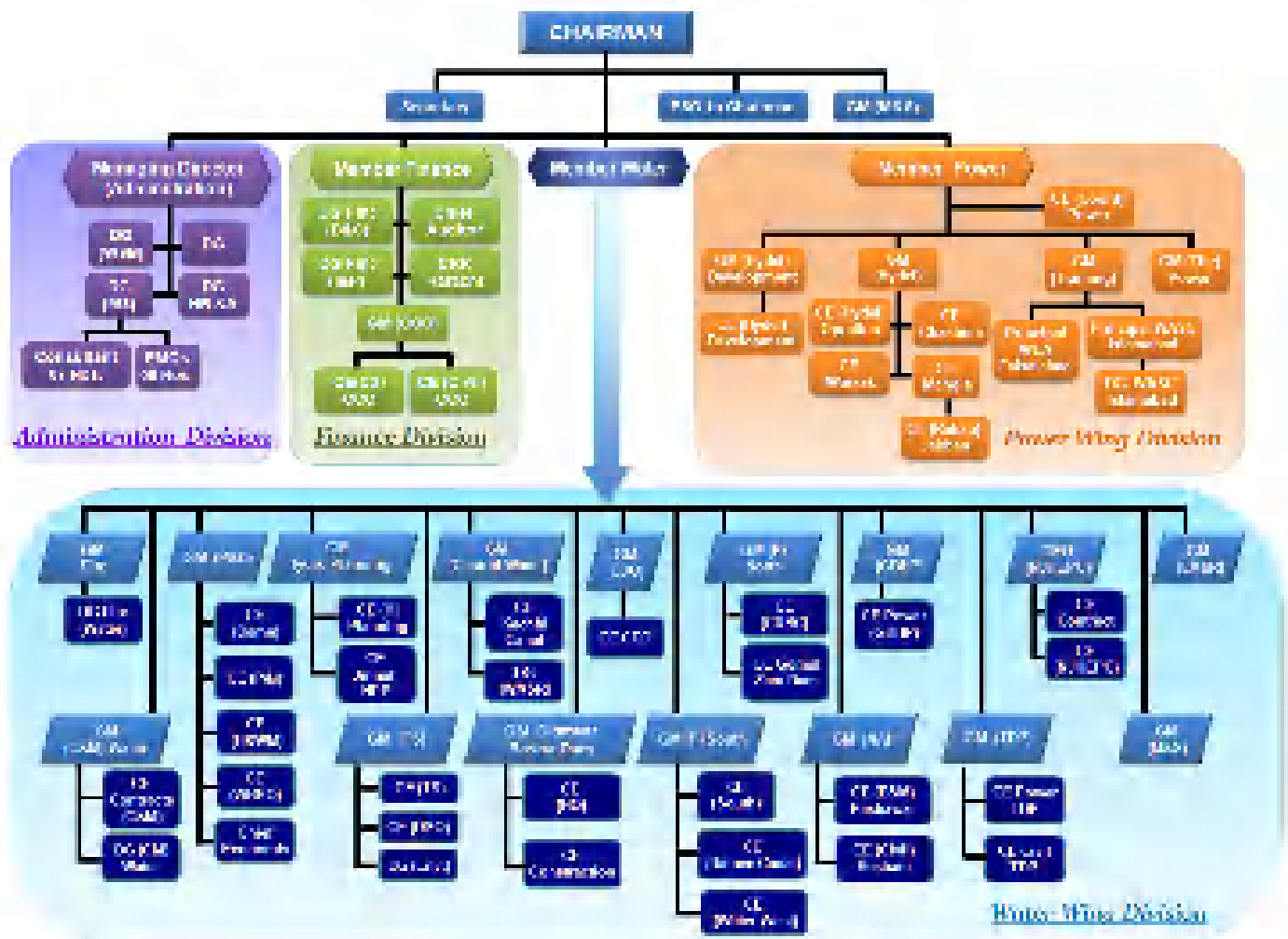
2.4.3 Organization of WAPDA

WAPDA was established with the following main charter of duties:

- 1) Integrated and rapid development and maintenance of water and power resources of the country;
- 2) Control of soil salinity and water logging to rehabilitate the affected land in order to strengthen the predominantly agricultural economy of the country;
- 3) Development of irrigation, water supply, and drainage projects;
- 4) Flood control;
- 5) Inland navigation.

- 6) Development of new hydropower projects in the public sector;
- 7) Operation and maintenance of hydropower stations; and
- 8) Refurbishment/rehabilitation of old hydro units.

The organizational structure of WAPDA is shown in Figure 2-9 below.



Source: Prepared by the Survey Team

Figure 2-9 Organizational Structure of WAPDA

WAPDA consists of four divisions, i.e., Administration, Finance, Water Wing, and Power Wing. The main roles of each division are described below:

Administration Division

The Administration Division is run by the managing director under direct control of the chairman. The managing director of the Administration Division is responsible for the following activities:

- 1) The director general of the WAPDA Sports Boards looks after the affairs of different

- sports boards of WAPDA for better sports activities among WAPDA employees and with other organizations.
- 2) The director general of Services looks after all service matters of the WAPDA employees including service structure of different employees and the implementation rules. It also keeps records and takes care of all properties belonging to WAPDA.
 - 3) Overall medical services provided to the employees of WAPDA are under the director general of Medical Services.
 - 4) The director general of Human Resources and Administration looks after the human resources activities, dealing establishment matters (BPS³-1-20), handling of deputation cases, and coordination between WAPDA and the Ministry of Water and Power.

Finance Division

The member finance is responsible for the functioning of the departments of Finance, Internal Audit, and Budget and Accounts headed by the chief auditor of the Internal Audit and the director general finance of B&C. He also exercises administrative control over the general manager of the Central Contracts Cell, director general of Taxes and director public relations.

The managing director of Administration is vested with the responsibility of overall administration and services.

The secretary of WAPDA, in addition to its role in looking after the day-to-day affairs of the Secretariat, prepares minutes of the authority's meetings, maintains records of its decisions, issues directives, monitors and implements authority's decisions, and coordinates among the different wings.

Water Wing Division

The Water Wing Division headed by member water is responsible for the following activities:

- 1) Execution of surface and sub-surface water projects;
- 2) Reconnaissance survey, preparation of feasibility reports, detail designs, tender documents, bidding process, supervision and implementation of the water resource projects including multipurpose hydropower projects, interprovincial canals, and reservoirs for irrigation and water supplies;
- 3) Operation of reservoirs and maintenance of dams and their associated structures;
- 4) Control of water logging and soil salinity to rehabilitate the affected land (salinity control and reclamation projects);
- 5) Collection/maintenance of hydrological data for utilization in future projects as well as for

³ Basic Pay Scale (BPS), all WAPDA's staffs are placed in BPS ranging from 1 to 22 depending on the educational background and work experience.

- operation; and
- 6) Flood control and inland navigation.

Power Wing Division

The Power Wing Division headed by member power is responsible for the following activities:

- 1) Refurbishment/rehabilitation of old hydropower stations.
- 2) Preparation of feasibility reports, detailed designs, tender documents, bidding documents, award of contracts, supervision and implementation of hydropower stations including switch yards in collaboration with Water Wing.
- 3) Operation and maintenance of all hydropower stations.
- 4) Procurement of spare parts for all hydropower stations in operation.
- 5) Maintenance of operational data of all hydropower stations.
- 6) Provision of necessary budget/funds for new/existing hydropower stations.
- 7) Sale of hydel energy generated to NTDC/CPPA and related affairs.

Training of all existing and newly recruited officers of Power Wing, Water Wing and Finance Divisions. The manpower of each division of WAPDA, as of June 2012, is shown in Table 2-8.

Table 2-8 Manpower of WAPDA

No.	Position	Division				Total
		Administration	Finance	Water Wing	Power Wing	
1	Managerial Staff (BPS 18 to 21)	256	48	132	42	478
2	Sr. Engineers/Sr. Scientific Officer (BPS-18)	-	-	339	61	400
3	Technical Staff	-	-	1,037	1,793	2,830
4	Non-Technical Staff (BPS 1 to 17)	2,963	891	8,308	2,324	14,486
Total		3,219	939	9,816	4,220	18,194

Source: Prepared by the Survey Team

2.4.4 Roles of Key Positions in the Power Wing Division

The Project is aimed to implement the rehabilitation and enhancement of the Mangla Power Station, the Project will be managed by the Power Wing Division of WAPDA as described in Sub-clause 2.3.3. The chief engineer of Coordination, general manager of Hydel Development, chief engineer of Hydel Development, general manager of Hydel, and chief engineer of Hydel Operation are key positions and persons for the Project. The main roles of each position are described below:

(1) Chief Engineer of Coordination

The chief engineer of Coordination under member power looks after the following activities:

- Coordination with other divisions of WAPDA regarding matters on power sector, and
- Arrangement of meetings to be convened by member power.

(2) General Manager of Hydel Development

The general manager of Hydel Development looks after the following activities:

- Refurbishment/rehabilitation of the existing hydropower station;
- Preparation of feasibility report, detail design, tender documents, bidding documents, award of contracts, supervision and implementation of refurbishment/rehabilitation works of the existing hydropower stations;
- Monitoring the progress of new hydropower projects being developed by the Water Wing Division;
- Preparation of the progress report of hydropower project under rehabilitation; and
- Arrangement of budgetary requirement for the on-going/future rehabilitation projects.

(3) Chief Engineer of Hydel Development

The chief engineer of Hydel Development is a staff officer to the general manager of Hydel Development. He assists the general manager of Hydel Development in all official matters as listed above.

(4) General Manager of Hydel

The general manager of Hydel looks after the following activities:

- Operation and maintenance issues on all hydropower stations,
- Preparation of operational data of all hydropower stations,

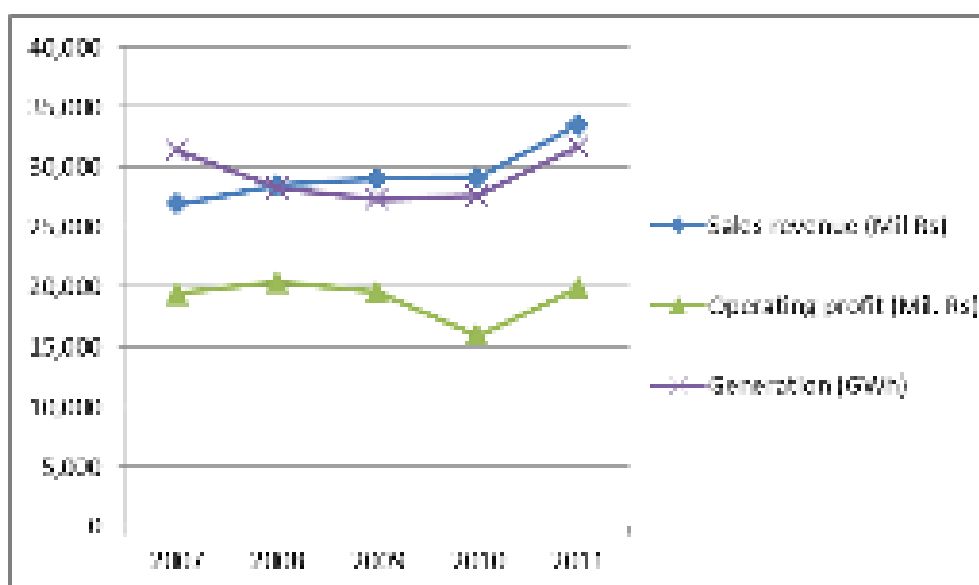
- Procurement of spare parts of all hydropower stations,
 - Provision or arrangement of necessary budget for all existing hydropower stations,
 - Sales of hydel energy generated to NTDC/CPPA and its related affairs, and
 - Training of all present and newly recruited officers of Power Wing, Water Wing and Finance Division of WAPDA.
- (5) Chief Engineer of Hydel Operation
- A staff officer of the general manager of Hydel Operation.
 - Assists the general manager of Hydel Operation in all operation and maintenance matters of existing hydropower stations.
 - Preparation of operational data/reports to be submitted to the higher offices in the country.

2.4.5 Financial Condition of WAPDA

This section describes and analyses the financial condition of Power Wing and also shows the financial outcome of the operation of hydropower stations.⁴

(1) Trend of Revenue and Profit

The revenue from selling electricity has been gradually increasing despite the decline of generation in 2008 and 2009 as shown in Figure 2-10.



Source: WAPDA Power Wing (Hydroelectric), Annual Account 2011, p.6

Figure 2-10 Trend of Generation, Revenue, and Profit (Unit: PRs million, GWh)

This is mainly due to the increase of bulk supply tariff, which is applied to the NTDC the single buyer of electricity from hydropower stations of WAPDA. As presented in Table 2-9, the increase of the tariff for 2011-2012, consisting of the fixed charge and the variable charge, has been approved by the NEPRA in November 2011. The fixed charge and variable charge of the tariff (2011-2012) is higher than that of 2009-2010.

Table 2-9 Trend of Bulk Supply Tariff

	2009-10	2011-12
Fixed charge (PRs/kW/Month)	414.02	549.042
Variable charge (PRs/kWh)	0.059	0.07707

Source: National Electric Power Regulatory Authority (NEPRA), "Determination of Tariff Petition filed by WAPDA Hydroelectric", No. NEPRA/TRF-173/WAPDA Hydro-2011.

The change in the structure of bulk supply tariff has significantly influenced the share of the

⁴ WAPDA Annual Report shows the consolidated balance sheet consisting of three wings (Power, Water, and Coordination). However, the business of the Power Wing can alone earn revenue by generating and selling electricity based on the income and cash flow statements of Power Wing.

revenue. Table 2-10 shows the revenue of variable charge which has declined by 26.2% in 2010 to 2011 while that of fixed charge has increased by 32.1%. The fixed charge is calculated based on the capacity of generation while the variable charge is based on the actual amount of sales of electricity, the revenue turned out to be more stable with less influence from the fluctuations of generation.

Table 2-10 Income Statement (2010-2011) of WAPDA Power Wing (Unit: PRs millions, %)

	2010		2011		Change (%)
	Amount (Mil. Rs.)	Share	Amount (Mil. Rs.)	Share	
Sale	29,092	100.0%	33,470	100.0%	15.0%
1. Variable charges	8,525	29.3%	6,293	18.8%	-26.2%
2. Fixed charges	20,566	70.7%	27,177	81.2%	32.1%
Cost of electricity	11,752	40.4%	12,789	38.2%	8.8%
Gross profit	17,339	59.6%	20,681	61.8%	19.3%
Operating expenses	1,429	4.9%	851	2.5%	-40.4%
Operating profit	15,910	54.7%	19,830	59.2%	24.6%
Other income	4,239	14.6%	4,457	13.3%	5.1%
Operating profit + Other income	20,150	69.3%	24,287	72.6%	20.5%
Hydel levies	6,696	23.0%	6,895	20.6%	3.0%
Financial cost	6,619	22.8%	6,542	19.5%	-1.2%
Net profit for the year	6,835	23.5%	10,849	32.4%	58.7%

Source: WAPDA Power Wing (Hydroelectric), Annual Account 2011

Note: Hydel levies consists of: 1) Net hydel profit to be paid to the Government of Khyber Pakhtunkhwa (Gov't of KPK) as an interim arrangement based on the instruction of the Government of Pakistan and 2) water usage charge to be calculated at PRs 0.15/kWh generated at the Mangla Power Station and be paid to Azad Jammu & Kashmir Government as per Memorandum of Understanding signed in 2003.

As the revenue increased and the operating expense decreased between 2010 and 2011, the operating profit has increased by 24.6% from PRs 15,910 million in 2010 to PRs 19,830 million in 2011.⁵ The net profit has also increased by 58.7% from PRs 6835 million in 2010 to PRs 10,949 million in 2011.

(2) Issues on the Financial Condition of WAPDA

WAPDA has achieved a good result of revenue and profit. However, there are several issues to be addressed and solved for better financial condition.

Circular Debt Problem

The power sector has been facing circular debt problem. NEPRA approved the tariff petition of the generation and distribution companies, which covered the full cost of generation and distribution. However, GOP notified that the tariff charged to customers will be lower than the full cost recovery level determined by NEPRA.

The GOP has instead promised to pay subsidies to the distribution companies in order to fill

⁵ According to WAPDA's Financial Department, the decrease of operating expense was due to the change in the cost items included in the operating expense. Therefore, the change of figures does not necessarily reflect the reduction in operating expense.

the gap in the cost recovery. However, the government has failed to make timely payment of subsidies, which resulted to revenue shortage of the distribution companies and delay in payment for the purchase of electricity from power stations. Power generation companies have been suffering from the increase of receivables and have been forced to stop or delay payments to their fuel suppliers in order to balance their cash flows. However, this has further caused delay in the purchase of fuel by power generating companies.⁶

In the case of WAPDA, the partial failure of payment by the NTDC, which purchases the electricity from hydropower stations of WAPDA based on bulk supply tariff, has worsened the cash flow condition of WAPDA.

This situation is clearly shown in a significant increase of receivables (trade debts) in WAPDA's balance sheet. Total amount of the receivables has increased by 26.9% in 2010 and 2011. Table 2-11 shows the 1-2 years old receivable has also increased from zero in 2010 to more than PRs 700 million, implying that the NTDC has been failing to pay the bulk supply tariff for a long time.

Table 2-11 Breakdown of Trade Debts (Receivables) (Unit: PRp million)

Aging of trade debts	2010	2011	Change	%
Net yet due	2,684.8	3,110.8	426.0	15.9%
Past due 0-365 days	21,323.9	29,623.5	8,299.6	38.9%
1-2 years	0	737.3	737.3	
Total	50,251.9	63,794.2	13,542.3	26.9%

Source: WAPDA Power Wing (Hydroelectric), Annual Account 2011, p.34

The increase of trade debts obviously worsens the cash flow of WAPDA. WAPDA has tackled this issue by stopping the repayment of loan to the GOP. Table 2-12 indicates the short-term liability especially the payables to the GOP which has significantly increased from PRs 43.5 billion in 2010 to PRs 54.7 billion in 2011 and generated surplus cash to WAPDA. The change in the amount of receivables (PRs 13.5 billion) is almost equal to the change in payables to the GOP (PRs 11.2 billion).

Table 2-12 Short-term Liability (Unit: PRs million)

	2010	2011	Change
Payable to GOP (debt service liability)	43,544.8	54,743.8	11,199.0
Payable to Provinces	23.2	23.2	0.0
Other Liabilities	3,082.1	1,144.2	-1,937.9
Total	46,650.2	55,911.3	9,261.1

Source: WAPDA Power Wing (Hydroelectric), Annual Account 2011, p. 28

The GOP has already started its efforts to resolve the circular debt problem by notifying an increase of consumer tariffs and by transferring the debt in the system to the newly

⁶ According to WAPDA Financial Department, the Government of Pakistan is paying subsidy to the generation companies for the purchase of fuel.

established company outside the energy sector. However, the outcome of such efforts has yet to be seen.

Bulk Supply Tariff

The full cost recovery is a pre-condition for a healthy financial condition of WAPDA. As mentioned earlier, WAPDA has obtained the approval for the increase of bulk supply tariff from the NEPRA. However, WAPDA has sent the petition with the proposal of higher tariff than the approved as shown in Table 2-13.

Table 2-13 Requested and Approved Bulk Supply Tariff

Tariff	2009-2010 (Approved)	2011-12 (Proposed)	2011-12 (Approved)
Variable charge (PRs/kWh)	0.059	0.130	0.0707
Fixed charge (PRs/kW/Month)	414.020	939.030	549.042
Average sale rate (PRs/kWh)	PRs 1.180/KWh	PRs 2.601/kWh	

Source: National Electric Power Regulatory Authority (NEPRA), "Determination of Tariff Petition filed by WAPDA Hydroelectric", No. NEPRA/TRF-173/WAPDA Hydro-2011

WAPDA has made this proposal because of various factors that influence its financial condition. Among others, the expected increase of O&M cost is a major factor. According to the document submitted to the NEPRA, WAPDA forecasted a significant increase of O&M cost as presented in Table 2-14.

Table 2-14 Actual and Forecasted Operation and Maintenance Cost (Unit: PRs million)

O&M Cost	2009-2010 (Determined)	2009-2010 (Audited)	2010-11 (Estimated)	2011-12 (Proposed)
Employee Cost	2,351	5,921	6,667	7,500
Repair & Maintenance	1,111	512	1,231	2,261
Admin. Expense	652	1,328	772	868
Total	4,114	7,761	8,670	10,629

Source: National Electric Power Regulatory Authority (NEPRA), "Determination of Tariff Petition filed by WAPDA Hydroelectric", No. NEPRA/TRF-173/WAPDA Hydro-2011

The proposed bulk supply tariff based on the expected increase of O&M cost has not been fully approved by the NEPRA. WAPDA plans to submit another petition to the NEPRA this year after the audit of the Financial Statements for 2011 has been completed (see Tables 2-15 and 2-16).

Table 2-15 Balance Sheet (2010-2011) of WAPDA Power Wing (Unit: PRs million, %)

	2010	2011	Change	
Current Assets	139,615	155,902	16,287	11.7%
Cash and bank balances	2,693	4,779	2,086	77.5%
Short-term investments	271	271	0	0.0%
Trade debts	50,252	63,794	13,542	26.9%
Advances and other receivables	84,975	84,631	(344)	-0.4%
Stores, spare parts and loose tools	1,424	2,427	1,003	70.4%
Non-current Assets	372,910	395,357	22,448	6.0%
Long-term investments	184,308	185,599	1,291	0.7%
Notes receivables	9,614	8,744	(870)	-9.1%
Long-term advances and receivables	8,650	8,768	117	1.4%
Long-term security deposits	2	2	(0)	-3.7%
Property, plant and equipment	164,737	186,803	22,066	13.4%
Investment in associates	4,056	4,056	0	0.0%
Investment in subsidiaries	1,543	1,386	(157)	-10.2%
ASSETS	512,525	551,260	38,735	7.6%
Current Liabilities	73,336	89,106	15,770	21.5%
Short-term borrowings	8,409	10,488	2,079	24.7%
Short-term liabilities	46,650	55,911	9,261	19.9%
Current portion of interest bearing loans and borrowings	6,122	6,134	12	0.2%
Other payables	11,822	16,111	4,289	36.3%
Accrued interest	332	461	130	39.1%
Non-current Liabilities	69,399	70,923	1,524	2.2%
Interest bearing loans and borrowings	55,987	53,158	(2,829)	-5.1%
Liability against assets subject to Ijarah	8,000	8,000	0	0.0%
Deferred grants	686	1,112	426	62.1%
Deferred liabilities	4,725	8,652	3,927	83.1%
Share Capital and Reserves	369,790	391,231	21,440	5.8%
Share capital	9,522	9,522	0	0.0%
Capital reserves	360,268	381,709	21,440	6.0%
EQUITY AND LIABILITIES	512,525	551,260	38,735	7.6%

Source: Source: WAPDA Power Wing (Hydroelectric), Annual Account 2011

Table 2-16 Cash Flow Statement (2010-2011) of WAPDA Power Wing (Unit: PRs million)

	2010	2011	Change	
CASH FLOWS FROM OPERATING ACTIVITIES				
Net profit for the year	6,835	10,849	4,014	58.7%
Adjustment for:				
Depreciation	3,920	4,260	340	8.7%
Financial cost	6,619	6,542	(77)	-1.2%
Ijarah rental	1,502	1,502	0	0.0%
Employee benefits	3,282	3,972	690	21.0%
Amortization of deferred credit	(211)	0	211	-100.0%
Provision for cost of feasibility studies on defunct projects	227	0	(227)	-100.0%
Provision for doubtful receivables	458	0	(458)	-100.0%

Amortization of grants	(400)	(361)	39	-9.8%
Liabilities written back	(6)	(1)	5	-83.7%
	15,390	15,914	524	3.4%
Sub-total (A)	22,225	26,763	4,539	20.4%
Working Capital Changes:				
(Increase)/decrease in current assets:				
Stores, spare parts and loose tools	17	(1,003)	(1,020)	-5901.0%
Trade debts	(9,973)	(13,542)	(3,569)	35.8%
Advances and other receivables	43,811	344	(43,466)	-99.2%
Increase/(decrease) in current liabilities:				
Short-term liabilities	12,387	9,532	(2,855)	-23.0%
Short-term borrowings	(38,754)	2,079	40,833	-105.4%
Other payables	(680)	4,446	5,126	-753.9%
Sub-total (B)	6,808	1,856	(4,952)	-72.7%
Cash Generated from Operations (A+B)	29,033	28,619	(413)	-1.4%
Financial cost	(7,573)	(6,413)	1,160	-15.3%
Ijarah rental	(1,087)	(968)	119	-10.9%
Net Cash Generated from Operating Activities	20,372	21,238	866	4.2%
CASH FLOWS FROM INVESTING ACTIVITIES				
Capital expenditure incurred on property, plant and equipment	(11,430)	(26,326)	(14,896)	130.3%
Long-term investment (net)	(12)	(1,291)	(1,280)	10888.9%
Notes receivables	921	870	(51)	-5.5%
Long-term advances and receivables	(8,452)	(117)	8,335	-98.6%
Transfer from reserve for GOP investment in corporate entities	0	(6)	(6)	#DIV/0!
Long-term security deposits	(0)	0	0	-166.9%
Net Cash used in Investment Activities	(18,972)	(26,870)	(7,898)	41.6%
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from interest bearing loans and borrowings	6,044	2,955	(3,089)	-51.1%
Interest bearing loans and borrowings repaid/transferred	(5,523)	(5,772)	(249)	4.5%
Proceeds from gov't investment	0	10,598	10,598	#DIV/0!
Employee benefits paid	0	(849)	(849)	#DIV/0!
Grants received	0	787	787	#DIV/0!
Net Cash Generated from Financing Activities	521	7,719	7,198	1382.0%
Net Increase in Cash and Cash Equivalent During the Year	1,921	2,086	166	8.6%
Cash and cash equivalent at the beginning of the year	772	2,693	1,921	248.7%
Cash and Cash Equivalent at the End of the Year	2,693	4,779	2,086	77.5%

Source: WAPDA Power Wing (Hydroelectric), Annual Account 2011

2.4.6 Present Activities/Status of Projects Supported by Other Donors

The present activities and status of projects in the power sector of Pakistan supported by other donor countries are summarized below:

WORLD BANK

No.	Project Description	Power Generation	Project Cost	Present Activities/Status
1 (i)	Tarbela 4th Ext. Hyd. Project - Consultancy Services, Assignment – A, Project being developed by WAPDA.	1,410 MW	USD 6.315 million	Preparation of the final tender documents for Civil and EM Works completed last week of April 2012.
(ii)	Tarbela 4th Ext. Hyd. Project Construction Phase, Assignment – B.	-	USD 928.9 million	Negotiations with the Consultants for carrying out Assignment – B, i.e., contract management and construction supervision commenced in May 2012. Project completion is expected in April 2017.
2	Dasu Hydropower Project being developed by WAPDA.	4,320 MW	USD 100 million	The Feasibility Study of Dasu Hydropower Project was completed on February 28, 2009. World Bank offered financing for the detailed engineering design and tender documents and project construction if project would be developed in stages. The proposal was agreed by WAPDA and Government of Pakistan. The Consultants were mobilized and commenced their services on September 19, 2011 for the preparation of detailed engineering design and tender documents.
3	Suki – Kinari Hyd. Power Project being developed through PPIB.	840 MW		The project being developed through private sponsors by PPIB. Tariff approved by NEPRA, WUA signed between sponsors and Govt. of KPK. Negotiation on other project agreements in progress, and Consultants are preparing detailed engineering design.
4	Pakistan Natural Gas Efficiency Project Rehabilitation of Natural Gas Pipeline Network and its Adjoining Facilities (Reduction of Unaccounted for Natural Gas (UFG) in Sui Southern Gas Company (SSGC) Gas Distribution Network)	-	IDA Credit: USD 100 million IBRD Loan: USD 100 million	The project aims to enhance the supply of natural gas in Pakistan by reducing the physical and commercial losses of gas in the pipeline system. The project is designed to reduce SSGS's UFG to about 5%, i.e., building up UFG reductions year by year until eliminating 22 billion cubic feet of UFG annually. An agreement has recently been signed between World Bank and Government of Pakistan for supply of IDA credit of USD 100 million and IBRD Loan USD 100 million for reduction of unaccounted for natural gas, for implementation of the project through SSGC.
5	Pilot Projects for Alternative Energy Development Board (AEDB) Replacement of Conventional Gas Geysers with Solar Water Heaters.	-	The loan from the World Bank is not yet finalized	Government of Pakistan is considering option for introducing solar water heaters to replace conventional gas geysers as a gas conservation measure as well as increase the overall efficiency of energy consumption. This program is under process with AEDB in consultation with the World Bank, but yet not finalized.

Source: Prepared by the Survey Team

United States Agency for International Development (USAID)

No.	Project Description	Power Generation	Project Cost	Present Activities/Status
1	Repair and Maintenance of Tarbela Power Station	-	USD 16.5 million	<p>USAID has provided a grant facility under Fixed Amount Reimbursement Agreement (FARA) of USD 16.5 million for the procurement of spare parts and equipments for the reliability enhancement of Tarbela Power Station. Following spare parts/equipmen has been purchased.</p> <p>Stator windings (Class F) for eight generators. Up-gradation of Scada System. Replacement of I.V and R.V seals. Replacement of worn out drainage pumps. Replacement of worn out un-watering pumps. Replacement of electro-mechanical Governors with PID control digital governors. Training/capacity building of officers. Out of USD 16.5 million, an amount of USD 10.879 million has been reimbursed to WAPDA and the remaining is to be reimbursed up to December 31, 2012.</p>

Source: Prepared by the Survey Team

Asian Development Bank (ADB)

No.	Project Description	Project Cost	Present Activities/Status
1	Power Distribution Enhancement Project (Tranche-II): Loan No. 2727	USD 242 million	The project was approved by ECNEC on September 12, 2010 and loan agreements were signed on January 28, 2011, sub projects are expected to be completed by June 30, 2018. The procurement under this tranche is in the advanced stage and cost of the project is estimated to be USD 302 million with a loan amount of USD 242 million which only covers STG component. Physical progress was not started, but majority of turn key projects are at the stage of contract signing. The contractors are expected to mobilize by the second quarter of 2012.
2	Power Distribution Enhancement Investment Program Support Component: Loan No. 2439	USD 10 million	Loan for support component of USD 10 million was signed with PEPCO on September 29, 2008 with loan closing date on December 31, 2018 for project preparation, implementation and monitoring activities and for capacity building of DISCOs. RFP issued six shortlisted firms, however, five firms submitted their proposals on February 9, 2012, which were evaluated by NTDC and after getting ADB's concurrence on the financial proposal of these firms was opened on March 15, 2012. The matter is now with ADB for approval.
3	Renewable Energy Development Sector investment program	USD 20 million	The Management Review Meeting held on 18 November, 2009 and the Board Approval was issued on 13 December, 2010. The project will focus on wind and other renewable energy power plants. It is expected that IPPs would add cumulative generating capacity of 150 MW – 250 MW.
4	Uch-II Thermal Power Project (private sector)	USD 150 million	The project is under implementation by a Private Power Production Company under PPIB. The expected commercial date of operation is December, 2012
5	Pak Zorlu Energy Power Project (private sector)	USD 36.8 million	The financial closing has been announced. Construction has been started. Expected commercial operation date is January, 2013
6	Pak Daharki Power Project (Dual Cycle Gas Fired Thermal Project) (private sector)	USD 46.75 million	The project has been commissioned in March 2011 through Foreign Foundation Private Producing Company under PPIB.
7	New Bong Escape Hydropower (private sector)	USD 37.3 million	This is the first Hydropower Project being constructed in Private Sector by Laraib Energy Limited. The Expected date of Commercial Operation is November, 2012.

Source: Prepared by the Survey Team

KFW AND KOREAN BANK

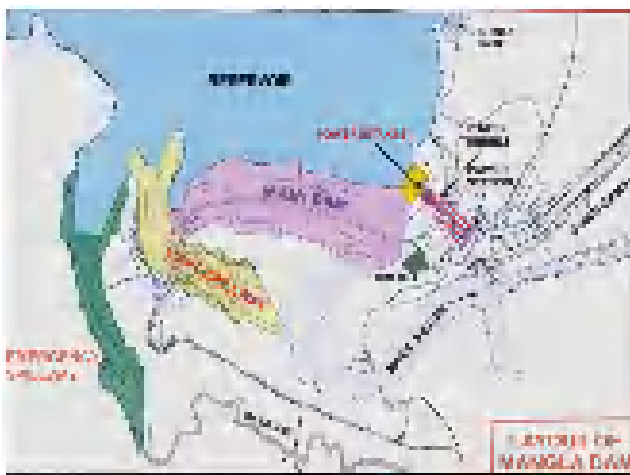
No.	Project Description	Project Cost	Present Activities/Status
1	220 KV Grid Station Ghazi Road Lahore and Allied Transmission Line Grid Station Transmission Line	EUR 11.290 million; W 17,903 million	Grid Station = Bidding/tendering in progress Transmission Line Material Procurement = 100% Total Disbursement Grid Station = EUR 0.067313 million Transmission Line Material = W 17,903 million

Source: Prepared by the Survey Team

2.5 Mangla Hydro Power Station

2.5.1 General

The Mangla Dam Project completed in 1967 is located on the Jhelum River about 120 km from the Capital Islamabad as illustrated in Figures 2-11 and 2-12. The project attained its maximum capacity of 1000 MW with the final extension of Units 9 and 10 (2 x 100 MW) in 1993-94. During high reservoir level period, Mangla is able to generate 1150 MW against the rated capacity of 1000 MW due to permissible overloading of 15%. The power station has been one of the major contributors to the national grid during the year (see Photo 2-1). The maximum load of 1150 MW and maximum daily generation of 27.600 MKWh were recorded on various dates. The power station contributed 6108 million units during the year, which was 1,335 million units more than last year's generation of 4,772.4 million units. The total generation since the commissioning was 194.4 billion units (KWh) as of June 30, 2011.



Source: Mangla Power Station Presentation File
 "Briefing for JICA on February 28, 2012.pptx"

Figure 2-11 Overall Arrangement of Mangla Power Station

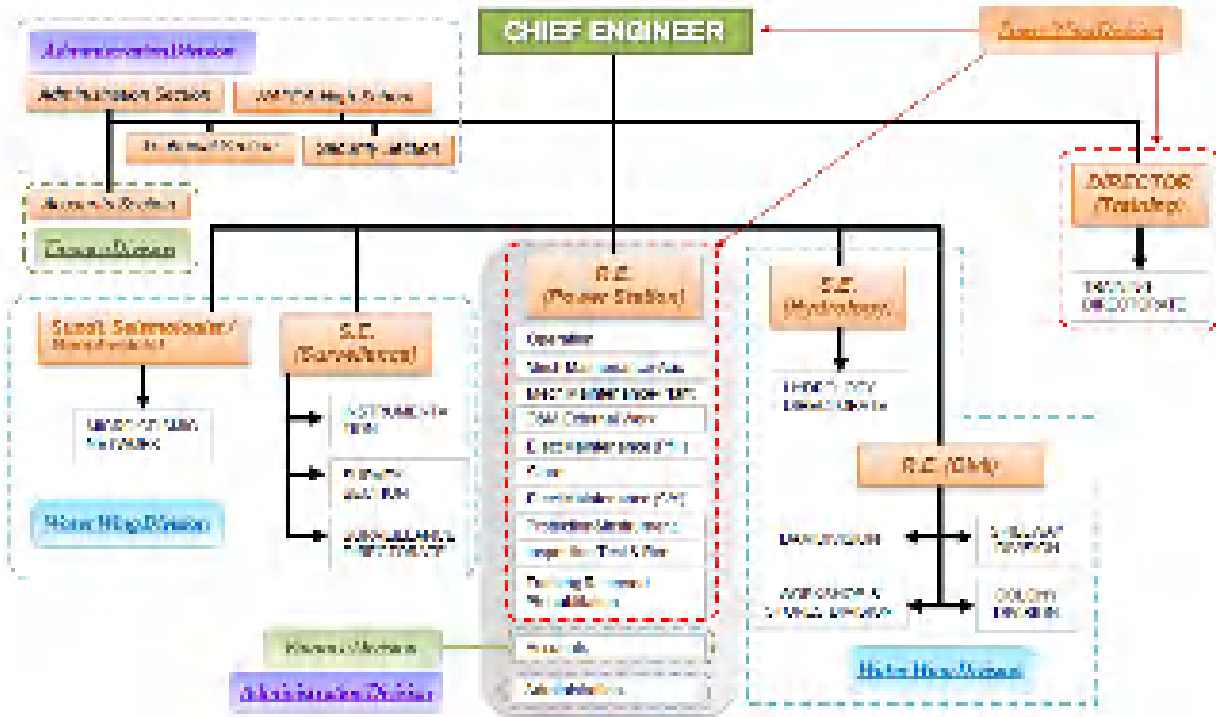


Source: Mangla Power Station Presentation File
 "Briefing for JICA on February 28, 2012.pptx"

Photo 2-3 Overview of Mangla Power Station

2.5.2 Organization of Mangla Power Station

Mangla Power Station is headed by the chief engineer. The present organization of Mangla Power Station is shown in Figure 2-13.



Source: Prepared by the Survey Team

Figure 2-13 Organizational Structure of Mangla Power Station

In the above organizational structure, the chief engineer and resident engineer of the Power Station are positions with great responsibility in the operation and maintenance of the Mangla Power Station.

The main roles of chief engineer and resident engineer (power station) are described below:

Chief Engineer

The chief engineer has overall responsibility for Mangla Dam, Mangla Power Station, small hydropower stations like Rasul Power Station, Shadiwal, Nandipur, Chichokimalian, and Renala. All the civil structures of dam, colonies, and offices are being looked after by the resident engineer (civil) while the Mangla Power Station is being controlled by the resident engineer (power station). One training directorate is also being run by director training under the chief engineer. The training directorate gives training to newly hired junior engineers and other technical staff to be assigned to different hydropower stations like Tarbela, Mangla,

Ghazi Barotha, Chashma, and Warsak.

Resident Engineer (Power Station)

The resident engineer (power station) has overall responsibility for the Mangla Power Station. He is responsible for the operation, maintenance, and protection of the power station. All sectional heads who are senior engineers directly report to the resident engineer. The resident engineer also performs liaison function between the Indus River System Authority (IRSA) and National Power Control Centre (NPCC) for the water releases and generation of the Mangla Power Station in light of allowed releases of IRSA and power requirements of NPCC.

The main activities of each section which are directly managed by the resident engineer (power station) are described below:

Operation Section

The Operation Section of Mangla Power Station is headed by a senior engineer who reports to the resident engineer (power station). The operation engineer (OE) is in charge of the operation and releasing of water as per requirement of IRSA, from Mangla Lake, through the power station for generation of electricity. The O.E. also supervises all technical/non-technical staff working in all shifts for round the clock operation of the power station. The O.E. generates trouble reports (TRs) in case of malfunction/faulty defect on any machine/equipment and refers to the concerned section for rectification of faults.

Mechanical Maintenance Auxiliary Section

The Mechanical Maintenance Auxiliary Section is headed by a senior engineer who is in charge of the mechanical maintenance of all the auxiliary equipment of the Mangla Power Station such as air compressors and O/H cranes dewatering pumps. This section is also responsible for the cleanliness of the power station.

Mechanical Maintenance Plant Section

This section looks after the mechanical maintenance of machines parts such as turbines, intake gates, draft tube gates, and governors. This section is also headed by a senior engineer (mechanical) who directly reports to resident engineer (power station).

Operation and Maintenance External Work Section

This section headed by a senior engineer is responsible for the electrical as well as mechanical maintenance of external works such as spillway gates, Jary irrigation outlet, power intake gates, Bong escape gates, and their associated structures.

Electrical Maintenance (Power House) Section

This section is also headed by a senior engineer (electrical) who directly reports to the resident engineer (power station). This section is responsible for the maintenance of all electrical equipment within the power house such as generators, exciters, compressor motors, gov. motors, power transformers, excitation, transformers, and D.C. batteries of the power station.

Store Section

This section headed by a senior engineer is responsible for the safety storage and handling of store items such as spare parts, transformer oil, turbine oil, and other consumable items. This section also keeps a record of all items received, issued, surveyed off, on a daily basis, as per requirement of different sectional heads.

Electrical Maintenance (Switch Yard) Section

This section headed by a senior engineer (electrical) is responsible for the electrical maintenance of 132/220 KV switchyard which includes circuit breakers, interconnecting transformers, isolators, bus bars, cable tunnel, 220 V D.C. batteries, and air compressors.

Protection and Instrumentation Section

This section headed by a senior engineer is responsible for the testing, calibration, and maintenance of all protection relays and instruments installed in the power house as well as the switchyard.

Inspection, Test and Record Section

This section headed by a senior engineer is responsible for the preparation of trouble reports, rectification and records. This section is also responsible for keeping a record of testing of all equipment by different sections. Also, it prepares monthly and annual reports for the information of the higher offices. In addition, this section is also responsible for the procurement of all spare parts as per requirement of different sections.

Rehabilitation Section

The Rehabilitation of Mangla Power Station is being looked after and co-ordinated by a senior engineer working directly under resident engineer (power station). He is also responsible for providing data specifications of the equipment required by the consultants/contractors. He reports progress of the rehabilitation to the resident engineer (power station) and higher offices.

Accounts Section

This section headed by a budget and accounts officer reports directly to the resident engineer (power station) and deals with the preparation of annual budget of the power station, salaries, and annual increments to the employees. This section also keep an eye on the expenditure of the different sections as per their budget provisions. They also prepare next year budget as per demand of the different sections of Power Station.

Administration Section

This section headed by an assistant director (administration) directly reports to the resident engineer (power station). This section deals with all administrative matters relating to the employees of the power station like leave, service record, promotion/demotion, punishment/rewards, recruitment and transfer of the employees with the approval of the competent authority.

The manpower for each section of the Mangla Power Station, as of June 2012, is shown in Table 2-18.

Table 2-17 Manpower of Mangla Power Station

No.	Position	Division				Total
		Administration	Finance	Water Wing	Power Wing	
1	Managerial Staff (BPS 18-21)	-	-	4	2	6
2	Operation Staff (BPS-18)	8	-	14	10	32
3	Technical Staff	-	-	289	344	633
4	Non-technical Staff (BPS 1-17)	-	34	341	90	465
Total		8	34	648	446	1,136

Source: Prepared by the Survey Team

2.5.3 Mangla Dam Raising Project

The Mangla reservoir had an initial capacity of 5.88 minor allele frequencies (MAF), which was reduced to 4.674 MAF in 2005 and will further reduce with the passage of time due to sediment deposition. Keeping in view the capacity loss due to sedimentation and provision for raising it to the original construction design, the raising of Mangla Dam was considered to cope with the ever increasing shortage of irrigation water and mitigate the effects of capacity loss of country's two major storage reservoirs in Mangla and Tarbela. The raising of Mangla Dam by 30 ft has almost been completed to regain the reservoir capacity loss due to sediment deposition and to make provision for future sedimentation.

The contract for the Construction of Main Works (Contract MDR-10) of the Mangla Dam Raising Project was awarded to a joint venture of one Chinese and five Pakistani contractors (CWEJV) on June 14, 2004 for an amount of PRs 13.793 billion. The joint venture is composed of the China International Water and Electric Corporation (CWE) as the lead company, and local contractors including DESCON Engineering, Sardar M. Ashraf D. Baluch, Interconstruct and Sachal Engineering Works. The construction schedule was completed in 39 months in September 2007. Construction of major components for main works i.e., main dam and power intake embankment, Sukian Dyke, Jari Dam and rim works, main and emergency spillways and Mirpur Bypass Road were substantially completed on December 26, 2009 except for some minor varied works.

Table 2-18 Salient Features of Raising of Mangla Dam

Item	Original Design	After Raising	Comparison
Reservoir			
Max. Water Level	366.5 m(1,202 ft)	378.7 m(1,242 ft)	+12.2 m
Min. Water Level	317.1 m(1,040 ft)	317.1m(1,040 ft)	+0.0 m
Reservoir Capacity	5,553 Mm ³ (4.5 MAF)	9,132 Mm ³ (7.4 MAF)	+3,579 Mm ³
Dam Body			
Crest Height	138.5 m(454 ft)	147.6 m(484 ft)	+9.1 m
Crest Length	3,350 m(10,300 ft)	3,400 m(11,150 ft)	+50 m
Intake level	376.2 m(1,234ft)	386.0 m(1,266 ft)	+9.8 m
Additional Capacity	-	3,550 Mm ³ (2.88 MAF)	-
Annual Generation	-	644 GWh	-

Source : WAPDA Hydrological Section of Mangla Dam

The scope of resettlement works for the Mangla Dam Raising Project is listed below:

- Land acquisition: 16,384 acres
- Number of population: 50,000
- Number of houses and other buildings: 13,404

The actual progress of the resettlement works, as of end of July 2012, is shown in Table 2-20. All construction works for houses, public utility buildings, water treatment system and roads

etc., in the new town has been already completed.

Table 2-19 Overall Progress of Resettlement Works

Name of New Town	Overall Progress	Remaining Number of Plots to be Handed Over
MIRPUR NEW CITY	86.3%	169
ISLAMGARH	96.0%	132
CHAKSAWARI	85.6%	362
DUDIAL	100.0%	-
SIAKH	100.0%	-

Source: Mangla Raising Project Office

It is expected to complete all remaining resettlement works including handover of housing to the residents as stated on the above table by the end of September 2012. Photos 2-4 and 2-5 show the aerial view of the Mangla Hydro Power Station and the embankment after dam raising.



Source: Prepared by the Survey Team

Photo 2-4 Mangla Hydro Power Station



Source: Prepared by the Survey Team

Photo 2-5 Embankment after Dam Raising

2.5.4 Hydel Training Center Mangla

The Hydel Training Center Mangla plays a pivotal role in capacity building of the officers and officials of Hydel organizations in WAPDA. It is the sole institution functioning at present to impart training to all the technical/non-technical employees of Water and Power Wings in WAPDA.

The detailed number of officers and officials trained in 1997 up to January 2012 at Hydel Training Centre Mangla is summarized in Table 2-20.

Table 2-20 Detailed Number of Trained Staffs from 1997 to 2012

No.	Categories	Name of Course	Number of Staffs Trained
1	Sr. Engineer due for Promotion as Superintending Engineer	Refresh Course	19
2	Jr. Engineer due for Promotion as Sr. Engineer	Sector Specific Course	29
3	Fresh Jr. Engineer of Hydel Generation	Induction Course	373
4	Turbine Operators and Sr. Attendants	Advance Operator Course	300
5	Fresh Attendants and Assistant Station Attendants	Basic Operator Course	728
6	Jr. Technicians, Fitters, Electricians, Assistant Station Attendants, Hammer Men, Blacksmith, Test Inspector, Welder, etc.	Basic Craftsman Course	785
7	Jr. Clerks, Sr. Clerks, Office Assistant	Ministerial Staff Course	201
8	Jr. Clerk eligible for Steno Grade-II	Ministerial Staff Course	26
9	Steno-Grade II to Steno Grade-I	Ministerial Staff Course	46
10	Jr. and Sr. Store Keepers Store Supervisor	Store Staff Course	24
11	Tracers, Draftsmen, Assistant Draftsman	Drawing Staff Course	23
12	Telephone Lineman, Operators, and Supervisors	Telephone Staff Course	34
13	Computer Office Application Course for Officers and Officials Stationed at Mangla	-	186
14	Internship of Student from Different Engineering Universities	-	246
Total			3,020

Source: Briefing to the Delegation at WAPDA Hydel Training Centre Mangla (1977-2011)

The annual schedule of training for the year 2012 at Hydel Training Centre Mangla is shown in Figure 2-14. It is expected that 200 staffs will be trained in year 2012.

Sr	Detail of Course	BPS	Code	capacity	Duration in weeks	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	Refresher Course (Pre-promotion) Category : Senior Engineer (Hydel Generation)	18	RC	10	04				16	12							
2	Sector Specific Course (Pre-promotion) Category: Junior Engineer (Hydel Generation)	17	SSC	10	06			5	14								
3	Junior Engineer Induction Course Categories:- Fresh Junior Engineer	17	JIC	10	8	9		3									
4	Upper Technical Subordinate Staff Course Category : Foreman / Operator	16	UTS	15	04						11	14					
5	Advance Operator Course Categories:- Turbine Operators & Sr. Attendants	11 & 12	AOC	15	8	2	25										
6	Basic Craftsmen Course (E&M) Categories:- Fitters/ASA's, Hammer men, Blacksmith, Electricians, Test Inspector, Lab Asstt: Winders Linemen, Asstt: Foreman, & related categories	5-15	BCC	15	14			5		9							
7	Basic Operator Course Categories:- Fresh Turbine Operators, Attendants & Sr. ASA's or related cat.	5-15	BOC	15	12									03		24	
8	Ministerial Training Course Categories:- Jr. Clerks, Sr. Clerks, Assistants & Jr. Suptd.	5-15	MTC-1	15	3												3 22
9	Ministerial Training Course Categories:- Jr. Clerks eligible for promotion as Stenographer-II	7	MTC-2	15	3				2 21								
10	Ministerial Training Course Categories:- Stenographer-II	12	MTC-3	15	3										1 20		
11	Store Staff Training Course Categories:- Jr. & Sr. Storekeepers & Store Supervisor	7-15	SST	15	3							2 21					
12	Drawing Staff Training Course Categories:- Tracer, Draftsmen,	7-15	DST	15	3											12	1
13	Telephone Staff Training Course Categories:- Telephone linemen, Operators, Supervisors	5-15	TST	15	3												10 29
14	Internship Training Course for Student Engineers	---	ITC	15	4					28	23	2 28	6	1 3 29			
15	Computer Office Application Course Categories:- Officers & Officials of Mangla only	5-17	COA	5	12												

Continued Activity after every 3 months

Source: Briefing to the Delegation in WAPDA Hydel Training Centre Mangla (1977-2011)

Figure 2-14 Annual Schedule of Training for the Year 2012

CHAPTER 3

REVIEW ON FEASIBILITY STUDY REPORT

CHAPTER 3 REVIEW ON FEASIBILITY STUDY REPORT

3.1 Outline of F/S

3.1.1 Objective of the F/S

The WAPDA has conducted the F/S for the up-gradation and refurbishment of generation units of the Mangla Power Station in 2011. The F/S was prepared by the joint venture of MWH (USA) and NESPAK (Pakistan) to help WAPDA in identifying the improvements of the Mangla generation units.

The objectives of the F/S were to determine the most viable alternative, in terms of the technical as well as the economical aspect for the up-gradation and/or refurbishment of the existing units of the Mangla Hydro Power Station. The adverse effect by the aging electrical / mechanical equipment and the effective utilization of the improved power potential after completion of the Mangla Dam Raising Project should be kept in mind.

The F/S was carried out in the period from June to December 2011.

3.1.2 Contents of the F/S Report

The F/S report consists of the following eight volumes.

- Volume 1 Executive Summary
- Volume 2 General
- Volume 3 Condition Assessment Generation and Unit Electrical
- Volume 4 Condition Assessment Turbine and Unit Electrical
- Volume 5 Condition Assessment Balance of Plant
- Volume 6 Development and Evaluation of Up-gradation and Rehabilitation Alternative
- Volume 7 Environmental Studies
- Volume 8 Appendices

3.1.3 Summary of the F/S Report

The F/S was carried out after the investigation and evaluation of a number of electrical and mechanical equipment, civil structure, hydrological data, outflow consideration/limitations at upstream and downstream, financial and economical considerations. This provided different refurbishment alternatives.

In the F/S report based on the assessment of the plant equipment, four alternatives namely Alternatives 0, 1A, 1B, and 2, were presented.

The summary of each alternative as described above is shown in Table 3-1.

Table 3-1 Expected Increase in Energy Output by Up-gradation/Refurbishment

Alternative	Unit Rating	Description	Remarks
0	No Up-gradation from the existing 1,150 MW in total (only rehabilitation) Units 1-10: 115 MW	<u>Turbine</u> - Replacement of turbine runner <u>Generator</u> - Replacement of stator winding - Replacement of stator core (Units 1-6) - New static digital excitation system	-
1A	Up-gradation to 1,310 MW in total Units 1-6: 135 MW Units 9-10: 135 MW Units 7-8: 115 MW (no change)	<u>Turbine</u> - Replacement of turbine runner (same as Alternative 0) <u>Generator with higher capacity</u> - Replacement of core and winding for generator (Units 1-6, 9-10) - New static digital excitation system <u>Others</u> - New power transformer and IPB	-
1B	Up-gradation to 1,380 MW in total Units 1-6: 135 MW Units 7-8: 150 MW Units 9-10: 135 MW	<u>Turbine</u> - Replacement of turbine runner (same as Alternative 0) <u>Generator with higher capacity</u> - Units 1-6, 9-10: same as Alternative 1A - Units 7-8: complete replacement of generators with 150 MW <u>Others</u> - New power transformer and IPB	-
2	Up-gradation to 1,500 MW in total Units 1-10: 150 MW	<u>Turbine</u> - Replacement of turbine runner (same as Alternative 0) <u>Generator with higher capacity</u> - Units 1-10: complete replacement of generators with 150 MW <u>Others</u> - Modification of intake structure - New power transformer and IPB	Demolition works of existing concrete foundation of generators required for all units except for Units 7 & 8.

Source: Feasibility Study for Up-gradation and Refurbishment of Generating Units of Mangla Power Station, December 2011

Each generating unit from Unit 1 to Unit 10 were ranked utilizing the ranking methodology. It assessed both the condition and the consequence.

The assessment concluded the urgent rehabilitation of generating equipment units 5, 6, 2, 1, 3

and 4 in order (Table 3-2).

Table 3-2 Recommended Unit Rehabilitation Order

Rank	Unit	Consolidated Score	Remarks
1	Unit 5	1.0000	Urgent
2	Unit 6	0.974	
3	Unit 2	0.755	
4	Unit 1	0.728	
5	Unit 3	0.581	
6	Unit 4	0.581	
7	Unit 7	0.111	Less Urgent
8	Unit 8	0.032	
9	Unit 9	0.000	
10	Unit 10	0.000	

Source: Feasibility Study for Up-gradation and Refurbishment of Generating Units of Mangla Power Station, December 2011

The construction costs were estimated for each alternative. The net present value (NPV), economic internal rate of return (EIRR), financial internal rate of return (FIRR) and benefit-cost ratio (BCR) were calculated with the utilization of inflation and escalation rates specified for the different inputs. Details are discussed in Sub-clause 7.3.

Table 3-3 Economic Analysis of Up-gradation Alternatives (2013 to 2047)

Alternative	Construction Cost		NPV		EIRR	FIRR	BCR
	million USD	billion PRs	million USD	billion PRs			
Alternative 0 1150 MW	350.8	29.82	181.0	15.38	20.9%	Not done	2.54
Alternative 1A 1310 MW	369.4	31.4	234.9	19.97	24.0%	22.6%	2.89
Alternative 1B 1380 MW	446.2	37.93	222.4	18.91	22.6%	Not done	2.52
Alternative 2 1500 MW	684.3	58.17	158.7	13.49	17.8%	Not done	1.69

Source: Feasibility Study for Up-gradation and Refurbishment of Generating Units of Mangla Power Station, December 2011

The F/S report concluded that Alternative 1A to be the most economically alternative, though the detailed information such as assumptions (discount rate) and methodology (calculation of economic benefit) were not described. It was also difficult to judge the accuracy of the figures shown in the report.

The F/S report also conducted the financial and economic analyses in case of including the benefit from CDM CER credits. The F/S also concluded that the additional benefit is marginal and there is not much difference in the result of calculation.

Table 3-4 Economic Analysis with CDM Allotment (2013 to 2047)

Alternative		NPV with CDM		EIRR w/ CDM	BCR w/ CDM
		million USD	billion PRs		
Alternative 0	1150 MW	N/A	N/A	N/A	N/A
Alternative 1A	1310 MW	246.5	20.95	24.5%	2.98
Alternative 1B	1380 MW	234.3	19.92	23.0%	2.60
Alternative 2	1500 MW	171.1	14.54	18.2%	1.74

Source: Feasibility Study for Up-gradation and Refurbishment of Generating Units of Mangla Power Station, December 2011

3.1.4 Conclusion and Recommendation of the F/S

The F/S report concluded that Alternative 1A (1310 MW total) is recommended since it satisfies all objectives from the scope of works. Alternative 1A also has the highest NPV, BCR, EIRR, and FIRR.

The F/S also recommended considering implementation of Alternative 1B, which is a modified version of Alternative 1A.

Investing in Static Var compensators, or by other means to satisfy the necessary reactive power requirements for the power system were also suggested.

3.2 Recommendation in the F/S and View of the Survey Team

3.2.1 Hydraulic Consideration and Limitations

The hydraulic limitations in the F/S report are the reservoir water level, tailrace water level, and water passage for consideration of turbine ratings.

When the dam height was increased by 30 feet, the reservoir water level increased by 40 feet, which is from 1202 feet to 1242 feet.

The water passages include the intake screen (trashracs), intake gate, concrete lined tunnel, steel lined tunnel, inlet valve, and tailrace channel (Bong Cannel). The water passage limitation is the base data for deciding the maximum output capacity of the turbine together with the head loss. Maximum water passage limitation is 49,000 cfs, (4,900 cfs/unit) which is the tailrace channel water passage limitation.

As the result of review, the Survey Team has judged that the above recommendation in the F/S report is acceptable.

3.2.2 Condition Assessment of Turbine and Unit Mechanical

The F/S report recommendations for the turbine and mechanical units are preferable as shown in Tables 3-9 to 3-12. The results of the review on the F/S report are as follows:

- (1) Units 1 to 4
Most of the recommendations made in the F/S report are acceptable except for some comments as mentioned in Table -9.
- (2) Units 5 and 6
Most of the recommendations made in the F/S report are acceptable except for some comments as mentioned in Table 3-10.
- (3) Units 7 and 8
Most of the recommendations made in the F/S report are acceptable except for some comments as mentioned in Table 3-11.
- (4) Units 9 and 10
Most of the recommendations made in the F/S report are acceptable except for some comments as mentioned in Table 3-12.

3.2.3 Condition Assessment of Generator and Unit Equipment

The essence of the current condition quoted from the F/S report is summarized in Table 3-13 to Table 3-16.

The F/S report mentioned the details of the current condition of the equipment, and methods of rehabilitation. Most of the requirements on the F/S report are understandable. The rehabilitation and up-grading idea is appreciated as mentioned on the attached tables.

There were a few site measurement data and analyses by the measuring data. Therefore, the Survey Team has added some analysis by data measured during the site visit. The result of analysis is mentioned in Chapters 4 and 5.

The comments of the Survey Team are described below:

According to the F/S report, almost all main parts of the generator and turbine would be rehabilitated; especially for Units 1 to 4, 5, and 6, with some of the main parts to be replaced with new ones. For example, for generator stator, the F/S report recommended replacing the core and winding only on the existing frame. This method is the most economical, but only the original manufacturer can do it more efficiently because only the original manufacturer knows the detail design of the existing equipment. It will be difficult for the other manufacturers to

match with the new rating and efficiency of the up-graded/rehabilitated equipment.

In addition to the above, the upper guide bearing's design is required to be changed, therefore, all parts of the generator are recommended to be replaced for Units 5 and 6.

(1) Units 1 through 4

Most of the requirements pointed out in the F/S report are understandable and the rehabilitation idea is appreciated with some comments, as mentioned in Table 3-13.

For up-gradation, the F/S report described different alternatives, and one of them requires foundation modification.

(2) Units 5 and 6

Most of the requirements pointed out in the F/S report are understandable and the rehabilitation idea is appreciated with some comments, as mentioned in Table 3-14.

For up-gradation, the F/S report described different alternatives, and one of them requires foundation modification.

(3) Units 7 and 8

Most of the requirements pointed out in the F/S report are understandable and the rehabilitation idea is appreciated with some comments, as mentioned in Table 3-15.

For up-gradation, the F/S report described different alternatives, and one of them needs foundation modification.

(4) Units 9 and 10

Most of the requirements pointed out in the F/S report are understandable and the rehabilitation idea is appreciated with some comments, as mentioned in Table 3-16.

For up-gradation, the F/S report described different alternatives, and one of them needs foundation modification.

The summary of up-gradation alternatives in the F/S report is shown in Table 3-18.

3.2.4 Condition Assessment of Balance of Plant (BOP)

(1) General

The essence of the current condition quoted from the F/S report is summarized in Table 3-17.

The control and protection system are involved in the BOP of the F/S. The scope of the control and protection system is classified into three categories: i. generation units, ii. switchyard, and

iii. station service.

The F/S evaluated almost all control and protection system that are outdated, and it recommended replacing a new system.

(2) Switchyard

Almost all devices are outdated. The F/S recommended replacing them with modern state-of-the-art substation automation system (SAS). Bus bar protection relays are scheduled to be replaced by digital relays. Battery systems for switchyard are all new within the last 10 years. It is assessed that the battery systems are not required to be replaced immediately.

The Survey Team has confirmed that the renovation works of the switchyard facilities are on going by another project. The evaluation of the switchyard is required more elaborately study and the interface arrangement with another project at the detailed design stage. The control and protection system for feeder lines of upgrading generators are included as the scope of project but transmission-lines' are not included.

(3) Station Service

The F/S report described the issues on the station service system as shown below:

The plant operation and maintenance personnel have reported that they faced a number of problems during the restoration process after a blackout scenario when they have to perform multiple manual operations to restore the normal configuration. There are many interlocking devices between the various breakers making the system very complex.

The F/S report recommended replacing the system entirely with a new system. The said report presented several alternative designs for replacement. The final recommendation was chosen to be Option 5 in Table 3-5.

The Survey Team has recommended replacing the station service circuits, namely 11kV and 415V circuits, as recommended in the F/S report.

Especially, the alternatives of the Options 4 and 5 in the F/S, those alternatives will be required the longer stoppage compared to another alternative options.

The Survey Team suggests considering the simplification of interlock, and total coordinated power supply redundancy among the high-voltage, medium-voltage and low-voltage.

The oil circuit breakers in 11kV circuits which are recommend replacing as described in the F/S report. The oil circuit breakers have a risk of fire and troublesome maintenance, therefore it is not used in the present industrial field.

In the power station, the station service circuit, especially 415V circuits are complicated and

modified frequently, therefore in many cases; the circuit diagrams are not reflected actual circuit correctly.

Table 3-5 Alternative Plans for Station Service Refurbishment in the F/S

Alternatives	Outline	Feature
Option-1 (Figure 3-1)	Refurbish but retain existing configuration	The 132 kV system failed to bring power station down.
Option-2 (Figure 3-2)	Refurbish and shift one SOTH to 220 kV side of the switchyard while retaining the existing configuration	The above trouble will be mitigated by using the 220 kV system supply.
Option-3 (Figure 3-3)	Refurbish and revise unit auxiliary supply configuration	Power supply redundancy will be further increased from Option-2. Switches changeover operation and interlock becomes more complicated.
Option-4 (Figure 3-4)	Refurbish and utilize unit block configuration	Automatic unit supply change over circuit is required at unit start/stop time. Switches changeover operation and interlock becomes more complicated. When the 220 kV and 132 kV fail, the same with Option-2.
Option-5 (Figure 3-5)	Refurbish and apply generator circuit breaker configuration	Two generator circuit breakers are attached to Units 2 and 7. Switches changeover operation and interlock becomes more complicated.

Source: Prepared by the Survey Team

- (4) Assumption of reason for recommendation of Option 5 for the Station service circuit in the F/S report

In the F/S report, there is no description why Option 5 is recommended preferentially.

The Survey Team assumes the reason of recommendation of Option 5 in the F/S report as below:

- a) Option-5 makes redundant power supply system from the two different generation units, which are connected different high voltage bus as 220kV and 132kV. It is more reliable compare to the actual system.
- b) Station service power supply will not be affected substation system troubles since the power is directed from the generation bus.

The Survey Team would like to point out the following matters against the Option 5.

- i) Spacing for circuit breaker installation is required the more deep study at site, and it possibility will be judged.
- ii) The installation work is required IPB piping modification with bending; it brings the

reducing the ventilation efficiency.

- iii) Different protection schema and operation manner will be required such two units against remaining eight units. Unified schema is easier for operation and maintenance.
- iv) The Redundancy of power supply can be realized by the study team's plan also.
- v) BUS system modification scheduling with units stop in the Option-5, which is difficult to make realizing. Unit shutdown of all units will be required more longer with comparing another alternatives.
- vi) The Survey Team plan can be proceeded to follow the unit upgrading schedule, because the configuration will not be changed dynamically at one time.

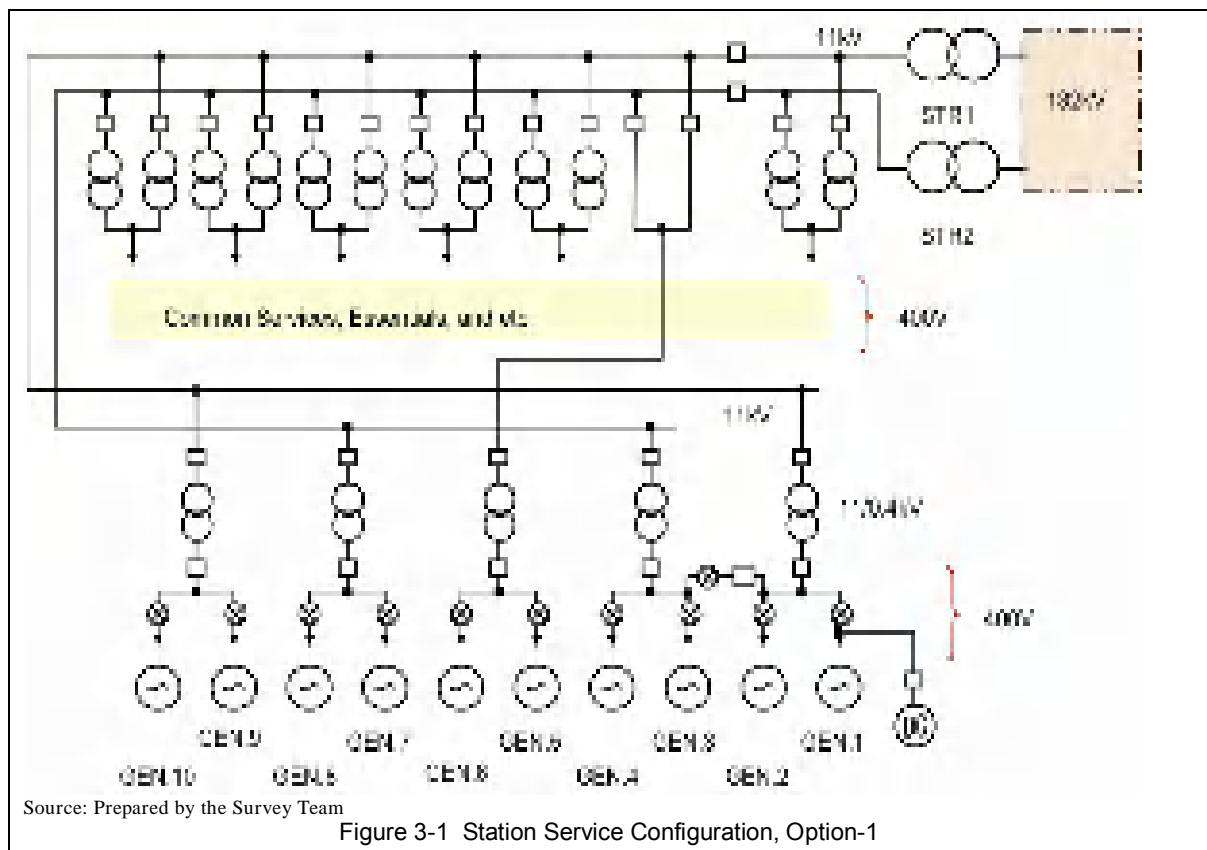
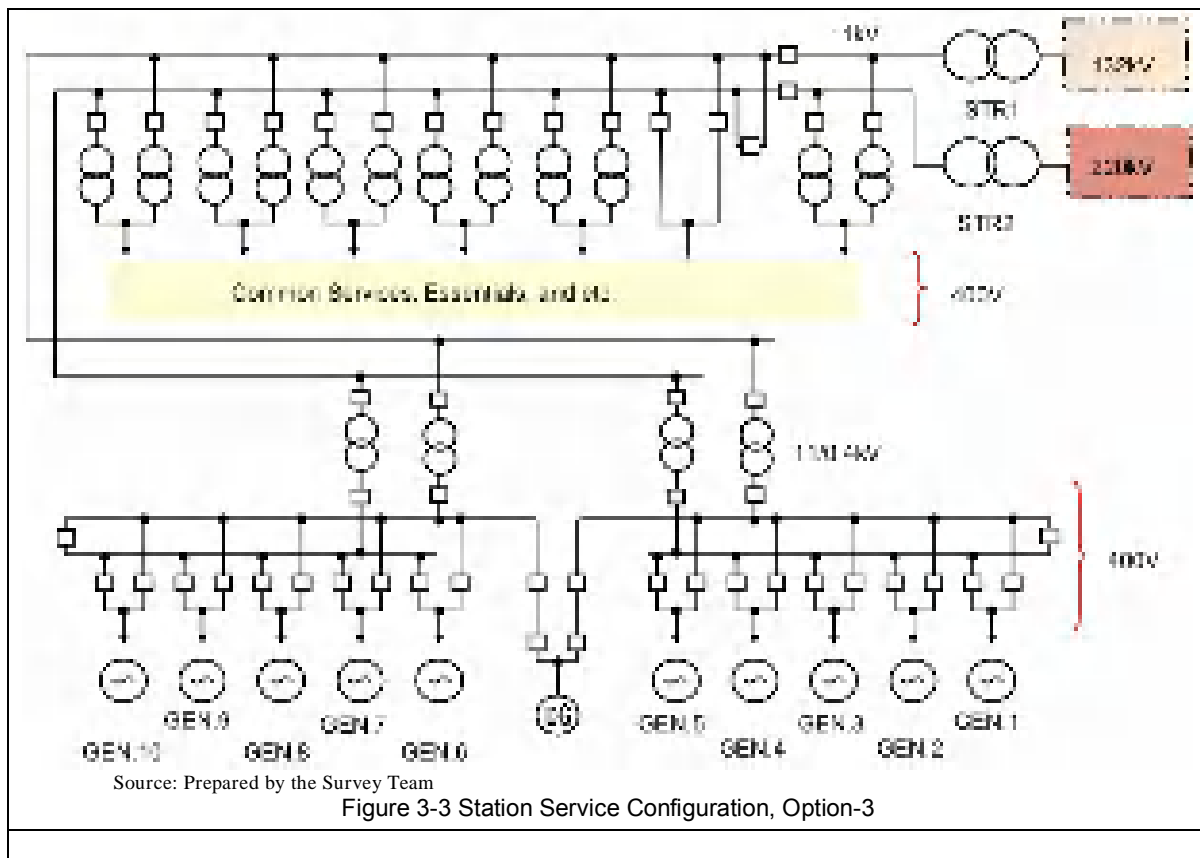
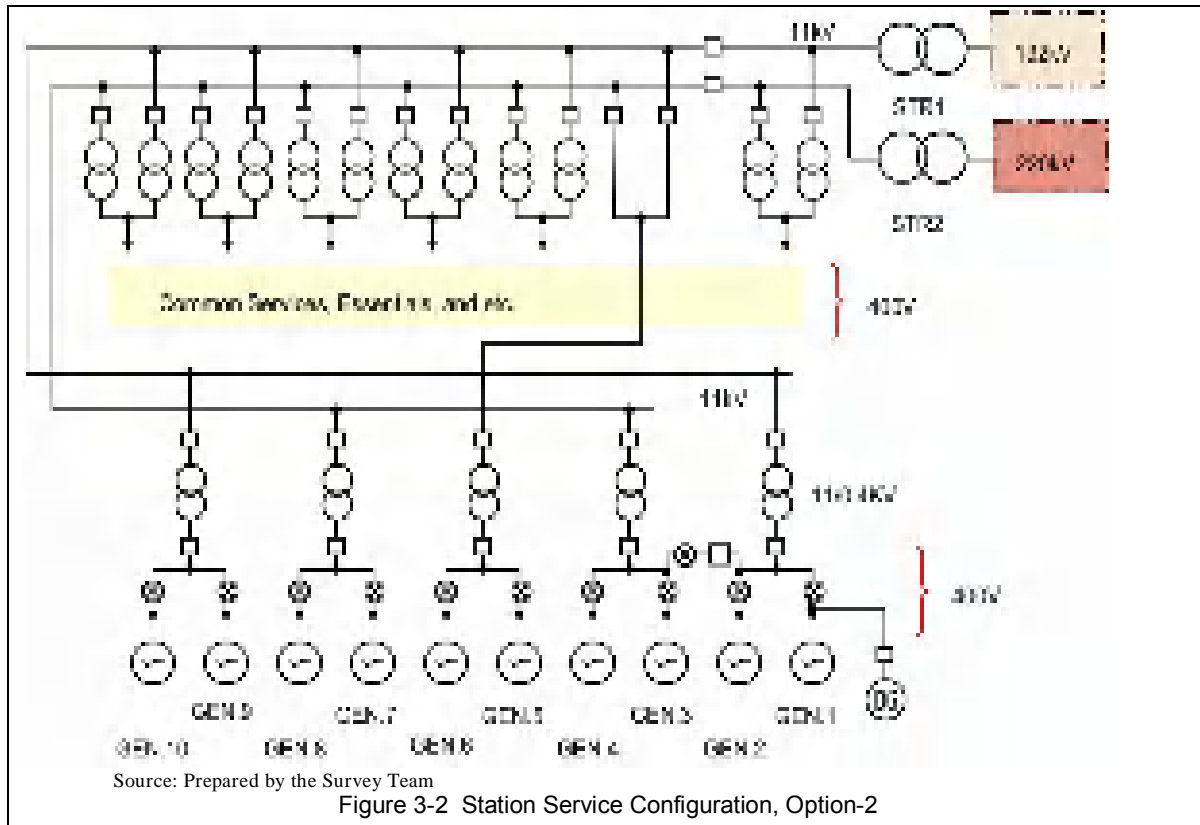
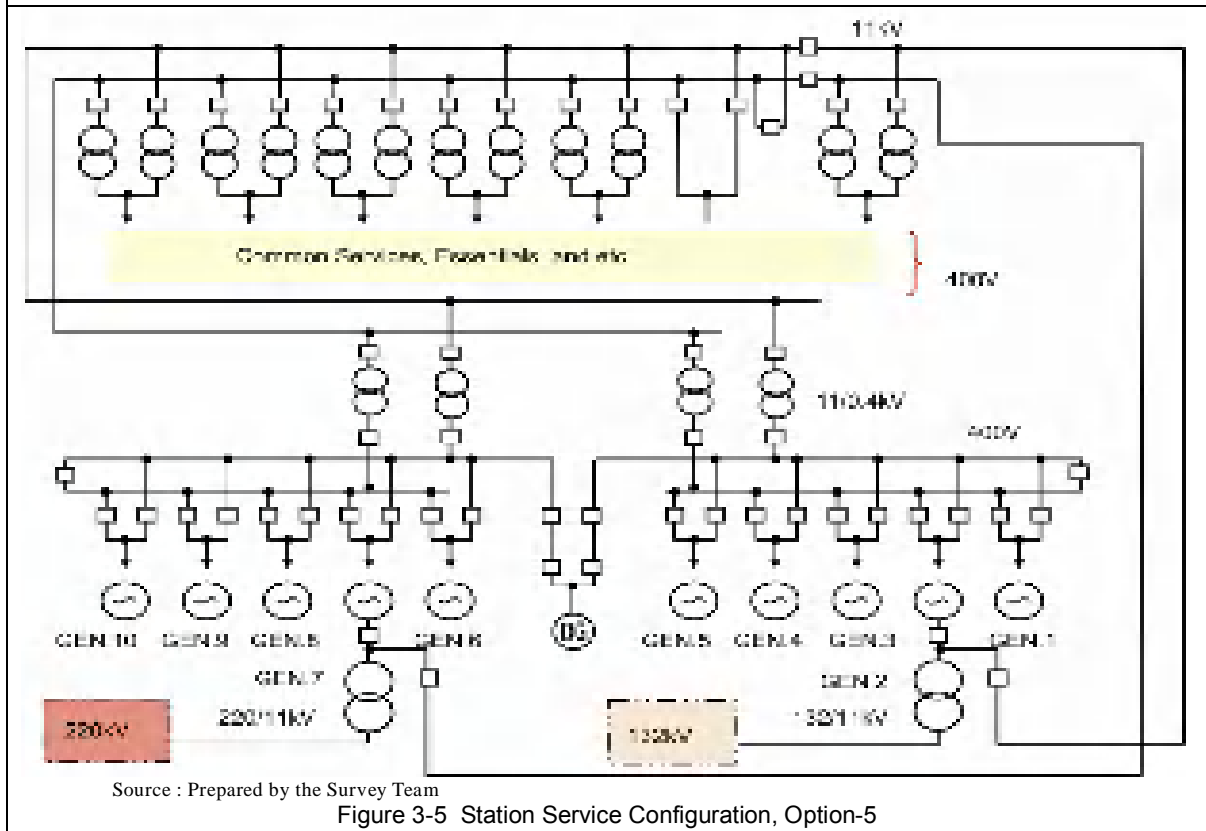
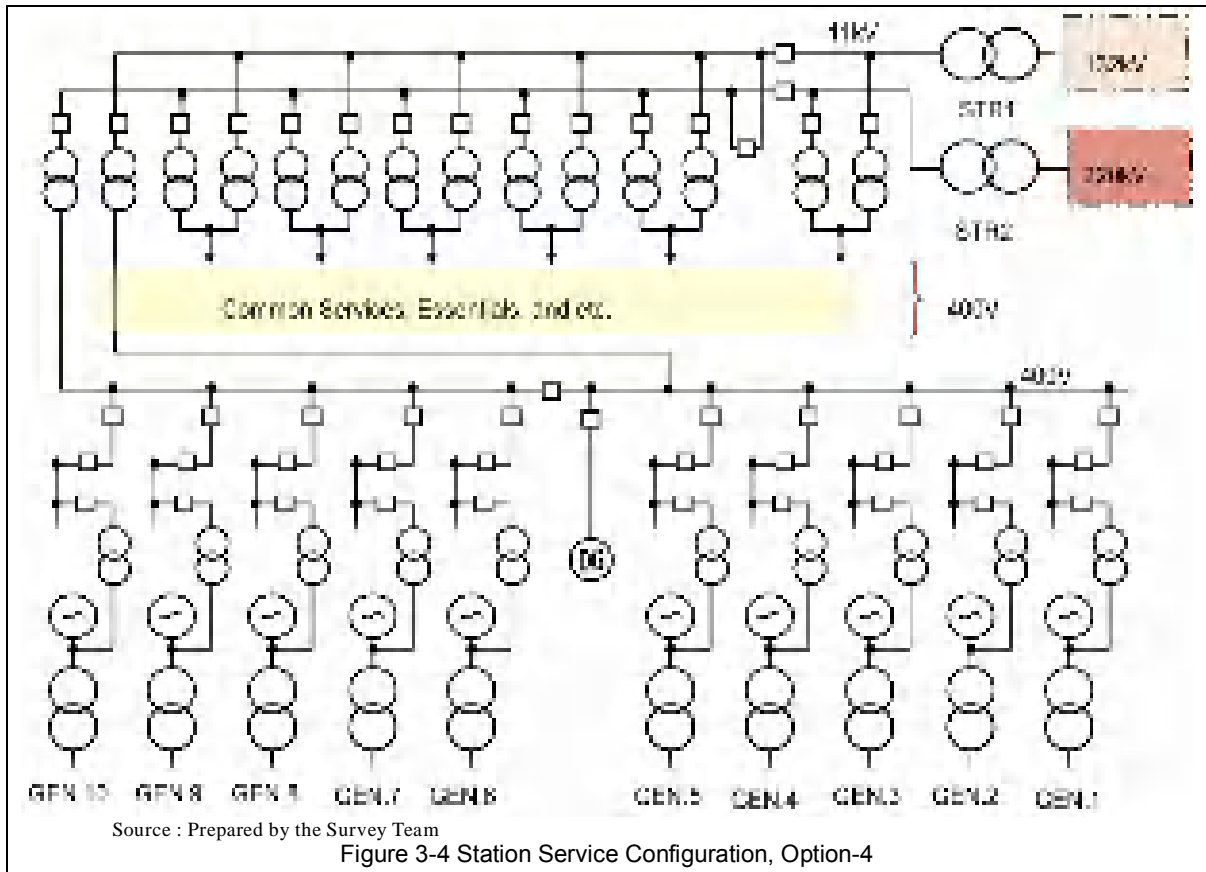


Figure 3-1 Station Service Configuration, Option-1





3.2.5 Condition Assessment of Civil Works

(1) Water Balance of Mangla Dam

The F/S report mentioned in the study under civil works includes the hydrological methodology and analysis procedure (RESOP-1 software by NESPAK), the dam sedimentation analysis (HEC-6 software by the United State Army Corps of Engineers) and the countermeasures against concrete degradation of generator and turbine foundations. The hydrological analysis forecast on inflow discharge until year 2097/98 for 88 years were based on the data from year 1922/23 to 2009/10 of the Mangla dam basin using by the RESOP-1 program. The result of the analysis is shown in Table 3-6 below.

Table 3-6 Water Balance in Mangla Dam Basin

Inflow and Outflow	MAF	mm ³
Average Annual Inflow	22.75	28,062
Average Annual Outflow for Irrigation	20.91	25,792
Average Annual Outflow in Kharif (April to September)	10.24	12,631
Average Annual Outflow in Rabi (October to March)	10.67	13,161
Average Annual Spill	2.00	2,467

Source: Feasibility Study for Up-gradation and Refurbishment of Generating Units of Mangla Power Station, December 2011

The penstock discharge from one intake gate was estimated at 9,000 ft³/s (254.9 m³/s). In the case of generating power using 10 generators with five penstocks, the planned discharge was calculated at 45,000 ft³/s (1,274 m³/s). After generating power at the Mangla Power House, the water flows to the New Bong Power Station (independent power project: IPP). The water intake of the New Bong Power Station, which is located downstream of the Mangla Power Station and under construction, is separated from the tailrace cannel of the Mangla Power Station. The capacity of the tailrace cannel flow is 49,000 cfs. Therefore, the water intake of the New Bong Power Station shall be designed to be less than capacity of the said cannel flow. Besides, the maximum water discharge of the Mangla Power Station before dam raising was designed as 45,000 cfs.

In consideration of the above, the Survey Team has judged that the quantity of the water discharge of the Mangla Power Station is not effect on the generating capability of the New Bong Power Station.

(2) Concrete Repair at Power House

Based on the results of the evaluation of the F/S report and the description of the site investigation under this study, concrete repair works at generators and turbines in the power houses are under consideration. Some cracks in the concrete surrounding the turbines have been observed, specifically at Units 5 and 6 which have big cracks with approximately 5 mm width. According to the F/S report, the use of epoxy injection and replacement of concrete with approximately 5.4 m³ were recommended as solution. However,, this study shall recommend

the use of epoxy injection and carbon fiber sheet. The reason for the occurrence of the serious cracks is not mentioned in the F/S report. In addition, the surrounding concrete of Unit 8 turbine has some leakage which should be repaired. The surrounding concrete of each intake structures (5 intakes in total) also have some minor cracks, which shall also be injected with epoxy, as recommended by the F/S report. However, more cracks from the concrete surrounding the turbines and generators of Units 1, 2, 4, 7, 9, and 10 were observed but not structurally serious. Concrete strength was examined using Schmidt Hammer and found no deterioration on the concretes. The locations recommended for repair/reinforcement under the study are shown in Table 3-7.

Table 3-7 Location for Concrete Repair and Strength of Existing Concrete

	No.1	No.2	No.3	No.4	No.5	No.6	No.7	No.8	No.9	No.10
Turbine					○	○				
Leakage								○		
Intake	○		○		○		○		○	
Concrete Strength (MPa)	48.2	50.3	44.0	48.5	51.6	52.4	50.2	51.6	48.3	50.2

Note: Locations for repair are described as . Standard strength for concrete is F=30 MPa

Source : Prepared by the Study Team

(3) Evaluation of Sedimentation

The sedimentation volume in the future may be estimated as follows and the comparison between the F/S report and actual survey data was conducted and summarized in Table 3-8.

- 1) Using sedimentation volume based on the previous surveyed data (1967-2010) and applying the same ratio to year 2011-2093.
- 2) Using sedimentation volume based on the sedimentation analysis for the F/S

Accordingly, the sedimentation will be reduced in the next 83 years by approximately 8%. It was explained that the mountainous slopes and river courses will gradually stabilize in the future. The sedimentation analysis in the F/S report may be correct and it would be the proper approach to calculate the volume of future sedimentation.

Table 3-8 Evaluation of the F/S Report on Sedimentation

Year	1967-2010	2011-2050	2051-2093	Total
Duration	44 years	40 years	43 years	127 years
Catchment Area	33,343 km ²			-
Sedimentation Volume	Actual Survey	1,589 mm ³	1,445 mm ³	1,554 mm ³
		(0.5%)	(0.5%)	(0.5%)
	WAPDA F/S Report	1,589 mm ³	1,461 mm ³	1,178 mm ³
		(0.5%)	(0.4%)	(0.3%)
				4,588 mm ³
				4,228 mm ³

Note: Figure inside the parenthesis describes the reducing rate of reservoir storage capacity

Source: Prepared by the Survey Team

Table 3-9 Review of the F/S Report Units 1 to 4 for Turbine Equipment

Parts Name	Recommendations in the F/S Report	Comments of the Survey Team	Note
Inlet Valves	Overhaul is recommended for all units with partial repairing together with the replacement of bypass valves and pipings for all units.	By-plane type inlet valves are recommended for reducing head loss and minimizing water leakage. Bypass valves and its piping are also replaced.	-
Spiral Casing	The wire draw, wire gall, lower guide vanes, and facing plates should be replaced. Overhaul of the inside casing including stay vane is recommended with repainting and wearing elements replacement.	Same as left. Measuring instruments including turbine water flow detector shall be replaced.	-
Turbine Runner	The current runner shall be replaced with a new runner.	New runners including runner corns shall be replaced.	-
Runner Wearing Rings	The new runners will be provided with new wearing rings and spares.	Same as left.	-
Guide Vane	All guide vanes for replacement units are recommended.	Same as left.	-
Guide Vane Operating Mechanism	Overhaul of the mechanism is recommended with parts replacement such as linkage bushings, gate operating ring, and bushings.	Gate operating ring shall be reused. Other parts shall be replaced same as left.	-
Head Cover	The wire draw, wire gall, upper guide vane and facing plate is replaced. Inspection of all head cover is recommended.	The head cover shall be replaced including adopting new design for turbine shaft and shaft seal.	-
Turbine Shaft	Inspection and one spare shaft for four units are recommended.	Same as left but does not require spare shaft supply.	-
Shaft Seal	Overhaul is recommended with wearing elements replacement.	The shaft seal shall be replaced by new one for improving the shaft seal performance.	-
Discharge Ring and Draft Tube	Inspection of rings and liners are recommended with blast and recoat.	Same as left	-
Pressure Balancing	No necessary work is expected.	Same as left.	-
Turbine Guide Bearing	No recommendation is provided.	All guide bearings shall be replaced by new one.	The thrust and guide bearings are to be included in the generator section.
Governor	New governors should be provided because spare parts are no longer available.	The new governor shall be of latest design, digital type with additional speed detector of SSG type.	-
Governor Pressure Oil system	Aside from maintenance, occasional component replacement is recommended.	The governor pressure oil supply system shall be replaced, if the operating pressure is applied higher pressure than the existing one.	-

Source: Prepared by the Survey Team

Table 3-10 Review of the F/S Report Units 5 and 6 for Turbine Equipment

Parts Name	Recommendations in the F/S Report	Comments of the Survey Team	Note
Inlet Valves	Overhaul is recommended for all units with partial repairing. Replacement of bypass valve and piping for all units shall also be applied.	By-plane type inlet valves are recommended for reducing head loss and minimizing water leakage. By-pass valve and its piping are also replaced.	-
Spiral Casing	The wire draw, wire gall, lower guide vane, and facing plates should be replaced. Overhaul of the casing inside including the stay vane is recommended with repainting and wearing elements replacement.	Same as left.	-
Turbine Runner	The current runner shall be replaced with a new runner.	Same as left.	-
Runner Wearing Rings	The new runners will be provided with new wearing rings and spares.	Same as left.	-
Guide Vane	All guide vanes for all replacement units are recommended.	Same as left.	-
Guide Vane Operating Mechanism	Overhaul of the mechanism is recommended with parts replacement such as linkage bushings, gate operating ring, and bushings.	Gate operating ring shall be reused. Other parts shall be replaced same as left.	-
Head Cover	The wire draw, wire gall, upper guide vane, and facing plate are replaced. Inspection of all head cover is recommended.	The head cover shall be replaced, including adopting a new design for the turbine shaft and shaft seal.	-
Turbine shaft	Inspection and one spare shaft for two units are recommended.	The turbine shaft shall be replaced by new design runner, although a spare shaft is not required.	-
Shaft Seal	Overhaul is recommended with wearing elements replacement including shaft sleeve replacement.	Shaft seal shall be replaced with a new design.	-
Discharge Ring and Draft Tube	Inspection of rings and liners are recommended with blast and re-coat.	Same as left	-
Pressure Balancing	No necessary work is expected.	Same as left.	-
Turbine Guide Bearing	No recommendation is provided.	All guide bearings shall be replaced by new one.	The thrust and guide bearings are to be included in the generator section.
Governor	New governors should be provided because spare parts are no longer available.	The governor shall be replaced with the latest digital type design with an additional SSG type speed detector.	-
Governor Pressure Oil System	Aside from maintenance, occasional component replacement is recommended.	The governor pressure oil supply system shall be replaced, if the operating pressure is applied higher pressure than the existing one.	-

Source : Prepared by the Survey Team

Table 3-11 Review of the F/S Report Units 7 and 8 for Turbine Equipment

Parts Name	Recommendations in the F/S Report	Comments of the Survey Team	Note
Inlet Valves	Overhaul is recommended for both units with partial repairing. Replacement of by-pass valve and piping for both units shall also be applied.	Same as left.	-
Spiral Casing	The wire draw, wire gall, lower guide vane, and facing plates should be replaced. Overhaul of the casing inside including the stay vane is recommended with repainting.	Same as left.	-
Turbine Runner	The current runner shall be replaced with a new runner.	Same as left.	-
Runner Wearing Rings	The new runners will be provided with new wearing rings and spares.	Same as left.	-
Guide Vane	All guide vanes for all replacement units are recommended.	Same as left.	-
Guide Vane Operating Mechanism	Overhaul of the mechanism is recommended with parts replacement such as linkage bushings, gate operating ring, and bushings.	Gate operating ring shall be reused. Other parts shall be replaced same as left.	-
Head Cover	The wire draw, wire gall, upper guide vane, and facing plate are replaced. Inspection of all head cover is recommended.	Same as left.	-
Turbine Shaft	Inspection and one spare shaft for two units are recommended.	Same as left but not recommended on spare shaft.	-
Shaft Seal	The shaft seal is not functioning. New design was requested, including the shaft sleeve replacement.	Same as left.	-
Discharge Ring and Draft Tube	Inspection of rings and liners are recommended with blast and recoat. Unit 8 leakage must be found and corrected. The source of this water leakage shall be found and repaired.	Same as left	-
Pressure Balancing	No necessary work is expected.	Same as left.	-
Turbine Guide Bearing	No recommendation.	Same as left.	The thrust and guide bearings are to be included in the generator section.
Governor	Although the condition of the governor is acceptable, new governors should be provided because spare parts are no longer available.	Same as left.	-
Governor Pressure Oil System	Aside from maintenance, occasional component replacement is recommended.	Same as left.	-

Source: Prepared by the Survey Team

Table 3-12 Review of the F/S Report Units 9 and 10 for Turbine Equipment

Parts Name	Recommendations in the F/S Report	Comments of the Survey Team	Note
Inlet Valves	Overhaul is recommended for all units with partial repairing. Replacement of by-pass valve and piping for all units shall also be applied.	Same as left.	-
Spiral Casing	The wire draw, wire gall, lower guide vane, and facing plates should be replaced. Overhaul of the casing inside including the stay vane is recommended with repainting and wearing elements replacement.	Same as left.	-
Turbine Runner	The current runner shall be replaced with a new runner.	Same as left	-
Runner Wearing Rings	The new runners will be provided with new wearing rings and spares.	Same as left.	-
Guide Vane	All guide vanes for all replacement units are recommended.	Same as left.	-
Guide Vane Operating Mechanism	Overhaul of the mechanism is recommended with parts replacement such as linkage bushings, gate operating ring, and bushings.	Gate operating ring shall be reused. Other parts shall be replaced same as left.	-
Head Cover	The wire draw, wire gall, upper guide vane, and facing plate are replaced. Inspection of all head cover is recommended.	Same as left.	-
Turbine Shaft	Inspection and one spare shaft for two units are recommended.	Same as left but spare shaft supply is not recommended	-
Shaft Seal	Overhaul is recommended with wearing elements replacement.	Same as left.	-
Discharge Ring and Draft Tube	Inspection of rings and liners are recommended with blast and recoat.	Same as left	-
Pressure Balancing	No necessary work is expected.	Same as left.	-
Turbine Guide Bearing	No recommendation is provided.	Same as left.	The thrust and guide bearings are to be included in the generator section.
Governor	New governors should be provided because spare parts are no longer available.	Same as left.	-
Governor Pressure Oil System	Aside from maintenance, occasional component replacement is recommended.	Same as left.	-

Source: Prepared by the Survey Team

Table 3-13 Review of the F/S Report Units 1 to 4 for Generator and Associated Equipment

Parts Name	Recommendations in the F/S Report	Comments of the Survey Team	Note
Stator	Replacement of core and windings is recommended. One new frame is required to be purchased.	New frames for 4 units are required to be purchased. In addition to the F/S report, air cooler should also be replaced. The F/S report also recommended in items for cooling system.	-
Rotor	Re-insulate poles with new top and bottom insulation collars. Provide new pole keys. Replace pole lead and damper connections. Rim shall be restacked and re-shrunk with new shrink keys.	All poles should be replaced due to their deterioration with new ones and with new keys. Also, brake ring should be replaced. Same idea as the F/S report for other items.	-
Thrust and Guide Bearing	Good condition.	Thrust bearing, thrust runner, and guide bearing are still in good condition but they were not replaced since commissioning. Therefore, replacement is recommended. Also, LBB may be replaced if the vertical weight of turbine/generator is increased.	-
Brake and Jack	Rehabilitate existing brakes and jacks. Supply and install new brake ring.	Same idea as the F/S report. Brake and jack are required to be replaced newly.	-
Cooling System	Install 12 new air intake RTDs and 12 new air exhaust RTDs. Replace all 12 coolers. Install water treatment and filtering system.	Same idea as the F/S report.	-
Brush Assembly and Collector Ring	Rehabilitate collector rings. Dismantle and dispose DC exciter, brushes, brush holder and commutator. Install new brush holder. Install new static excitation system.	Same idea as the F/S report. In case DC exciter will remain in existing position to keep generator in flywheel effect, the collector ring and brush holder should be replaced.	-
Main Leads	Most of the parts can be reused. Replace flexible connections as required.	Same idea as the F/S report.	-
Excitation System	Replace with static, digital system.	Same idea as the F/S report.	-
Circuit Breaker	No medium voltage circuit breaker		-
Main Bus (IPB)	Rated 13.2 kV, 6287 A and possible to reuse.	Same idea as the F/S report.	-
Fire Protection	It is maintained in a ready to operate condition.	Same idea as the F/S report.	-
Protective Relaying	Replace with modern digital protective relays	Same idea as the F/S report.	-
Unit Controls, Instrumentation and Mechanical Protections	Replace with modern digital control system. Replace all instruments. Provide additional instrumentation. Upgrade mechanical protection system.	Same idea as the F/S report.	-
Step-Up Transformer	Rehabilitation is necessary, such as oil processing, refurbishing of oil coolers, replacing tap changers, and so on.	Same idea as the F/S report.	-

Source : Prepared by the Survey Team

Table 3-14 Review of the F/S Report Units 5 and 6 for Generator and Associated Equipment

Parts Name	Recommendations in the F/S Report	Comments of the Survey Team	Note
Stator	Replacement of core and windings is recommended. One new frame is requested to be purchased.	Replacement of all the parts are required with the reason mentioned in Sub-clause 3.2.3 and due to the following; - Major short circuit happened. The design of upper guide bearing should be changed. - Unit 5 is operating with only limited output. - Both coils for Units 5 and 6 were damaged and were replaced with non-original manufacturer's coil.	-
Rotor	Re-insulate poles with new top and bottom insulation collars. Provide new pole keys. Replace pole lead and damper connections. Replace pole tangential supports with new clamping hardware. Rim shall be re-shrunk with new shrink keys.		-
Thrust and Guide Bearing	The cause of the oil vapors and splashes from the upper and lower guide bearings should be found and corrected.		-
Brake and Jack	Rehabilitate existing brakes and jacks. Replace air and oil lines. Supply and install new brake ring.		-
Cooling system	Install 12 new air intake RTDs and 12 new air exhaust RTDs. Replace all 12 coolers. Install water treatment and filtering system.		-
Brush Assembly and Collector Ring	Rehabilitate collector rings. Dismantle and dispose DC exciter, brushes, brush holder, and commutator. Install new brush holder. Install new static excitation system.		-
Main Leads	Most of the parts can be reused. Replace flexible connections as required.		-
Excitation System	Replace with static, digital system.		-
Circuit Breaker	No medium voltage circuit breaker		-
Main Bus (IPB)	Rated 13.2 kV, 6287 A and possible to reuse.		Same idea as the F/S report.
Fire Protection	It is maintained in a ready to operate condition.	Same idea as the F/S report.	-
Protective Relaying	Replace with modern digital protective relays	Same idea as the F/S report.	-
Unit Controls, Instrumentation and Mechanical Protections	Replace with modern digital control system. Replace all instruments. Provide additional instrumentation. Upgrade mechanical protection system.	Same idea as the F/S report.	-
Step-Up Transformer	Rehabilitation is necessary such as oil processing, refurbishing of oil coolers, replacing tap changers, and so on.	Same idea as the F/S report.	-

Source : Prepared by the Survey Team

Table 3-15 Review of the F/S Report Units 7 and 8 for Generator and Associated Equipment

Parts Name	Recommendations in the F/S Report	Comments of the Survey Team	Note
Stator	As the typical life expectancy will come soon, windings should be replaced with minimal priority. Its core should be replaced with the same reason given above.	In addition to the above, one frame should be replaced to mitigate risks.	-
Rotor	Field poles and windings can be reused after re-insulation. Most other parts are possible to use.	Same idea as the F/S report.	-
Thrust and Guide Bearing	Good condition		-
Brake and Jack	Gaskets, return springs, limit switches and brake pads should be replaced and other parts can be reused after some rehabilitation.		--
Cooling System	Air coolers, all TRDs, piping inside of air housing should be replaced.		-
Brush Assembly and Collector Ring	Most of the parts can be reused with some rehabilitation. Old finger type brush holders should be replaced.		-
Main Leads	Only flexible connectors shall be inspected and replaced, if necessary.		-
Excitation System	Voltage regulator should be replaced with digital type.		--
Circuit Breaker	No medium voltage circuit breaker		-
Main Bus (IPB)	Rated 12.5 kV, 6000 A and possible to reuse.	Same idea as the F/S report.	-
Fire Protection	It is maintained in a ready to operate condition.		-
Protective Relaying	Outdated, replace with modern digital protective relays.		-
Unit Controls, Instrumentation and Mechanical Protections	Outdated, upgrade and replace with modern digital control system.		-
Step-up Transformer	Rehabilitation is necessary such as oil processing, refurbishing of oil coolers, replacing tap changers and so on.	Same idea as the F/S report.	-

Source: Prepared by the Survey Team

Table 3-16 Review of the F/S Report Units 9 and 10 for Generator and Associated Equipment

Parts Name	Recommendations in the F/S Report	Comments of the Survey Team	Note
Stator	To assure reliability for the next 40 years, the winding shall be replaced in 10 to 15 years.	Same idea as the F/S report.	-
Rotor	Most of the parts are possible for reuse.		-
Thrust and Guide Bearing	Good condition		-
Brake and Jack	Only brake pads should be replaced.		-
Cooling System	For every cooler, one RTD for measuring the inlet air temperature and one RTD to measure the exhaust air temperature should be installed. Air coolers and piping material inside of the air housing should be replaced.		-
Brush Assembly and Collector Ring	All of the parts can be reused.		-
Main Leads	Suitable to reuse.		-
Excitation System	The forced outage rate, plus the lack of spare parts mean that the voltage regulator portion of the system requires updating.	According to the Mangla engineer; AVR's of units 9 and 10 are more sensitive. Any variation in the system trips the units. In order to avoid frequent tripping of units and to keep the system stable, whenever the load demand decreases there is an option to shut down any unit, units 9 and 10 were preferred to be shut down first. Due to problematic AVR's, these units start to peak and shut down afterwards. These factors contributed to more numbers of start/stop. Therefore, these systems are recommended for replacement.	-
Circuit Breaker	No medium voltage circuit breaker		-
Main Bus (IPB)	Rated 15 kV, 10,000 A and possible to reuse.	Same idea as the F/S report.	-
Fire Protection	It is maintained in a ready to operate condition.		-
Protective Relaying	Outdated, replace with modern digital protective relays.		-
Unit Controls, Instrumentation and	Outdated, upgrade and replace with modern digital control system.		-

Mechanical Protections			
Step-Up Transformer	Rehabilitation is necessary such as oil processing, refurbishing of oil coolers, and so on.	Same idea as the F/S report.	-

Source : Prepared by the Survey Team

Table 3-17 Review of the F/S Report for Balance of Plant (BOP)

Plant Name	Recommendations in the F/S Report	Comments of the Survey Team	Note
Intake Structure and Power Tunnels	Trash rack at Intake No.2 should be repaired and all of the intake trash racks should be inspected for damage. Steel tunnel coating is required for Tunnel 5. All concrete surface spalls and cracks with seeping water will need to be repaired.	Same idea as the F/S report	-
Bifurcation and Penstocks	The penstock liners and the bifurcations are expected to be suitable for another life cycle with little or no corrective action. It is recommended that Tunnel 5 should have the scoured portion of its coating system restored.	Same idea as the F/S report.	-
Irrigation Valves	The irrigation valves and operating systems appeared to be in good condition. In order to continue for another 40 years of operation, the valve operating mechanisms should be disassembled, inspected, tested, and repaired as needed.	Overhaul and water leakage stop repair are recommended for another 40 years of operation.	-
Draft Tube Gates and Associated Structures and Equipment	An additional mechanism for positioning the gate guides in the pier is recommended. But this additional mechanism requires an extension of the gate guide, which causes interference to irrigation valve operation. Detailed study is requested as a part of the project upgrade.	Same idea as the F/S report.	-
Spillway Gates	It was not required for any rehabilitation of spillway gates because the said gates were rehabilitated during the dam raising project.	Same idea as the F/S report.	-
Powerhouse Cranes	The powerhouse cranes appeared to be in good condition and should require only periodic maintenance and testing to provide an additional 40 years of operation.	Same idea as the F/S report	-
Cooling Water Systems	The cooling water systems are currently functional, but piping and valve replacement will be necessary to continue a reliable operation for an additional 40 years.	Same idea as the F/S report.	-
Station Drainage and Unit Dewatering Systems	The drainage and dewatering systems seem to be in satisfactory condition. It is recommended that all drainage and dewatering pumps must be replaced to continue for additional	Same idea as the F/S report	-

	40 years of operation.		
Fire Protection Systems (non-generator)	The fire protection system performance should be improved by adding fire detection devices (smoke or heat detectors) to the control room, 11 kV switchgear rooms, cable tunnels and the transformers bay.	Same idea as the F/S report	-
Generator Fire Protection Systems	No issues were noted with the generator fire protection systems.	Same idea as the F/S report	-
Oil Purification Systems	This system is in good condition. No additional work should be required.	Same idea as the F/S report	-
Compressed Air Systems	No additional work is expected to be required for the powerhouse compressed air system.	Same idea as the F/S report	-
Heating Ventilation and Air Conditioning	No additional work is expected to be required for this system.	Same idea as the F/S report	-
Service Water System	No additional work is expected to be required for this system.	Same idea as the F/S report	-
Sewage Systems	No additional work is expected to be required for this system.	Same idea as the F/S report	-
Switchyard	Switchyard will remain operational for another life cycle.	Same idea as the F/S report	-
Switchyard Protection, Metering and Control Systems	Switchgears replacement plan was managed by the other project. Most of the control and protection equipment are outdated. It is recommended to replace the modern system as substation automatic system (SAS). Protection relays are also recommended to replace the numerical (digital) relay system.	Refurbish plan of switchyard shall be followed to the NPCC plan. The refurbish work by this project will be limited to the necessary refurbishing work with generation upgrading. Switchyard Supervisory Control and Data Acquisition System (SCDA) is implemented based on the NPCC plan. Most switchyard refurbish works can be planed independently without generation upgrading work, therefore it is preferable to plan as the other project.	-
Switchyard DC Systems (batteries, chargers, DC distribution systems)	Battery was replaced recently, so no requirement of change. One battery charger is recommended to replace.	Ditto as above.	-
Station Service/Auxiliary Electrical Systems – AC (switchgear, transformers, panelboards, motor control centers)	The FS recommended the new station service circuit with two generators circuits breakers which is selected from five alternative ideas in the FS.	The MV, LV circuit related generation upgrading will be renewed. MV system configuration will be redesigned to be more reliable. It is not the same with the FS recommendation.	-
Station DC Systems (batteries, chargers, DC distribution systems)	Battery was replaced recently, so no requirement of change. There are 50 V, and 230 V DC voltage systems. It is recommended to consider the unified voltage.	The redesign of DC supply system will be required by changing the excitation systems and new SCADA system.	-
Standby Generators	The standby generators are recent generators and there sizes are suited for load with ample overcapacity. The standby	Same idea as the F/S report.	-

	generators themselves are suitable for use during the life cycle of the plant.		
Powerhouse Grounding System	No additional work is expected to be required for this system.	Same idea as the F/S report.	-
Station Low Voltage Systems – Lighting, Receptacles	It is recommended that the entire low voltage system be replaced with a new one as part of the unit and station auxiliary supply system upgrade.	LV circuit related generation upgrading that will be renewed. The building service facilities will not be touched.	-
Station Fire Detection	There is no fire detection system. It is recommended that a modern, digital fire detection system be implemented throughout the powerhouse.	The building service facilities will not be touched by this project.	-
Instrumentation and Control Systems	The FS recommended the replacement of the whole units control systems.	Systems related upgrading of generation units will be renewed using programmable logic controller (PLC) and SCADA	-
Communication with Load Dispatch System	The load dispatch system (LDS) upgrading project is under implementation.	The plan will be managed by the NTDC/NPCC. The automatic load frequency control (ALFC) or other active and reactive power control matters from the NPCC will be consistent with the new PLC and SCADA design.	-
Elevators and Other Systems,	Based on the age of elevators, the elevators should undergo an inspection by a qualified elevator service representative. The result of the inspection should be incorporated in the scope of work for elevator service.	Same idea as the F/S report.	-

Source : Prepared by the Survey Team

Table 3-18 Review of the F/S Report - Summary of Up-gradation Alternative

Alternative	-	1 – 4	5 and 6	9 and 10	7 and 8	Comments of the Survey Team
Up-gradation Alternative 1	Output after Up-gradation	168.75 MVA (135 MW)			143.75 MVA (115 MW) (overload value)	-
	Modification	The generator rotor would be reused and the generator stator would be replaced.			No margin to upgrade without changing the dimensions, therefore output is the same as existing.	-
Up-gradation Alternative 2 (Option 1)	Output after Up-gradation	187.5 MVA (150 MW)			187.5 MVA (150 MW)	Foundation for all units except units 7 and 8 should be changed. (Demolition is necessary)
	Modification	Diameter of the generator will be increased.			Stator core length will be increased while maintaining the diameter.	
Up-gradation Alternative 2 (Option 2)	Output after Up-gradation	187.5 MVA (150 MW)			187.5 MVA (150 MW)	Foundation modification is necessary but not significant demolition.
	Modification	Stator core length will be increased.			Stator core length will be increased while maintaining the diameter.	

Note: This table is the summary of Up-gradation Alternative Study described in the Sub-clause 1.3.8.3 of the F/S Report. This study comprised two up-gradation alternatives, i.e., 135 MW and to 150 MW.

Source : Prepared by the Survey Team

Table 3-19 Review of the F/S Report - Summary of Categories

Category 1	Do nothing	Minimal maintenance and running the units to failure.	-
Category 2	Up-gradation to existing overload rating 115 MW	Turbine replacement required. Generator would be provided with new core, rewound with new stator windings. Excitation system would be changed.	-
Category 3	Up-gradation to 135 MW with minimum modifications	Generator will require new stators and rebuild rotor components. Not necessary to add a significant cost to the turbine components compared to the 115 MW alternative.	Recommended up-gradation is 135 MW each for Units 1-4, 5 & 6, and 9 & 10. For Units 7 & 8 are to be rehabilitated to 115 MW each.
Category 4	Up-gradation to maximum possible output of 150 MW	New generator will be provided.	-

Note: This table is the summary of the four categories for each output of 115 MW, 135 MW, and 150 MW.

Source: Prepared by the Survey Team

Table 3-20 Summary of Up-Grade Idea in the F/S Report

Number of Alternative	Recommendations in the F/S Report	Comments of the Survey Team
Alternative 0	Base case, 1150 MW station, existing 125 MVA, 0.8 power factor (just rehabilitation)	-
Alternative 1A	Up-gradation to 1310 MW, 2 x 125 MVA and 8 X 168 MVA generators, 0.8 power factor	-
Alternative 1B	Up-gradation to 1380 MW, 2 x 187.5 MVA and 8 x 168 MVA generators, 0.8 power factor	-
Alternative 2	Up-gradation to 1500 MW, 10 x 187.5 MVA generators, 0.8 power factors	Proposal on the F/S report can be achieved only by demolishing the foundation of generators for all units except for units 7 and 8. The Survey Team recommended the up-gradation without demolish work.

Note: This table is the summarized alternatives described in Sub-clause 1.4.5 of the F/S report with the Survey Team's comments.

Source: Prepared by the Survey Team

3.3 Points to be stated in the F/S Report and to be considered in the Detailed Design

3.3.1 Points to be Stated in the F/S Report

The following items have not been studied in the F/S report.

(1) Estimation of winding life

The winding life should be analyzed using common methods. The result of analysis by the Survey Team is described in Sub-clause 5.2.1.

(2) Measuring data

There is no measuring data (such as insulation resistance) in the F/S report. The result of measuring of insulation resistance is described in Sub-clause 4.6.1.

(3) Maximum gross head and effective head after dam raising.

There is no description of maximum gross head and effective head after dam raising. The result of study by the Survey Team is described in Sub-clause 5.6.1.

3.3.2 Main Points to be Considered in the Detailed Design

The following items shall be considered at the Detailed Design Stage.

(1) Lower bearing bracket

The weights of rotating parts are increased when upgraded. The bearing bracket should be studied according to the upgraded weight.

(2) Rotating parts weight and water thrust

The weight of rotating parts and water thrust are increased when upgraded. Proper analysis is also needed.

(3) Operation limit study and setting change

There is no description of the operation limit study and setting change for limiting generator output after dam raising.

(4) Station service circuit

The simplification of interlock, and total coordinated power supply redundancy among the high-voltage, medium-voltage and low-voltage shall be considered.

CHAPTER 4

FINDINGS IN THE PLANT SURVEY

CHAPTER 4 FINDINGS OF THE PLANT SURVEY

4.1 Basic Features of the Plant

4.1.1 Dam Water Level

The basic features of the water level of Mangla Dam for generation are shown in the following Table 4-1:

Table 4-1 Basic Features of the Plant

Contents	Before Dam Raising	After Dam Raising
Max. Reservoir Water Level	EL 1,102 ft = 336.1 m	EL 1,142 ft = 348.3m

Source: Prepared by the Survey Team

4.1.2 Turbine

The main ratings of turbine are as follows:

- i. Units 1 through 4

Manufacturer	Mitsubishi Heavy Industry, Japan
Type	Francis
Rated Output	138,000 BHP at 295 ft head (103 MW at 89.9 m head)
Maximum Output	198,000 BHP at 380 ft head (147.7 MW at 115.8 m head)
Rated Discharge	4,550 cfs (129 m ³ /s)
Rated Speed	166.7 rpm
Rough zone	0-80 MW, with a less rough spot around 30 MW
Commissioning Year	1967 for Units 1 and 2, 1968 for Unit 3, 1969 for Unit 4

- ii. Units 5 and 6

Manufacturer	CKD Blansko, Czechoslovakia
Type	Francis
Rated Output	138,000 BHP at 295 ft head (103 MW at 89.9 m head)
Maximum Output	198,000 BHP at 380 ft head (147.7 MW at 115.8 m head)
Rated Discharge	4,515 cfs (128 m ³ /s)
Rated Speed	166.7 rpm
Rough zone	0-80 MW, with a less rough spot around 30 MW
Commissioning Year	1973 for Unit 5, 1974 for Unit 6

- iii. Units 7 and 8
 - Manufacturer ACEC, Belgium
 - Type Francis
 - Rated Output 103 MW
 - Maximum Output 148 MW
 - Rated Discharge 4,306 cfs (122 m³/s)
 - Rated Speed 166.7 rpm
 - Rough zone 0-80 MW, with a less rough spot around 50 MW
 - Commissioning Year 1981

- iv. Units 9 and 10
 - Manufacturer CKD Blansko, Czechoslovakia
 - Type Francis
 - Rated Output 103 MW at 90 m/295 ft head
 - Maximum Output 148 MW at 115 m/380 ft head
 - Rated Discharge 4,515 cfs (12.9 m³/s)
 - Rated Speed 166.7 rpm
 - Rough zone 0-80 MW, with a less rough spot around 50 MW
 - Commissioning Year 1993 for Unit 9, 1994 for Unit 10

4.1.3 Generator

The main ratings of generator and electrical equipment are as follows:

- (1) Generator
 - i. Units 1 through 4
 - Manufacturer Hitachi, Japan
 - Rated Output 125,000 kVA
 - Rated Power Factor 0.8
 - Rated Voltage 13,200 V
 - Rated Frequency 50 Hz
 - Rated Speed 166.7 min⁻¹
 - Insulation Class B
 - Overload 115%
 - Year of Manufacture 1965 for Units 1, 2, and 3, 1967 for Unit 4

 - ii. Units 5 and 6
 - Manufacturer SKODA, Czechoslovakia
 - Rated Output 125,000 kVA

Rated Power Factor	0.8
Rated Voltage	13,200 V
Rated Frequency	50 Hz
Rated Speed	166.7 min ⁻¹
Insulation Class	F
Overload	115%
Year of Manufacture	1971

iii. Units 7 and 8

Manufacturer	Hitachi, Japan
Rated Output	125,000 kVA
Rated Power Factor	0.8
Rated Voltage	13,200 V
Rated Frequency	50 Hz
Rated Speed	166.7 min ⁻¹
Insulation Class	B
Overload	115%
Year of Manufacture	1979

iv. Units 9 and 10

Manufacturer	SKODA, Czechoslovakia
Rated Output	125,000 kVA
Rated Power Factor	0.8
Rated Voltage	13,200 V
Rated Frequency	50 Hz
Rated Speed	166.7 min ⁻¹
Insulation Class	F
Overload	115%
Year of Manufacture	1991

(2) Isolated Phase Bus

i. Units 1 through 4

Manufacturer	BBC, Germany
Current Capacity	6,287 A

ii. Units 5 and 6

Manufacturer	BBC, Germany
Current Capacity	6,287 A

- iii. Units 7 and 8
 - Manufacturer Simelectro, France
 - Current Capacity 6,000 A (This figure is smaller than the current of 115% overload operation)
 - iv. Units 9 and 10
 - Manufacturer Energoved Praha, Czechoslovakia
 - Current Capacity 10,000 A
- (3) Generator Transformer
- i. Unit 1
 - Manufacturer Savigiliano, Italy
 - Rated Capacity 138 MVA (This is smaller than the overload output of the generator)
 - Rated Voltage 12.5/132 kV
 - ii. Unit 2
 - Manufacturer Skoda, Czechoslovakia
 - Rated Capacity 138 MVA (This is smaller than the overload output of the generator)
 - Rated Voltage 12.5/132 kV
 - iii. Unit 3
 - Manufacturer Skoda, Czechoslovakia
 - Rated Capacity 144 MVA
 - Rated Voltage 12.5/220 kV
 - iv. Units 4 through 6
 - Manufacturer Savigiliano, Italy
 - Rated Capacity 138 MVA (This is smaller than the overload output of the generator)
 - Rated Voltage 12.5/220 kV
 - v. Unit 7
 - Manufacturer Italtrafo, Italy
 - Rated Capacity 144 MVA
 - Rated Voltage 12.5/220 kV
 - vi. Units 8 through 10
 - Manufacturer Skoda, Czechoslovakia
 - Rated Capacity 144 MVA
 - Rated Voltage 12.5/220 kV

All units are properly operating with appropriate temperatures of generator winding and

bearing during the Survey Team’s site visit except Unit 5. Only Unit 5 is operating with the limit output of 70 MW to 80 MW due to past accident as described in Sub-clause 4.6.1.

4.2 Operating History of the Plant

All units are properly operating except Unit 5, and operating history is as follows:

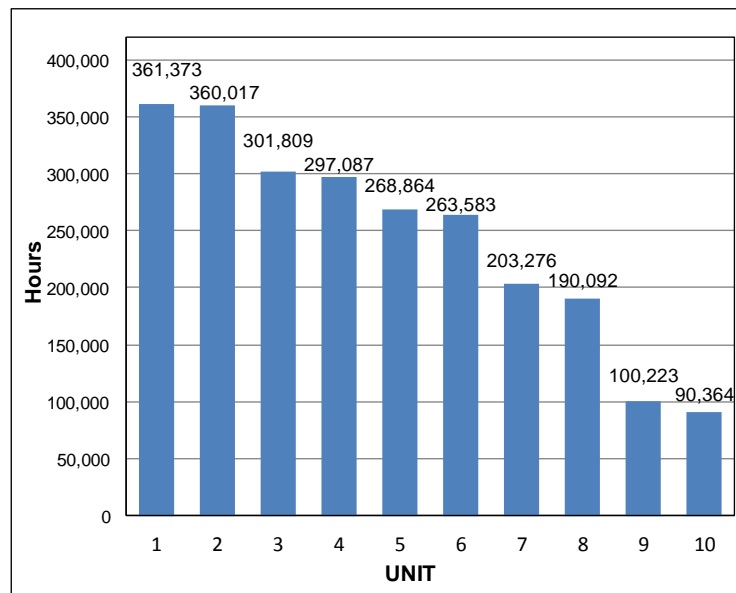
(1) Commissioning Dates and Accumulated Operating Hours

Commissioning dates and total operating hours since commissioning for each unit shown in the following Table 4-2 and Figure 4-1:

Table 4-2 Total Operating Hours (up to 31 Dec. 2011)

Unit Number	Total Operating Hours	Commissioning Date	Unit Number	Total Operating Hours	Commissioning Date
Unit 1	361,373 hrs	03/07/1967	Unit 6	263,583 hrs	11/03/1974
Unit 2	360,017 hrs	14/07/1967	Unit 7	203,276 hrs	19/06/1981
Unit 3	301,809 hrs	07/03/1968	Unit 8	190,092 hrs	22/08/1981
Unit 4	297,087 hrs	17/06/1969	Unit 9	100,223 hrs	24/09/1993
Unit 5	268,864 hrs	29/12/1973	Unit 10	90,364 hrs	06/07/1994

Source: WAPDA (Mangla Hydro Power Station)



Source: WAPDA (Mangla Hydro Power Station)

Figure 4-1 Total Operating Hours from Commissioning for Each Unit

(2) Number of Start/Stop

List of number of start/stop of each unit is collected and shown in the following Table 4-3:

Table 4-3 Number of Start/Stop

Year	U-1	U-2	U-3	U-4	U-5	U-6	U-7	U-8	U-9	U-10
1969	50	115	57	42	-	-	-	-	-	-
1970	37	44	86	102	-	-	-	-	-	-
1971	26	74	66	75	-	-	-	-	-	-
1972	22	62	76	50	-	-	-	-	-	-
1973	15	33	53	28	-	-	-	-	-	-
1974	30	86	191	25	61	77	-	-	-	-
1975	26	67	84	36	76	84	-	-	-	-
1976	38	50	103	33	52	60	-	-	-	-
1977	28	49	120	82	38	38	-	-	-	-
1978	32	60	81	115	34	42	-	-	-	-
1979	64	37	82	82	25	43	-	-	-	-
1980	35	65	82	73	21	24	-	-	-	-
1981	21	78	88	104	33	20	84	82	-	-
1982	24	23	110	96	97	35	203	198	-	-
1983	21	19	55	50	28	39	79	105	-	-
1984	14	29	141	135	88	51	225	214	-	-
1985	35	84	197	184	79	40	250	253	-	-
1986	27	22	60	71	40	39	105	68	-	-
1987	22	23	36	99	50	48	67	69	-	-
1988	13	23	88	74	58	63	23	26	-	-
1989	14	22	36	13	61	59	61	66	-	-
1990	25	26	54	23	76	31	35	38	-	-
1991	14	18	43	36	10	15	35	36	-	-
1992	11	19	71	85	20	21	83	100	-	-
1993	26	39	123	150	31	25	54	85	45	-
1994	48	54	142	106	20	21	54	65	50	22
1995	16	23	73	89	18	22	79	35	46	53
1996	14	24	33	52	19	20	50	45	52	54
1997	23	33	222	149	17	23	113	163	261	240
1998	19	22	109	124	22	24	133	151	172	184
1999	19	49	165	167	22	34	241	276	256	262
2000	54	56	296	266	32	37	270	318	321	412
2001	74	44	278	333	53	59	297	268	357	356
2002	66	20	335	334	25	27	324	349	422	399
2003	43	29	197	204	96	96	50	66	112	138
2004	58	37	206	179	196	102	96	160	225	261
2005	43	41	179	145	55	47	41	90	127	126
2006	31	20	204	173	34	74	35	94	137	153
2007	13	15	101	98	101	129	24	83	148	118
2008	27	15	125	131	142	180	31	104	125	109
2009	14	16	88	87	88	90	34	77	96	77
2010	23	36	101	96	104	168	129	172	143	152
2011	10	15	182	181	18	135	196	198	206	144
Total Number	1,265	1,716	5,219	4,777	2,040	2,142	3,501	4,054	3,301	3,260

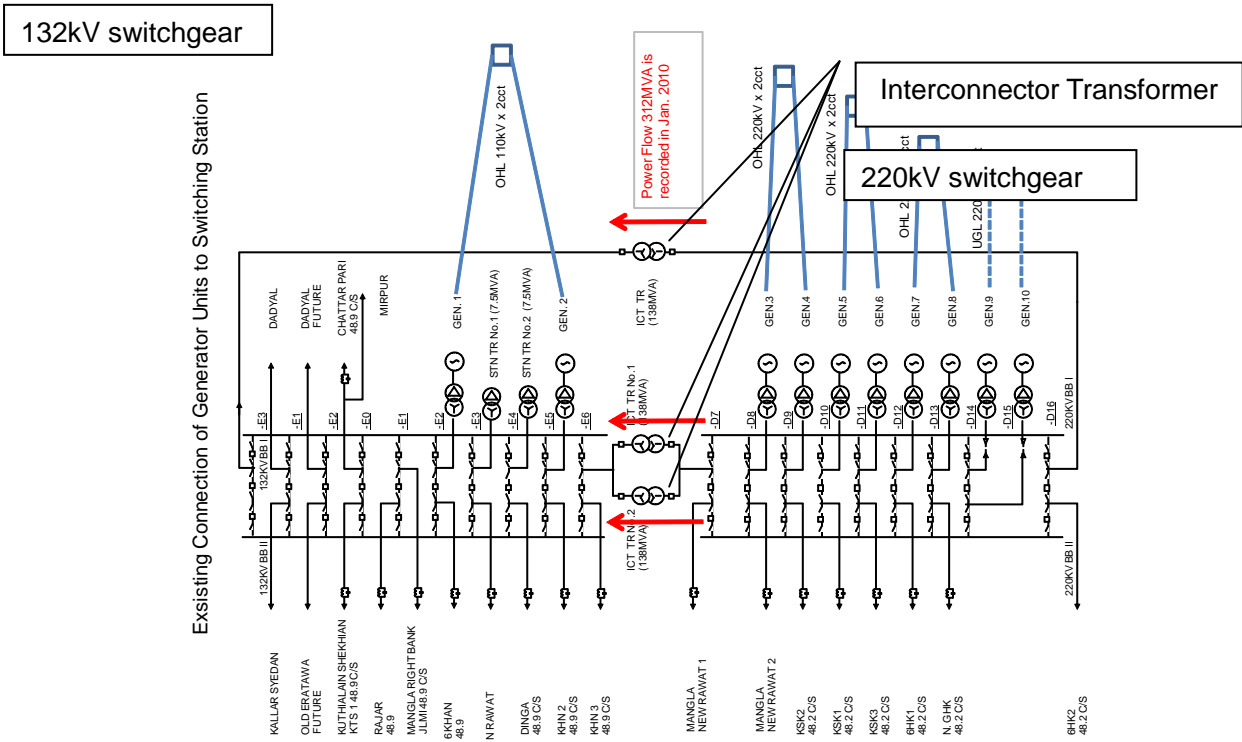
Source: WAPDA (Mangla Hydropower Station)

From the above table, there are some points which were clarified by WAPDA as described below.

A large difference between the total numbers of start/stop of Units 1 and 2 and those of Units 3

and 4 is found from the above table. This reason is to avoid overloading of 138 MVA, 132/220 kV interconnector transformers and to enhance system stability, as Units 1 and 2 are connected to 132 kV bay in the switchgear while Units 3 and 4 are connected to 220 kV bay. Therefore, the numbers of start/stop of Units 1 and 2 are less as compared to Units 3 and 4.

To easily understand the above explanation, the connection diagram of 132/220 kV interconnector transformers in the switchyard is shown in Figure 4-2 below.



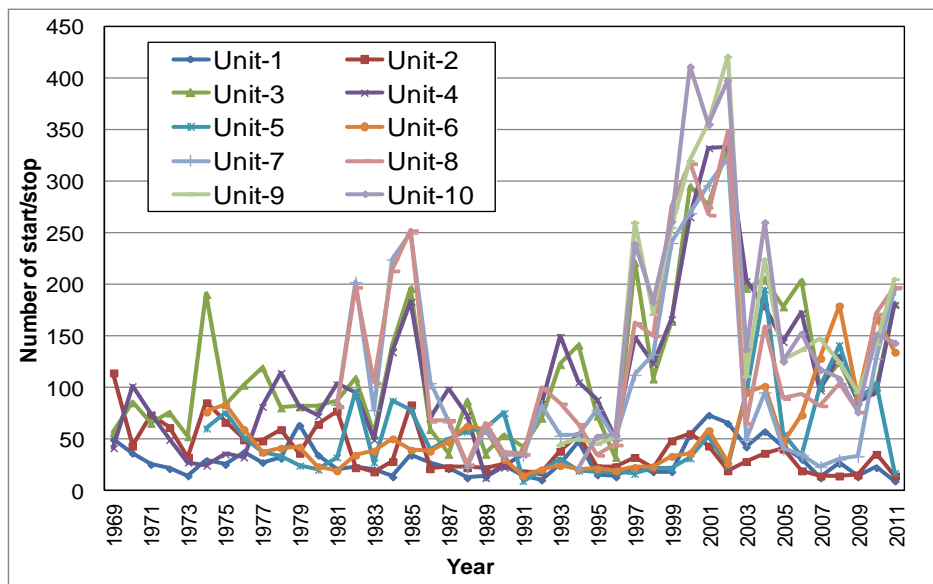
Source: Prepared by the Survey Team

Figure 4-2 Connection Diagram of 132/220 kV Interconnector Transformers

The power flow of the switchyard is always one-way, as indicated by the arrow above.

The total numbers of start/stop of Units 9 and 10 are relatively large although these units are new as compared to the other units. This is because the AVRs of Units 9 and 10 are more sensitive and any variation in this system trips the units. In order to avoid frequent tripping of units and to keep the system stable, whenever load demand decreases and there is option to shut down any unit, Units 9 and 10 are preferred to be shut down first. Due to problematic AVRs, these units were started for peaking and shut down afterwards. These factors contributed to higher number of start/stop.

From 1997 to 2002, a large number of start/stop was carried out since the start/stop of the generating units has been dictated by the National Power Control Center (NPCC) in Islamabad based on prevailing system requirements/conditions.

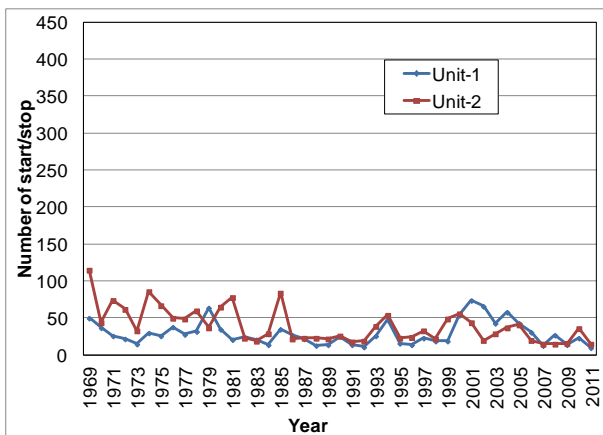


Source: WAPDA (Mangla Hydro Power Station)

Figure 4-3 Number of Start/Stop (All Units)

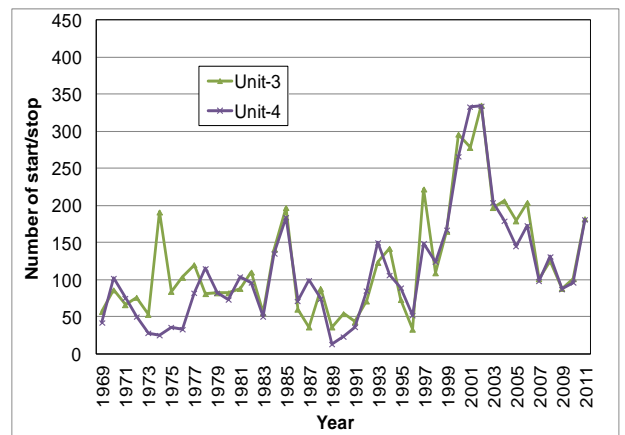
The above Figure 4-3 shows the number of start/stop of all units from their commissioning date up to 2011. As it is difficult to see the operation trend in this graph, it was divided into groups as shown in Figures 4-4 to 4-8 below.

These five graphs show the trend of the group operation. Operation of power station is decided according to the request of NPCC, and this trend means that the power station accordingly selects units by groups.



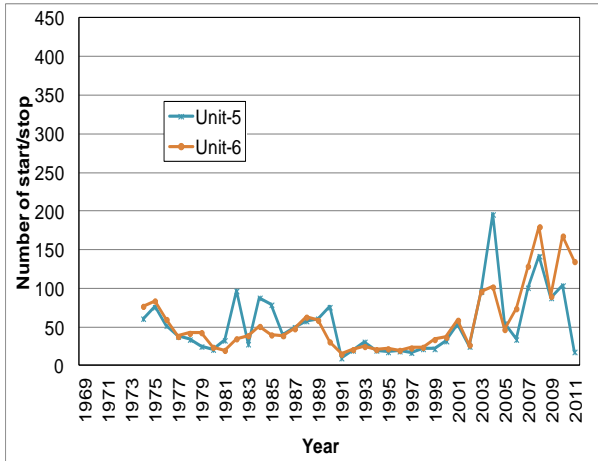
Source: WAPDA (Mangla Hydro Power Station)

Figure 4-4 Number of Start/Stop (Units 1 & 2)



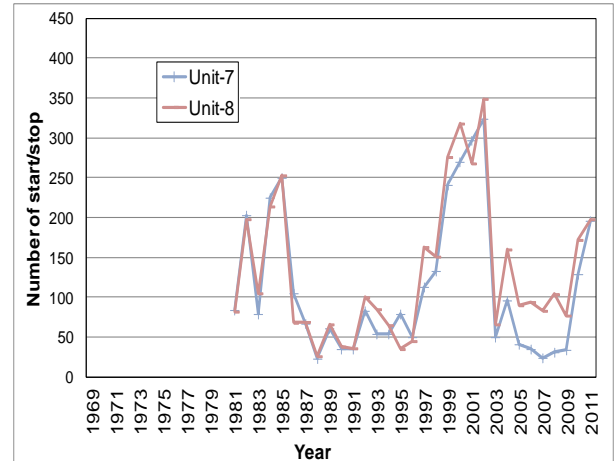
Source: WAPDA (Mangla Hydro Power Station)

Figure 4-5 Number of Start/Stop (Units 3 & 4)



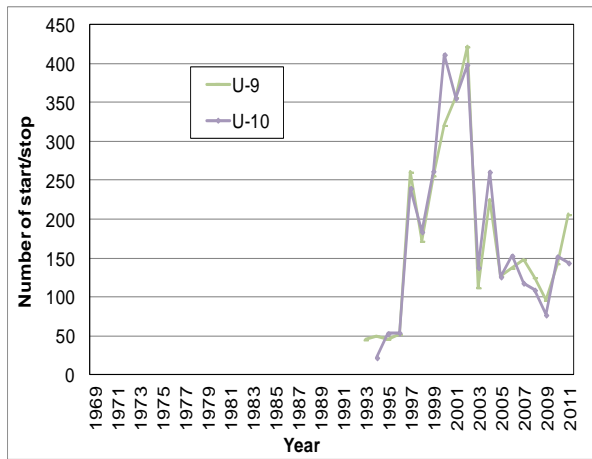
Source: WAPDA (Mangla Hydro Power Station)

Figure 4-6 Number of Start/Stop (Units 5 & 6)



Source: WAPDA (Mangla Hydro Power Station)

Figure 4-7 Number of Start/Stop (Units 7 & 8)



Source: WAPDA (Mangla Hydro Power Station)

Figure 4-8 Number of Start/Stop (Units 9 & 10)

(3) Study of Operating Head after Raising the Reservoir Level

The dam level is raised up to 30 feet and reservoir water level is raised to 40 feet. The turbine output shall be studied in consideration of head loss at each water flow operation. The study result on this issue is described in Section 5.3.

(4) Operation Limit Study and Setting Change

After raising the reservoir water level without any rehabilitation and enhancement of the electrical equipment capacity such as generator, IPB and main transformer together with associated auxiliary equipment, the turbine output shall be limited below the maximum capacity of electrical equipment for preventing overloading. Naturally, the limiting output manual operation is possible, but it is preferable to limit the guide vane opening by turbine load limiting device at high reservoir water level. The load limiting operation shall be high reservoir season (rainy season) and the limiting value shall be set considering capability and characteristics of each turbine.

4.3 Maintenance Management

4.3.1 Staffs for the Maintenance Work

The maintenance work of all mechanical and electrical equipment of Mangla Power Station is carried out by Mechanical Maintenance Auxiliary Section, Mechanical Maintenance Plant Section, Operation and Maintenance External Work Section, Electrical Maintenance (Power House) Section, and Electrical Maintenance (Switch Yard) Section under the organization of Mangla Power Station as described in Sub-clause 2.5.2. The total number of maintenance staffs in Mangla Power Station who belong to the Power Wing Division of the said organization is approximately 200 out of 446 total staffs of Power Wing Division in Mangla Power Station.

4.3.2 Maintenance Conditions

All equipment are properly maintained by power station maintenance staffs and the prescribed check sheets/formats are duly filled by them on daily, monthly, and biennial bases.

This is the reason that all the equipment are in good condition and operating safely though more than 40 years have passed especially for Units 1 to 4.

4.3.3 Subcontract for Maintenance

The maintenance work is done by WAPDA without any maintenance contract with any original supplier or any maintenance company. Main equipment such as turbine/generator are maintained properly by the staffs who were trained by the original manufacturers.

4.3.4 Spare Parts Management

Most of the spare parts are stored in the warehouse properly. According to the information of the store engineer, sufficient spare parts are stocked except for Units 5 and 6. Storing conditions of stator windings are shown in Photo 4-1 while some types of stored carbon brushes are shown in Photo 4-2. Stator windings were stored with dust but they are in useful condition, and carbon brushes are available from the market in Pakistan.



Source: Prepared by the Survey Team

Photo 4-1 Storing Conditions of Stator Windings



Source: Prepared by the Survey Team

Photo 4-2 Some Types of Carbon Brushes

Furthermore, the most important apparatuses such as lifting beam for tandem operation by two overhead travelling cranes and lifting device to lift up the generator rotor are stored in the erection bay with good maintenance. Photo 4-3 and Photo 4-4 show the lifting beam and device.



Source: Prepared by the Survey Team

Photo 4-3 Lifting Beam



Source: Prepared by the Survey Team

Photo 4-4 Lifting Device

4.4 Hydraulic Mechanical

4.4.1 General

Total nominal discharge capacity : 49,000 cfs (1,386 m³/s)

Each tunnel discharge capacity : 9,800 cfs (277 m³/s)

4.4.2 Turbine Inlet Valves

(1) Units 1 through 4

Type : Butterfly with solid disc
 Manufacturer : Mitsubishi Heavy Industry, Japan
 Size : 16 ft (4.88 m) diameter
 Design Head : 560 ft (170.8 m)

(2) Units 5 and 6

Type : Butterfly with solid disc
 Manufacturer : Mitsubishi Heavy Industry, Japan
 Size : 16 ft (4.88 m) diameter
 Design Head : 560 ft (170.8 m)

(3) Units 7 and 8

Type : Butterfly with bi-plane disc

Manufacturer : ACEC, Belgium
Size : 16 ft (4.88 m) diameter
Design Head : 560 ft (170.8 m)

(4) Units 9 and 10

Type : Butterfly with flow through disc
Manufacturer : CKD Blansko, Czechoslovakia
Size : 16 ft (4.88 m) diameter
Design Head : 560 ft (170.8 m)

4.5 Turbine and Unit Mechanical Equipment

The vibration and noise level of turbine and unit mechanical equipment are measured on all operating units, which are shown in the data sheet in Table 4-4. The Survey Team confirmed that there is no abnormal vibration and noise level for the existing turbine and unit mechanical equipment.

(1) Noise Level Measurement

Measurement positions for checking the noise level are presented below:

- 1) About 1 m from the turbine pit entrance
- 2) Turbine pit inside
- 3) About 1 m from draft tube manhole

(2) Vibration Level Measurement

Measurement positions for checking the vibration level are presented below:

- 1) Turbine bearing
- 2) Surrounding turbine upper cover fixing bolt
- 3) Top of the guide vane
- 4) Surrounding centre of draft tube manhole
- 5) Top of generator upper bracket

Table 4-4 Data Sheet of Vibration and Noise

Measuring unit No.	GV Opening (%)	Output (MW)	Date	Noise level (Db)			Vibration level (1/100 mm/s)					
				(1)-1	(1)-2	(1)-3	(2)-1a	(2)-1b	(2)-2	(2)-3	(2)-4	(2)-5
1	102	50	2012/3/12	98/104	105/109	108/115	1.7	6.2	1.8	1.4	No data	0.9
2	94	50	2012/3/12	95/102	103/107	106/114	1.9	5.3	1.7	1.0	35.0	0.9
3	94	51	2012/3/12	100/105	105/109	106/115	6.7	2.7	2.0	1.3	14.3	0.8
4	93	51	2012/3/12	99/105	105/109	109/115	1.0	6.5	2.8	1.3	38.2	0.8
5	92	58	2012/3/12	96/104	102/109	103/107	1.6	2.5	1.7	1.3	19.5	0.8
6	Under stopping											
7	98	60	2012/3/12	87/99	91/99	91/101	1.0	0.8	0.4	0.4	3.5	0.4
8	98	60	2012/3/12	87/95	90/99	94/103	0.8	0.8	0.4	0.4	3.3	0.5
9	90	65	2012/3/12	91/99	98/104	102/108	1.4	1.6	0.8	0.9	38.0	0.5
10	91	65	2012/3/12	93/100	98/105	104/108	2.5	2.2	1.0	0.8	33.0	0.6

Source : Survey Team

- (1)-1 About 1 m from the turbine pit
- (1)-2 Turbine pit inside
- (1)-3 About 1 m from draft tube manhole
- (2)-1a At turbine bearing
- (2)-1b At turbine bearing
- (2)-2 Near turbine upper cover fixing bolt
- (2)-3 Top of the guide vane
- (2)-4 Near the centre of draft tube manhole
- (2)-5 Top of generator upper bracket

4.6 Generator

4.6.1 Current Operating Conditions

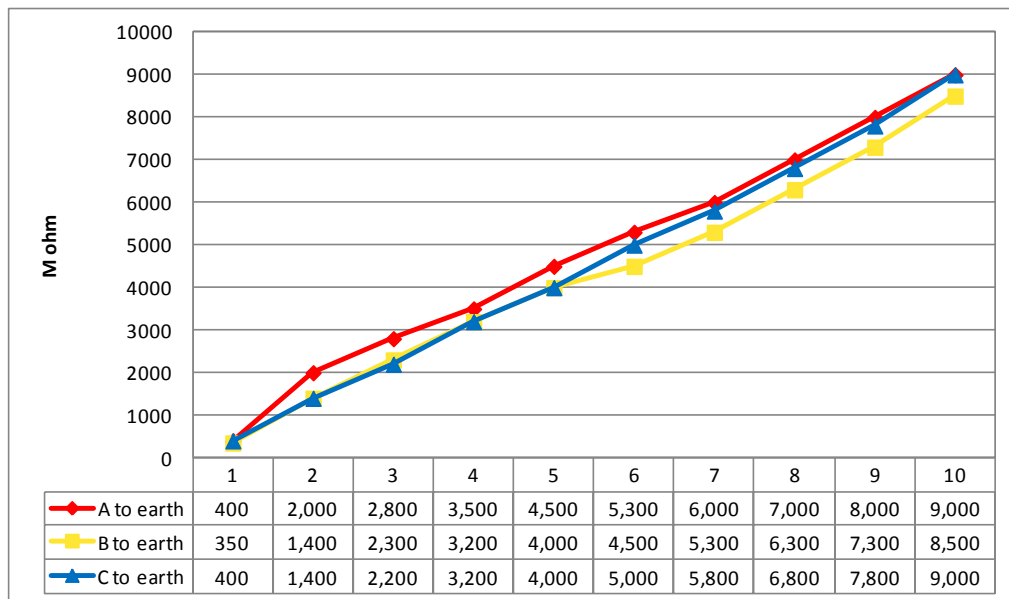
(1) Insulation Resistance Measurement Test

In addition to the data collection, the Survey Team measured insulation resistance of stator winding of Unit 6, which has been stopped for normal maintenance work since February 29, 2012. The measured data of Unit 6 are shown in Table 4-5 and Figure 4-9.

Table 4-5 Insulation Resistance

PHASE	[unit: M-ohm]									
	1 min	2 min	3 min	4 min	5 min	6 min	7 min	8 min	9 min	10 min
A to earth	400	2,000	2,800	3,500	4,500	5,300	6,000	7,000	8,000	9,000
B to earth	350	1,400	2,300	3,200	4,000	4,500	5,300	6,300	7,300	8,500
C to earth	400	1,400	2,200	3,200	4,000	5,000	5,800	6,800	7,800	9,000

Source: Data measured by the Survey Team



Source: Prepared by the Survey Team

Figure 4-9 Insulation Resistance of Unit 6

A, B and C means each phase, i.e.: A is red phase, B is yellow phase and C is blue phase, in accordance with WAPDA's standards.

From the above figure, polarization index (PI) value for each phase is as follows:

- Phase A: 22.5
- Phase B: 24.3
- Phase C: 22.5

These figures appeared too high, and when the measuring data is read, the measuring range was changed after 1 minute reading. The 2 min. to 10 min. readings have the same range.

Therefore, tentative PI values are just calculated as (10 min. value)/(2 min. value) and these figures are:

- Phase A: 4.5
- Phase B: 6.1
- Phase C: 6.4

These figures are still more than 2.5. Therefore, the coils are not in absorption condition. This is because WAPDA's maintenance is so good. ("More than 2.5" is quoted from the Technical Report No. 752 issued by The Institute of Electrical Engineers of Japan. This report suggested that PI should be more than 1.5 to 2.5)

The figures of other units' test data, which were measured by WAPDA, are shown in Table 4-6.

Table 4-6 Test Data of Insulation Resistance

UNIT 1	1 min	10 mins	Measuring Date	Temperature	Winding Resistance
A to earth	950	5,000			
B to earth	950	5,000	19 Jan. 2010	17 °C	2.6 mΩ
C to earth	1,000	5000			

PI value is 5 ~ 5.3

UNIT 2	1 min	10 min	Measuring Date	Temperature	Winding Resistance
A to earth	850	3,000			
B to earth	950	3,000	08 Nov. 2009	28 °C	2.8 mΩ
C to earth	850	2,800			

PI value is 3.2 ~ 3.5

UNIT3	1 min	10 min	Measuring Date	Temperature	Winding Resistance
A to earth	1,400	4,500			
B to earth	1,200	4,000	08 Feb. 2010	24°C	2.6 mΩ
C to earth	1,200	4,200			

PI value is 3.2 ~ 3.5

UNIT 5	1 min	10 min	Measuring Date	Temperature	Winding Resistance
A to earth	2,300	15,000			
B to earth	2,000	18,000	04 Jan. 2009	18.7°C	2.4 mΩ
C to earth	2,000	17,000			

PI value is 6.5 ~ 9.0

UNIT 6	1 min	10 min	Measuring Date	Temperature	Winding Resistance
A to earth	1,800	15,000			
B to earth	1,800	14,500	25 Jan. 2009	21°C	2.4 mΩ
C to earth	1,800	15,000			

PI value is 8.1 ~ 8.3

UNIT 8	1 min	10 min	Measuring Date	Temperature	Winding Resistance
A to earth	1,000	3,200			
B to earth	900	3,000	24 May 2009	30°C	3.2 mΩ
C to earth	1,000	3,200			

PI value is 3.2 ~ 3.3

UNIT 9	1 min	10 min	Measuring Date	Temperature	Winding Resistance
A to earth	2,000	7,500			
B to earth	2,000	6,000	24 Mar. 2009	27°C	3.8 mΩ
C to earth	1,800	6,500			

PI value is 3.0 ~ 3.8

UNIT 10	1 min	10 min	Measuring Date	Temperature	Winding Resistance
A to earth	2,000	7,500			
B to earth	1,900	7,500	16 Apr. 2009	28°C	3.8 mΩ
C to earth	1,800	6,500			

PI value is 3.6 ~ 3.9

Source: WAPDA (Mangla Hydro Power Station)

The above measurement data reveal that all the stator coils are operating in good condition.

(2) Power Factor under Operation

Power factor was calculated by dividing the generated power (MW) by the reactive power (MVar) from the operation record on a typical day having maximum power generated for each month during 2011.

Maximum power generation date for each month is shown in Table 4-7 below.

Table 4-7 Maximum Power Generation Date for Each Month

Season	Month	Load (MW)	Time/Date
Spring	February	776	7 p.m. on 18-02-2011
	March	712	7 p.m. on 01-03-2011
	April	889	8 p.m. on 30-04-2011
Summer	May	1,060	5 p.m. on 31-05-2011
	June	1,097	8 p.m. on 20-06-2011
	July	1,035	8 p.m. on 03-07-2011
Autumn	August	1,060	8 p.m. on 31-08-2011
	September	1,120	1 p.m. on 09-09-2011
	October	1,115	8 p.m. on 05-10-2011
Winter	November	1,115	6 p.m. on 30-11-2011
	December	1,111	7 p.m. on 01-12-2011
	January	754	7 p.m. on 22-01-2011

Source: WAPDA (Mangla Hydro Power Station)

Active power (MW) and reactive power (MVar) during each time/date above have been checked from the operation records and the power factor calculated from these figures is

shown in the following Table 4-8:

Table 4-8 Operation Record with Power Factor (PF)

At 7 p.m. on 18 Feb. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10	
Power (MW)	87	87	84	84	Stand-by	88	86	86	87	87	
Reactive Power (MVAR)	-10	-10	-10	-10		-10	-10	-10	-10	-10	-10
Power Factor	-0.99	-0.99	-0.99	-0.99		-0.99	-0.99	-0.99	-0.99	-0.99	-0.99

At 7 p.m. on 01 Mar. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10	
Power (MW)	80	80	77	77	Stand-by	79	79	80	80	80	
Reactive Power (MVAR)	0	0	0	0		0	0	0	0	0	0
Power Factor	1.0	1.0	1.0	1.0		1.0	1.0	1.0	1.0	1.0	1.0

At 8 p.m. on 30 Apr. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10
Power (MW)	91	91	90	90	70	93	90	90	92	92
Reactive Power (MVAR)	30	30	30	30	10	30	30	30	30	30
Power Factor	0.95	0.95	0.95	0.95	0.99	0.95	0.95	0.95	0.95	0.95

At 5 p.m. on 31 May 2011

Unit No.	1	2	3	4	5	6	7	8	9	10
Power (MW)	111	111	111	109	70	112	108	108	111	111
Reactive Power (MVAR)	40	40	40	40	10	40	40	40	40	40
Power Factor	0.94	0.94	0.94	0.94	0.99	0.94	0.94	0.94	0.94	0.94

At 8 p.m. on 20 Jun. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10
Power (MW)	114	114	114	114	70	115	113	113	115	115
Reactive Power (MVAR)	40	40	40	40	10	40	40	40	40	40
Power Factor	0.94	0.94	0.94	0.94	0.99	0.94	0.94	0.94	0.94	0.94

At 8 p.m. on 03 Jul. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10	
Power (MW)	115	115	115	115	Stand-by	115	115	115	115	115	
Reactive Power (MVAR)	20	20	20	20		20	20	20	20	20	20
Power Factor	0.99	0.99	0.99	0.99		0.99	0.99	0.99	0.99	0.99	0.99

At 8 p.m. on 31 Aug. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10
Power (MW)	110	110	110	110	70	110	110	110	110	110
Reactive Power (MVAR)	30	30	30	30	10	30	30	30	30	30
Power Factor	0.96	0.96	0.96	0.96	0.99	0.96	0.96	0.96	0.96	0.96

At 1 p.m. on 09 Sep. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10
Power (MW)	115	115	115	115	85	115	115	115	115	115
Reactive Power (MVAR)	40	40	40	40	0	40	40	40	40	40
Power Factor	0.94	0.94	0.94	0.94	1.0	0.94	0.94	0.94	0.94	0.94

At 8 p.m. on 05 Oct. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10
Power (MW)	115	115	115	115	80	115	115	115	115	115
Reactive Power (MVAR)	30	30	30	30	0	30	30	30	30	30
Power Factor	0.97	0.97	0.97	0.97	1.0	0.97	0.97	0.97	0.97	0.97

At 6 p.m. on 30 Nov. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10
Power (MW)	115	115	115	115	80	115	115	115	115	115
Reactive Power (MVAR)	31	29	29	29	0	30	30	30	29	30
Power Factor	0.97	0.97	0.97	0.97	1.0	0.97	0.97	0.97	0.97	0.97

At 7 p.m. on 01 Dec. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10
Power (MW)	115	115	114	114	80	115	114	114	115	115
Reactive Power (MVAR)	30	30	30	30	0	30	30	30	30	30
Power Factor	0.97	0.97	0.97	0.97	1.0	0.97	0.97	0.97	0.97	0.97

At 7 p.m. on 22 Jan. 2011

Unit No.	1	2	3	4	5	6	7	8	9	10
Power (MW)	94	94	93	93	Stand-by	96	94	Stand-by	95	95
Reactive Power (MVAR)	20	20	20	20		20	20		20	20
Power Factor	0.98	0.98	0.98	0.98		0.98	0.98		0.98	0.98

Source: WAPDA (Mangla Hydro Power Station)

The above data show that all units are operated with power factor of more than 0.9 although the rated power factor is 0.8.

Operating power factor of the power station is normally requested by NPCC according to the system requirement. Then, the power factor of Mangla is purely controlled by NPCC to meet the system requirement.

(3) Temperature of Stator Winding and Thrust Bearing

Temperature of stator winding and thrust bearing was confirmed from the operation records.

i. Temperature of Stator Winding

Temperature of stator winding is shown in Table 4-9 and described below. The generators seem to be operated safely.

Alarm temperature is 85°C and temperatures of Units 7 and 8 on May 31, 2011 were

above this value. But the plant engineer explained that these figures are the results of visual measurement of the meter, and they do not know the actual figures. However, nothing abnormal was observed on that day. To eliminate the malfunction like this, these temperature meters will be calibrated during rehabilitation work, and this calibration will be required in the Tender Specification.

Table 4-9 Temperature of Stator Winding

Date	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 7	Unit 8	Unit 9	Unit10
18 Feb. 2011	50	50	49	52	-	50	51	53	50	46
01 Mar. 2011	48	48	48	50	-	49	54	57	47	43
30 Apr. 2011	62	61	62	65	57	62	63	63	66	61
31 May 2011	73	73	69	77	56	71	86	85	74	73
20 Jun. 2011	71	74	72	80	57	67	74	76	70	70
03 Jul. 2011	71	69	71	77	-	66	76	77	66	65
31 Aug. 2011	75	78	78	65	40	55	74	79	62	61
09 Sep. 2011	75	77	79	81	No data					
05 Oct. 2011	73	78	81	81	64	70	No data			

Source: WAPDA (Mangla Hydro Power Station)

ii. Temperature of Thrust Bearing

Temperature of thrust bearing is shown in Table 4-10, and generators seem to be operated safely. Alarm temperature is 65°C. Some are over this figure. Same explanation as in the stator winding was made by the plant engineer.

Table 4-10 Temperature of Thrust Bearing

Date	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 7	Unit 8	Unit 9	Unit10
18 Feb. 2011	53	-	59	55	-	27	46	46	49	61
01 Mar. 2011	54	-	-	-	-	28	46	39	50	62
30 Apr. 2011	58	-	62	59	-	45	46	40	59	69
31 May 2011	56	-	62	59	49	45	46	39	57	70
22 Jan. 2011	53	-	58	52	-	25	46	-	48	59

Source: WAPDA (Mangla Hydro Power Station)

(4) Stopping Units during the Survey Team's Visit

During the site visit of the Survey Team from February 27 to March 3, 2012, Unit 6 was stopped on February 29 for normal maintenance by WAPDA and Unit 9 was stopped on March 1, 2012 according to the request of National Transmission Dispatch Company (NTDC). This stoppage gave an opportunity for the Survey Team to inspect the units closely and to perform

certain tests required.

(5) Past Incident Record

Major faults and/or incidents occurred only in Units 5 and 6, and the course of major faults of Unit 5 is shown in Table 4-11.

Table 4-11 Past Incident Record for Unit 5

Date of Tripping	Cause/Extent of Damage	Repair/Date
29-07-1990	Unit while running at 100 MW and 48 MVAR tripped on split phase protection due to failure of straight joint of one of the three parallel paths of Y-phase.	Repaired by WAPDA staff. Unit is synchronized with the system on 04-08-1990.
04-08-1990	Unit tripped on split phase and generator differential protection while increasing load from 30 MW to 80 MW and the following damages occurred: 67 coils damaged (44 front and 23 rear); Gouging of stator core at three different points; and Grounding of six poles of main rotor.	Repaired by WAPDA staff. Unit is synchronized with the system on 22-10-1990.
31-12-1990	Unit tripped on split phase protection while increasing load from 30 MW to 100 MW due to failure of joints of the two parallel paths of Y-phase.	Repaired by WAPDA staff. Unit is synchronized with the system on 06-01-1991.
18-01-1991	At the time of synchronization, unit tripped on over speed and the following apparent damages occurred: Stator Coils 338 Nos.(169 front & 69 rear) Field Pole Winding 13 Nos. (out of 36) Brake Ring Segments 5 Nos. (out of 12) Brake Pad Lining 10 Nos. (out of 10) Brake Assembly 1 No. (out of 3) Rotor Fan Plate 1 No. (out of 3) Rotor Fan Blades 12 (out of 36) Space Heaters 3 Nos. (out of 6) Micro Switch for Brakes 3 Nos. Bottom Cover Plates of Stator Windings 9 Nos.	Repair of core, rotor and rewinding of stator with F-class insulation (previously B-class) was carried out by M/S DEC China through a contract with WAPDA. Unit is synchronized with the system on 17-03-1992.
11-05-1996	Unit tripped while running at 125 MW, 15 MVAR on generator differential protection and generator stator earth leakage and the following damages occurred: Yellow phase line lead bus bar had sparked over; Red and yellow phase line lead bushing was damaged; and Top layer of insulation of red and blue phase line lead busbar was burnt.	Repaired by WAPDA staff. Unit is synchronized with the system on 18-05-1996.
11-11-2010	Unit tripped while running at 115 MW, 20 MVAR on split phase and generator differential protection and the following damages occurred: 31 front and 7 rear coils affected/damaged; Pressing fingers and stator core laminations between Slots No. 250 & 253 were found damaged/affected; and Insulation resistance of 3 rotor poles was zero and voltage drop across 6 rotor poles was less than permissible value.	Repaired by WAPDA staff. The representative of original manufacturer of equipment, M/S CKD NOVE ENERGO, visited Mangla from 05-02-2011 to 07-02-2011 and inspected the repair work carried out by WAPDA. He submitted the preliminary inspection report. Detailed permanent technical solution report is pending.

Source: WAPDA (Mangla Hydro Power Station)

The course of major fault of Unit 6 is shown in Table 4-12.

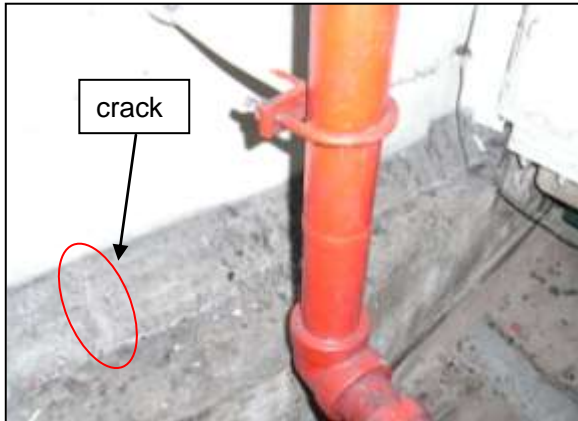
Table 4-12 Past Incident Record for Unit 6

Date of Tripping	Cause/Extent of Damage	Repair/Date
27-01-1985	Unit while running at 90 MW, -1 MVAR tripped on stator earth leakage protection due to insulation failure of red phase coil and the following damage occurred: One coil (front) of red phase is found punctured at the top edge.	Repaired by WAPDA staff. Unit is synchronized with the system on 04-04-1985.
22-05-1990	Unit while running at 82 MW, 36 MVAR tripped on split phase protection due to insulation failure of the three parallel paths of yellow phase.	Repaired by WAPDA staff. Unit is synchronized with the system on 04-06-1990
30-11-1990	Unit while running at 100 MW, 30 MVAR tripped on split phase protection due to opening of yellow phase joint and the following damages occurred: 3 stator coils of yellow phase; and Pole No. 18 of main rotor found earthed.	Repaired by WAPDA staff. Unit is synchronized with the system on 19-02-1991.
20-09-1992	Unit while running at 100 MW, 20 MVAR tripped on over speed due to failure of governor and the following damages occurred: Stator windings were found damaged at different places; Stator core was also found damaged at a number of places around the periphery; and Field coil of Pole No. 30 and damper windings of all the rotor poles were found damaged.	Repair of core, rotor and rewinding of stator with F-class insulation (previously B-class) was carried out by M/S DEC China through a contract with WAPDA. Unit is synchronized with the system on 29-03-1993.
01-04-1993	Unit while running at 85 MW and 2 MVAR tripped on stator earth leakage and over speed and the following damages occurred: All the three bus bars between stator and Joint No. 1 along with fiber supporting at two different places were found sparked over.	Repaired by WAPDA staff under the supervision of M/S DEC China. Unit is synchronized with the system on 07-04-1993.

Source: WAPDA (Mangla Hydro Power Station)

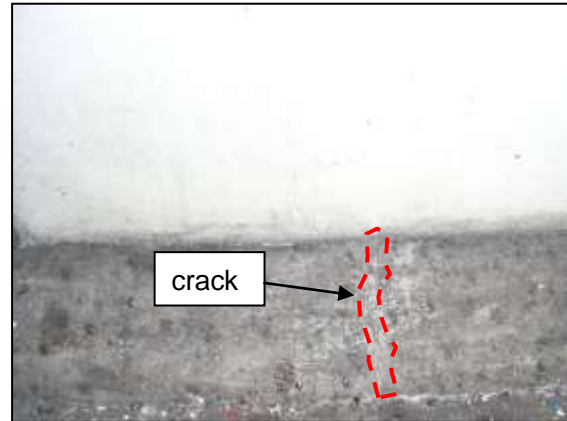
(6) Small Cracks on the Concrete below the Stator Frame

Some cracks were found on the concrete below the stator frame, when the Survey Team entered Unit 2 generator pit (inside of air housing), as shown in Photo 4-5. This shall be inspected in detail at the detailed design stage.



Source: Prepared by the Survey Team

Photo 4-5 Cracks on Concrete of Stator Frame (1/2)



Source: Prepared by the Survey Team

Photo 4-5 Cracks on Concrete of Stator Frame (2/2)

(7) Condition of Auxiliary Equipment

i. Cooling Water Supply System

Cooling water supply system is nominally connected by the same interconnected piping. It is tapped from the upstream side of the turbine inlet valves on all units (as shown in Photo 4-6 below) except for Units 5 and 6, which are supplied water from the downstream of the valves. Units 1 through 4 each have standby cooling pumps (as shown in Photo 4-7 below).



Source: Prepared by the Survey Team

Photo 4-6 Cooling Water Supply System



Source: Prepared by the Survey Team

Photo 4-7 Standby Cooling Pumps for Units 1 to 4

ii. Compressed Air System for Brake

The system is still in good condition as shown in Photo 4-8 below. This photo shows the compressors for Units 1 to 4.



Source: Prepared by the Survey Team

Photo 4-8 Compressed Air System for Units 1 to 4

iii. Oil Lifting Equipment

Equipment is still in good condition as shown in the photos below. Photo 4-9 shows the equipment for Unit 3 and Photo 4-10 shows that for Unit 7.



Source: Prepared by the Survey Team

Photo 4-9 Oil Lifting Equipment for Unit 3



Source: Prepared by the Survey Team

Photo 4-10 Oil Lifting Equipment for Unit 7

iv. Overhead Travelling Crane and Lifting Beam for Generator Rotor

According to the senior mechanical engineer in Mangla, the condition of both cranes is satisfactory as shown in Photos 4-11 and 4-12 below. Therefore, no replacement of parts is required. In addition to this, the lifting beam for tandem operation of both cranes and lifting device for rotor are safely stored in the erection bay.



Source: Prepared by the Survey Team

Photo 4-11 Over Head Traveling Crane



Source: Prepared by the Survey Team

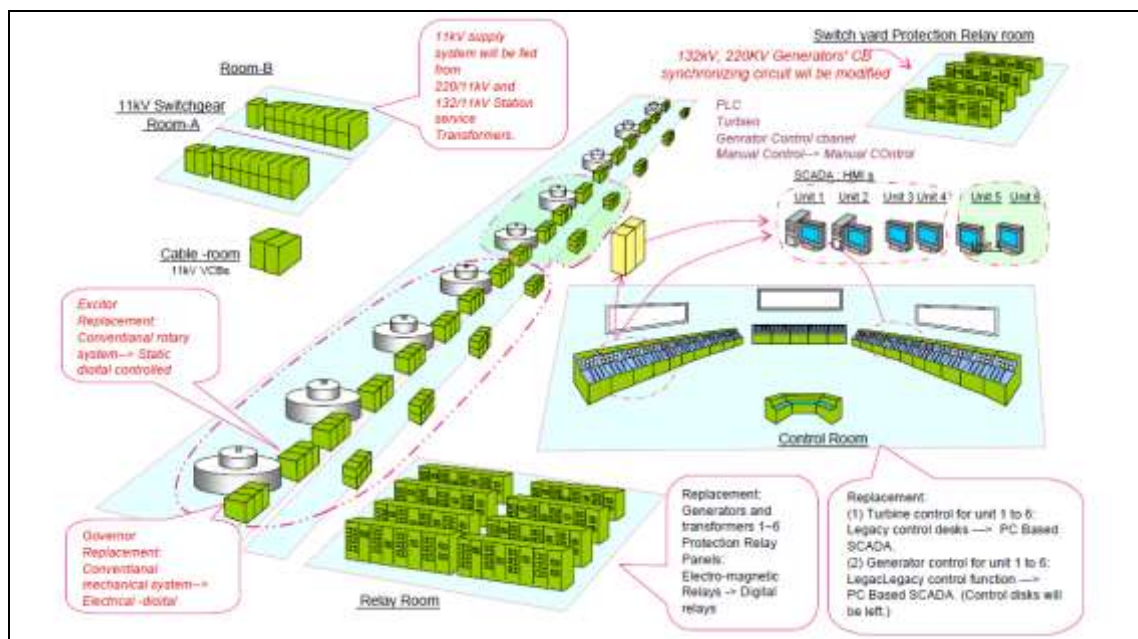
Photo 4-12 Lifting Beam for Generator Rotor

4.7 Control and Protection

4.7.1 Present Situation of Control and Protection System

The control and protection system have been modified whenever generation units and transmission lines were expanded. At present, 220 kV and 132 kV transmission lines and ten sets of turbine-generator, intake gates, and irrigation valves are supervised and controlled from the control room of the Mangla Power Station.

Figure 4-10 below shows the overview of control and protection facilities for Mangla Power Station.



Source: Prepared by the Survey Team

Figure 4-10 Conceptual Picture of Power Station Control System

The system is well managed and maintained by the staffs of the power station. Though the system performance is maintained as the original condition, the devices and wires in the control and protection circuit were deteriorated. The renewal of such wires and devices is a pressing issue for reliable operation.

Actually, implementation of SCADA system for transmission lines by NTDC/NPCC is ongoing. The requirement for more linked and flexible operation with the network will be increased by reason of the growing electrical demand. The correspondence on this matter will be required for the control and protection system. The present system faces difficulty to meet this requirement.

4.7.2 Subject of Survey for Control and Protection

The components of control and protection system for Mangla Power Station are vast and complicated. Understanding the whole system requires further site investigation. Therefore, the subjects of site investigation focus on the control and protection equipment related to the generator and turbine refurbishment and upgrading.

The key points of the site survey are as follows:

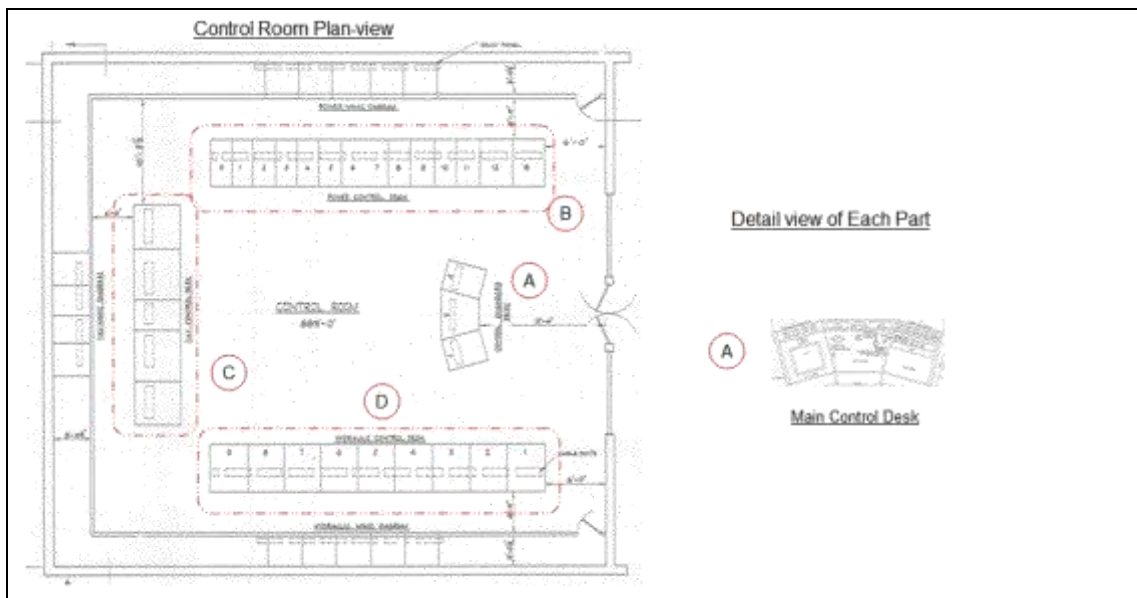
- a. Which equipment requires renovation or replacement with the upgrade of generating capacities?
- b. Which equipment has potential risks on the future operation due to the aging of material and devices?
- c. What are the present issues on the operation and maintenance of the facilities?

4.7.3 Control Room Arrangement

Almost all facilities in the power station, switchyard, and Mangla Dam can be monitored by the control desks in the control. The major status of equipment, fault status, and measured values are indicated on the control desks with conventional lamps and meters.

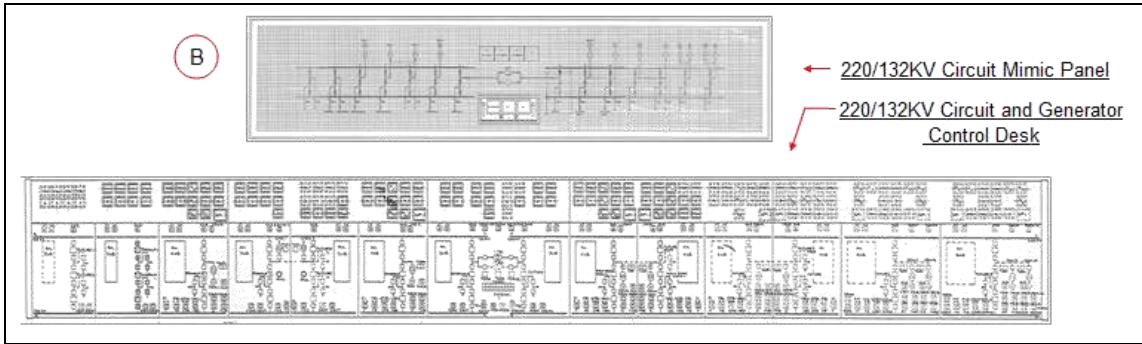
The arrangement of control desk is shown in Figures 4-11 through 4-14.

The SCADA system consoles for generation unit will be installed in the control room.



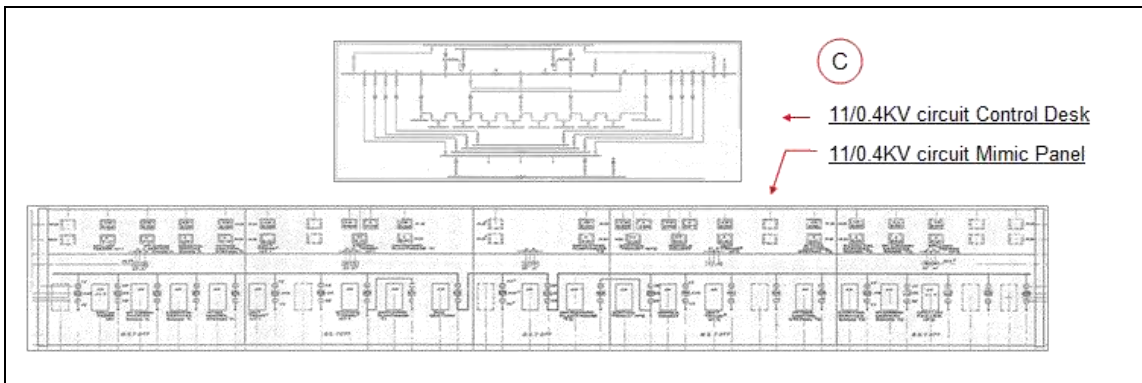
Source: Prepared by the Survey Team

Figure 4-11 Control Desk Arrangement in Control Room



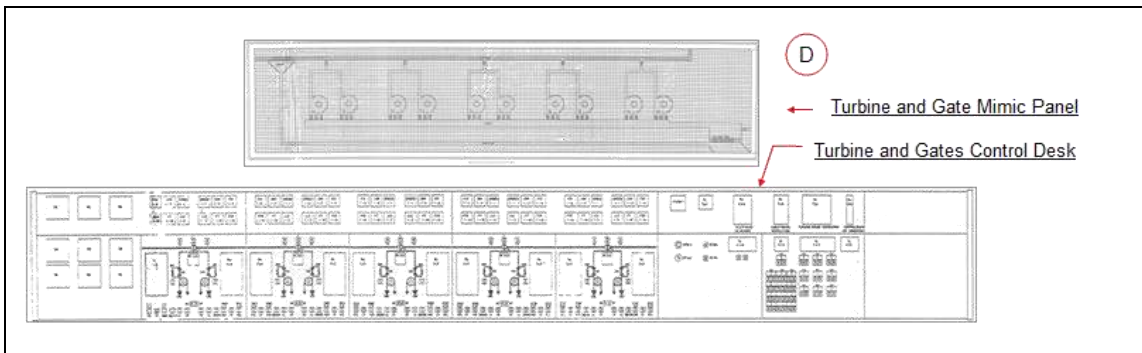
Source: Prepared by the Survey Team

Figure 4-12 Switchyard Control Desk Arrangement in Control Room



Source: Prepared by the Survey Team

Figure 4-13 Station Service Control Desk Arrangement in Control Room



Source: Prepared by the Survey Team

Figure 4-14 Turbine Control Desk Arrangement in Control Room

4.7.4 Control and Protection for Turbine-Generator

(1) Control

The present control is through manned manual semi-automatic start control. The generator and turbine status are continually monitored at the generator room through the governor/turbine.

Control cabinets and AVR/generator control the cabinets. The control room also monitors such status as needed through the control desks.

The unit is controlled, step by step, from the control room with manual operating or regulating switches on the control desk. The operation proceeds through the following steps by the operator manually:

Inlet valve open → Turbine start → Excitation → Synchronizing

Auxiliary equipment such as cooling water pumps and oil pressure pumps are controlled locally with local control panels. The system consists of conventional magnetic relays, switches, and indicators.

(2) Protection

There are three trip modes, i.e: 86-1, 86-2, and 86-3. The irrigation valve control is required at the trip situation. The protection relays are almost BBC's and Hitachi's old electro-mechanical types. These were not manufactured. The relays are well maintained; however, the potential of malfunction or non-operation due to aging cannot be measured. The generation unit protection panels are installed at places shown in Table 4-13 below.

Table 4-13 Installation Place of Protection Relay Panels

Protection Areas	Installation Place of Protection Relay
Generator and Turbine	Relay room in power station
Step-up Transformer	
HV Generator Feeder	Relay room in switchyard control house

Source: Prepared by the Survey Team

(3) Irrigation Valve Control

The irrigation valves require combinational governing operation with turbine. The new design must involve such operation manner.

4.7.5 Control and Protection for Generation Units

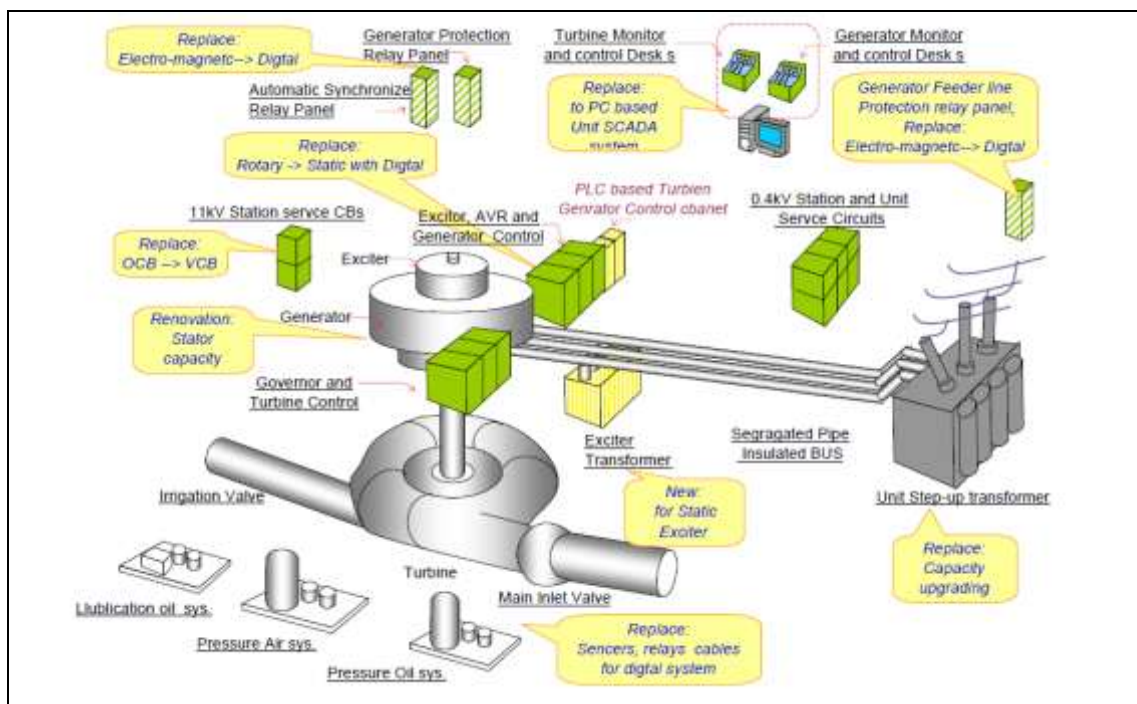
Main equipment and their peripheral equipment are summarized in the following Table 4-14. These are targets for control and protection of generation units.

Table 4-14 Target Equipment of Generation Units Control System

Main Equipment	Peripheral Equipment
Turbine	Turbine, Irrigation Valve, Governor/Turbine Control Panel and Peripheral Equipment of the Turbine.
Generator	Generator, Exciter, AVR/Generator Control Panel, IPB and Peripheral Equipment of the Generator.
Step-up Transformer	Step-up Transformer, Cooling System for the Transformer, Tap Changer and Peripheral Equipment of the Transformer.

Source: Prepared by the Survey Team

The image of control equipment and subjected control facilities are shown in Figure 4-15 below.



Source: Prepared by the Survey Team

Figure 4-15 Conceptual Picture of Generation Unit Control System

4.7.6 Control and Protection for Step-up Transformer

(1) Control

The generation unit does not furnish the generator circuit breaker. The generator feeder is directly connected to the step-up transformer. High voltage feeder of the step-up transformer is connected to one and half circuit breakers.

The step-up transformer furnishes off-load tap changer and transformer cooling system. The transformer status is monitored from the control room.

(2) Protection

The protection relay for transformer consists of conventional electro-magnetic protection relays and mechanical relays such as Buchholz relay. Both the generator heavy fault and transformer heavy fault bring the generator emergency stop into high voltage (220 kV or 132 kV) circuit breaker trips.

4.7.7 Control and Protection for Switchyard

(1) Circuit Configuration

The facilities of power transmission are installed in the switchyard. The system consists of eight transmission lines with one and half circuit breaker configuration (1.5 CB) on 220 kV and 13 transmission lines with one and half circuit breaker configuration (1.5 CB) on 132 kV. The 132 kV and 220 kV systems are linked by the three inter-connection transformers. The two generators are connected to the 132 kV system via two step-up transformers while eight generators are connected to the 220 kV system via eight step-up transformers.

The switchyard facilities are monitored and controlled from the control room in the powerhouse. The protection relays for switchyard facilities are installed in the relay room in the switchyard. The control and protection signals are linked by the long distance (about 2 km) cables between the powerhouse and the switchyard.

(2) Actual Refurbishment Work

The replacement work of old circuit breakers and protection relays is implemented along the NTDC/NPCC's plan. The SCADA of Mangla switchyards has been implemented by NTDC/NPCC. It intends to control the circuit breakers from the dispatch center and control room of Mangla via SCADA system.

(3) Control

The control and protection system mainly consists of conventional wired logic relay schematic sequence circuits. Indicator, auxiliary relays and wires are still used from the original installed condition. Present control system and supervised facilities are shown in Table 4-15 below.

Table 4-15 Switchyard Control System Work

Circuit	Present Condition
Control and Monitoring for Transmission Lines	Conventional monitoring systems are installed in the power station control room. SCADA control system is under implementation.
Control and Monitoring for Generator Feeders	
Control and Monitoring for 220 kV/132 kV Inter-connection Transformers	
132 kV/11 kV Station Service Transformers	

Source: Prepared by the Survey Team

(4) Protection

Actually, generator feeder line protections are installed in the same protection panels of transmission lines, which are connected to same bays of feeder lines, as shown in Table 4-16.

Table 4-16 Switchyard Protection System Work

Circuit	Present Condition
Protection for Transmission Lines	Conventional protection relay systems are installed in the switchyard control room.
Protection for Generator Feeders	
Protection for 220 kV/132 kV Inter-connection Transformers	
132 kV/11 kV Station Service Transformers	

Source: Prepared by the Survey Team

4.7.8 Control and Protection for Station Service System

(1) Alternative Current (AC) Power Supply

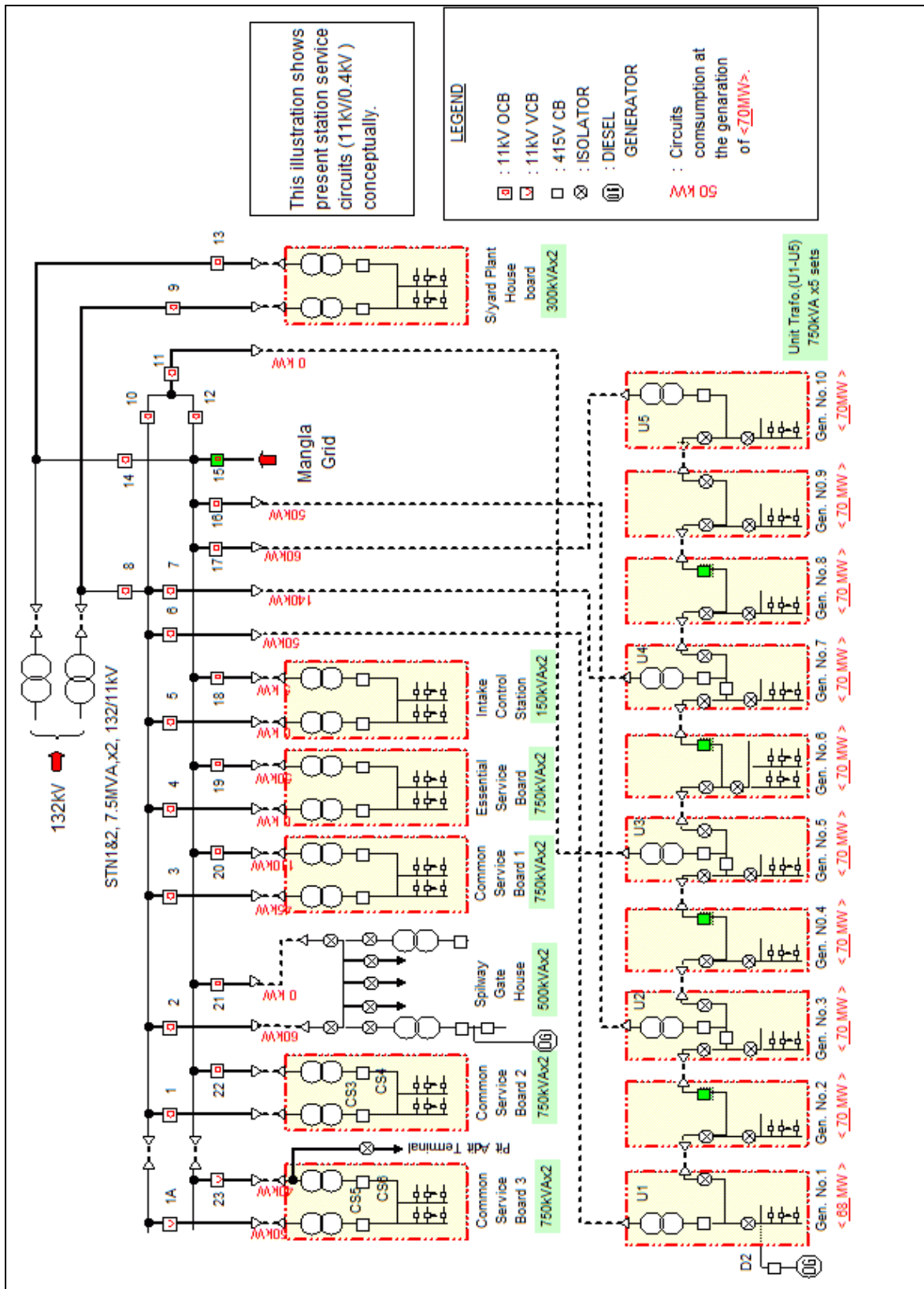
The 132 kV bus supply the power to two sets of station service transformers (132/11 kV-7.5 MVA), and each transformer supplies power to two split buses. In total, 19 transformers (11/0.4 kV) are connected to these buses, and the transformers supply the 400 V AC to the stations' facilities. The station service diagram is shown in Figure 4-16.

(2) Direct Current (DC) Power Supply

Mangla control system uses two levels of DC voltages. One is 230 V DC for control and device drive, and another is 50 V for status indication and alarming.

There are two DC 230 V battery systems. One system is for Units 1 to 6 and another system is for Units 5 to 10. One battery set consists of two banks (170 Ah - 2 sets) of batteries, and two sets of battery chargers.

Battery banks have been renewed during the last ten years. There is no requirement for replacing them.



Source: Prepared by the Survey Team

Figure 4-16 Actual Station Service Circuit

4.7.9 Photographs of Control and Protection

 A photograph of a control room with several operators seated at desks with computer monitors. The room has a greenish tint and a grid ceiling. A date stamp '05.17.2012 08:41' is visible in the bottom right corner.	 A close-up photograph of a generator synchronizing relay panel. The panel is dark with various components and a date stamp '05.17.2012 10' is visible on the right side.
<p>Photo 4-13 Control Room</p>	<p>Photo 4-14 Generator Synchronizing Relay</p>
 A photograph of a large, white industrial cubicle with a person standing in front of an open door. The floor is polished and reflects the overhead lights. A date stamp '05.17.2012 09:41' is visible in the bottom right corner.	 A photograph of a generator protection relay panel with two main units and numerous cables connected to them. A date stamp '05.17.2012 10:24' is visible in the bottom right corner.
<p>Photo 4-15 Governor and AVR Cubicle for Unit 1</p>	<p>Photo 4-16 Generator Protection Relay</p>
 A photograph of a long row of green 11 kV station service cubicles in a hallway. A date stamp '05.24.2012 09:38' is visible in the bottom right corner.	 A photograph of a long row of green 400 V station service cubicles in a hallway. A person is visible in the distance. A date stamp '05.24.2012 10:16' is visible in the bottom right corner.
<p>Photo 4-17 11 kV Station Service Cubicles</p>	<p>Photo 4-18 400 V Station Service Cubicles</p>

Source: Prepared by the Survey Team

4.8 Switchyard

4.8.1 Outline of Switchyards

The 132/220 kV switchyard, as shown in Photo 4-19, is located at about 1.2 km southeast from the power station. The switchyard is an outdoor conventional type with one and half circuit breaker configuration.

The 132 kV and 220 kV bus are connected by three 132 kV/220 kV 138 MVA transformers with total capacity of 414 MVA.



Source: Prepared by the Survey Team

Photo 4-19 Switching Station

Two generators of Units 1 and 2 are connected to the 132 kV bus and the generators of Units 3 to 10, eight units in total, are connected to 220 kV bus through their generator step-up transformers.

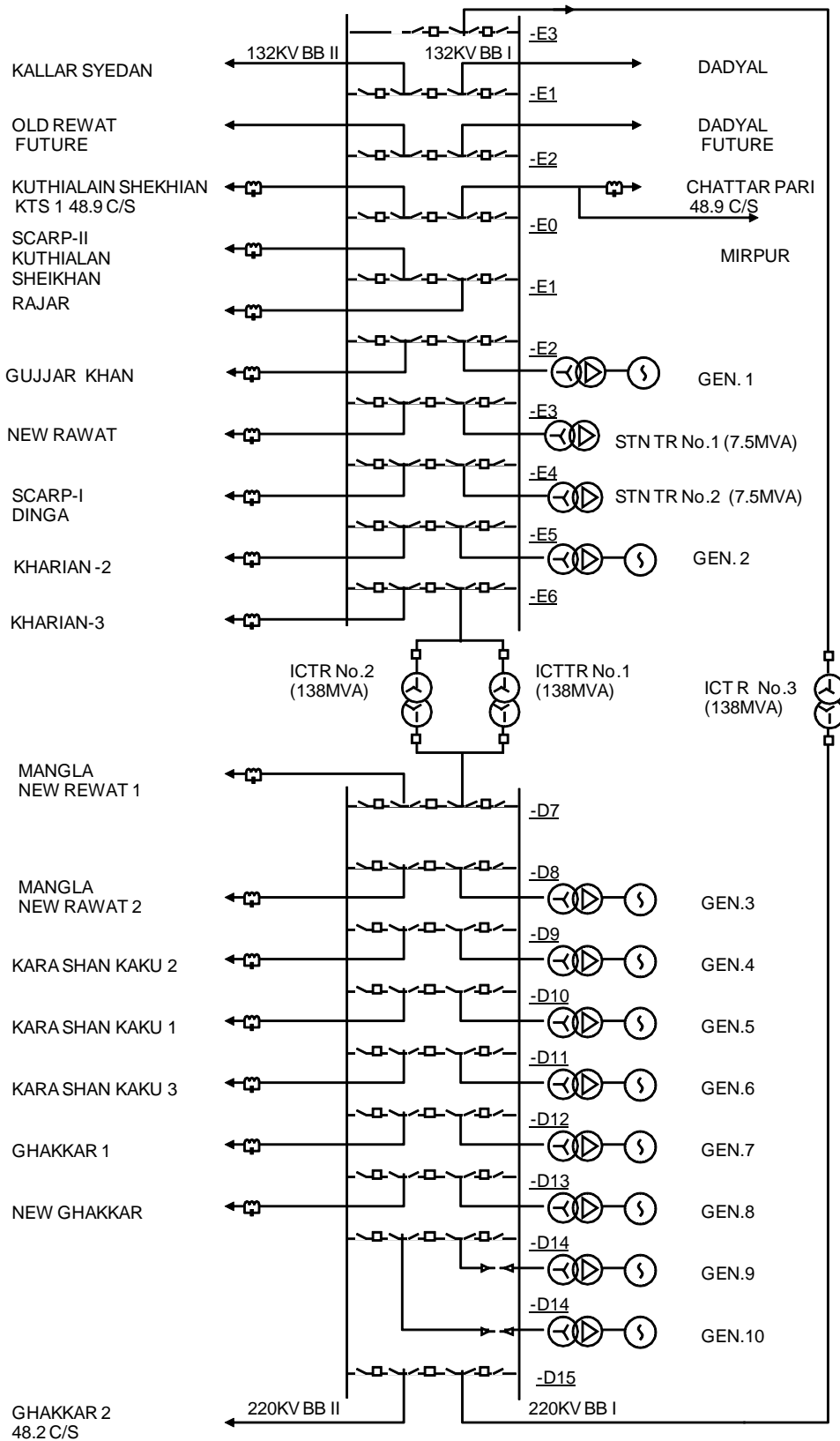
Eleven 132 kV and eight 220 kV transmission lines are emanated from the switchyard. Besides, two transmission bays are prepared in 132 kV for future expansion.

The single line diagram is shown in Figure 4-17, and the layout of transmission towers connecting the power station and switchyard is shown in Figure 4-18.

At present, Units 1 to 8 are connected by overhead line and Units 9 and 10 are connected by underground XLPE cable, which is planned to be changed to overhead line in the near future by NTDC to keep the reliability.

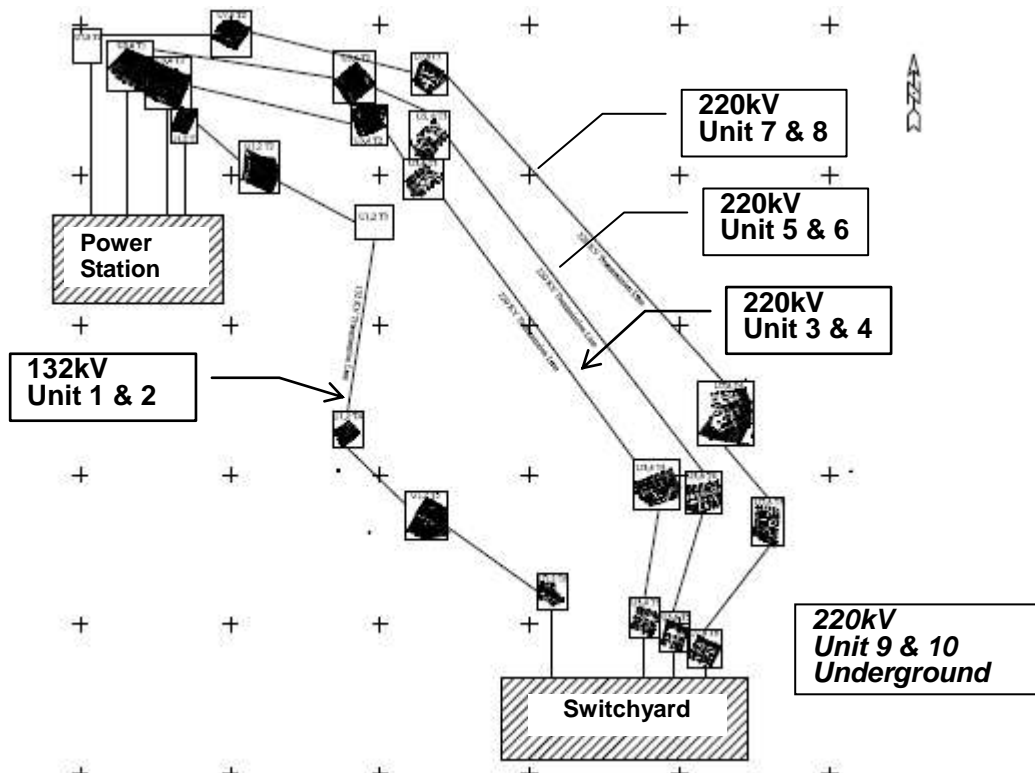
The switchyard consists of the following main equipment and associated systems:

- 132 kV and 220 kV Bus Bars
- Circuit Breakers
- Disconnecting and Earthing Switches
- Current and Voltage Transformers
- Surge Arresters
- Line Traps
- 132/220 kV Interconnector Transformers
- 132/11 kV Station Service Transformers
- Steel Structure
- Protection Panels



Source: Prepared by the Survey Team

Figure 4-17 Single Line Diagram



Source: Prepared by the Survey Team

Figure 4-18 132 kV and 220 kV Overhead Line between Power Station and Switchyards

The section photo of the cable trench between power station and switchyard is shown in Photo 4-20. Previously, all power cables for Units 1 to 10, 11 kV station service power cables, and control/protection/measurement cables have been installed in the trench. After the fire that happened in 2008, power cables for Units 1 to 8 were converted to overhead line.



Source: Prepared by the Survey Team

Photo 4-20 Power Flow of 220 kV to 132 kV in Switching Station in 2010

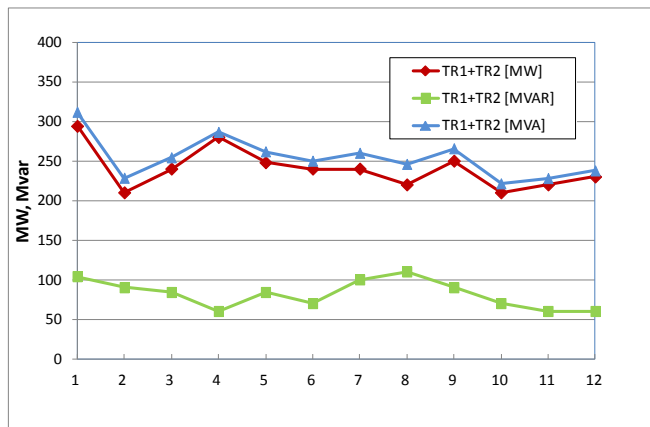
4.8.2 Generator Connection to Switching Station Bus

The power flow in the switchyard is always one-way, namely, 220 kV to 132 kV, through the 220 kV/132 kV inter-connecting transformer.

In January 2010, 310 MW power flow was recorded, which exceeded the capacity of two 138 MW transformers (276 MW in total). Then, one 138 MW inter-connecting transformer was additionally installed by the end of 2011 for sufficient capacity.

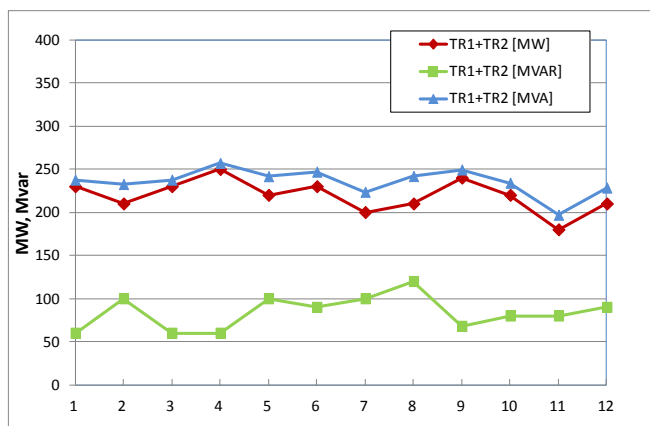
At present, Units 1 and 2 are connected to 132 kV bus in the switchyard and Units 3 to 10 are connected to 220 kV via 13.2/132 kV and 13.2/220 kV step-up transformers installed in the power station, respectively.

Monthly maximum power flows of 220 kV to 132 kV in 2010 and 2011 are shown in Figures 4-19 and 4-20, respectively. Maximum power flows vary from 200 MVA to 250 MVA. About 310 MVA was recorded in January 2010.



Source: WAPDA (Mangla Hydro Power Station)

Figure 4-19 Power Flow of 220 kV to 132 kV in Switching Station in 2010



Source: WAPDA (Mangla Hydro Power Station)

Figure 4-20 Power Flow of 220 kV to 132 kV in Switching Station in 2011

With the enhancement of the generator, the connection change is recommended, which is discussed in Chapter 5.

4.8.3 Switchgears

There are 27 and 29 (total 56) circuit breakers for 220 kV and 132 kV side, respectively. The circuit breakers were originally air-blast type. However, they are in the process of being replaced with SF6 type breakers.

As of May 2012, 21 and 24 circuit breakers for 220 kV and 132 kV, respectively, have already been replaced to SF6 type. Then, 6 and 5 circuit breaker for 220 kV and 132 kV, respectively, are scheduled to be replaced in the near future.

4.8.4 Replacement Required with the Enhancement Project

After discussing with the manager of the switchyard, the following points need to be studied:

The results of studies and the recommendations are discussed in Chapter 5.

1) Bus Bar for 220 kV and 132 kV

After enhancement of the generating capacity, current capacity of bus bars shall be studied.

2) Current Transformer Capacity

After enhancement of the generating capacity, ratio of the current transformers shall be studied.

3) Transmission Line Capacity

After enhancement of the generating capacity, ratio of the current transformers shall be studied.

4.9 Existing Conditions for Mangla Dam

4.9.1 Meteorology Feature

There are four seasons in Pakistan, i.e.: winter with cold and dry season from December to February, spring with hot and dry season from March to May, summer with hot, rainy and monsoon season from June to September, and autumn as transition period from October to November. Pakistan's climate consists of the desert climate (BW) in the central southern area, steppe climate (BS) in the northern area, and temperate climate in summer rain (Cw) in the northern mountainous area. There are five meteorological stations upstream of Mangla Dam (see Table 4-17) and the monitoring of temperature, humidity, precipitation, evaporation, insolation time, and wind direction/velocity is done by WAPDA. The data is kept by the Surface

and Water Division of Hydrology (GM of Planning and Design: Mr. Irshed Ahmad) of WAPDA.

Table 4-17 Location of Meteorological Stations Maintained by WAPDA

Station	River Basin	Latitude	Longitude	Elevation
Domel	Upper Jhelum	34°22'04"	73°28'08"	686 ft (209.1 m)
Pallandri	Lower Jhelum	33°43'10"	73°41'06"	1,402 ft (427.3 m)
Kotli	Poonch	33°29'05"	73°52'52"	610 ft (185.9 m)
Kallar	Kanshi	33°25'00"	73°22'00"	518 ft (157.9 m)
Mangla Dam	Local	33°07'28"	73°38'00"	282 ft (86.0 m)

Source: WAPDA P&D Division

Table 4-18 shows the maximum and minimum mean temperatures of each month at the meteorological stations during the last ten years.

Table 4-18 Monthly Temperatures (Unit: °C)

1) Domel Station

Month	1	2	3	4	5	6	7	8	9	10	11	12
Max	16	18	24	29	33	35	34	33	33	30	24	18
Min	2	3	8	13	16	20	20	22	17	12	7	2

2) Pallandri Station

Month	1	2	3	4	5	6	7	8	9	10	11	12
Max	14	15	21	26	30	30	28	27	27	25	21	16
Min	1	2	6	11	14	17	19	19	14	11	7	3

3) Kotli Station

Month	1	2	3	4	5	6	7	8	9	10	11	12
Max	18	19	26	32	36	37	33	32	32	30	25	20
Min	2	6	9	14	20	22	23	23	18	13	8	2

4) Kallar Station

Month	1	2	3	4	5	6	7	8	9	10	11	12
Max	19	20	27	32	37	37	35	33	33	30	26	21
Min	4	6	12	16	21	23	23	23	19	16	11	4

5) Mangla Station

Month	1	2	3	4	5	6	7	8	9	10	11	12
Max	19	22	28	34	40	38	35	34	34	32	27	22
Min	4	7	13	18	22	24	25	24	22	16	10	4

Source: WAPDA P&D Division

The meteorological station of Mangla Dam recorded 40°C as the maximum temperature in May and 4°C as the minimum temperature in December and January.

The precipitation in the catchment area of Mangla Dam is shown in Table 4-19.

Table 4-19 Monthly Rainfall (Unit: mm)

1) Domel Station

Month	1	2	3	4	5	6	7	8	9	10	11	12	Total
Monthly Mean	100	158	104	86	77	145	273	183	89	38	39	72	1364
Hourly Max	72	141	74	43	43	88	155	159	81	61	45	101	-

2) Pallandri Station

Month	1	2	3	4	5	6	7	8	9	10	11	12	Total
Monthly Mean	93	161	87	61	42	126	257	167	70	40	26	51	1181
Hourly Max	66	178	69	86	58	59	194	125	51	64	51	68	-

3) Kotli Station

Month	1	2	3	4	5	6	7	8	9	10	11	12	Total
Monthly Mean	70	112	77	38	43	95	209	184	63	28	18	38	975
Hourly Max	65	125	65	40	71	56	72	74	36	50	27	65	-

4) Kallar Station

Month	1	2	3	4	5	6	7	8	9	10	11	12	Total
Monthly Mean	50	90	58	52	29	76	194	106	67	33	30	52	837
Hourly Max	70	96	38	51	27	83	273	98	107	80	51	39	-

5) Mangla Dam Station

Month	1	2	3	4	5	6	7	8	9	10	11	12	Total
Monthly Mean	34	54	43	26	30	90	204	188	60	16	12	26	783
Hourly Max	33	70	42	51	56	48	133	72	59	25	22	83	-

Source: WAPDA P& D Division

For the annual precipitation, the Domel and Pallandri stations have 1343 mm and 1109 mm, respectively. Precipitation in Kotli, Kallar, and Mangla Dam stations were 975 mm, 793 mm, and 783 mm, respectively, which constituted comparatively less rain.

The tendency of precipitation from 2001 to 2010 in the Mangla Dam basin is indicated in Table 4-20.

Table 4-20 Tendency of Precipitation from 2001 to 2010

(mm/year)

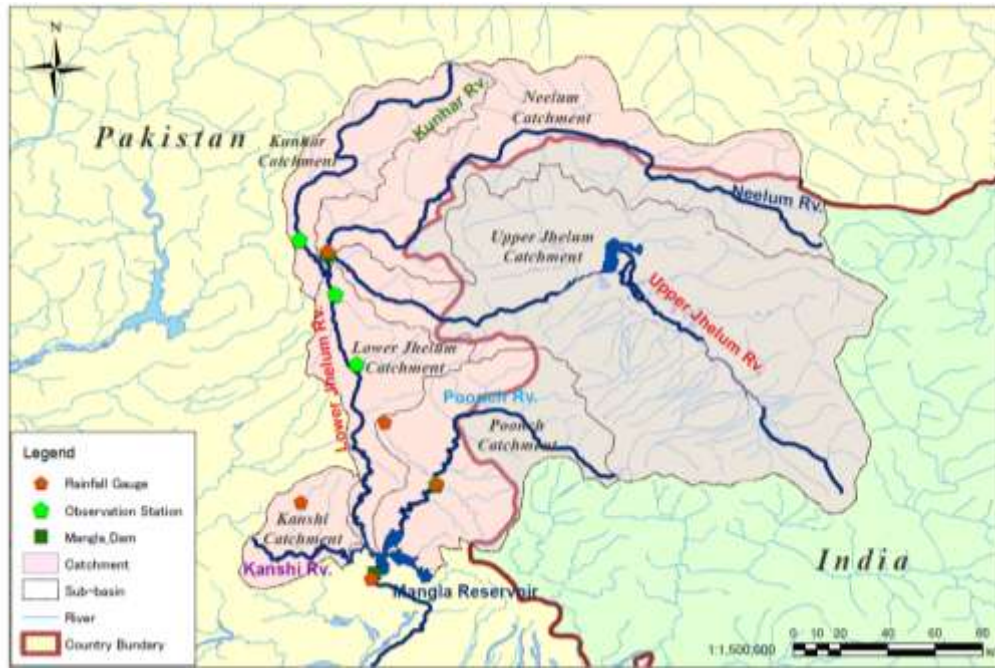
Year	Meteorological Station					Average
	Domel Sta.	Pallandri Sta.	Kotli Sta.	Kallar Sta.	Mangla Sta.	
2001	926	1,180	-	734	573	853
2002	1,087	881	817	858	534	835
2003	1,607	1,432	1,016	1,026	884	1,193
2004	1,474	1,056	881	961	825	1,039
2005	1,566	650	743	457	-	854
2006	2,187	1,112	1,411	1,099	1,049	1,372
2007	1,132	1,081	1,003	145	948	862
2008	1,795	1,284	1,298	1,056	879	1,262
2009	51	1,093	625	567	527	573
2010	1,608	1,319	977	1,027	825	1,151
Average	1,343	1,109	975	793	783	-

Source: WAPDA P& D Division

According to the above table, the precipitation in 2005, 2007, and 2009 in the Mangla Dam basin did not compare much with the other years. Accordingly, climate change was not observed in the last ten years.

4.9.2 Basin of Mangla Dam

The river system in the Mangla Dam basin consists of Neelum, Kunhar, Upper Jhelum, Lower Jhelum, Poonch, and Kanshi rivers (see Figure 4-21) and these catchment areas are indicated in Table 4-21.



Source : Prepared by the Survey Team

Figure 4-21 Basin of Mangla Dam

Table 4-21 Catchment Area of Mangla Dam Basin

River Name	AJK (Pakistan Side)			AJK (Indian Side)			Total		
	mile ²	km ²	(%)	mile ²	km ²	(%)	mile ²	km ²	(%)
Neelum	1,875	4,854	32.6	965	2,498	13.5	2,840	7,352	22.0
Kunhar	940	2,434	16.3	-	-	-	940	2,434	7.3
Upper Jhelum	312	831	5.6	5,218	13,509	73.3	5,530	14,340	43.0
Lower Jhelum	1,930	4,997	33.5	-	-	-	1,930	4,997	15.0
Poonch	690	1,786	12.0	940	2,434	13.2	1,630	4,220	12.7
Total	5,747	14,902	100.0	7,123	18,44	100.0	12,870	33,343	100.0
(%)		44.7			55.3			100.0	

Source: WAPDA F/S Report

The inflow area from AJK India side was 55.3% of total catchment area and its 73.3% came from the Upper Jhelum River. The inflow area from the Pakistan side was 44.7% and its 32.6% came from Neelum River and 33.5% from Lower Jhelum River.

There are six major observation stations for monitoring and flood warning in the Mangla Dam basin as shown in Table 4-22.

Table 4-22 Six Observation Stations for Monitoring in Mangla Dam Basin

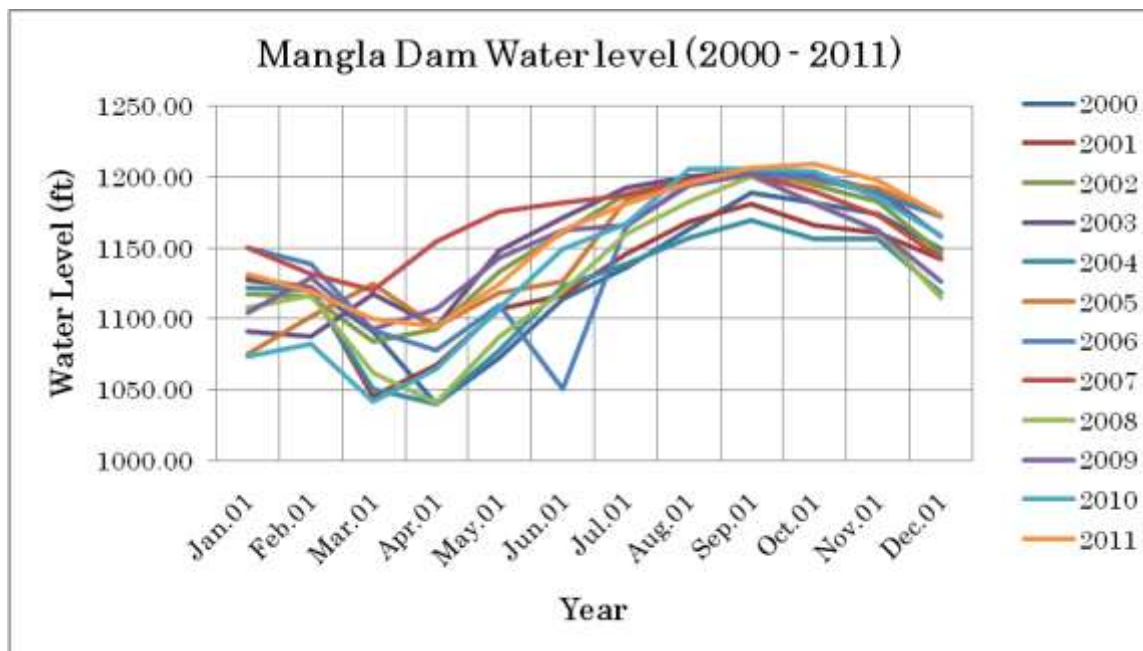
Station	River	Latitude	Longitude	Elevation	Lag Time
Muzaffarabad	Neelum	34:21:32	73:28:18	787 m	8.25 hrs
Talhatta	Kunhar	34:24:52	73:21:45	877 m	8.75 hrs
Domel	Upper Jhelum	34:22:04	73:28:08	209 m	8.00 hrs
ChattarKlass	Lower Jhelum	34:12:18	73:29:52	632 m	6.50 hrs
Azad Pattan	Lower Jhelum	33:56:27	73:34:43	543 m	2.50 hrs
Kotoli	Poonch	33:29:05	73:52:52	186 m	1.00 hr

Note: The lag time is the arrival time of the flood from the station to Mangla Dam.

Source: WAPDA Hydrological Section of Mangla Dam

4.9.3 Water Level of Mangla Dam

The water level at Mangla Dam from 2000 to 2010 is shown in Figure 4-22. According to the figure, the water level in March, April, and May becomes low due to the dry season and the water is utilized for irrigation.



Source: WAPDA Hydrological Section of Mangla Dam

Figure 4-22 Mangla Dam Water Level since 2000

The monitoring stations have records of river discharges and water level. The historical floods are indicated in Table 4-23.

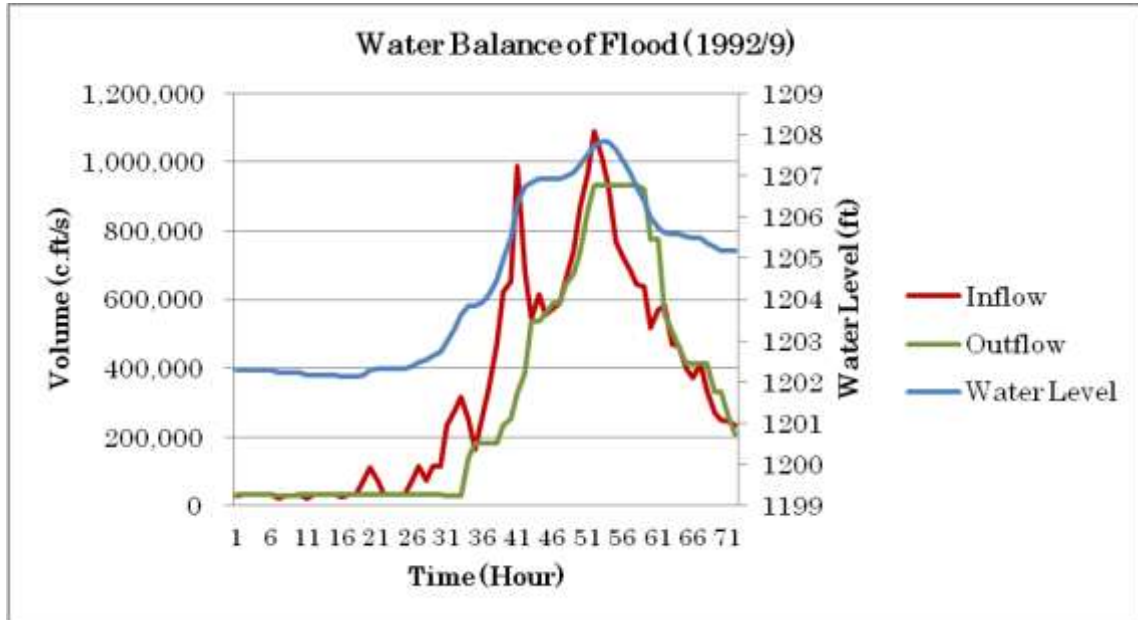
Table 4-23 Historical Floods

Year	Date	Lag Time	Inflow (cfs)	Inflow (m ³ /s)
1928	17 Jul.	49 hrs	600,000	16,980
1978	6 Aug.	63 hrs	396,475	11,220
1988	7 Dec.	94 hrs	425,515	12,042
1992	11 Sep.	77 hrs	1,090,000	30,847
2010	31 Jul.	85 hrs	267,181	7,561

Note: The lag time means the time from start of rainfall in the area to occurrence of flood at Mangla Dam.

Source: WAPDA Hydrological Section of Mangla Dam

In case of 1992, the total inflow volume into the Mangla Dam was estimated at 38,347 acre foot (AF) (47.3 million m³) and the outflow to the Jhelum River was estimated at 40,373 AF (49.8 million m³) (see Figure 4-23).



Source: WAPDA Hydrological Section of Mangla Dam

Figure 4-23 Water Balance Flood in September 1992

4.9.4 Dam/Reservoir Condition (Annual Inflow and Sedimentation)

The design levels of Mangla Dam and the reservoir capacity are indicated in Table 4-24.

Table 4-24 Outline of Mangla Dam Level

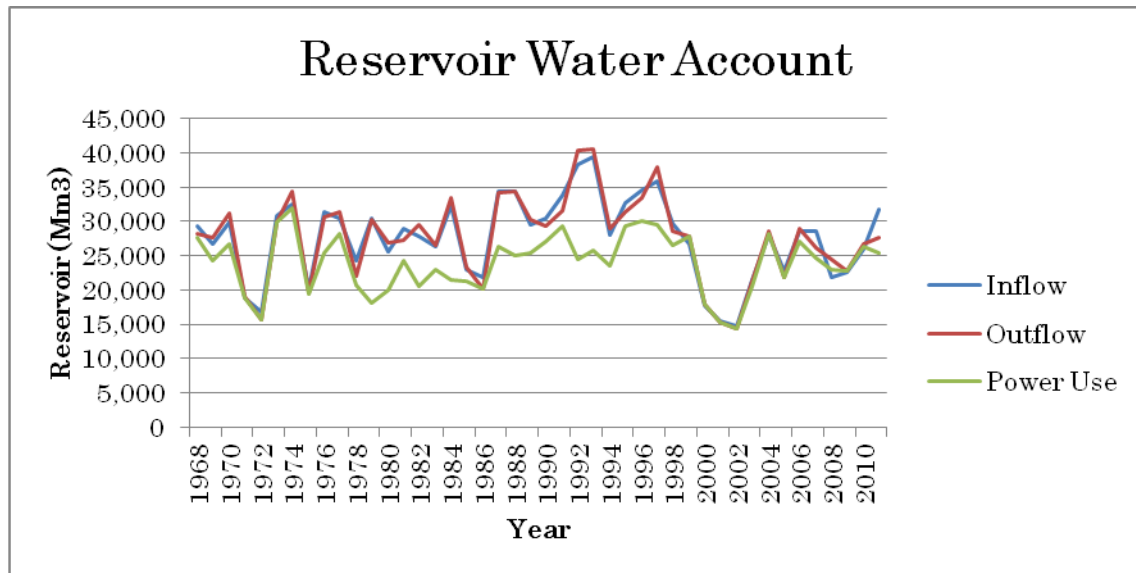
Item	Original Design	After Dam Raising	Comparison
Reservoir			
Max. Water Level	366.5 m (1,202 ft)	378.7 m (1,242 ft)	+12.2 m
Min. Water Level	317.1 m (1,040 ft)	317.1 m (1,040 ft)	+0.0 m
Reservoir Capacity	5,553 million m ³ (4.5 million AF)	9,132 M m ³ (7.4 MAF)	+3,579 million m ³
Dam Body			
Crest Height	138.5 m (454 ft)	147.6 m (484 ft)	+9.1 m
Crest Length	3,350 m (10,300 ft)	3,400 m (11,150 ft)	+50 m
Intake Level	376.2 m (1,234 ft)	386.0 m (1,266 ft)	+9.8 m
Additional Capacity	-	3,550 million m ³ (2.88 million AF)	-
Annual Generation	-	644 GWh	-

Source: WAPDA Hydrological Section of Mangla Dam

4.9.5 Water Balance of Reservoir

Mangla Dam's reservoir capacity was estimated at 5,553 million m³ before raising and the balance between inflow and outflow during the operation from 1968 to 2011 is shown in Figure 4-24. The averages of inflow and outflow were 27,600 million m³ (22.376 million AF) and 27,545 million m³ (22.331 million AF), respectively. The outflow used for the power generation

was estimated at 23,981 million m³ (19.442 million AF) on average and it is supplied for irrigation after generation as per intent of Indus River System Authority (IRSA). Also, the water volume released during big floods was 3,729 million m³ (3.023 million AF) on average through the main spillway.

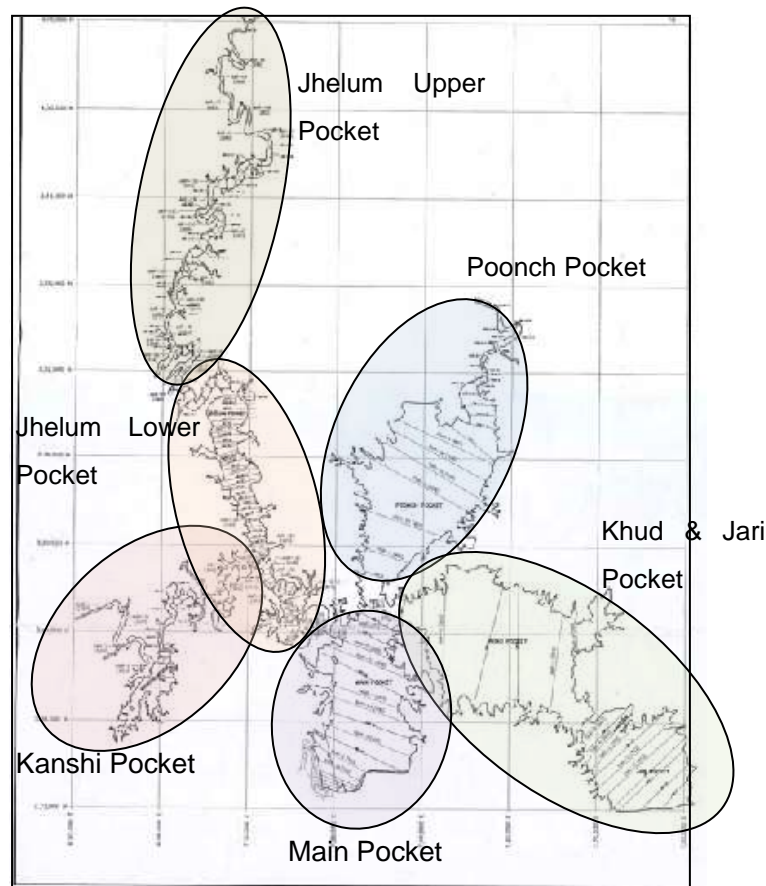


Source: WAPDA Hydrological Section of Mangla Dam

Figure 4-24 Reservoir Water Account (1968 to 2010)

4.9.6 Sedimentation of Mangla Dam

The contribution of sediments in the reservoir from different rivers in the catchment area is given in Table 4-24. The hydrographic survey for sediment was carried out 11 times after the construction of Mangla Dam. The sediment pockets are shown in Figure 4-25.



Source : Prepared by the Survey Team

Figure 4-25 Sediment Pocket at Mangla Dam

Table 4-25 Deposited Sediment Volume at Each Pocket (Unit: million m³)

Year	Upper Jhelum	Lower Jhelum	Kanshi	Poonch	Main	Khud & Jari	Total
1967	16.10	3.76	2.28	11.10	4.56	-	37.81
1968	16.10	3.76	2.28	11.10	4.56	-	37.81
1969	16.10	3.76	2.28	11.10	4.56	-	37.81
1970	16.10	3.76	2.28	11.10	4.56	-	37.81
1971	26.93	3.18	1.27	10.43	2.76	-	44.58
1972	26.93	3.18	1.27	10.43	2.76	-	44.58
1973	26.93	3.18	1.27	10.43	2.76	-	44.58
1974	13.72	6.82	4.48	13.62	1.69	18.53	58.86
1975	13.72	6.82	4.48	13.62	1.69	18.53	58.86
1976	13.72	6.82	4.48	13.62	1.69	18.53	58.86
1977	13.72	6.82	4.48	13.62	1.69	18.53	58.86
1978	13.72	6.82	4.48	13.62	1.69	18.53	58.86
1979	5.48	7.00	1.55	3.98	3.54	5.78	27.33
1980	5.48	7.00	1.55	3.98	3.54	5.78	27.33
1981	5.48	7.00	1.55	3.98	3.54	5.78	27.33
1982	5.48	7.00	1.55	3.98	3.54	5.78	27.33
1983	5.48	7.00	1.55	3.98	3.54	5.78	27.33
1984	3.92	10.04	1.77	6.94	6.82	3.36	32.86
1985	3.92	10.04	1.77	6.94	6.82	3.36	32.86
1986	3.92	10.04	1.77	6.94	6.82	3.36	32.86
1987	3.92	10.04	1.77	6.94	6.82	3.36	32.86
1988	3.92	10.04	1.77	6.94	6.82	3.36	32.86

1989	12.73	10.29	2.15	6.01	17.77	2.90	51.85
1990	12.73	10.29	2.15	6.01	17.77	2.90	51.85
1991	12.73	10.29	2.15	6.01	17.77	2.90	51.85
1992	12.73	10.29	2.15	6.01	17.77	2.90	51.85
1993	12.73	10.29	2.15	6.01	17.77	2.90	51.85
1994	-2.42	-0.84	0.54	9.08	36.55	-1.09	41.83
1995	-2.42	-0.84	0.54	9.08	36.55	-1.09	41.83
1996	-2.42	-0.84	0.54	9.08	36.55	-1.09	41.83
1997	-2.42	-0.84	0.54	9.08	36.55	-1.09	41.83
1998	-2.99	-0.36	1.04	7.04	22.98	-0.32	27.38
1999	-2.99	-0.36	1.04	7.04	22.98	-0.32	27.38
2000	-2.99	-0.36	1.04	7.04	22.98	-0.32	27.38
2001	-7.78	-7.30	14.25	13.20	12.47	3.00	27.83
2002	-7.78	-7.30	14.25	13.20	12.47	3.00	27.83
2003	-2.57	0.88	0.42	-2.21	16.43	2.25	15.19
2004	-2.57	0.88	0.42	-2.21	16.43	2.25	15.19
2005	-2.57	0.88	0.42	-2.21	16.43	2.25	15.19
2006	9.10	0.19	0.57	-0.27	11.31	-1.01	19.90
2007	9.10	0.19	0.57	-0.27	11.31	-1.01	19.90
2008	9.10	0.19	0.57	-0.27	11.31	-1.01	19.90
2009	9.10	0.19	0.57	-0.27	11.31	-1.01	19.90
2010	9.10	0.19	0.57	-0.27	11.31	-1.01	19.90
Total	328.05	179.93	100.60	304.33	521.55	155.19	1,589.65
Ratio	21%	11%	6%	19%	33%	10%	100%

Source: WAPDA Hydrological Section of Mangla Dam

According to the monitoring reports of Mangla office of WAPDA, there are three major pockets for the sediment volume such as Main Pocket, Jhelum Upper Pocket, and Poonch Pocket. The total sediment from 1967 to 2010 was measured at 1,589.65 million m³ and the average sedimentation per year was estimated at 36.13 million m³. The maximum sedimentation was observed in 1978 and 1993 from the hydrographic surveys for sediment. However, the sedimentation volume was decreasing after 2000 due to stability of the riverbed and the catchment area slopes.

CHAPTER 5

STUDY ON REHABILITATION AND ENHANCEMENT

CHAPTER 5 STUDY ON REHABILITATION AND ENHANCEMENT

5.1 Turbine

5.1.1 Study on Rehabilitation of Turbine

The Survey Team's comments on the recommendations related to the turbines in the F/S report are described in Tables 3-9 to 3-12 of Chapter 3.

The result of the study for rehabilitation of the turbines in the Project is shown below.

(1) Units 1 to 4

1) Inlet Valve

The water leakage from the inlet valve when fully closed is so excessive that it is difficult to reduce by simple maintenance works. When any maintenance work inside the turbine is required, the intake gate is closed, which results to the stoppage of the two units. Without closing intake gate, it is very difficult to do any work inside the turbine due to excessive leakage water from fully closed inlet valve. A bi-plane type inlet valve is recommended to minimize water leakage for doing any work inside turbine without closing intake gate but closing inlet valve. By replacing inlet valve to bi-plane type one, head loss would be reduced is effective for high efficiency power generation together with only one unit stopping for one unit turbine inside work.

In consideration of the above, the Survey Team recommended to replacing the existing butterfly inlet valve by a bi-plane type, although the F/S report recommended that the existing butterfly inlet valve be repaired only for utilization in the future.

The bi-plane type inlet valve is designed such that there will be no requirement for greasing, which is better from the viewpoint of ecology.

In addition, it is recommended that the by-pass valve and its piping be replaced through the Project.

2) Spiral Casing

Overhaul of the spiral casing with partial replacement and repair is recommended. Measuring instruments, including the turbine water flow detector, shall be replaced to match the new design monitoring system. Almost all the measuring signals shall be transferred to new control system. It is difficult to add the signal transfer unit to existing measuring instrument due to out-of-date instrument.

3) Turbine Runner

The turbine runner shall be replaced with a new designed runner.

4) Guide Vane

Guide vanes shall be replaced with the latest design.

New design guide vane is not required feeding lubricant grease.

5) Guide Vane Operating Mechanism

Overhaul of the guide vane operating mechanism is required for replacement of some parts except gate operating ring which shall be reused.

6) Head Cover

The head cover shall be replaced in order to adopt the new design of the turbine shaft and shaft seal.

As recommended below item (8), shaft seal is recommended to replace, in this case, head cover shall also be replaced for mounting the new shaft seal equipment.

7) Turbine Shaft

Inspection and spare preparation of the turbine shaft is requested, however, there is no need for a spare shaft as suggested in the F/S report. Because there is almost no possibility using spare shaft forever.

8) Shaft Seal

The shaft seals shall be replaced with new designs for improving their performance.

9) Discharge Ring and Draft Tube

Inspection of the discharge ring and draft tube liner, and treatment with blasting and re-coating are required.

10) Turbine Guide Bearing

The guide bearing shall be replaced with new one.

11) Governor

The governors shall be replaced with the latest design, which is of digital type and requires a speed signal generator (SSG) with speed detector.

The existing speed detector shall be taken out.

The mechanical-type position detector for the guide vane shall be replaced with an electrical-type position detector. Communication between governor system and control system is required. For providing sufficient communications with new control system, all of the electrical component of governor shall be replaced.

12) Governor Pressure Oil System

The governor pressure oil system shall be replaced with a new design for long life operation of the system. Almost all the component of governor oil pressure system is no more manufacturing, therefore getting spares in the market is impossible. So, all of the pressure oil system shall be replaced.

(2) Units 5 and 6

Units 5 and 6 rehabilitation is the same as Units 1 to 4, except for the following equipment:

1) Guide vane operating mechanism

The guide vane operating mechanism shall be replaced with a new one.

2) Turbine shaft

The turbine shaft shall be replaced with a new one.

(3) Units 7 to 10

Although overhaul of Units 7 to 10 is also required with the replacement of some equipment, the operation period of these units is not so long as compared to Units 1 to 6. Periodical maintenance shall be required.

An output power limitation control is required after raising the reservoir level in order to prevent damage due to the limitation of the capacity of the generator, including IPB and the main transformer.

5.1.2 Study on Rehabilitation of Auxiliary Equipment for Turbine

(1) Cooling Water System

The cooling water supply system is normally connected by the same interconnected piping. It is tapped from the upstream side of the turbine inlet valve on all units except for Units 5 and 6, which are supplied downstream of the valves.

Units 1 to 4 have stand-by cooling pumps each. These pumps have been working ever since their commissioning, therefore, they should be replaced with new ones through the Project.

The cooling water system is currently functional without any major fault, but piping and valve replacement are required for continuous reliable operation for another 40years.

(2) Compressed Air Systems for Generator Brakes

No replacement is required.

(3) Oil-lifting Equipment

No replacement is required.

(4) Overhead Traveling Crane and Lifting Beam for Generator rotor

According to the information of a senior mechanical engineer in Mangla Power Station, the conditions of both cranes are satisfactory. Therefore, no replacement of the parts is required. In addition, the lifting beam for tandem operation of both cranes and the lifting device for the rotor is safely stored in the erection bay.

5.1.3 Study on Enhancement of Turbine

The turbine characteristics for both cases of just rehabilitation and enhancement are completely the same, because both cases are required to correspond to the raising of the water level of Mangla Dam.

(1) Units 1 to 4

The scope of the works for enhancement of turbine and unit mechanical equipment is same as that for rehabilitation as mentioned in Sub-clause 5.1.1.

(2) Units 5 and 6

The scope of the works for enhancement of the turbine and unit mechanical equipment is the same as that for rehabilitation as mentioned in Sub-clause 5.1.1.

(3) Units 7 to 10

The scope of the works for Units 7 to 10 is recommended to be just rehabilitation as mentioned in Sub-clause 5.1.1. The output water limitation shall be considered for limiting the generator output due to the limitation of electrical equipment such as generator, IPB, and main transformer.

5.1.4 Study on Enhancement of Auxiliary Equipment for Turbine

(1) Cooling Water System

Cooling water supply system is normally connected by the same interconnected piping. It is tapped from the upstream side of the turbine inlet valves on all units except for Units 5 and 6, which are supplied with water from downstream of the valves.

Units 1 to 4 have separate individual stand-by cooling pumps. These pumps have been working ever since their commissioning, and therefore, should be replaced with new ones.

The cooling water system is currently functional, but piping and valve replacement is

necessary for continuous reliable operation for another 40 years.

(2) Compressed Air Systems for Generator Brakes

If more capacity is necessary from the existing capacity, replacement should be considered.

(3) Oil Lifting Equipment

If the existing capacity is not adequate, then replacement of the lifting equipment should be considered.

5.2 Generator

5.2.1 Study on Rehabilitation of Generator

The following study for generators was undertaken by using the data given in Section 4.2:

(1) Study of Generator Stator Coil

Estimation of remaining life for generator stator coil

From the data of “number of start/stop” and “operating hours”, the remaining life of the stator winding is estimated by N-Y Map method which is presented in the report of the “Institute of Electrical Engineers of Japan”.

1) Operating hours

The total operating hours after commissioning of each unit is as follows;

Table 5-1 Total Operating Hours

Unit Number	Total Operating Hours	Commissioning Date	Unit Number	Total Operating Hours	Commissioning Date
Unit 1	361,373 hrs	03/07/1967	Unit 6	263,583 hrs	11/03/1974
Unit 2	360,017 hrs	14/07/1967	Unit 7	203,276 hrs	19/06/1981
Unit 3	301,809 hrs	07/03/1968	Unit 8	190,092 hrs	22/08/1981
Unit 4	297,087 hrs	17/06/1969	Unit 9	100,223 hrs	24/09/1993
Unit 5	268,864 hrs	29/12/1973	Unit 10	90,364 hrs	06/07/1994

Source: WAPDA (Mangla Hydropower Station)

2) Number of start/stop

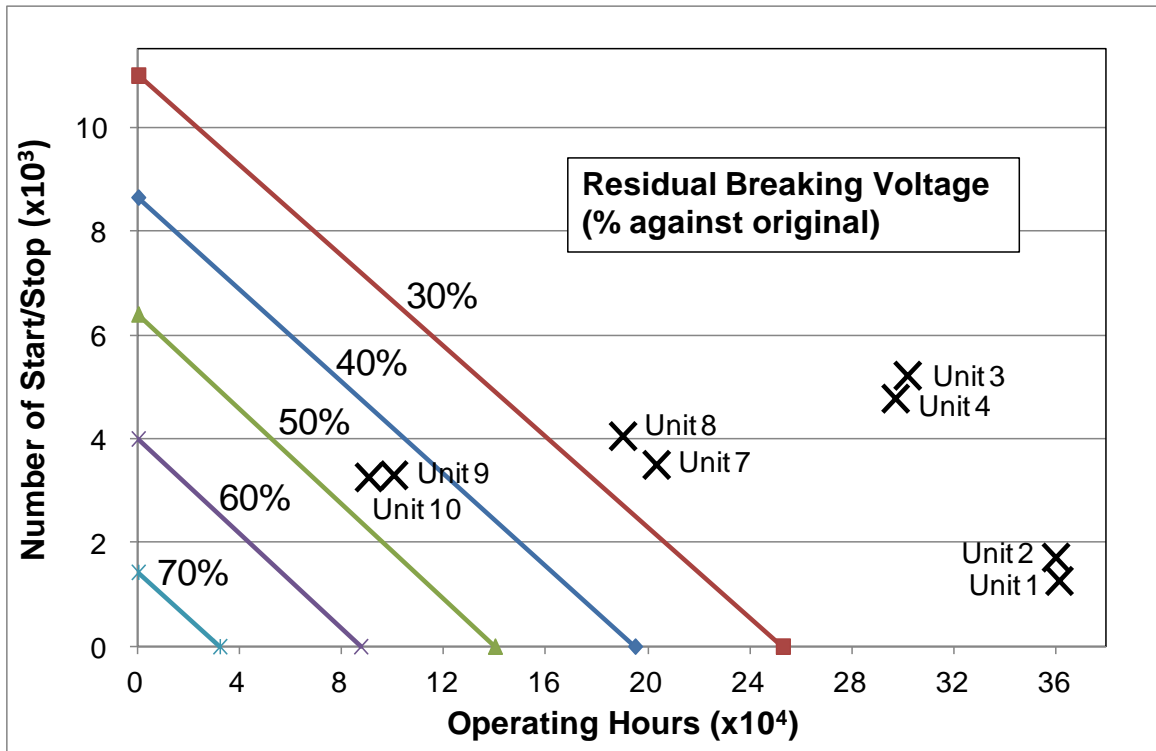
The number of start/stop of each unit is mentioned in Section 4.2, and the total numbers after commissioning are as follows;

Table 5-2 Number of Start/Stop

-	U-1	U-2	U-3	U-4	U-5	U-6	U-7	U-8	U-9	U-10
Total Number of Start/Stop	1,265	1,716	5,219	4,777	2,040	2,142	3,501	4,054	3,301	3,260

Source: WAPDA (Mangla Hydropower Station)

3) Estimation of residual life



From the above data, residual life of the stator winding is estimated as follows. This estimation used the graph of N-Y Map.

Source: Institute of Electrical Engineers of Japan, Modified by the Survey Team

Figure 5-1 N-Y Map

The N-Y map is taken from the report of the “Institute of Electrical Engineers of Japan”. However, since this map seems to be too severe, it will be used only as reference if the data is near the border of the limit line.

This N-Y map shows the percentage of residual breaking voltage against the original breaking voltage. Original breaking voltage, which should be confirmed from the original manufacturer, is usually 4-5 times of the rated voltage.

Lower limit of the breaking voltage, which is the life limit, is 1000 V plus 2 times of the rated voltage (so called 2E + 1000).

The rated voltage of Mangla is 13,200 V, therefore the lower limit (voltage of life limit) is

27,400 V. On the other hand, when the original breaking voltage is assumed as 5 times of rated voltage, this original figure is calculated as 66,000 V. Then 27,400V of “2E + 1000” is 41% of original breaking voltage. This means that the 41% line is the border of life limit.

i. Unit 1

Operating hours since the commissioning up to the end of 2011: 361,373 hours

Number of start/stop: 1265

Taking into account the above two parameters in the N-Y map, the residual breaking voltage showed less than 30%; this means the stator winding of Unit 1 generator is already beyond the typical life of expectancy. Therefore, the stator coils for this unit need to be replaced.

ii. Unit 2

Operating hours since the commissioning up to the end of 2011: 360,017 hours

Number of start/stop: 1716

Taking into account the above two parameters in N-Y map, the residual breaking voltage showed less than 30%, this means the stator winding of Unit 2 generator is already beyond the typical life expectancy. Therefore, stator coils for this unit need to be replaced.

iii. Unit 3

Operating hours since the commissioning up to the end of 2011: 301,809 hours

Number of start/stop: 5219

Taking into account the above two parameters in N-Y map, the residual breaking voltage showed less than 30%, which means that the stator winding of Unit 3 generator is already beyond its typical life expectancy. Therefore, stator coils for this unit need to be replaced.

iv. Unit 4

Operating hours since the commissioning up to the end of 2011: 297,087 hours

Number of start/stop: 4777

Taking into account the above two parameters in the N-Y map, the residual breaking voltage showed less than 30%, which means that the stator winding of Unit 4 generator is already beyond its typical life expectancy. Therefore, the stator coils for this unit need to be replaced.

v. Unit 5

Operating hours since the commissioning up to the end of 2011: 268,864 hours

Number of start/stop: 2040

Stator coils were rewound in 1991 and repaired in 2010. This unit is now operating at reduced load. However, the replaced coils are not from the original manufacturer, thus, the stator coils are recommended to be replaced.

vi. Unit 6

Operating hours since the commissioning up to the end of 2011: 263,583 hours

Number of start/stop: 2142

As the design of the generator of this unit is the same as Unit 5, the same trouble as Unit 5 is expected. Therefore, stator coils are recommended to be replaced.

vii. Unit 7

Operating hours since the commissioning up to the end of 2011: 203,276 hours

Number of start/stop: 3501

From the N-Y map, the stator coil of this unit is also in its last stage of life, but only 30 years have passed since the commissioning and the result of the insulation resistance test showed they are operating safely. Taking these into consideration and to assure reliable operation for the next 40 years, the stator coil is better to be replaced.

viii. Unit 8

Operating hours since the commissioning up to the end of 2011: 190,092 hours

Number of start/stop: 4054

From the N-Y map, the stator coil of this unit is also in its last stage of life, but only 30 years have passed since the commissioning and the result of the insulation resistance test showed the coils are operating safely. Taking these matters into consideration and to assure reliable operation for the next 40 years, the stator coil is better to be replaced.

ix. Unit 9

Operating hours since the commissioning up to the end of 2011: 100,223 hours

Number of start/stop: 3301

Stator coils for this unit are quite new, thus, replacement is not required.

x. Unit 10

Operating hours since the commissioning up to the end of 2011: 90,364 hours

Number of start/stop: 3260

Stator coils for this unit are quite new, thus replacement is not required.

From the above, stator winding (coil) of Units 1 to 4 are required to be replaced with new coils, regardless of the grade of rehabilitation (with enhancement or without enhancement).

For Units 5 and 6, although the stator coils were replaced in 1991, a major short circuit to the ground happened and rewinding was made as mentioned in Section 4.6. Therefore, replacement of the coils is recommended.

(2) Study of Other Parts of Generators (Other than Stator Coil)

Other parts were also studied whether rehabilitation/replacement is necessary or not.

The summary table is given on the following page of Section 3.2.4 and recommended parts to be replaced are as follows.

1) Units 1 to 4

i. Stator

Winding: By the reasons mentioned above, winding should be replaced.

Core: As these are beyond their typical life, the core should be replaced.

Frame: All frames should be replaced.

Necessary action:

Stator foundation should be inspected. There are some small cracks on the concrete below the stator.

Foundation bolts should also be inspected.

ii. Rotor

Field poles and field windings should be replaced, although the F/S report mentioned they can be reused. The reason is that they are beyond their typical life.

The following parts should also be replaced;

Top and bottom insulation collars, pole keys, pole leads, and damper connectors.

Other small parts will be decided after inspection at the detailed design stage such as non-destructive examination.

It is necessary to inspect rim plates and shrink keys at the detailed design stage and decide whether re-stacking is needed or not.

iii. Thrust and Guide Bearing

The thrust and guide bearing are in good condition.

iv. Brakes and Jacks

Brake and jack are required to be replaced newly.

v. Generator Cooling System

The following parts should be replaced:

Air coolers, all RTDs, and piping material inside of air housing.

vi. Generator Brush Assembly and Collector Rings

The static excitation system is recommended instead of the existing rotating excitation system, the generator brush and collector rings should be replaced with new ones, including the upper shaft.

In case these parts will remain in their existing positions to keep the generator flywheel effect, the collector ring and brush holder should be replaced.

vii. Generator Main Leads

Most of the parts can be used with some rehabilitation such as re-insulation or improvement of contact conditions. Flexible connectors should be replaced.

viii. Excitation System

As the existing system is rather obsolete system, this should be replaced with static digital excitation system.

ix. Generator Main Bus (Isolated Phase Bus)

Some tests such as insulation resistance measurement and bus resistance measurement, or other systemic tests, are necessary but they seem to be reused.

2) Units 5 and 6

Although the F/S report mentioned another idea, all parts for these units, except the main-bus (IPB), are recommended to be replaced, with the reasons mentioned above in Section 3.2.3 and with the reasons such as;

- Major short circuit happened and design of upper guide bearing need to be changed.
- Unit 5 is operating with only limited output.
- Both coils for Units 5 and 6 were damaged and replaced with non-original manufacturer's coil.

3) Units 7 and 8

Most of the comments for these units are the same as the F/S report.

i. Stator

Winding : As this will soon reach the typical life expectancy, windings should be replaced. But priority is not so high.

Core : Core should be replaced due to the same reason as mentioned above.

Frame : All frames should be replaced.

ii. Rotor

Field poles and field windings are still in good condition, so they can be reused after re-insulation.

It is possible to reuse most of the other parts.

iii. Thrust and Guide Bearings

Thrust and guide bearings are in good condition.

iv. Brakes and Jacks

Brake and jack are required to be replaced newly

v. Generator Cooling System

The following parts should be replaced:

Air coolers, all RTDs, and piping material inside of air housing.

vi. Generator Brush Assembly and Collector Rings

Brush holder, although apparently in good condition, are old finger-type brush holders and should be replaced with new ones.

Most of other parts can be used with some rehabilitation.

vii. Generator Main Leads

Most of the parts can be used with some rehabilitation such as re-insulation or improvement of contact conditions.

Flexible connectors should be inspected and replaced, if necessary.

viii. Excitation System

It may be possible to reuse, but for highest reliability the voltage regulator should be the digital type to eliminate analog component drift.

ix. Generator Main Bus (Isolated Phase Bus)

Some tests such as insulation resistance measurement, bus resistance measurement, or other systemic tests, are necessary but they seem to be reused.

4) Units 9 and 10

Most of the comments for these units are same as the F/S report.

i. Stator

To assure reliable operation for the next 40 years, the stator winding needs to be replaced in next 10 to 15 years.

ii. Rotor

Most of the parts are possible to reuse.

iii. Thrust and Guide Bearing

The thrust and guide bearing are in good condition.

iv. Brakes and jacks

Brake and jack are required to be replaced newly.

v. Generator Cooling System

For every cooler, one RTD for measuring the inlet air temperature and one RTD to measure the exhaust air temperature should be installed.

The following parts should be replaced;

Air coolers and piping material inside of air housing.

vi. Generator Brush Assembly and Collector Rings

All the parts can be reused.

vii. Generator Main Leads

The generator main leads are suitable to reuse.

viii. Excitation System

According to the Mangla operation staff, as mentioned in Sub-clause 4.2;

AVRs of Units 9 and 10 are more sensitive and any variation in this system trips the units, e.g., whenever load demand decreased, there is an option to shut down any unit, Units 9 and 10 are preferred to be shut down first. Due to problematic AVRs these units were started for peaking and shut down afterwards. Therefore, the number of start/stop for these units is rather high than any other units.

Therefore, this system is recommended to be replaced.

ix. Generator Main Bus (Isolated Phase Bus)

The generator main bus is suitable for reuse.

5.2.2 Study on Enhancement of Generator

(1) Units 1 to 4

The replacement of stator coils is recommended as mentioned above in Section 5.1 whether enhancement is considered or not. Aside from the stator coil, other parts required to be replaced are given below. More parts other than just rehabilitation are added here, which are required to be replaced due to increase in weight of the generator.

i. Stator

All parts such as winding (coil) and core should be replaced.

Necessary action

Stator foundation should be inspected. There are some small cracks on the concrete below the stator.

Foundation bolts should also be inspected.

If the load in the vertical and horizontal directions is increased by around 30% after enhancement, it seems to be fine because the original foundation design has more than 50% margin.

ii. Rotor

Only the rotor spider and rim plates can be used and other parts such as poles and field winding should be replaced due to the increase in current.

The deterioration of field winding are expected as same conditions as the stator winding. Therefore these parts are recommended to be replaced, as stator winding is judged to be replaced.

iii. Brakes and Jacks

Brake and jack are required to be replaced newly.

iv. Generator Cooling System

The following parts should be replaced: air coolers, all RTDs, and piping material inside of air housing.

v. Generator Brush Assembly and Collector Rings

According to the capacity increase, the excitation system will also be upgraded, and static excitation system is recommended. Furthermore, a new upper shaft with collector rings should be provided.

In case the existing DC exciter will remain in its position to keep the generator flywheel effect, the collector ring and brush holder should be replaced.

vi. Generator Main Leads

According to the capacity increase, the main leads must also be upgraded, therefore replacement is necessary.

vii. Excitation System

According to the capacity increase, the excitation system must be upgraded, and static excitation system is recommended. Furthermore, a new upper shaft with collector rings should be provided.

viii. Generator Main Bus (Isolated Phase Bus)

According to the capacity increase, the current rating must be increased, therefore this should be replaced with upgraded IPB.

ix. Guide and Thrust Bearing

According to the weight increase, the guide bearing, thrust bearing, and thrust runner (which is mounted on the rotor) should be replaced.

Thrust bearings were not replaced these more than 40 years from the commissioning of these units, and then they must be deteriorated. Thrust bearing is the most important mechanical parts, which support the rotating parts of not only generator rotating parts but also turbine rotating parts. If these parts will be damaged, a serious accident of turbine/generator will be expected. This accident may extend another parts damage and cause very long term unit stoppage for repair. This is the reason that these bearings are recommended to be replaced.

(2) Units 5 and 6

The Survey Team recommended the replacement of all parts for Units 5 and 6 due to the reasons mentioned above in Sub-section 3.2.3 and the following:

- Major short circuit happened and design of the upper guide bearing needs to be changed.
- Unit 5 is operating with only limited output.
- Both coils for Units 5 and 6 were damaged and replaced with non-original manufacturer's coil.

It is further recommended that design of the guide bearing should be changed to reduce oil splashes.

(3) Units 7 and 8

Same as Units 1 to 4, when these units are required to be upgraded.

- (4) Units 9 and 10

Same as Units 5 and 6, when these units are required to be upgraded.

5.2.3 Study on Enhancement of Auxiliary Equipment for Generator

According to the enhancement of the generator output, the IPB and generator transformer should be checked as below:

- (1) IPB

The current rating of each IPB is 6,287A for Units 1 to 6, 6000 A for Units 7 and 8, 6300 A for Units 9 and 10. On the other hand, the current rating, after enhancement up to 180 MVA of generator capacity, should be 7873 A. Therefore, the existing IPBs of the object units of enhancement do not have enough current rating, and they need to be replaced.

- (2) Generator Transformer

The rated capacity of existing generator transformers are 138 MVA for Units 1, 2 and 4 to 6, and 144 MVA for Units 3 and 7 to 10. Therefore, after enhancement to 180 MVA of generator capacity, all the transformers of object units of enhancement need to be replaced.

5.3 Control and Protection

5.3.1 General

- (1) The facilities aimed for rehabilitation and enhancement through the Project include:
- i. Control and protection system for upgrading units; and
 - ii. Control systems significantly requiring improvement.
- (2) Selection criteria of aimed facilities
- i. Upgrading of units will replace the governors, automatic voltage regulator (AVRs), and associated auxiliary equipment with turbines, generators, and step-up transformers. New control, protection, and interface circuits among them should be installed.
 - ii. The following modifications shall improve the operation performance and stabilities for the
-

Mangla Power Station:

- Units 3 and 4 will be connected to 132 kV bus for reduction of overloading of interconnection transformers (132/220 KV).
- Modification of 11 kV station service circuit for station service restoration.

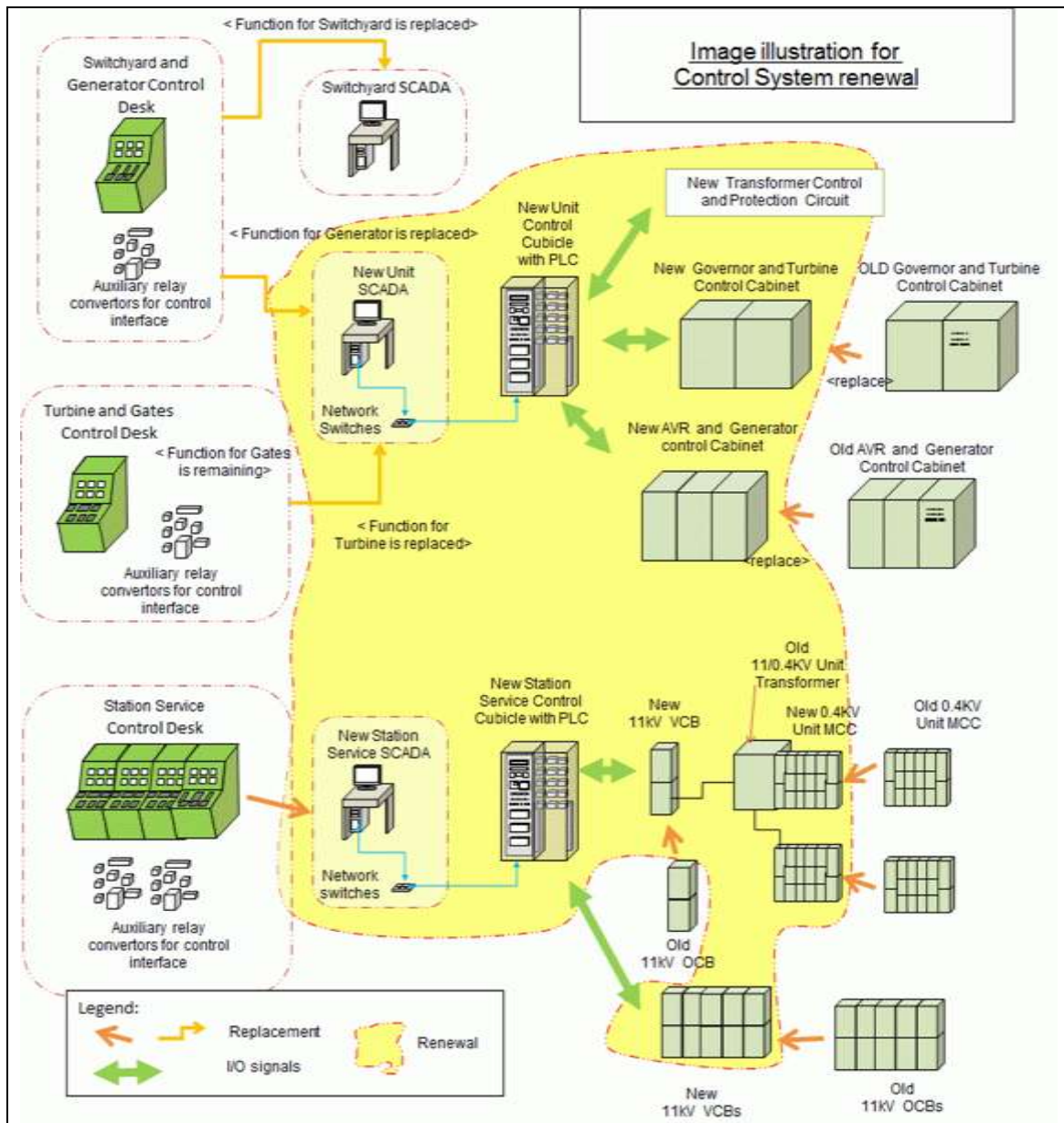
(3) Countermeasure against aged facilities

Not only units for upgrading but also almost all facilities in the power station are aged.

Remaining facilities will be subjected to replacement or rehabilitation works, but such works require long-time unit stoppages, which affect the power conveyance under the power shortage.

However, through good maintenance of the power station, such facilities can be kept in operating condition for the time being. Therefore, it is preferable that the control and protection system rehabilitation will be done parallel with the main units programmed for repair or overhaul by other projects.

Illustration of the replacement or modification of the control system is shown in Figure 5-2.



Source: Prepared by the Survey Team

Figure 5-2 Image Illustration for Control System Renewal

5.3.2 Control and Protection for Generation Units

(1) Components of Control System

The Survey Team recommended that the control system will be replaced from the conventional wired logic circuit with programmable logic controller (PLC) and supervisory control and data accusation system (SCADA), which is the same option as in the F/S. The system will be configured by the following components. A sample of the four generation units control system is shown in Figure 5-3.

1) Unit Local Control Panel (Cubicle)

The PLCs will be equipped in the unit local control panels. This panel performs to control the turbines and generators automatically through the governor /turbine control cabinets, and AVR/generators cabinets. The PLCs are linked to SCADA in the control room for remote control. All of the field data are collected to the PLCs, then the PLCs will send the collected data to SCADA through a network.

2) Programmable Logic Controller (PLC)

The PLC performs the functions instead of the conventional wired logic sequence control circuit, and additionally, will implement the automatic units control functions.

3) Touch Panel

Local control panels will have touch panels, which perform the human machine interfaces instead of conventional indicators and switches. The touch panel will show the status of units and measurement values on the LCD.

The PLC is an electronic device; normally capacities of the voltage or breaking current for field devices are not enough to control directly, and some of field sensors' signals also cannot match PLCs' input. Therefore, some of interface circuits will be installed between the PLCs and such field equipment. Such interfacing circuit is called an interposing circuit in this report. This circuit will be equipped in specified panels beside the PLCs, which are called in this report as interposing relay panels.

4) Units SCADA (Supervisory Control and Data Accusation system)

This SCADA consists of PLC SCADA servers (data server), human machine interface (HMIs), engineering work station, and network switches. It is not a SCADA system for grid system control. It controls and supervises the turbine and generator from the control room instead of actual conventional turbine control desks, and generator and switchyard control desks. The SCADA system is based on the PCs (personal computers).

5) HMI

This is a human interface device between the operator and SCADA control system. The HMIs' screen (LCD) shows the status and condition of turbines, generators, step-up transformers, and such associated auxiliary equipment. The HMI receives the operator's control command for the turbine and generator via a keyboard or a mouse. It is prepared for each generation unit.

6) PLC SCADA Server (PC)

This is a data server between the HMIs and PLCs. The operator's commands are written in the database, and this database is read by the PLC. Collected status and measured value by the PLC is transferred to the PLC SCADA server, written in the database, and read by the HMIs.

7) Historical Event Recorder Function

This function chronologically arranges and shows the occurring events and troubles on the screens (LCD) or printers.

8) Periodical Data Report Function

This function performs to arrange and print the measured data such as energy production, water discharge, voltage, and current per day, week, or month.

9) Engineering Work Station (PC)

This computer is used for SCADA system maintenance. A system administrator can change the system parameters and troubles are analyzed through this computer.

10) Automatic Synchronizer

Actually, two sets of automatic synchronizer are used for ten units. These synchronizers are also old, and the VT signal selection circuit is complicated.

Automatic synchronizer for upgrading units will have an independent automatic synchronizer for each two units. (e.g., Units 1 and 2, Units 3 and 4)

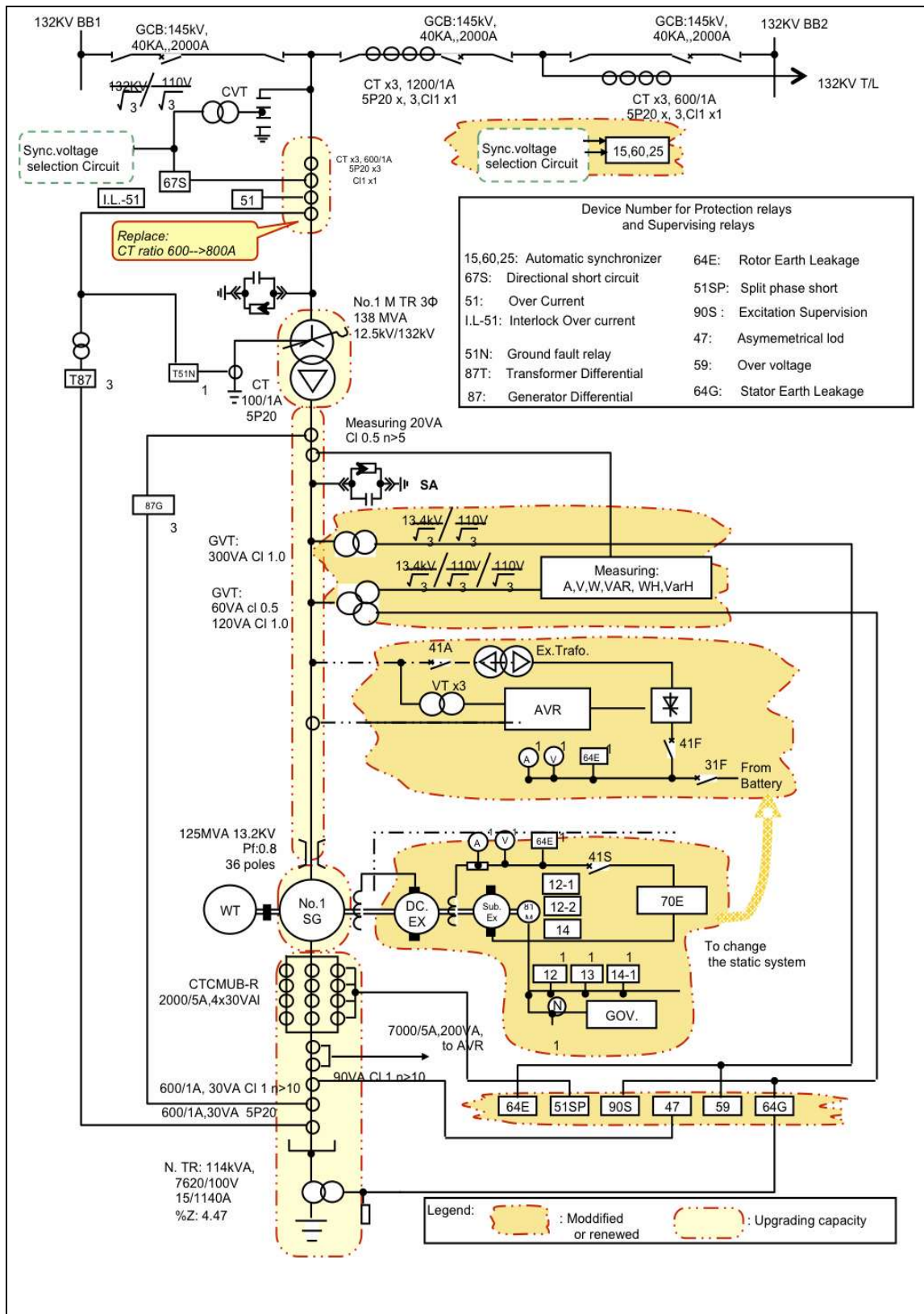
- i) This modification can be able to revise and adjust the synchronizing circuits without interruption of the synchronization of another unit.
- ii) Circuit breaker closing and generator voltage and speed adjustment parameters can be adjusted per each two units.
- iii) The cost of an automatic synchronizer is actually not high.

(2) Protection Relay System

The Survey Team recommended replacing the conventional protection relays with digital relays, which is the same option as in the F/S.

The attached single line diagram, Figure 5-4, shows the modification places and protection relay elements.

The protection relay elements are almost the same as actual system. Some of the additional elements will be added as VT failures.



Source: Prepared by the Survey Team

Figure 5-4 Single Line Diagram for Generation Unit with Modification Places

5.3.3 Control and Protection for Switchyard

(1) Opinion of the Survey Team about the Switchyard Control and Protection

The control and protection of transmission lines should be designed with unified philosophy between both ends of stations. Therefore, planning should be a concern of the NTDC/NPCC and opposite side stations. Due to such situation, the Project will modify the related facilities for generation upgrading. The modification of the transmission line protection and control system can almost be done separately from generation unit modification work.

(2) Control

Mainly, the control and protection system consists of conventional wired logic sequence circuits. The indicators, auxiliary relays, and wires are still used from the original installed condition.

The circuit control function will be maintained as the original. The F/S report recommended to replace entirely with a new system, but the Project will not replace to modern circuit as PLC due to reason (1) above.

Intended scope of the Project is shown in Table 5-3.

Table 5-3 Switchyard Control System Work

Circuit	Scope of Refurbish Work
Control and Monitoring for Transmission Lines	Not part of the scope
Control and Monitoring for Generator Feeders	Automatic synchronization for circuit breaker is part of the scope; others are not part of scope. *1
Control and Monitoring for 220 kV/132 kV Interconnection Transformers	Not part of the scope
132 kV/11 kV Station Service Transformers	Not part of the scope, but some circuits will be modified by the Project.

Source: Prepared by the Survey Team

Note *1: Synchronizing relays will be installed per unit for simplification of VT selection circuit.

(3) Protection

Actually, generator feeder line protections are installed with the same protection panels of transmission lines, which are connected with the same bays of feeder lines. The function of the feeder protection (over current and unit differential relays) will be implemented in the new generator unit protection systems. Related circuits of bus protection and breaker failures protections will be exempted from the scope because they are deeply related to other transmission lines and circuits.

Some transmission line protection relays were replaced already with digital protection relays.

Table 5-4 Switchyard Protection System Work

Circuit	Scope of Refurbish Work
Protection for Transmission Lines	Not part of the scope
Protection for Generator Feeders	Not part of the scope, but some circuits will be modified by the Project.
Protection for 220/132 kV Interconnection Transformers	Not part of the scope
132 kV/11 kV Station Service Transformers	Not part of the scope, but some parts will be modified by the Project.

Source: Prepared by the Survey Team

(4) Resetting Parameters for Actual Protection Relays

The set values and parameters of protections relays as bus protection, CB failures, feeder line protections will be required to change.

The protection relays will not be changed by the Project. The modified circuits and cable relocation are required, which are consequences of the generator feeders' relocation. These will be implemented by the Project.

(5) Relocation of Generator Feeders

The control and protection circuit modification for the generator feeder lines will be required in the generator upgrade. Table 5-5 shows the modification bays. These protection and control systems for the bays are the targets of modification work.

Table 5-5 Modified Bay Comparison

Bay No.	Original Circuit	Feeder CT Ratio	Circuit CBs Rate	New Circuit	Remarks
E1	T/L Spare	-	-	GEN1. Feeder	Remove
E2	GEN1. Feeder	600/1 A	-	GEN2. Feeder	-
E4	STR TR. No.2	-	-	GEN3. Feeder	-
E5	GEN2. Feeder	-	-	GEN4. Feeder	Remove and Standby
D8	GEN3. Feeder	-	-	ICT TR No.3	-
D9	GEN4. Feeder	-	-	STR TR No.3	220/11 kV
D15	ICT TR No.3	-	-	Spare	-

Source: Prepared by the Survey Team

Note: T/L (Transmission Line), GEN (Generator), ICT TR (Inter Connection Transformer), STR TR (Station Service Transformer)

(6) Summary Table of Transmission Line Equipment

In the case of the upgraded generator is 150 MW (PF=0.8), its step-up transformer's capacity will be more than 187 MV control and protection system. The rated current is around 820 ampere (A) at 132 kV circuit, and 410 (A) at 220 kV circuit.

Current transformer (CT) ratios for the system should also be changed.

Consideration for interruptible short circuit currents of the circuit breakers should also be

studied against the generator upgrading.

Tables 5-6 and 5-7 below show present facilities for each circuit for reference in the study.

Table 5-6 Summary of 132 kV Transmission Line Circuits

BAY		Circuit Name	CB TYPE	CT Ratio	Main Protection Relay
-E3	1*	ICT No.3	*GCB4	1600-800-400/1 A	
	C*		*GCB4	1600-800-400/1 A	
	2*	No facilities			
-E1	1	DADAYAL	*GCB5	800/1 A	(DZ) GE:SHPM101
	C		*GCB5	800/1 A	
	2	KALLAR SYEDAN	*GCB5	800/1 A	(DZ) GE:SHPM101
-E2	1	DADYAL FUTURE		1600-800-400/1 A	
	C			1600-800-400/1 A	
	2	OLD RATAWA FUTURE		1600-800-400/1 A	
E0	1	CATTAR PARI / MIR PUR	*ACB3	600-300/1 A	(DZ) ABB:REL670
	C		*ACB3	1200/1 A	
	2	KUTHIALAIN SHEKHIAN	*ACB3	600-300/1 A	(DZ),BBC:L3 wyS
E1	1	MANGLA RIGHT BANK	*GCB2	600-300/1 A	(DZ),BBC:L3 wyS
	C		*GCB2	1200/1 A	
	2	RAJAL	*GCB2	600-300/1 A	(DZ),BBC:L3 wyS
E2	1	GEN. No.1	*ACB1 -> *GCB2	600/1 A	
	C		*GCB2	1200/1 A	
	2	G KHAN	*ACB1 -> *GCB2	600-300/1 A	(DZ),BBC:L3 wyS
E3	1	STN TR No.1	*ACB1	50/1 A, 300/1 A	
	C		*GCB2	1200/1 A	
	2	N RAWAT	*GCB2	600-300/1 A	(DZ),BBC:L3 wyS
E4	1	STN TR No.2	*ACB1-> *GCB2	50/1A, 300/1 A	
	C		*ACB3	1200/1 A	
	2	DINGA	*ACB3	600-300/1 A	(DZ),BBC:L3 wyS
E5	1	GEN. No.2	*ACB1 -> *GCB2	600/1 A	
	C		*GCB2	1200/1 A	
	2	KHN 2	*ACB1 -> *GCB2	600-300/1 A	(DZ) ABB:REL670
E6	1	ICT TR No.1	*GCB2	600/1 A	
	C		*GCB2	1200/1 A	
	2	KHN 3	*GCB2	600-300/1 A	(DZ) ABB:REL670

Source: Prepared by the Survey Team

Note 1: BUS-I side circuit, 2: BUS-II side circuit, C: Middle circuit

Table 5-7 Summary of 220 kV Transmission Line Circuits

BAY		Circuit Name	CB TYPE	CT Ratio	Main Protection Relay
D7	1*	ICT TR No.1	*GCB3	400/1 A	
	C*		*GCB3	1500/1 A	
	2*	MANGLA NEW RAWATA 1	*GCB3	1000-500/1 A	(DZ) BBC:LZ31-20
D8	1	GEN. No. 3	*GCB3	400/1 A	
	C		*GCB3	1500/1 A	
	2	MANGLA NEW RAWATA 2	*GCB3	1000-500/1 A	(DZ) BBC:LZ31-20
D9	1	GEN. No. 4	*GCB3	400/1 A	
	C		*GCB3	1500/1 A	
	2	KSK 2	*GCB3	1000-500/1 A	(DZ) SIE:7SA 5131
D10	1	GEN. No. 5	*ACB3	400/1 A	
	C		*ACB3	1500/1 A	
	2	KSK 1	*ACB3	1000-500/1 A	(DZ) SIE:7SA 5131
D11	1	GEN. No. 6	*ACB3	400/1 A	
	C		*ACB3	1500/1 A	
	2	KSK 3	*ACB3	1000-500/1 A	(DZ) BBC: LZ32
D12	1	GEN. No. 7	*GCB1	400/1 A	
	C		*GCB1	1500/1 A	
	2	GHK 1	*GCB1	1000-500/1 A	(DZ) BBC: LZ32
D13	1	GEN. No. 8	*GCB1	400/1 A	
	C		*GCB1	1500/1 A	
	2	N. GHK	*GCB1	1000-500/1 A	(DZ) BBC: LZ32
D14 β	1	GEN. No. 9	*GCB1	400/1 A	
	C		*GCB1	1500/1 A	
	2	GEN. No. 10	*GCB1	400/1 A	
D15	1	ICT No.3	*GCB7	2400-1200-600/1 A	
	C		*GCB6	2400-1200-600/1 A	
	2	GHK 2	*GCB6	2400-1200-600/1 A	(DZ) GE: SHNB102

Source: Prepared by the Survey Team

Note: 1: BUS-I side circuit, 2: BUS-II side circuit, C: Middle circuit

<u>Abbreviation:</u>		
SIE: SIEMENSE	BBC: BROWN BOVERI	GE: GENERAL ELECTRIC
(DZ) : Distance relay	GEN: Generator Feeder Line	
ACB: Air blast Circuit Breaker	GCB: Gas Circuit Breaker	
*ACB1: BBC, DHVF-170 nc4d, 145 kV-21.9 kA	*ACB2: ABB, DLF-145 nc2d, 145 kV-30.6 kA	
*ACB3: ABB, DLF-245 nc4, 245 kV-31.5 kA	*GCB1: ABB, HPL245/25B1, 245 kV- 40 kA	
*GCB2: SIEMENSE, 3AP FG, 145 kV-40 kA	*GCB3: SIEMENSE, 3AP F1, 245 kV-50 kA	
*GCB4: ABB, LTB 145 D1/B, 145 kV-40 kA	* GCB5: ABB, HPL 145/2501,145 kV-50 kA	
*GCB6: SPRENCHER ENERGY, HGF-114/1 A, 245 kV-40 kA	*GCB7: NUOVS MAGRINI GALILEO, 245 kV-50 kA	
ACB -> GCB: There is a plan to replace from ACB to GCB.		

(7) Requirement of Modification for Switchyard SCADA

The program or parameter of SCADA should be modified to adapt to the relocated generator feeders and station service transformers' locations. The generator feeders CTs ratios will be changed, and the measuring program will also require modification.

For more effective supervision of the power station, data exchange via LAN will be requested for this SCADA and generating unit SCADAs.

5.3.4 Protection and Control System for Station Service

(1) Circuit Configuration Plan by the Survey Team

Figures 5-5 and 5-6 show the idea of the Survey Team. This plan totally considers the modification generator feeder replacement and station service circuit. It is designed more simply to avoid the complicated interlock and operation procedure of switchgears, in which the increase of components in the circuits will correspondingly increase trouble and complexity.

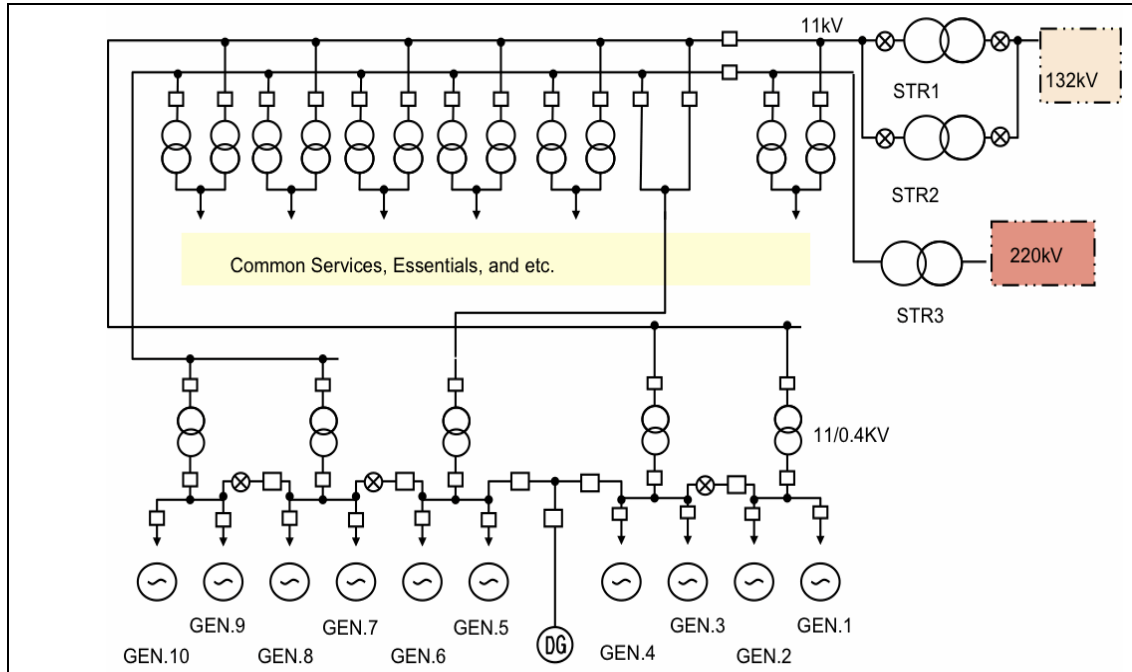
Overall modification requires station service stoppage for a long time. This means prolonged unit stops, thus it is not a realistic solution for the Mangla Power Station. The station service modification work requires unit stoppage for as short time as possible. The Survey Team's concept considers this matter.

Figure 5-7 shows the circuit transition through the modification work.

- Redundancy of power supply:

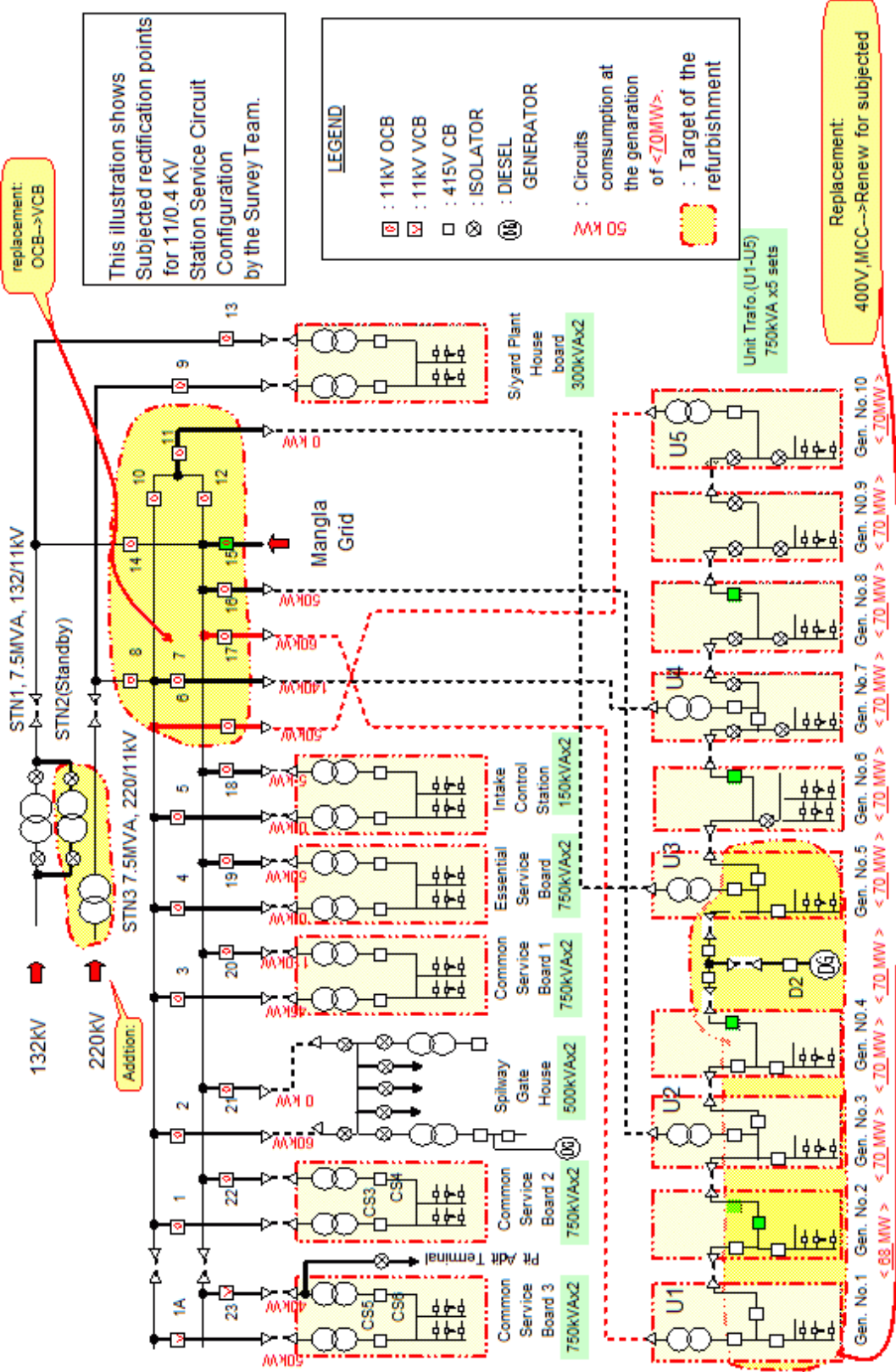
Station service power transformers are connected with 132 kV bus and 220 kV bus. The 220 kV transformer is an additional, while one of the existing 132 kV transformers can be used as standby transformer.

The Survey Team suggest further study on modification of station service power supply circuit at the detailed design (D/D) stage.



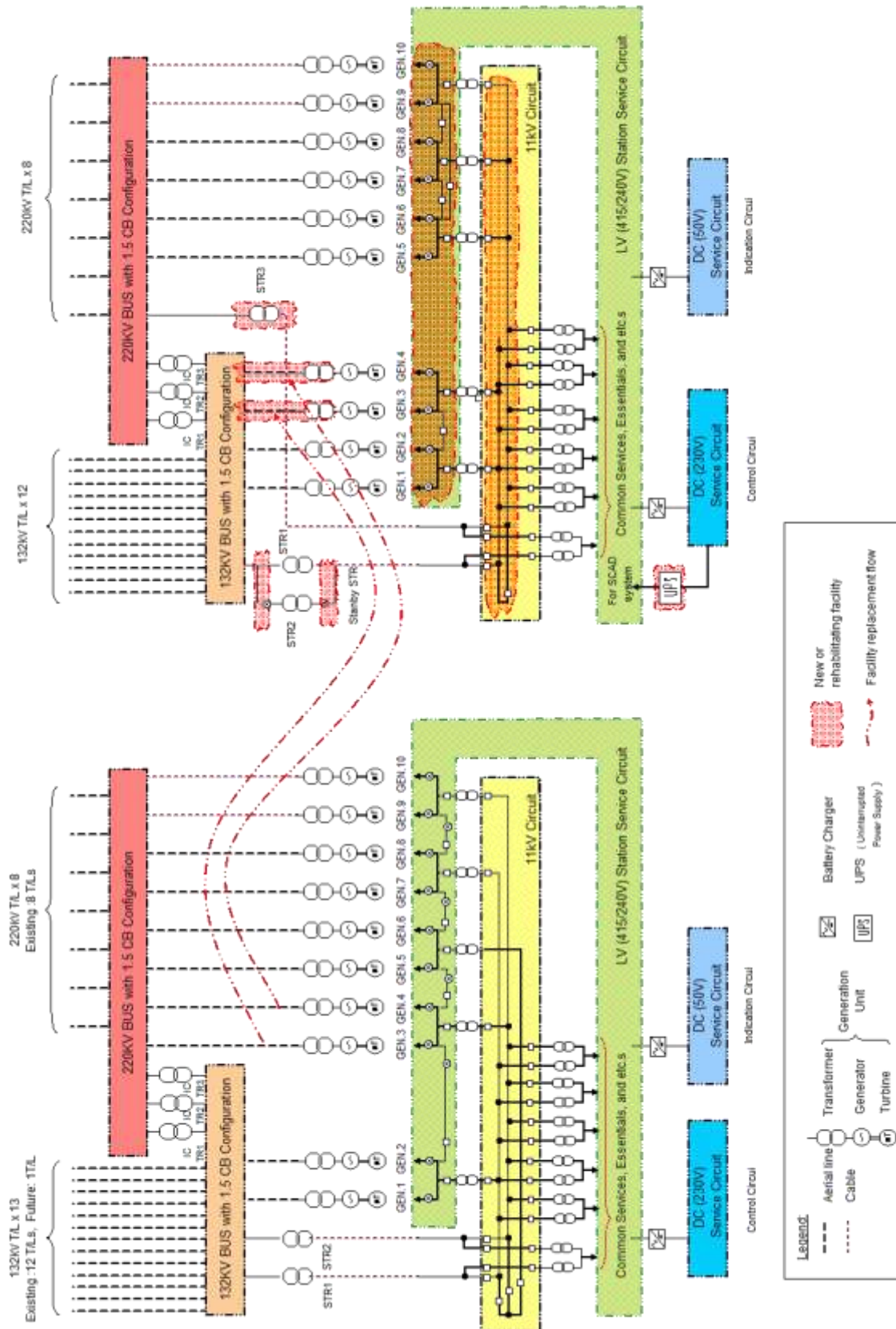
Source: Prepared by the Survey Team

Figure 5-5 Station Service Configuration by the Survey Team



Source : Prepared by the Survey Team

Figure 5-6 Suggested Station Service Circuit by the Survey Team



Source : Prepared by the Survey Team
 Figure 5-7 Station Service circuit Transition

(2) Necessity of Low Voltage (415 V) Circuit Modification

The F/S report's alternative plans also required low voltage-side modification.

Particularly for options 3, 4, and 5, it seems that the effective result cannot be obtained without low voltage circuit modification as described in Sub-section 3.2.4.

Low voltage circuit modification requires further study of actual circuits. For example, the connected loads will be classified into the following categories in the table below to adapt each operation scenario such as blackout start, normal start and run.

Table 5-8 Categories of Low Voltage Circuit

Class-A	Equipment must operate before units start.	Condition of blackout start
Class-B	Equipment should operate during unit operation	Condition of unit operation
Class-C	Equipment can allow stoppage of operation in a few hours.	Availability of operation after unit synchronizing

Source: Prepared by the Survey Team

(3) Appurtenant Work

The replacement of low-voltage circuit cables and mold circuit breakers which are installed and connected to "the motor control center cabinets for turbine and generator auxiliary equipment" are also required with the upgrading of such facilities.

(4) Service Circuit Breakers of 11kV Station

Actually, there are a total 26 sets of 11 kV circuits; 24 sets of oil circuit breaker (OCBs) and two sets of vacuum circuit breakers (VCBs) were installed recently. The OCBs are almost outdated, and are recommended to be replaced with VCBs. It is the same recommendation in the F/S.

5.3.5 Control and Protection for 11KV Generator Circuit Breaker

The F/S report recommended the modification plan for the station service circuit as option-5 as described in Sub-section 3.2.4. This plan requires generator circuit breakers installation between the transformer and the generator. Unit supply of 11/0.4 kV transformer branches from the 11 kV side of step-up transformer with the station service 11 kV circuit breaker.

Power supply for generator and turbine auxiliaries is fed from the unit supply transformer after excitation. The Survey Team is against this plan:

Some of auxiliaries such as the cooling water system should be operated before unit starts.

Station drainage system should be continually operated without turbine operation condition.

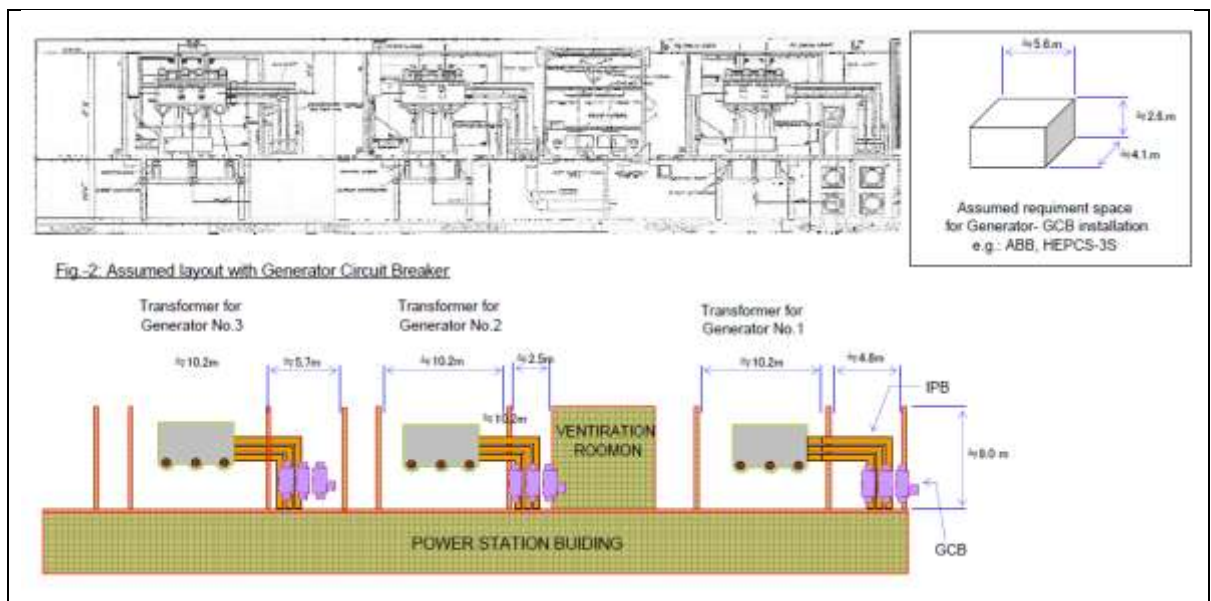
For the installation of generator CB, it requires high cost and large-scale building and IPB modification.

The 11 kV side generator current is around 8000 amperes. The price of generator circuit breaker is very high and there are not so many suppliers in the market.

Finally, some of the essential or common services still require power supply before the start and stoppage of the unit like the cooling water system and drainage system. Other power sources are still required for them. Therefore, such modification cost performance is not as high as anticipated in the F/S report. And it still remain as the requirement of common and essential power supply.

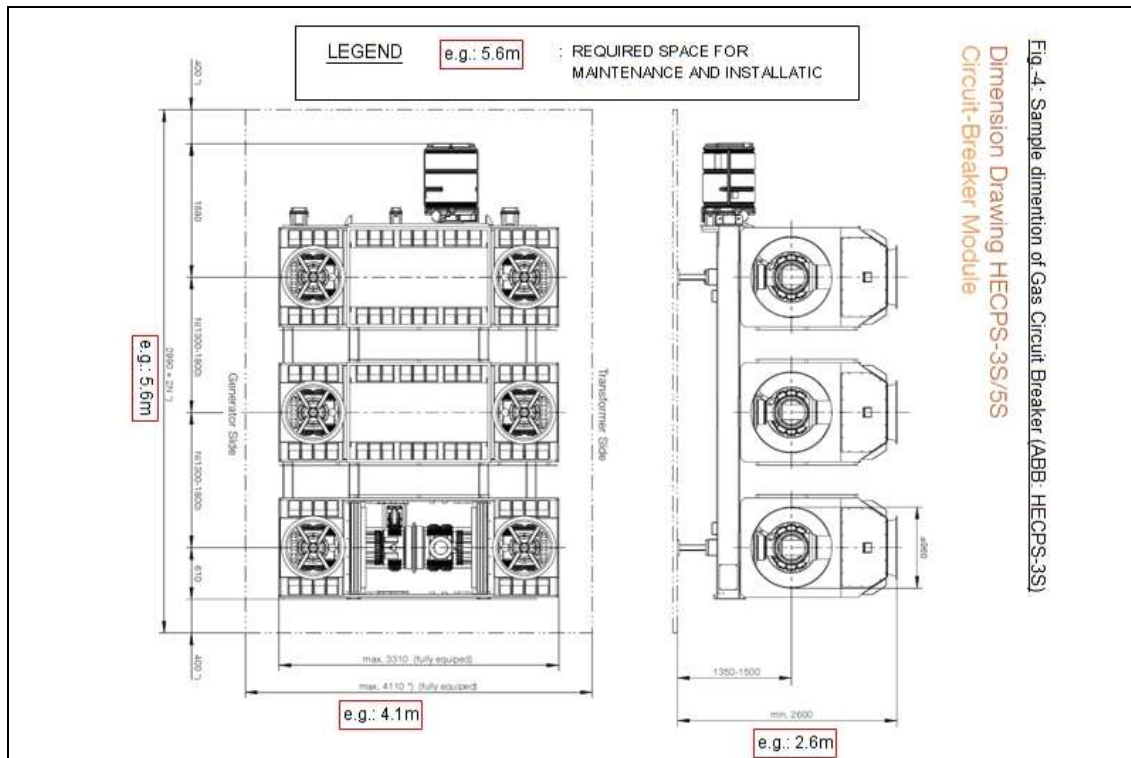
Figures 5-8 and 5-9 show an example of 11 kV generator circuit breaker installation and a sample of circuit breaker size.

The Survey Team suggest further study on modification of 11 kV generator circuit breaker at the detailed design (D/D) stage.



Source: Prepared by the Survey Team

Figure 5-8 Sample Layout for GCB Setting



Source: Prepared by the Survey Team

Figure 5-9 Sample Dimension of GCB

5.4 Switchyard

5.4.1 Study on Rehabilitation and Enhancement of Switchyard

To lessen the power flow from 220 kV to 132 kV in the switchyard, the generators' connections to 132 kV and 220 kV are required to be modified.

In the rehabilitation and enhancement project, the step-up transformers for the subject units shall be replaced by new ones to meet the enhanced capacity of 180 MVA, which is now 138 MVA for Units 1 to 4 and 144 MVA for Units 6 to 10.

Taking the opportunity, the generators connecting to 132 kV are increased to four units from two units at present, namely Gen. 1 to Gen. 4 to be connected to 132 kV and the remaining six units remain to be connected to 220 kV. The modification of the step-up transformers is shown in Table 5-9.

The Survey Team recommends conducting the simulation for verifying the stability of new power system in switchyard based on the their recommendation on the above at the detailed design (D/D) stage.

Table 5-9 Proposed Modification of Generator Connection to Switchyard

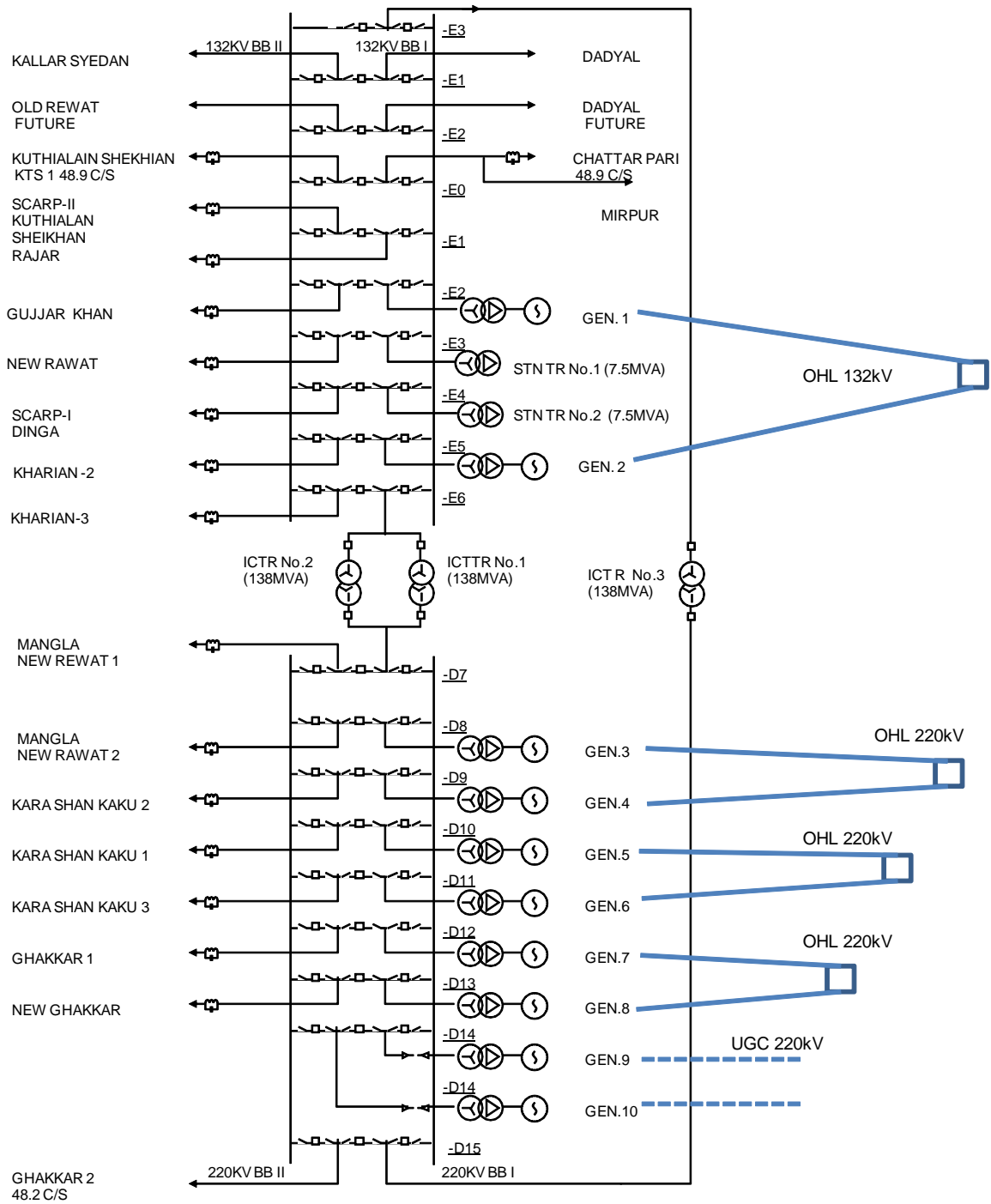
Existing Capacities are 138 MVA or 144 MVA			Modified Capacity: 180 MVA		
Generator	Step Up Tr.	SWS Bus	Generator	Step Up Tr.	SWS Bus
Unit 1	12.5/132 kV	132 kV	Unit 1	12.5/132 kV	132 kV
Unit 2	12.5/132 kV	132 kV	Unit 2	12.5/132 kV	132 kV
Unit 3	12.5/220 kV	220 kV	Unit 3	12.5/132 kV	132 kV
Unit 4	↑	↑	Unit 4	12.5/132 kV	132 kV
Unit 5			Unit 5	12.5/220 kV	220 kV
Unit 6			Unit 6	↑	↑
Unit 7			Unit 7		
Unit 8			Unit 8		
Unit 9	↓	↓	Unit 9	↓	↓
Unit 10	12.5/220 kV	220 kV	Unit 10	12.5/220 kV	220 kV

Source: Prepared by the Survey Team

Remarks: Rated voltage of generators output is 13.2 kV

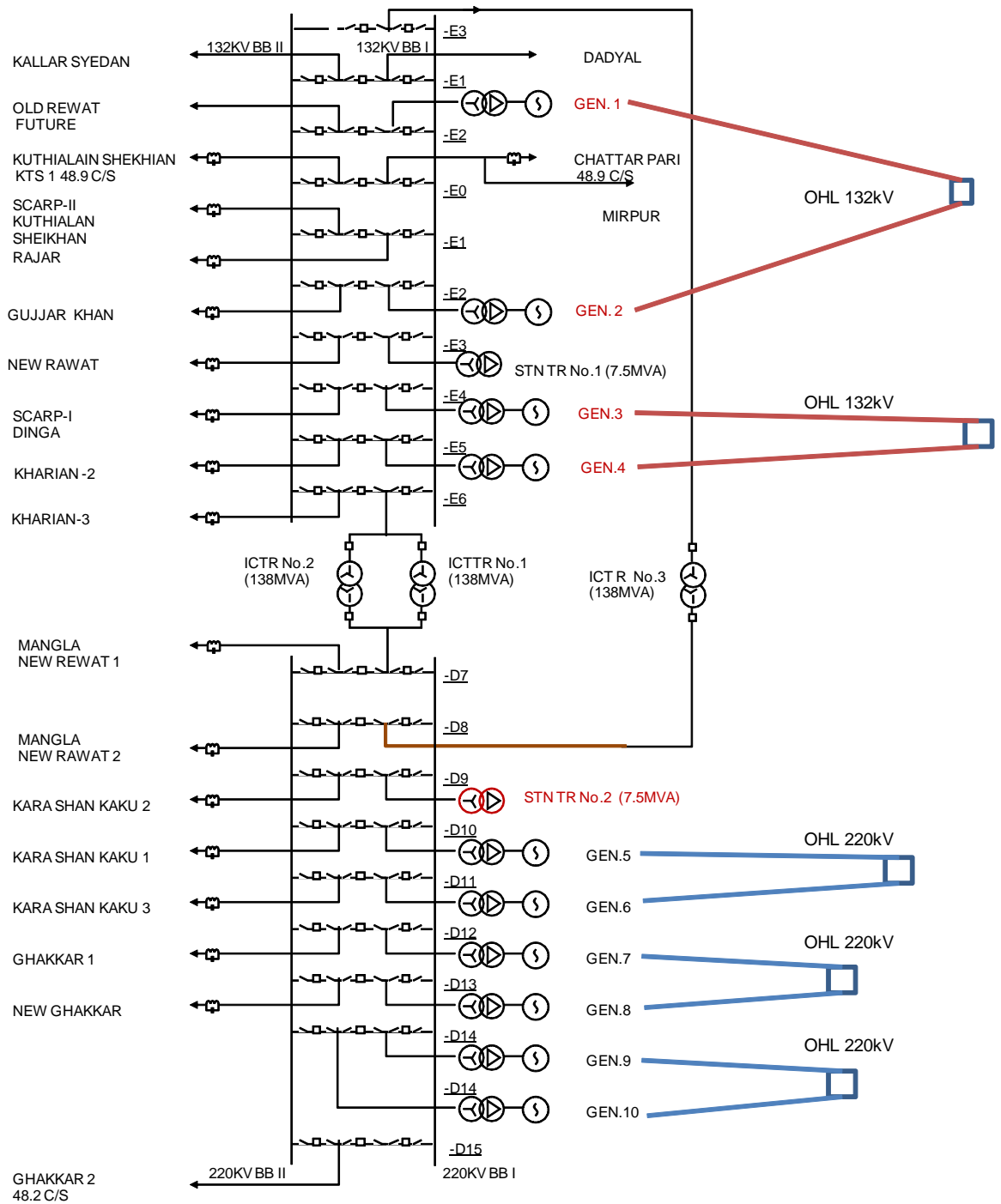
(1) Connection Diagrams for Before and After

The existing and proposed modification of generators' connection to the switchyard is shown in Figures 5-10 and 5-11, respectively.



Source: Prepared by the Survey Team

Figure 5-10 Existing Generator Connection to Switchyard



Source: Prepared by the Survey Team

Figure 5-11 Modified Generator Connection to Switchyard

(2) Procedure

The procedures of modification are as follows:

- 1) Underground cable connection of Units 9 and 10 generators to switchyard is modified to connect by 220 kV overhead line, which is done by NTDC
- 2) Rehabilitation and enhancement of Units 5 and 6:
No change in connection
- 3) Rehabilitation and enhancement of Units 1 and 2
No change in connection
- 4) Rehabilitation and enhancement of Units 3 and 4:
 - Change the step-up transformers for Units 3 and 4 to the voltage ratio of the 12.5/132 kV from 12.5/220 kV.
 - Connections of transmission lines for Units 1 and 2 are shifted to bay-E1 & E2 from E2 & E5, respectively.
 - Dismount station transformer No.2 7.5 MVA from bay E4
 - Shift the transmission lines for Units 3 and 4 to bay 132 kV E4 & E5 from 220 kV D8 & D9, respectively.
 - Connect a new station transformer No.2 220/11 kV 2.7 MVA to the bay of 220 kV D9
 - Shift the interconnecting transformer No.3 to bay D8 from the bay D15
- 5) Rehabilitation and enhancement of Units 7 and 8
No change in connection
- 6) Rehabilitation and enhancement of Units 9 and 10
No change in connection

5.5 Civil Works

5.5.1 Structure Reinforcement and Improvement

For the turbine and generator foundation, the diagnosis test for concrete strength by Schmidt Hammer was carried out on 27 February 2012 and the result is shown in Table 5-10. In general, a crack with less than 0.3 mm is a hair crack and not harmful to the structure even without any countermeasure.

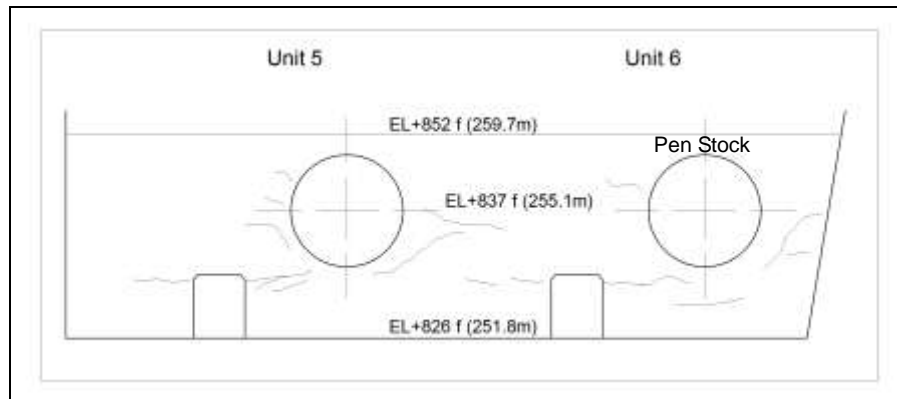
Table 5-10 Cracks in Power House

Foundation	Average Strength (N/mm ²)	Crack		Countermeasures
		Location	Size	
No.1	48.2	-	0.3 mm >	Epoxy Injection
No.2	50.3	-	0.3 mm >	Epoxy Injection
No.3	44.0	-	0.3 mm >	Epoxy Injection
No.4	48.5	-	0.3 mm >	Epoxy Injection
No.5	51.6	Around Pen Stock	> 5 mm	Epoxy Injection +Carbon Fiber
No.6	52.4	Around Pen Stock	> 5 mm	Epoxy Injection + Carbon Fiber
No.7	50.2	-	0.3 mm >	Epoxy Injection
No.8	51.6	Gallery	0.3 mm >	Epoxy Injection
No.9	48.3	-	0.3 mm >	Epoxy Injection
No.10	50.2	-	0.3 mm >	Epoxy Injection
-	55.4	Crane wall (Up)	0.3 mm >	Epoxy Injection
-	40.4	Crane wall (Down)	0.3 mm >	Epoxy Injection

Source: Prepared by the Survey Team

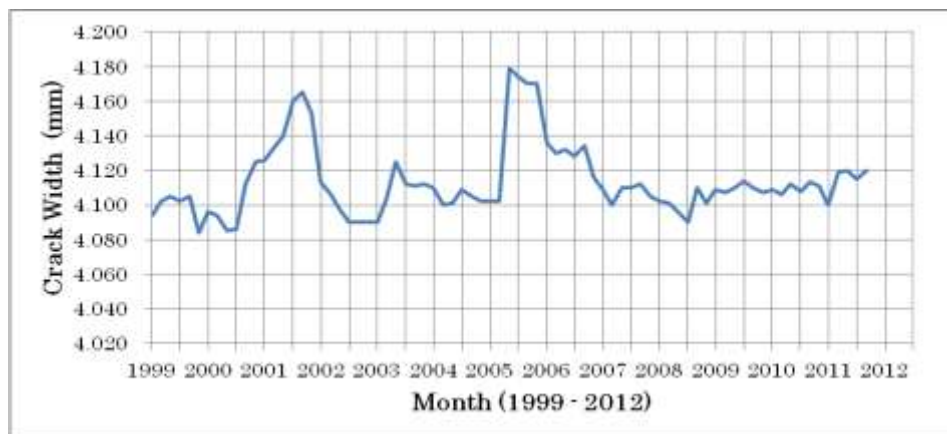
The result of investigation revealed that a crack has occurred around the penstock (see Figure 5-11) with more than 5 mm width slanted at Units 5 and 6, which is necessary for urgently repair with epoxy injection and carbon fiber sheet. Figure 5-12 shows the movement of the crack width at the Unit 5 foundation from 1999 up to 2012. The cracks have not expanded width between 4.08 mm to 4.18 mm. Other cracks are also observed and these are just bigger than hair cracks, which also need epoxy injection to prevent water penetration. WAPDA is consistently observing the crack in order to confirm the movement such as enlargement or slip, however, some observation data are available at the power station but not in all facilities. Actually, the foundation needs to be replaced by new high-strength concrete up to the portion of the crack. Replacement is not possible because there are adjacent equipment such as the turbine and generator. Therefore, reinforcement using

epoxy injection and carbon fiber sheet shall be recommended.



Source: Prepared by the Survey Team

Figure 5-12 Cracking Around Units 5 and 6



Source: WAPDA Hydrological Section of Mangla Dam

Figure 5-13 Crack Width at Unit 5 Foundation

In case of improvement and optimization of the generator, the reinforcement/new foundation must consider effects occurring through the acting force in the opposite direction of the generator at the foundation, when it is at emergency stop. Secondly, due to the upgrading of the generating units for optimization, the foundation and oil pit may be changed in size and shape, which the F/S report did not mention.

Accordingly, the reinforcement and improvement works must be considered in order to cater to the aforementioned matters and these need to be incorporated into the cost estimation and implementation schedule.

The Survey Team recommends introducing a three-dimensional (3-D) measurement for grasping the present conditions and analyzing the transition of the existing cracks. These data can be utilized to map out the appropriate countermeasures against the existing cracks and large-sized earthquake in the future.

5.6 Rehabilitation and Enhancement Scenarios

5.6.1 Review of Maximum Output of Turbine and Generator

In the review of the scenarios for rehabilitation and enhancement through the Project, the Survey Team has calculated the maximum turbine output in consideration of the raising of Mangla Dam, as follows:

- | | |
|---|---------------------------------------|
| (1) Reservoir water level after dam raising | : EL 1,242 ft (378.8 m) |
| Tailrace water level | : EL 836 ft (255.0 m) |
| Gross head at maximum output | : 123.8 m |
| (2) Each unit maximum allowable discharge capacity | : 4,900 cfs (138.7 m ³ /s) |
| (3) 1) Head loss at intake tunnel for 9,800 cfs | : 10.3 ft (3.14 m) |
| 2) Head loss at trashracks for 9,800 cfs | : 2.0 ft (0.61 m) |
| 3) Head loss at bi-plane type inlet valve for 4,900 cfs | : 1.83 ft (0.56 m) |

Note: Head loss in case of butterfly-type inlet valve is 2.76 ft (0.84 m)

- (4) Effective head at maximum output
= Gross head – Head losses
= 123.8 m – (3.14+0.61+0.56) m = 119.5 m

The turbine maximum output will be calculated as follows;

$$P_{\max} = 9.8 \cdot Q_{\text{at } P_{\max}} \cdot H_{\text{at } P_{\max}} \cdot \eta_T \text{ KW}$$

Where $Q_{\text{at } P_{\max}} = 138.7 \text{ m}^3/\text{s}$

$$H_{\text{at } P_{\max}} = 119.5 \text{ m}$$

$$\eta_T = 93.0\% \text{ (Estimated turbine efficiency at } P_{\max}\text{)}$$

Therefore $P_{\max} = 151.1 \text{ MW}$

Based on the above maximum turbine output, the Survey Team recommended the rehabilitation and enhancement concept of the Project as follows:

(1) Main recommendation by the Survey Team is:

1) Generator's Capacity: Enhancement up to 180 MVA/unit from the existing 125 MVA/unit

2) Output: Enhancement up to 144 MW/unit with 0.8 power factor

(2) Main difference compared with the F/S report is that the Survey Team's idea does not include modification of the existing concrete foundation of turbines and generators.

The basic feature of the turbine and generator (generator output is 144 MW/unit at rated power factor) as existing and after enhancement is shown in Table-5-11.

Table 5-11 Basic Features of Turbines and Generators (generator's output: 144 MW/unit)

-	Rates	Existing A	After Enhancement B	Ratio B/A
Turbine	Rated output	138 kBHP=103MW	172.7 kBHP=126.6MW	122.9%
	Rated discharge	4,550cfs=128.8 m ³ /s	4,900cfs=138.7m ³ /s	107.7%
	Effective head	295f=89.9m	334f=101.9m	113.3%
	Maximum output	198 kBHP= 147.7MW	151.1MW	102.3%
	Discharge at maximum output	4,936cfs=139.7m ³ /s	138.7 m ³ /s	99.3%
	Effective head at maximum output	380f=115.8m	119.5m	103.2%
	Rated speed	166.7 min ⁻¹	166.7 min ⁻¹	-
Generator	Rated capacity	125MVA	180MVA	144.0%
	Rated power factor	0.80	0.80	-
	Output at rated power factor	100MW	144MW	144.0%
	Rated voltage	13.2kV	13.2kV	-
	Rated speed	166.7 min ⁻¹	166.7 min ⁻¹	-
	Overload (Continuous operation)	115% (115MW)	No overload capacity (144MW)	125.2%

Source: Prepared by the Survey Team

5.6.2 Priority of Rehabilitation and Enhancement

(1) Priority of Turbine Rehabilitation

Considering the duration of the unit operation and numbers of repair for the turbine runner and associated equipment present conditions, the replacement or rehabilitation is recommended as shown in the following Table 5-12.

i Units 1 to 4

The operating duration is more than 45 years. The life of a turbine is 40 to 45 years in accordance with the Japan Electrical Association's recommendation. Repair welding is limited to three times as advised in the same recommendation. Considering these limits, major parts of turbines shall be replaced with new ones, except embedded parts. Rehabilitation of embedded parts shall also be done together with replacement of rotating parts.

ii Units 5 and 6

Although the operating duration after replacement of turbine runner is not so long, the design of the turbine may be not adequate for further long time operation. Therefore, replacement of major parts of the turbine to new technology design runner is recommended.

iii Units 7 and 8

While the numbers of the repair welding are more than three times, it is less than 1/2 times of Units 1 to 4. Thus, other long duration operation might be possible same as Units 1 to 4. However, continuous careful repair of the runner is required until the end of the turbine life.

iv Units 9 and 10

Same as above Units 7 and 8.

Table 5-12 Priority of Rehabilitation of Turbine

Unit	Inlet Valve	Runner	Governor	Other Equipment
1 to 4	Leakage water from valve packing to turbine is extremely high and leakage water at pipe connection is also very high. Prior to rehabilitation of turbine, rehabilitation or replacement of inlet valve shall be done.	Repair welding of each runner is done every 2 or 3 years after starting operation. The repair welding in Japan is limited for 3 times to prevent breakage. Total number of re-welding is more than 10 times and preferable to replace to a new runner.	Mechanical type governor is operating and the manufacturing of this type had been suspended long time ago. Therefore, spare parts supply is not available together with maintenance engineers. So, replacement of the governor system is required.	The wired damages and rust shall be repaired and overhaul of the irrigation valve is required for further long time operation. Measuring instrument and electrical wiring shall be replaced for getting maintenance data in the new control system.
5 and 6	Same as above	For getting good characteristics turbine, replacement of turbine major parts is required.	Same as left	Same as above
7 and 8	Still good condition	Still good condition	Still good condition	Still good condition
9 and 10	Still good condition	Still good condition	Still good condition	Still good condition

Source: Prepared by the Survey Team

From the above table, rehabilitation or replacement of inlet valve, runner, governor, and irrigation valve for Units 1 to 6 is urgently required.

(2) Priority of Generator Rehabilitation

The following Table 5-13 is the summary of the generator's current condition from the study of rehabilitation in Sub-section 5.2.1, and shows the priority of rehabilitation.

Table 5-13 Priority of Rehabilitation of Generator

Unit No.	Analysis by N-Y Map	Analysis by Insulation Resistance Measurement	Analysis by Past Fault/Incident	Judgment
1 to 4	Stator winding is already beyond the typical life expectancy	Still Good	-	Urgent rehabilitation is necessary
5 and 6	Fault/incident of the winding occurred some times (As some windings have been replaced, analysis by N-Y map cannot be conducted)	Still Good	Fault/incident occurred frequently in the past.	Urgent rehabilitation is necessary
7 and 8	Stator winding is in the last stage of life, but priority is not so high	Still Good	-	Rehabilitation is necessary, but priority is not so high
9 and 10	Stator winding is quite new, as compared to other units	Still Good	-	Rehabilitation is necessary, but priority is not so high

Source: Prepared by the Survey Team

From the above table, rehabilitation for Units 1 to 6 is urgently required. For Units 7 and 8, rehabilitation is also required although it is of second priority, and Units 9 and 10 is of last

priority.

5.6.3 Rehabilitation and Enhancement Scenarios Recommended by the Survey Team

In consideration of Tables 5-12 and 5-13, the Survey Team recommended the following two scenarios for rehabilitation and enhancement of generators to increase their capability up to 144 MW per unit at PF 0.8 (rated capacity is 180 MVA).

Scenario A: Rehabilitation and Enhancement for Units 1 to 4

Scenario B: Rehabilitation and Enhancement for Units 1 to 6

The comparison table of the above scenarios are shown in Table 5-14.

Table 5-14 Rehabilitation and Enhancement Scenarios (144MW/unit)

Scenarios	Against Rated Capacity			Against Overload Capacity		
	Existing	After Enhancement	Incremental Generating Power	Existing	After Enhancement	Incremental Generating Power
A	1,000MW in total	Enhancement to 1,176 MW in total Units 1-4: 144MW Units 5-10: 100MW (no change)	176MW (+17.6%)	1,150MW in total	Enhancement to 1,266 MW in total Units 1-4: 144MW Units 5-10: 115MW (no change)	116MW (+10.1%)
B		Enhancement to 1,264 MW in total Units 1-6: 144MW Units 7-10: 100MW (no change)	264MW (+26.4%)		Enhancement to 1,324 MW in total Units 1-6: 144MW Units 7-10: 115MW (no change)	174MW (+15.1%)

Source: Prepared by the Survey Team

5.6.4 Expected Increased Amount of Power Generation

The Survey Team has calculated the annual power generation which is expected to be increased by the implementation of the Project.

(1) Future Forecast of Water Balance at Mangla Dam

The future forecast of water balance at Mangla dam in the period from the year of 2012 to 2053 for 42 years was calculated as shown in Table 5-15 based on the past hydrology data of Mangla dam including inflow, outflow and sedimentation etc. from the year of 1968.

Table 5-15 Future Forecast of Water Balance

Year	Inflow (MAF)	Outflow (MAF)	Spillage (MAF)	Year	Inflow (MAF)	Outflow (MAF)	Spillage (MAF)
2012	25.26	23.30	0.98	2035	31.94	25.03	7.22
2017	28.20	25.29	3.34	2036	31.43	24.83	5.75
2019	23.92	20.99	0.08	2037	24.10	22.85	2.44
2020	25.56	22.58	2.84	2038	24.86	22.96	1.32
2022	24.60	22.45	1.60	2039	26.83	23.74	3.27
2024	22.68	21.93	0.10	2040	31.05	24.42	6.12
2025	23.40	22.98	1.14	2042	23.96	23.21	2.31
2027	27.64	24.11	3.27	2047	27.17	22.84	3.32
2030	27.12	22.20	1.33	2049	31.02	24.99	5.75
2031	28.02	23.41	4.65	2050	26.65	24.05	1.44
2032	24.75	22.57	3.23	2051	23.73	23.17	2.39
2033	21.78	21.05	0.91	2053	24.28	23.55	1.26
2034	25.98	22.99	2.78	Average	22.74	21.05	1.64

Source: Prepared by the Survey Team

(2) Annual Power Generation of the Existing Power Plant

The annual power generation of the existing power plant in Mangla Power Station in the period from 2001 to 2010 for the past ten (10) years is shown in the following table. The average annual power generation for the past 10 years is calculated to be 5,000.1 [GWh].

Table 5-16 Annual Power Generation of Existing Power Plant

Year	Annual Power Generation [GWh]
2001	3,398.9
2002	5,363.2
2003	5,058.9
2004	4,218.5
2005	5,445.9
2006	6,150.9
2007	4,687.3
2008	4,797.4
2009	4,772.4
2010	6,107.6
Average Annual Power Generation	5,000.1
Average Plant Factor [%]	49.6

Source: Prepared by the Survey Team

(3) Annual Power Generation for Scenario A (for 4 units)

The annual power generation after the implementation of Scenario A, which will be enhanced up to 1,266 MW in total from the existing 1,150 MW, in the period from 2012 to 2053 for 42 years is shown in the following table. The average annual power generation is calculated to be 6,585.9 GWh which is added 1,585.8 GWh from 5,000.1 GWh of the existing plant. The said incremental energy is expected to cover about 892,000 households in accordance with the calculation using the figure of the average electricity consumption of domestic in Table 9-18,

Chapter 9.

Table 5-17 Annual Power Generation after Implementation of Scenario A (144MW/unit)

Year	Annual Power Generation [GWh]	Year	Annual Power Generation [GWh]	Year	Annual Power Generation [GWh]
2012	5,548.2	2026	6,241.9	2040	7,691.5
2013	7,389.8	2027	7,629.9	2041	6,330.6
2014	5,203.0	2028	5,980.8	2042	7,224.3
2015	3,943.3	2029	4,722.3	2043	4,894.5
2016	6,436.5	2030	6,767.4	2044	3,283.8
2017	8,118.5	2031	7,646.8	2045	3,482.5
2018	5,960.0	2032	7,347.3	2046	5,150.3
2019	5,981.1	2033	6,729.3	2047	7,152.0
2020	7,402.9	2034	7,333.6	2048	6,370.5
2021	6,038.5	2035	7,976.5	2049	7,827.6
2022	7,241.5	2036	7,915.5	2050	7,656.9
2023	6,719.5	2037	7,167.3	2051	7,316.6
2024	7,148.7	2038	7,024.1	2052	6,552.9
2025	7,374.8	2039	7,447.1	2053	7,237.3
Average Annual Power Generation					6,585.9
Average Plant Factor [%]					59.4

Source: Prepared by the Survey Team

(4) Annual Power Generation for Scenario B (for 6 units)

The annual power generation after the implementation of Scenario B, which will be enhanced up to 1,324 MW in total from the existing 1,150 MW, in the period from 2012 to 2053 for 42 years is shown in the following table. The average annual power generation is calculated to be 6,660.8 GWh which is added 1,660.7 GWh from the existing plant. The said incremental energy is expected to cover about 934,000 households which is calculated in the same manner as the above (3).

Table 5-18 Annual Power Generation after Implementation of Scenario B (144MW/unit)

Year	Annual Power Generation [GWh]	Year	Annual Power Generation [GWh]	Year	Annual Power Generation [GWh]
2012	5,548.2	2026	6,255.6	2040	7,845.5
2013	7,439.3	2027	7,798.3	2041	6,388.5
2014	5,203.0	2028	5,994.7	2042	7,360.8
2015	3,943.3	2029	4,722.3	2043	4,894.5
2016	6,436.5	2030	6,873.2	2044	3,283.8
2017	8,297.7	2031	7,800.4	2045	3,482.5
2018	5,960.0	2032	7,497.6	2046	5,150.3
2019	6,037.8	2033	6,771.5	2047	7,289.9
2020	7,502.3	2034	7,457.6	2048	6,243.5
2021	6,038.5	2035	8,142.3	2049	8,001.0
2022	7,325.7	2036	8,120.7	2050	7,826.6
2023	6,747.0	2037	7,303.7	2051	7,465.3
2024	7,222.2	2038	7,106.5	2052	6,558.9
2025	7,515.1	2039	7,566.3	2053	7,370.3
Average Annual Power Generation					6,660.8
Average Plant Factor [%]					57.4

Source: Prepared by the Survey Team

5.6.5 Recommendation in the F/S Report

As described in the previous clauses in this chapter, the Survey Team has proposed the rehabilitation and enhancement of generators to increase their capability up to 144 MW per unit at PF 0.8 (rated capacity is 180 MVA), instead of the existing one which has a capability of 115 MW (rated capacity is 125 MVA), on the condition that the existing concrete foundations are to be used without rehabilitation. Meanwhile, in the F/S report, it is recommended to rehabilitate and enhance the generator for upgrade up to 135 MW per unit at PF 0.8 (rated capacity is 169 MVA).

The Survey Team has reviewed the recommended idea in the F/S report, in particular, from the technical aspects as below.

(1) Annual Power Generation for Scenario A (for 4 units)

The annual power generation after the implementation of Scenario A, which will be enhanced up to 1,230 MW in total (enhancement of 4 generators up to 135 MW) from the existing 1,150 MW, in the period from 2012 to 2053 for 42 years is shown in the following table. The average annual power generation is calculated to be 6,532.6 GWh which is added 1,532.5 GWh from 5,000.1 GWh of the existing plant. The said incremental energy is expected to cover about 862,000 households.

Table 5-19 Annual Power Generation after Implementation of Scenario A (135MW/unit)

Year	Annual Power Generation [GWh]	Year	Annual Power Generation [GWh]	Year	Annual Power Generation [GWh]
2012	5,548.2	2026	6,233.4	2040	7,569.4
2013	7,325.9	2027	7,511.2	2041	6,314.0
2014	5,203.0	2028	5,972.4	2042	7,132.9
2015	3,943.3	2029	4,722.3	2043	4,894.5
2016	6,392.0	2030	6,724.3	2044	3,283.8
2017	7,978.5	2031	7,552.5	2045	3,482.5
2018	5,960.0	2032	7,253.0	2046	5,150.3
2019	5,946.0	2033	6,697.2	2047	7,060.6
2020	7,332.6	2034	7,265.7	2048	6,356.1
2021	6,038.5	2035	7,874.4	2049	7,746.9
2022	7,187.8	2036	7,787.7	2050	7,542.8
2023	6,705.3	2037	7,082.1	2051	7,226.9
2024	7,085.2	2038	6,964.1	2052	6,537.6
2025	7,263.1	2039	7,373.0	2053	7,147.2
Average Annual Power Generation					6,532.6
Average Plant Factor [%]					60.6

Source: Prepared by the Survey Team

(2) Annual Power Generation for Scenario B (for 6 units)

The annual power generation after the implementation of Scenario B, which will be enhanced up to 1,270 MW (enhancement of 6 generators up to 135 MW) in total from the existing 1,150

MW, in the period from 2012 to 2053 for 42 years is shown in the following table. The average annual power generation is calculated to be 6,588.4 GWh which is added 1,588.3 GWh from the existing plant. The said incremental energy is expected to cover about 894,000 households.

Table 5-20 Annual Power Generation after Implementation of Scenario B (135MW/unit)

Year	Annual Power Generation [GWh]	Year	Annual Power Generation [GWh]	Year	Annual Power Generation [GWh]
2012	5,548.2	2026	6,242.9	2040	7,689.7
2013	7,352.0	2027	7,642.9	2041	6,361.7
2014	5,203.0	2028	5,982.0	2042	7,232.3
2015	3,943.3	2029	4,722.3	2043	4,894.5
2016	6,417.1	2030	6,772.6	2044	3,283.8
2017	8,140.5	2031	7,658.1	2045	3,482.5
2018	5,960.0	2032	7,358.6	2046	5,150.3
2019	5,985.2	2033	6,735.8	2047	7,161.2
2020	7,410.0	2034	7,364.1	2048	6,243.5
2021	6,038.5	2035	7,988.8	2049	8,001.0
2022	7,247.5	2036	7,931.3	2050	7,839.6
2023	6,734.8	2037	7,177.9	2051	7,326.2
2024	7,154.7	2038	7,028.8	2052	6,558.9
2025	7,376.4	2039	7,458.0	2053	7,247.2
Average Annual Power Generation					6,588.4
Average Plant Factor [%]					59.2

Source: Prepared by the Survey Team

5.6.6 Conclusion of Recommendation of Rehabilitation and Enhancement Scenarios

As the result of calculation in Tables 5-17 to 5-20, it reveals that the generator's output of 144MW per unit is more advantageous than 135MW at the average annual power generation. However, in case of 144 MW, the expected number of days which would be reached the maximum output of 1,266MW (4 units enhancement) and 1,324MW (6 units enhancement) is limited to 65 days and 54 days respectively due to the restriction of water resources which are stored to Mangla Dam. Thereby, the average plant factor of 144MW, which is defined as the ratio of the average power load of a power plant to its rated capacity, is lower than 135MW. (The average plant factor of 144MW at Scenario A and B is 59.4% and 57.4%, while one of 135MW is 60.6% and 59.2% respectively)

It means that the operation of generator's output with 135 MW is more efficient in terms of the level of plant factor.

Therefore, the Survey Team also can recommend the rehabilitation and enhancement concept with generator's output of 135 MW per unit with 0.8 power factor in accordance with the recommendation in the F/S report, and the subsequent review of this chapter is carried out based on it.

Incidentally, the Survey Team has judged that there is no any change on the result of

technical reviews mentioned in the preceding clauses by adopting the generator's output 135 MW per unit instead of 144 MW, except the capacity of main transformer which is changed to 169 MW instead of 180 MVA which is described in Sub-clause 5.4.1.

The basic feature of the turbine and generator (generator output is 135 MW/unit at rated power factor) as existing and after enhancement is shown in Table-5-21.

Table 5-21 Basic Features of Turbines and Generators (generator's output: 135 MW/unit)

-	Rates	Existing A	After Enhancement B	Ratio B/A
Turbine	Rated output	138 kBHP=103MW	172.7 kBHP=126.6MW	122.9%
	Rated discharge	4,550cfs=128.8 m ³ /s	4,900cfs=138.7m ³ /s	107.7%
	Effective head	295f=89.9m	334f=101.9m	113.3%
	Maximum output	198 kBHP=147.7MW	138.0MW	93.4%
	Discharge at maximum output	4,936cfs=139.7m ³ /s	138.7 m ³ /s	99.3%
	Effective head at maximum output	380f=115.8m	109.92m	94.9%
	Rated speed	166.7 min ⁻¹	166.7 min ⁻¹	-
Generator	Rated capacity	125MVA	168.75MVA	135.0%
	Rated power factor	0.80	0.80	-
	Output at rated power factor	100MW	135MW	135.0%
	Rated voltage	13.2kV	13.2kV	-
	Rated speed	166.7 min ⁻¹	166.7 min ⁻¹	-
	Overload (Continuous operation)	115% (115MW)	No overload capacity (135MW)	117.4%

Source: Prepared by the Survey Team

As the conclusion, the Survey Team recommended the following two scenarios for rehabilitation and enhancement of the generator for upgrade up to 135 MW per unit at PF 0.8 (rated capacity is 169 MVA).

Scenario A: Rehabilitation and Enhancement for Units 1 to 4

Scenario B: Rehabilitation and Enhancement for Units 1 to 6

The comparison table of the above scenarios are shown in Table 5-22.

Table 5-22 Rehabilitation and Enhancement Scenarios (135MW/unit)

Scenarios	Against Rated Capacity			Against Overload Capacity		
	Existing	After Enhancement	Incremental Generating Power	Existing	After Enhancement	Incremental Generating Power
A	1,000MW in total	Enhancement to 1,140 MW in total Units 1-4: 135MW Units 5-10: 100MW (no change)	140MW (+14.0%)	1,150MW in total	Enhancement to 1,230 MW in total Units 1-4: 135MW Units 5-10: 115MW (no change)	80MW (+7.0%)
B		Enhancement to 1,210 MW in total Units 1-6: 135MW Units 7-10: 100MW (no change)	210MW (+21.0%)		Enhancement to 1,270 MW in total Units 1-6: 135MW Units 7-10: 115MW (no change)	120MW (+10.4%)

Source: Prepared by the Survey Team

5.6.7 Study on Superiority of Japanese Technology

The Survey Team reviewed the superiority of water turbine generator products manufactured by Japanese manufacturing firms compared to those of other overseas manufacturers in order to formulate the Project as a STEP Yen loan.

However, it is considered that there is no broad distinction between Japanese and the overseas manufacturers in terms of technical capability to meet the requirement of rehabilitation and enhancement proposed in this study.

Therefore, the superiority of Japanese manufacturers is explained from the viewpoint of "reliability of equipment" based on past operating records at Mangla Power Station, which were provided by WAPDA through this preliminary survey.

(1) Annual Power Generation and Operating Ratio

Based on the actual data of annual power generation and operating hours of each unit of water turbine generator from the commissioning date up to December 31, 2011, the average annual power generation and operating ratio were calculated as shown in Table 5-23.

As indicated in the above table, the average annual power generation of each unit is calculated below:

- Units 1 to 4 (both turbine and generator are Japanese products): 581 [GWh/year]
- Units 7 & 8 (turbine is an overseas product and generator is Japanese product): 492 [GWh/year]
- Units 5 & 6, 9 & 10 (both turbine and generator are overseas products): 436 [GWh/year]

The operating ratio of each unit is also calculated below:

- Units 1 to 4: 81.3 [%]
- Units 7 & 8: 68.2 [%]
- Units 5 & 6, 9 & 10: 69.7 [%]

Table 5-23 Past Operating Record at Mangla Power Station

Unit No.	Manufacturer		Commissioning Date	Power Generation [GWh]	Operating Hour [hour]	Total Days from Commissioning Date*1 (C)	Total Hours from Commissioning Date*2 (D)=(C)*24	Average Annual Power Generation [GWh]		Operating Ratio [%]
	Turbine	Generator						(E)=(AC)x365	%	
1			03-Jul-67	29,307	340,770	16,252	390,048	658	-	87.4
2	Mitsubishi	Hitachi	14-Jul-67	28,017	339,577	16,241	389,784	630	-	87.1
3			07-Mar-68	23,015	286,155	16,004	384,096	525	-	74.5
4			17-Jun-69	21,815	282,725	15,537	372,888	512	-	75.8
5	CKD Blansco	CKD Blansco	29-Dec-73	19,203	256,400	13,881	333,144	505	-	77.0
6			11-Mar-74	18,903	258,391	13,809	331,416	500	-	78.0
7	Escherwyse	Hitachi	25-May-81	15,439	188,648	11,177	268,248	504	-	70.3
8			22-Jul-81	14,618	176,528	11,119	266,856	480	-	66.2
9	CKD Blansco	CKD Blansco	24-Sep-93	6,913	87,956	6,672	160,128	378	-	54.9
10			06-Jul-94	6,321	79,054	6,387	153,288	361	-	51.6
Total				183,551	2,296,204	127,079	3,049,896	5,053	-	75.29
Units 1 through 4				102,154	1,249,227	64,034	1,536,816	581	100.0	81.3
Units 7 & 8				30,057	365,176	22,296	535,104	492	84.7	68.2
Units 5 & 6, 9 & 10				51,340	681,801	40,749	977,976	436	75.0	69.7

Source: Prepared by the Survey Team

Note: *1 Total number of days from the commissioning date to December 31, 2011

*2 Total number of hours from the commissioning date to December 31, 2011

(2) Fault Record

Regarding Units 1 to 4, 7 and 8, the Survey Team confirmed that any failure or trouble affecting the generating capability or functions of the water turbine generator has not occurred from the commissioning date up to present.

On the other hand, for Units 5 and 6, the damages of the stator winding, stator core and field winding of generator has been occurring frequently. Since the first failure occurred in 1990, similar failures have occurred six times with stoppage of a generator for a total of 20 months. Unit 6 has had five times failures with stoppage of generator for a total of 12 months since the first failure occurred in 1985.

In addition, despite the short operating period which is less than 20 years, Units 9 and 10 recorded the lowest operating ratio in all units. Unit 9 was 54.93% and Unit 10 was 51.57%, due to the fault of AVR (automatic voltage regulator) of the exciter causing frequent irregular trips.

(3) Conclusion

As described above, it is judged that Japanese products of water turbine generator have superiority from the viewpoint of "reliability of equipment" backed by the past operating records at Mangla Power Station.

However, as for annual power generation and operating ratio, these figures are influenced by the operating pattern. The Survey Team confirmed from WAPDA that Units 1 and 2 are connected to 132 kV system and Units 3 through 10 are connected to 220 kV system. There are thirteen 132 kV transmission lines emanating from 132 kV bays of switchyard in Mangla Power Station. To meet the growing load demand of 132 kV transmission lines, (3) interconnection auto transformers (132 kV/220 kV) have been installed. For system stability and also to avoid overloading of interconnecting auto transformers, Unit 1 and Unit 2 were normally run at base load and these were the last units to stop with. That is the reason that the number of operating hours of Unit 1 and 2 are more and the number of start / stop is much less as compared to the other units.

5.6.8 Study on Possibility of Formulating the Project as STEP Loan

The Japanese products of water turbine generator have superiority from the viewpoint of "Reliability of Equipment", however, there is no remarkable distinction of technical aspects between the Japanese manufacturers and the overseas ones. Therefore, it seems have a low potential for the formulating the Project as STEP loan.

In case the Project is implemented by general untied Japanese ODA loans instead of STEP

loan, the Survey Team recommends the following measures in order to maintain the high quality and performance of the Project which is envisaged in this study:

- (1) The Tenderer shall meet the following requirements as the qualification of Tenderer.
 - 1) experience of rehabilitation project of hydropower station on same scale of Mangla Power Station and except for own country
 - 2) experience of rehabilitation project of hydropower station with other company's products
 - 3) actual performance for safety operation more than 5 years after rehabilitation project
 - 4) experience of project funded by JICA, JBIC, World Bank and ADB

(2) Burden of Expense on Reverse Engineering

The cost for the reverse engineering shall be born by the Contractor including the electrical tariff to compensate the stoppage of water turbine generator for the reverse engineering by the Contractor. The said cost shall be evaluated at the cost evaluation stage.

(3) Life Cycle Cost (LCC)

A life style cost (LCC) consists of certain portion, which is operation cost and fuel cost, and uncertain portion such as replacement cost of equipment, or expenses for replacement with spare parts.

The comprehensive evaluation at the cost evaluation stage shall be considered the LCC, which consists of maintenance cost (equipment cost, installation cost, personnel expenses, etc.) and stoppage duration of water turbine generator required for maintenance, for 10 years operation after commissioning.

The Tenderers shall calculate the maintenance cost required for 35 years operation including overhaul works of turbines and generators which will be carried once a decade.

In addition, the Tenderers shall calculate a monetary loss caused by unscheduled shutdown due to any failure or damage of the equipment based on past actual performance owned by each Tenderer. As for the Tenderers who could not prove their past performance for 35 years operation, the Tender Documents shall stipulate the calculation methods for such Tenderers, for example, the determined sum of the cost shall be added in their tender price.

CHAPTER 6

ENVIRONMENT AND SOCIAL CONSIDERATIONS

CHAPTER 6 ENVIRONMENTAL AND SOCIAL CONSIDERATIONS

6.1 Environmental and Social Considerations

6.1.1 Necessity of an IEE or EIA

(1) Pakistan Regulations on EIA

The legal basis for the necessity and scheme of an Environmental Impact Assessment (EIA) is given by the following two regulations in Pakistan.

- Pakistan Environmental Protection Act (PEPA), 1997 (Act No. XXXIV OF 1997)
- Pakistan Environmental Protection Agency Review of Initial Environmental Examination and Environmental Impact Assessment Regulations, 2000 (S.R.O. 339 (1)/2001)

The PEPA 1997 is an act provided for the protection, conservation, rehabilitation and improvement of the environment, for the prevention and control of pollution, and promotion of sustainable development; namely the basic act for the environmental administration in Pakistan. Article 12 of the act stipulates on the IEE or EIA requirements as follows:

12. Initial environmental examination and environmental impact assessment.
—(1) No proponent of a project shall commence construction or operation unless he has filed with the Government Agency designated by Federal Environmental Protection Agency or Provincial Environmental Protection Agencies, as the case may be, or, where the project is likely to cause adverse environmental effects, an environmental impact assessment, and has obtained an approval from the Government Agency in respect thereof.

Source: Basic Act for the Environmental Administration in Pakistan

Pakistan EPA (Review of IEE and EIA) Regulations, 2000, defines project types that require or does not require an IEE or EIA.

Schedule I in the regulation, as specified in the “Rule 3 Projects requiring an IEE”, lists types of projects that require an IEE.

- ‘Hydroelectric power generation less than 50 MW’ is in the list.

Schedule II in the regulation, as specified in the “Rule 4 Projects requiring an EIA”, lists types of projects that require an EIA.

- ‘Hydroelectric power generation over 50 MW’ is in the list.

Article 5. “Projects not requiring an IEE or EIA” prescribes that;

(1) A proponent of a project not falling in any category listed in Schedules I and II shall not be required to file an IEE or EIA: Provided that the proponent shall file –

(a) an EIA, if the project is likely to cause an adverse environmental effect;

(b) for projects not listed in Schedules I and II in respect of the Federal Agency issued guidelines for construction and operation, an application for approval accompanied by an undertaking and an affidavit that the aforesaid guidelines shall be fully complied with.

(2) Notwithstanding anything contained in Sub-regulation (1), the Federal Agency may direct the proponent of the project, whether or not listed in Schedule I or II, to file an IEE or EIA, for reasons to be recorded in such direction:

Provided that no such direction shall be issued without the recommendation in writing of the Environmental Assessment Advisory Committee constituted under Regulation 23.

(3) The provisions of Section 12 shall apply to a project in respect of which an IEE or EIA is filed under Sub-regulation (1) or (2).

Source: Pakistan EPA Regulations, 2000

(2) Project Necessity of an IEE or EIA

Interpreted with the advice of the Environment Cell of WAPDA and international standard context as well as Japanese concerned regulations, Article 12 of PEPA, 1997 requires application of EIA for new project where new installation of facility or physical structure are commenced, as well as for the one that is likely to cause an adverse environmental effects.

The concerned Project does not fall in the category of new project, but project of rehabilitation (as refurbishment) and enhancement (as up-gradation) of existing facility inside Mangla Power Station. Therefore, neither IEE nor EIA are supposed to be applied to this Project.

However, Schedule I and II in Pakistan EPA (Review of IEE and EIA) Regulations, 2000 does not specify the project type clear and distinct enough to distinguish between new and rehabilitation project, in respect where Japanese corresponding regulations distinctively

define those. If only project size is counted, the concerned Project would fall under Schedule II which means that EIA is required since the Project will enhance the capacity of generation by 116 MW to 174 MW. Further, Article 5 of the above Regulation 2000 gives the Federal Agency, namely Pakistan Environmental Protection Agency (Pak-EPA), the authority of judging IEE/EIA requirement.

Considering these, WAPDA should consult with Pak-EPA and prepare the necessary filing to follow their instruction as required, before the next step of the study.

6.1.2 Environmental Evaluation

(1) Concerned Regulations

The following are the primary regulations of environmental protection and environmental impact assessment system in Pakistan and AJK (Azad Jammu & Kashmir) governments, concerning the proposed Project.

- Pakistan National Conservation Strategy (NCS), 1992;

It outlines the country's primary approach toward encouraging sustainable development, conserving natural resources, and improving management and efficiency in the use of resources.

It has 14 core areas in which policy intervention is considered crucial for the preservation of Pakistan's natural and physical environment. The core areas that are relevant in the context of the Project are pollution prevention and increasing energy efficiency.

- Pakistan Environmental Protection Act, 1997

Two organizations are given authority to administer the provisions of the Act, namely, Pakistan Environmental Protection Council (PEPC) and Pakistan Environmental Protection Agency (Pak-EPA). The PEPC, members of which include representatives of the government, industry, other professionals, and NGOs, supervises the functions of Pak-EPA. The Pak-EPA is responsible for ensuring enforcement of National Environmental Quality Standards (NEQS) and authorized to delegate powers to its provincial counterparts and provincial EPAs /EPD (environmental protection agencies and department). One of the functions delegated by Pak-EPA to the provincial EPAs/ EPD is the review and approval of EIA reports for projects undertaken in their corresponding jurisdictions.

- National Environmental Policy, 2005

The policy, while recognizing the goals and objectives of the National Conservation Strategy and other existing environment-related national policies, strategies and action

plans, provides broad guidelines to the federal and local governments for addressing environmental concerns and ensuring effective management of their environmental resources.

- National Environmental Quality Standards

- The S.R.O. 549(1)/2000 contains two national standards: one for municipal and liquid industrial effluents, and the other for industrial gaseous emission.
- The S.R.O. 528(1)/2001 regulates specific requirements on self-monitoring and reporting by industries.
- The S.R.O. 1062(1)/2010 stipulates ambient air quality standards.
- The S.R.O. 1063(1)/2010 stipulates drinking water quality standards.
- The S.R.O. 1064(1)/2010 stipulates noise standards.

- Hazardous Substance Rules 2003

The regulation set the rules to deal with hazardous substances and gave a list of these substances.

- AJK Environmental Protection Act 2000

The Act with registration No. 696-702/LD/Leg/2000 describes the establishment, powers, and functions of the Environmental Protection Council and Agency in AJK.

(2) Possible Impacts and Mitigation

The project components only extend to the repair and replacement of existing turbines, generators, and their peripherals inside the power station. Any permanent physical transformation will not occur to the environment, external to and surrounding the power station.

In this section, possible environmental and social impacts regarding the project activities of overhaul, repair and replacement are briefly identified¹. Accordingly, corresponding mitigation measures are also examined where and when required. Examinations here are based on the JICA Guidelines for Environmental and Social Considerations (April 2010), the discussions with the Environmental Cell of WAPDA, the survey at Mangla Power Station, the environmental review of the FS report for Mangla Refurbishment Project by WAPDA (hereinafter referred to as the FS report) and other legal review of Pakistan EPA (Environmental Protection Agency).

The following are the impacts and mitigation measures examined:

¹ This project falls into category C under the JICA guidelines for environmental and social guidelines, since JICA's financing component, repair and replacement of facilities, is not likely to have a minimal adverse impact on the environment. This chapter is not a requirement of JICA, but recommendation to the project proponent.

1) Water use for other purpose

Impacts

Impacts on water uses other than power generation were examined whether they would possibly occur with the operation rule of the existing reservoir water, although the issue is not discussed in the FS report.

There will be no change of water flow downstream due to the rehabilitation project. Irrigation water is secured on first priority regardless of the project, by the given rules with AJK-Government, according to both Environmental Cell and Mangla Power Station Office of WAPDA. Also, since water flow downstream will not change at all, there will be no impacts on local water use for local water supply, local industries, fishing, local recreation, water transportation, and other activities.

Mitigation

No mitigation measures are required for this purpose since no impacts are expected.

2) Water quality

Impacts

At the current stage, procurement procedure is not clearly designed yet.

If construction camp is set up during procurement work, the FS report assumes 70 to 80% of consumed 15 l/capita/day-water will become sewage with 50 to 75 persons presumed working. However, the construction camp will not necessarily be set up due to the prospective scale and method of works necessary for replacing turbines and generators and other equipment on scheme of JICA project.

During procurement as well as operation, spilling and leakage of lubricants, oils and other petroleum products may occur.

Mitigation

Monitoring of effluent water quality discharged from the sewage system of the power station should be conducted on quarterly basis or more if necessary. It may be recommended on key parameters of oil and grease content as well as on the standard parameter of BOD, TDS, coli-form groups, and chlorine for both wastewater discharge and its receiving water upstream and downstream discharge outlet.

In case of a construction camp being set up, domestic and chemical effluent waters from the camp should be treated before the discharge into the environment, with on-site sanitation

systems, namely septic tanks along with soakage pits. In addition, proper monitoring to check the compliance with the National Environmental Quality Standards (NEQS) should be carried out periodically.

To avoid pollution of ground and surface water by spilling and leakage of lubricants, oils, and other petroleum products, the following measures are recommended:

- Standard Operation Procedures (SOPs) for procurement and operation to be prepared and followed to minimize any oil spills and leakage.
 - Proper design of storage places and facilities with encasement
 - Employment of good engineering practices, such as collection and recycling of lubricant oils.
 - Introduction of new design of replacement equipment or its parts that require no or less lubricant oils, such as for turbine inlet valves.
- 3) Noise, vibration, and dust emission during construction works for replacement.

Impacts

There will be no environmental significant impacts of noise, vibration, and dust through the rehabilitation and replacement works since the existing power station is sufficiently distant from the inhabited area and a good network of paved access road from the trunk road to the project site already exists. Only the risks of on-site workers may be considered during dismantling of existing units (generators, turbines and their peripherals) and they should be taken care of with protective measures for working labor's health and safety.

Mitigation

- No mitigation for noise, vibration, and dust is necessary for residential quarters since the project site (power station) is at least a few kilometers away from the nearest inhabited area.
- SOPs for guarding labor health and safety to be prepared and followed to minimize the workers risk during rehabilitation and replacement work.
- Noise and vibration should be controlled by distance and barrier of noise-absorbing material. It should be controlled below 80 dBA (from 1 meter at the source) according to the FS report.
- Ear muffs and other personal protective equipment should be provided to workers during work activities.
- A proper system of monitoring noise and air pollution may be developed by the Contractor duly approved by the Consultant.

4) Solid Waste

Impacts

An amount of solid waste will be generated from dismantled units that will consist of hazardous and non-hazardous waste. Inappropriate disposal of hazardous and non-hazardous waste may cause significant adverse impact on the local environment.

Mitigation

Hazardous and non-hazardous waste should be handled separately in disposal.

- Those separately treated solid waste should be safely disposed only in demarcated waste disposal sites.
- Precautionary planning of solid waste management prior to implementation of dismantling work is recommended.
- For collection of waste, supply of fiber-glass-waste-bins throughout project site, that of separate bins for recyclable material, avoidance of using polyethylene bags, and keeping the practice of tight sealing waste-collection-containers at all times are required.
- For final disposal of waste, non-hazardous waste should be disposed according to the locally ordinary practice properly chosen from incineration, composting or sanitary landfill, while hazardous waste should be managed separately.

5) Other impacts during construction (rehabilitation and replacement).

Impacts

i) Movement of heavy machine and equipment for installation

Hauling and movement of heavy machine and equipment may cause some risks to pedestrian, livestock, animal, other traffic, local utility network, or do hindrance and jam to local traffic.

ii) Construction camp and worker-related issues

If construction camp is set up during construction works for rehabilitation and replacement, it might cause impacts on flora and fauna resulting to soil erosion for site clearance, interference with agriculture and grazing area, disease transmission and soil contamination by solid waste and air pollution with generators of electricity for labor camp, besides the sewage issue stated above in "2) Water quality".

iii) Workers exposure to hazardous materials and other safety risks during dismantling stage of old equipment

This is also related to labor health issue during construction. Project workers may be exposed to wastes containing hazardous material e.g., asbestos, PCBs and paint

materials. They may be also exposed to safety risks, such as falling from height, injury of accidents, and hit by collapsing material.

Mitigation

i) Movement of heavy machine and equipment for installation

Precautionary planning for traffic routes and transport of equipment before travelling is recommended, with consideration to visibility during transport, placing signs-signals-marks in compliance with local authority, scheduling allowing safety speed, preventive measures for spill, and falling load from vehicles and safe parking with standard procedure.

ii) Construction camp and worker-related issues

The best mitigation measures should be not setting up any construction camp. If it cannot be avoided, the following measures need to be taken.

- The construction camp should reuse an old site that was used for Mangla Dam Raising Project.
 - Stock of stripped top soil for later re-vegetation and use of proper drainage system for avoiding soil erosion.
 - Proper waste water treatment as stated in "2) Water quality".
 - Proper solid waste management as stated in "4) Solid waste".
 - Though the whole area around the reservoir of Mangla Power Station is owned by WAPDA, a comprehensive tree plantation plan is recommended along the construction camp.
 - Mini-stack and silencer should be installed for generator on-site. Periodical maintenance and monitoring of emission gases to check compliance with NEQS are the duties of the Contractor.
- iii) Workers exposure to hazardous materials and other safety risks
- For prevention from exposure to asbestos, PCBs and hazardous paint materials, prepare SOPs to treat unknown materials that might be in contact with, and give standard instruction to workers in the initial stage of works during dismantling of old units.
 - Preparation of plan, equipment and reporting for accidental spill clean-up, and removal of hazardous materials.
 - Workers be required to wear personal protective equipment (PPEs) such as helmet, gloves, overalls, goggles, safety shoes, and inner protection wears to avoid exposure to hazardous materials or to avoid injury of collapse, fall and others.
 - Provision of medicine, emergency kits and vehicle on-site for emergency rescue as a duty of the Contractor.
 - Provision of a space for protected storage of hazardous materials and paints.

- To avoid collapse hazard, supporting arrangement for structures under dismantling, removal, and replacement.

6.1.3 Environmental Management

(1) Water Quality Management

In order to prevent contamination of the environment, for water with oily discharge, treatment facilities should be installed in the power station. The treatment system, through which all the discharge is treated, includes a drainage system to collect surface water runoff and treatment facility for oily water before discharge into the sewer. To ensure that, leveling drains, operator training, and monitoring of effluent and discharged water will be needed. The cleaned water recycle in power station may be recommended. At least, effluent of power station should be discharged through sewage system or through infiltration facility into surface water.

The power station have not conducted water quality monitoring on water of reservoir and discharged water from dam so far. In order to ensure the effects of water treatment in compliance with NEQS, periodical monitoring is recommended for oily content as well as standard parameter of BOD, TDS, coli-form groups, and chlorine.

(2) Treatment or Management of Hazardous Waste Oil and Material

In the operation stage of power station, the solid waste management system should be established in handling and disposing sludge and other solid waste. Solid waste including hazardous waste, oily rags, used fuel, and lubricant oil filters are to be collected in leak-proof and fire-proof containers and transported for proper and legitimate disposal site/facility.

According to the Mangla Power Station Office, waste oil are routinely packed in drum-can and transferred to Cante Area (Army Area), 5 km from the power station. In order to strengthen the current management activities on solid and hazardous waste, rechecking the inventory of those materials and wastes in the power station, reviewing the SOPs for management of those materials and wastes, and the preparation of comprehensive solid waste management plan are recommended.

6.2 Project Impact on GHG Emission Reduction

The project intends to directly contribute to GHG emission reduction through hydropower plants rehabilitation and enhancement aiming to generate renewable energy, which does not emit GHG at generation, with the use of hydropower.

This section made an estimation for project impact on GHG emission reduction, with available data of WAPDA and calculation with JICA Climate Finance Impact Tool (Mitigation) Draft Ver.

1.0, June 2011, on mitigation-17-hydro sector.

6.2.1 Methodology on Emission Reduction

The GHG emission reduction through hydropower is determined as the difference between baseline emissions (GHG emissions with the power generation of fossil fuel that will be replaced by enhanced hydropower of the Project) and project emissions after project activity of hydropower plants enhancement. The formula is as follows.

$$ER_y = BE_y - PE_y \text{ (t-CO}_2\text{/y)}$$

- **ER_y**: GHG emissions reduction in year y achieved by the project (t-CO₂/y)
- **BE_y**: GHG emissions at fossil fired power plants in year y (t-CO₂/y) (Baseline emission)
- **PE_y**: GHG emissions after running hydro pow

6.2.2 Scenarios of Rehabilitation and Enhancement

Project impacts on GHG emission reduction are calculated for the following two scenarios that are proposed in Chapter 5 as well as for the individual unit.

Table 6-1 Scenarios of Rehabilitation and Enhancement

Scenarios	Unit
Scenario-A	Unit 1,2,3, & 4
Scenario-B	Unit 1,2,3,4,5, & 6

6.2.3 Quantity of Electricity to be Increased after Project Implementation

For each unit, the capacity of generation will be enhanced from 115 MW to 135 MW. Then, the quantity of electricity to be increased after project implementation (EG_{pj,y}) is the following, with respect to each scenario.

Scenario-A: With 4 units enhanced, the total increase of generation will be 80 MW and 1,532.5 GWh annually.

Scenario-B: With 6 units enhanced, the total increase of generation will be 120 MW and 1,588.3 GWh annually.

6.2.4 Calculation of Baseline Emission

If hydropower plants are enhanced, the corresponding electric power supply can be replaced from the fossil fired power into hydropower. Amount of GHG emission from electric power supply is reduced through the replacement of conventional fossil fired power with hydropower generation. When the existing hydropower plants decrease in performance by deterioration, plant improvement increases the power generation efficiency and reduces the electric power supply from the existing power plants. Thus, GHG emission should be equal to that from

suppressed fuel combustion. The formula is as follows:

$$BEy = FCi \times NCVi \times COEFi$$

Type	Items	Description
Output	BEy	Baseline emission: GHG emissions of fuel consumption replaced by the hydropower (t-CO ₂ /y)
Input	FCi,y	Suppressed amount of fuel i (kL,m ³ ,t/y)
	NCVi	Net Calorific Value of each fuel type (GJ/ kL, m ³ , t)
	COEFi	CO ₂ emission factor of each fuel type (t-CO ₂ /TJ)

Source: Prepared by the Survey Team

(1) Evaluation of FCi,y

When hydropower plants connect to the grid, the existing power plants in the grid should be replaced in a decreasing order of unit fuel cost. Reducing fuel type and its priority should be determined on such view.

a) Electric power supply in each fuel type of grid power under WAPDA

Type of fuels and its electric power supply (GWh/y) and consumption (kL,m³,t/y) in each fuel type comprised the grid power of WAPDA.

Table 6-2 Power Supply in Each Fuel Type of Grid Power under WAPDA

Fuel type	Quantity of Generated Electricity (GWh/y)	Fuel Consumption (converted to crude oil)	
		Consumed Volume	Unit
Crude oil	22,738	6,742	ktoe
Gas	27,085	8,493	ktoe
Coal	136	73	ktoe

Source: Answers of WAPDA Environment Cell to the Questionnaire of the Study Team, May 2012, with reference to Pakistan Energy Year Book 2009, Table 1.6 and Table 5.3.

Note: The concerned values above are the same for both Scenario-A and Scenario-B.

b) Priority of target fuel for reducing

Since the unit fuel cost has not been available from WAPDA in the study, fuel unit costs were set in the order of petroleum, gas, and coal for evaluation.

c) Essential amount of fuels

In Pakistan, because of energy source diversification promotion, multiple fuel types (petroleum, gas, coal) can be used within the grid. Therefore, fuels at some level of amount should be set aside for minimum operation of plants for each fuel type. In conclusion, 5% of the total electric power supply is set aside as essential amount of fuels.

d) Reducible fuel type and electric power supply

Excluding the essential amount of fuels computed in c), the reducible amount of fuels is identified in priority order of target fuel for reducing, and the reducible fuel type and electric power supply are computed as shown in Table 6-3.

Table 6-3 Suppressible Quantities of Power Generation by Fuel Type

	Suppression Priority	Quantity of Generated Electricity	Quantity Unable to Suppress	Suppressible Quantity
		MWh/y	MWh/y	MWh/y
Petroleum	1	22,737,700	2,498	22,735,202
Gas	2	27,084,740	2,498	27,082,242
Coal	3	136,400	2,498	133,902

Source: Values calculated with JICA Climate-FIT(Mitigation) Draft Ver. 1.0, June 2011, on hydro sector

(2) Net Calorific Value (NCVi) and CO2 Emission Factor (COEFi) of Each Fuel Type

Based on the reducible amount of fuels in d), GHG emissions of electric power generation with fossil fuels should be replaced with hydropower supply of the Project (EGpj,y), Tables 6-4, 6-5 and 6-6 show the calculation.

Table 6-4 Net Calorific Value and CO2 Emission Factor of Each Fuel Type

Fuel Type	Net Calorific Value (unit)		CO2 Emission Factor (unit)	
Crude oil	43.0	Gj/t	77.4	t-CO2/TJ
Gas	0.0365	GJ/m3	56.1	t-CO2/TJ
Coal	19.8	GJ/t	94.6	t-CO2/TJ

Source: Answer of WAPDA Environment Cell to the Questionnaire of the Study Team, May 2012, with reference to Pakistan Energy Year Book 2009, Appendix 7.4 and unit conversion by JICA Study Team

Table 6-5 CO2 Emissions of Thermal Power to be Replaced after the Project for Scenario-A

Fuel Type	Quantity Unable to Suppress	Suppressible Quantity	Suppressed Quantity	Heat Efficiency	Caloric CO2 Emission Factor	Fuel Suppressed Quantity	CO2 Emission Reduced Quantity
	MWh/y	MWh/y	MWh/y	%	t-CO2/TJ	ktoe/y	t-CO2/y
Petroleum	2,498	22,735,202	1,532,500	29.0%	77.4	454.4	1,472,452
Gas	2,498	27,082,242	0	27.4%	56.1	0.0	0
Coal	2,498	133,902	0	16.2%	94.6	0.0	0
Total			1,532,500			454.4	1,472,452

Source: Values calculated with JICA Climate-FIT(Mitigation) Draft Ver. 1.0, June 2011, on hydro sector

Table 6-6 CO2 Emissions of Thermal Power to be Replaced after the Project for Scenario-B

Fuel Type	Quantity Unable to Suppress	Suppressible Quantity	Suppressed Quantity	Heat Efficiency	Caloric CO2 Emission Factor	Fuel Suppressed Quantity	CO2 Emission Reduced Quantity
	MWh/y	MWh/y	MWh/y	%	t-CO2/TJ	ktoe/y	t-CO2/y
Petroleum	2,498	22,735,202	1,588,300	29.0%	77.4	470.9	1,526,065
Gas	2,498	27,082,242	0	27.4%	56.1	0.0	0
Coal	2,498	133,902	0	16.2%	94.6	0.0	0
Total			1,588,300			470.9	1,526,065

Source: Values calculated with JICA Climate-FIT(Mitigation) Draft Ver. 1.0, June 2011, on hydro sector

6.2.5 Calculation of Project Emission

The GHG emissions from hydropower supply after the Project starts will be "0".

$$PE_y = 0$$

However, if the hydropower plant has reservoir, methane will be generated from the reservoir. Actually, the concerned hydropower plant of the Project, Mangra Hydropower Station, has its reservoir. Then, the formula below shall be applied. When methane is less than 1% of baseline emission, it can be ignored.

$$PE_y = (EF_{RES} \times EG_{PJ,y})/1000$$

- EF_{RES} : Default GHG emission factor from reservoir
(Default value at 23rd CDM conference: 90 kg-CO₂/MWh)
- $EG_{PJ,y}$: Amount of power supply from hydropower plants in year y (MWh/y)
- 1000 : Net conversion factor(1t-CO₂=1000 kg-CO₂)

Table 6-7 Project Emission from Reservoir for Scenario-A

-	Emission Factor	Quantity of Electricity	Quantity of Emission
GHG	0.09 t-CO ₂ /MWh	1,532,500 MWh	137,925 t-CO ₂

Source: GHG emission factor values specified in 23rd CDM committee meeting

Table 6-8 Project Emission from Reservoir for Scenario-B

-	Emission Factor	Quantity of Electricity	Quantity of Emission
GHG	0.09 t-CO ₂ /MWh	1,588,300 MWh	142,947 t-CO ₂

Source: GHG emission factor values specified in 23rd CDM committee meeting

6.2.6 GHG Emission Reduction after Project Activity

The following are the results of the calculation for GHG emission reduction after the Mangla Power Station Rehabilitation and Enhancement Project.

(1) Scenario-A (With 4 units enhanced)

1) Scenario-A: Baseline emission

$$BE_y = FC_i \times \text{conversion factor (41.868: TJ/ktoe)} \times COEF_i$$

BE_y	Baseline emission: GHG emission associated with fuel consumption which is assumed to be replaced by hydropower generation	1,472,452	t-CO ₂ /y
	Reduction of fuel type I consumption in scope of reduction	-	ktoe/y
FC_i	Crude oil	454	ktoe/y
	Gas	0	ktoe/y
	Coal	0	ktoe/y
	Others	0	ktoe/y
$COEF_i$	CO ₂ emission factor per net calorific value of fuel type i	-	t-CO ₂ /TJ
	Crude oil	77.4	t-CO ₂ /TJ
	Gas	56.1	t-CO ₂ /TJ
	Coal	94.6	t-CO ₂ /TJ
	Others	0	t-CO ₂ /TJ

Source : Prepared by the Survey Team

2) Scenario-A: Project emission **PE_y**

PE_y	Project emission: GHG emission after project activity	137,925	t-CO ₂ /y
PE_{res}	Emission from reservoirs	137,925	t-CO ₂ /y

Source : Prepared by the Survey Team

3) Scenario-A : GHG emission reduction after project activity **ER_y = BE_y - PE_y** [t-CO₂/y]

ER_y	GHG emission reduction after project activity	1,334,527	t-CO ₂ /y
BE_y	Baseline emission: GHG emission reduction associated with fuel consumption which is assumed to be replaced by hydropower generation	1,472,452	t-CO ₂ /y
PE_y	Project emission: GHG emission after project activity	137,925	t-CO ₂ /y

Source : Prepared by the Survey Team

GHG Emission Reduction for Scenario-A = 1,334,527 [t-CO₂/y]

(2) Scenario-B (With 6 units enhanced)

1) Scenario-B: Baseline emission **BE_y**

BE_y	Baseline emission: GHG emission associated with fuel consumption which is assumed to be replaced by hydropower generation	1,526,065	t-CO ₂ /y
FC_i	Reduction of fuel type I consumption in scope of reduction	-	ktoe/y
	Crude Oil	471	ktoe/y
	Gas	0	ktoe/y
	Coal	0	ktoe/y
	Others	0	ktoe/y
COEF_i	CO ₂ emission factor per net calorific value of fuel type i	-	t-CO ₂ /y
	Crude oil	77.4	t-CO ₂ /y
	Gas	56.1	t-CO ₂ /y
	Coal	94.6	t-CO ₂ /y
	Others	0	t-CO ₂ /y

Source : Prepared by the Survey Team

2) Scenario-B: Project emission **PE_y**

PE_y	Project emission: GHG emission after project activity	142,947	t-CO ₂ /y
PE_{res}	Emission from reservoirs	142,947	t-CO ₂ /y

Source : Prepared by the Survey Team

3) Scenario-B: GHG emission reduction after project activity **ER_y = BE_y - PE_y** [t-CO₂/y]

ER_y	GHG emission reduction after project activity	1,383,118	t-CO ₂ /y
BE_y	Baseline emission: GHG emission reduction associated with fuel consumption which is assumed to be replaced by hydropower generation	1,526,065	t-CO ₂ /y
PE_y	Project emission: GHG emission after project activity	142,947	t-CO ₂ /y

Source : Prepared by the Survey Team

GHG Emission Reduction for Scenario-B = 1,383,118 [t-CO₂/y]

CHAPTER 7

PROJECT IMPLEMENTATION PLAN

CHAPTER 7 PROJECT IMPLEMENTATION PLAN

7.1 Implementation Policy

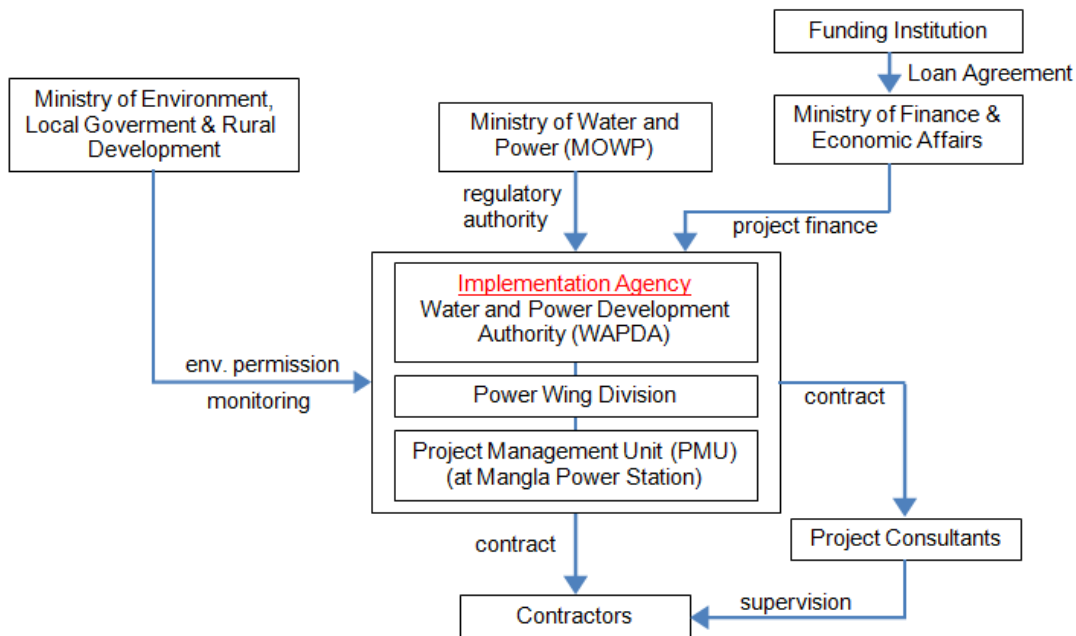
7.1.1 General Procedure for Obtaining Approval of the Project

- (1) Normally, a Planning Commission Form-2 (PC-II) is first prepared and accomplished by the executing agency responsible for the implementation of the project. This form is important to obtain the approval of the Planning Commission for the allocation of funds for the conduct of the F/S of the project.
- (2) Then, the feasibility study will be prepared by the implementation agency by hiring a consultant. The implementation agency through the Ministry of Water and Power (MoWP) and Economic Affairs Division (EAD) will approach different donor agencies for arrangement of loan agreement (foreign exchange component) to execute the project.
- (3) The Planning Commission Form-I (PC-I) is then prepared by the concerned department. PC-I is a document prescribed by the Planning Commission for processing of development projects. It contains the details of project objectives, justification, implementation, construction schedule, location, salient features, cost estimates, financing schedule, cost-benefit ratio and its economic rate of return (EIRR).
- (4) The concerned department submits the prepared PC-I to the MoWP for evaluation and onward submission to the Planning Commission of Pakistan.
- (5) Planning Commission examines the proposed project in depth by circulating it to all the stakeholders, provincial governments (if involved) and the Ministry of Finance for their comments/reservations (if any).
- (6) After getting the comments of all the stakeholders, a working paper is prepared by the Planning Commission of Pakistan.
- (7) In light of that working paper and keeping in view the overall cost of the project, the case is elevated to the Central Development Working Party (CDWP) if the cost of the project is up to PRs 1,000 million. The meeting is chaired by the deputy chairman of the Planning Commission, and attended by all stakeholders, i.e., EAD, Ministry of Finance, provincial government, MoWP and the implementation department/agency.

- (8) If the value of the project is more than PRs 1,000 million, then it is elevated to the Executive Committee of National Economic Council (ECNEC) for approval. The ECNEC is headed by the finance minister and constituted by EAD, Planning Commission of Pakistan, provincial governments, MoWP and the implementation department/agency.
- (9) After the approval of the project, the case will be transmitted by the Planning Commission of Pakistan to the Finance Division for the release of funds as per the schedule given in PC-I.

7.1.2 Implementation Process of the Project

A draft implementation process of the Project is shown in Figure 7-1:



Source: Prepared by the Survey Team

Figure 7-1 Project Implementation Process

The following are the envisioned undertakings of the implementation agency (WAPDA), consultants, and contractors of the Project:

(1) Implementation Agency

The implementation agency for the Project will be WAPDA under the supervision of the Energy Division of MOWP. It was assessed that WAPDA has enough technical capabilities to implement the Project with its abundant experiences as implementation agency for hydropower projects such as Warsak Hydropower Station, Tarbera Dam, Mangla Dam, Chashma Hydropower Station and Ghazi Barotha Hydropower station etc. In addition,

WAPDA has established the structure for the development of human resources such as the Hydel Training Center Mangla as described in Chapter 2.5.4.

The WAPDA will be responsible for the implementation of the Project as listed below:

- 1) The manpower of the project management unit (PMU) for the Project is shown in Table 7-1. The PMU will consist of staff coming from the Power Wing Division in WAPDA Headquarter. The PMU office will be located in Mangla Power Station. As for other specialists such as environmental specialists and land officer, they will be assigned from the other divisions in WAPDA Headquarter, when needed.

Table 7-1 Manpower of the Project Management Unit (PMU)

No.	Position	BPS	Required Number of Staff
1	Project Manager	19	1
2	Senior Engineer (Mechanical)	18	1
3	Senior Engineer (Electrical)	18	1
4	Senior Engineer (Civil)	18	1
5	Junior Engineer (Mechanical)	17	1
6	Junior Engineer (Electrical)	17	1
7	Junior Engineer (Civil)	17	1
8	B & A.O	17	1
9	Foreman (Mechanical)	16	1
10	Foreman (Electrical)	16	1
11	Asst. B & A.O	16	1
12	Stenographer	15	1
13	Office Assistant	14	1
14	Sub-Engineer (Mechanical)	11	2
15	Sub-Engineer (Electrical)	11	2
16	Sub-Engineer (Civil)	11	1
17	A/cs Assistant	11	2
18	Others (non-technical)	-	26
Total			46

Source: Prepared by the Survey Team

The roles and responsibilities of key officers in the PMU are the following:

Project Engineer

- i) He will act as the superintending engineer (electrical/mechanical) having sufficient experience in the field of construction, rehabilitation, and operation of hydropower plants.
- ii) He will have the overall responsibility for the project.
- iii) He will be responsible for the execution of the project from its initial stage up to the

completion stage.

- iv) He will perform as a liaison between departments, consultants, contractors, and the loan agency.
- v) He will be in charge of the administration, accounts, and security of the project.
- vi) He will be responsible for the overall administration management for the implementation of the project through WAPDA staff, consultants, and contractors.
- vii) He will maintain the project accounts to get the proposed budget estimates and cash flow requirements including maintenance of expenditure accounts through project accounts officers.
- viii) He will look after the security of the equipment, the consultants and the contractors working in the project.
- ix) He will maintain copies of the progress of the project as per time schedule submitted by the contractors monthly/yearly, and provide completion report to all stakeholders.

Senior Engineer (Mechanical)

- i) He has sufficient experience in the mechanical portion of the Project.
- ii) He will be responsible for the mechanical parts inspection, installation, and testing as per schedule of the Project.
- iii) He will prepare the daily progress report, monthly progress report, and completion report relating to the mechanical portion.
- iv) He will assist the project engineer in the execution of his duties.

Senior Engineer (Electrical)

- i) He has sufficient experience in the electrical portion of the Project.
- ii) He will be responsible for the electrical parts inspection, installation, and testing as per schedule of the Project.
- iii) He will prepare the daily progress report, monthly progress report, and completion report relating to the electrical portion.
- iv) He will assist the project engineer in the execution of his duties.

Senior Engineer (Civil)

- i) He has sufficient experience on the civil side of the hydropower construction and rehabilitation.
- ii) He will be responsible for the inspection and execution of civil works by the contractor as per WAPDA specifications.
- iii) He will prepare the daily, monthly, and completion reports relating to the civil portion.
- iv) He will assist the project engineer in all civil engineering works.

Junior Engineer (Mechanical)

- i) He is an engineering graduate in mechanical discipline having an experience in the construction and rehabilitation projects of hydropower project.
- ii) He will assist the senior engineer (mechanical) in the execution of his duties.

Junior Engineer (Electrical)

- i) He is a engineering graduate in electrical discipline having an experience in the construction and rehabilitation of hydropower project.
- ii) He will assist the senior engineer (electrical) in the execution of his duties.

Junior Engineer (Civil)

- i) He is a civil engineering graduate having an experience in the construction and rehabilitation of hydropower project.
- ii) He will assist the senior engineer (civil) in the execution of his duties.

Foremen (Mechanical & Electrical)

- i) They are diploma holders in their respective field (mechanical and electrical) having sufficient experience in the construction, rehabilitation and maintenance works of hydropower plant.
- ii) They will coordinate among the related departments and provincial authorities for the smooth implementation of the Project.
- iii) They will perform coordination among concerned agencies prior to securing the environmental certificate of the Project from the Ministry of Environment, Local Government and Rural Development.
- iv) They will assist and cooperate with the project consultants.
- v) They will perform close communication with institution(s) of the project fund during tendering, contracts, procurement, project progress and the other information related to the Project.
- vi) They will monitor tender announcement, tender closing, evaluation and contract.
- vii) They will assist the contractor for custom clearance of import/re-export equipment and materials, and special tools for the Project.
- viii) They will assist in the issuance of payment certificates.
- ix) They will provide assignment of operators and maintenance staffs for new facilities.
- x) They will provide commissioning of facilities, operation and maintenance.

WAPDA has to secure budget and staffs to execute the above duties.

(2) Competent Authority (MoWP)

The competent authority for the Project is MoWP. The MoWP will be responsible for the

following:

- 1) Oversee the performance of WAPDA in the implementation and O&M of the projects in light of the government instructions/directives.
- 2) Monitor the overall performance of WAPDA and watch the progress and status of projects under implementation or maintained by the attached departments.
- 3) In case of any bottlenecks where other ministries are involved, MoWP will approach the other ministries for the removal of these bottlenecks for the smooth implementation and O&M of the Project.

(3) Consultant

The consultant will be responsible for the activities below. Items in parentheses are the corresponding output of each activity.

- 1) Conduct detailed design and preparation of tender documents. (Tender Documents)
- 2) Prepare cost estimate and time schedule. (Cost Estimate and Schedule)
- 3) Conduct site visit and assist the employer in the conduct of tendering process. (Addendum)
- 4) Prepare pre-qualification documents. (P/Q Documents)
- 5) Conduct tender evaluation. (Evaluation Report)
- 6) Assist employer to carry out contract negotiation. (Contract Agreement and Minutes)
- 7) Review drawings for approval of equipment, materials, and construction method. (Comment Letters)
- 8) Witness shop inspection. (Inspection Report)
- 9) Witness site inspection. (Inspection Report)
- 10) Monitor progress and issue interim payment certificate. (Progress/Payment Certificate)
- 11) Prepare monthly progress report. (Monthly Reports)
- 12) Assist employer to issue taking-over certificate. (Taking-over Certificate)
- 13) Prepare completion report. (Completion Report)
- 14) Review as-built drawings and compile. (Compiled As-built Drawings)
- 15) General works regarding supervision during construction:
 - To assist employer to supervise whole project activities including supervision of contractor and environmental impact assessment;
 - To arrange interface between employer and JICA; and
 - To provide employer's engineers with technical assistance regarding construction, operation, and maintenance.

(4) Contractor

The contract of the contractor for the Project will be made on a turnkey basis. Therefore, the contractors will be responsible for the following:

- 1) Engineering and procurement of equipment and materials related to the Project including site survey and design.
- 2) Shop test, packing, shipping, customs clearance and delivery to site.
- 3) Pre-commissioning and commissioning tests.
- 4) Training of WAPDA engineers at the manufacturer's factory.
- 5) On-the-job training for the WAPDA engineers in the project site.
- 6) Maintenance of facilities during defects liability period.

7.1.3 Selection of Consultant

Projects are normally identified first by the respective department such as WAPDA through a reconnaissance survey and broad features/location of the projects as defined in the survey report. The consultancy firms/JVs are hired by the implementation agency for carrying out the feasibility study, detailed design study or construction supervision of the project until its completion. Then, the terms of reference (TOR) for further studies, as defined above are prepared. The Project is then advertised to hire the services of consultancy firms/JVs for its implementation. The following steps are undertaken according to the guidelines prepared by the Pakistan Engineering Council (PEC) keeping in view the World Bank/Asian Development Bank or other donor agencies criterion. However, for a specific project, if any donor agency has shown interest in funding, the procedures/criteria for hiring of consultants are shared with the agency and finalized in light of the donors' requirements.

The following steps are followed in the selection of consultant:

Step-1

The expression of interest (EOI) is an invitation of the implementation agency to eligible firms/JVs published in the national press. The consultancy firms registered with the PEC are provided with the EOI document. The firms/JVs are then asked to submit qualifications as well as experience of their permanent staff, overall experience of the firm, and experience of projects of similar nature. The time given for submission of the EOI documents is generally about a month.

Step-2

The evaluation of EOI documents of each firm/JV is done by a committee designated by the implementation agency. The evaluation is based on the qualification/experience of similar nature of the firm/JV as well as proposed key personnel. Based on the overall/similar experience, suitable firms are pre-qualified. This process takes about a month and a half.

Step-3

The pre-qualified firms/JVs are issued a Request for Proposal (RFP) documents and they are asked to submit their technical and financial proposals under two separate envelopes

within the stipulated time, which is generally about 45 days. However, the time can be adjusted depending on the size of the assignment.

Step-4

The technical proposals are first opened and evaluated by a committee designated by the implementation agency as per PEC guidelines on quality-based selection (QBS), or quality- and cost-based selection (QCBS) with the following criteria:

- i) Qualification of the Firm/JV
- ii) Approach and Methodology
- iii) Key Personnel (Qualifications & Experience)

This evaluation is to be done for about a month and a half.

Step-5

The evaluation report of the Standing Committee is submitted to the implementation agency for approval. This takes 20 to 30 days.

- i) In case of QBS, the financial proposals of the firms whose technical proposals met the minimum qualifying mark are opened. The firm/JV who obtained the highest score on the Technical Proposal plus the Financial Proposal will be declared as winner and the consultancy services contract agreement will be signed with the winning firm/JV.
- ii) In QCBS, 80% weightage is given to the technical proposal and 20% to the financial proposal of each firm or JV.

Step-6

The evaluation report is also sent to the donor agency for their vetting/concurrence. After receipt of concurrence from the donor agency, the evaluation report is submitted to the implementation agency for contract negotiations with the firm/JV which takes 30 to 45 days.

Step-7

After negotiations and preparation of the final draft of consultancy services contract agreement, the implementation agency's final approval is sought and contract signing is done within 20 to 30 days.

7.1.4 Procurement of Goods and Services

(1) Mode of Procurement

The Project shall be carried out as one package under an International Competitive Bidding (ICB) mode. Tender documents shall be released to tenderers that will pass the pre-qualification criteria.

(2) Origin for Procurement

Origin of the equipment and materials for the Project will not be specified due to the principle of the ICB; however, the successful tenderer shall have experience in similar projects, be financially stable, employ capable engineers to manage the Project, and the tender shall propose first class equipment and materials. Tender documents shall therefore clearly mention the tenderer's qualification and experience, equipment quality, function and technical guarantees, etc., and their evaluation criteria to prevent lowering the quality of the Project.

(3) Guarantee Period

It will be specified in the contract documents that the plant shall be guaranteed for a certain period after taking over. It is proposed that a 24-month guarantee period be specified in the tender documents. If plant has defects, poor quality, improperly installed, etc., an accident may arise in a few months after energizing.

Besides, it is preferably mentioned in the tender documents that the contractor has the duty to train WAPDA's operators and maintenance staff during construction and defects liability period.

7.1.5 Transportation

There are two transportation routes used in Pakistan. One is shipping to Karachi by ship and inland transportation by truck. Another one is flying to Islamabad by air cargo, and then inland transportation to Mangla by truck. A comparison table on the distances of the different landing ports is shown in Table 7-2 and transportation route map is shown in Figure 7-2. In the past project, the route from Karachi is generally used, however, the Survey Team recommends that the route from Karachi will be used for general cargoes and the route from Islamabad will be used for smaller items and during emergency cases.

Table 7-2 Transportation Route

Port	Conveyance	Distance to Power Station	Via
Karachi	By ship and truck	1,500 km	Hyderabad, Multan, Lahore
Islamabad	By air and truck	200 km	-

Source: Prepared by the Survey Team



Source: Prepared by the Survey Team

Figure 7-2 Route Map of Transportation

The condition of the roads used for inland transportation to the site is good and the maximum loading condition of any bridge along the route is limited to 40 tons. Trailer trucks could access the temporary storage yard in the site directly.

7.2 Implementation Schedule

For the large scale rehabilitation and enhancement project, there are four scenarios of the implementation schedule. The basic condition of each scenario is listed below:

(1) Scenario-A1

The implementation schedule for Scenario-A1, which is the rehabilitation and enhancement of four (4) units with double unit stoppage, is shown in Figure 7-3. The total duration of the Project was estimated at 95 months from the preparation stage of JICA loan agreement to the completion of the commissioning test on-site.

(2) Scenario-A2

The implementation schedule for Scenario-A2, which is the rehabilitation and enhancement of four (4) units with single unit stoppage, is shown in Figure 7-4. The total duration of the Project was estimated at 110 months from the preparation stage of JICA loan agreement to the completion of the commissioning test on-site.

(3) Scenario-B1

The implementation schedule for Scenario-B1, which is the rehabilitation and enhancement of six (6) units with double unit stoppage, is shown in Figure 7-5. The total duration of the Project was estimated at 107 months from the preparation stage of JICA loan agreement to the completion of the commissioning test on-site.

(4) Scenario-B2

The implementation schedule for Scenario-B2, which is the rehabilitation and enhancement of six (6) units with single unit stoppage, is shown in Figure 7-6. The total duration of the Project was estimated at 132 months from the preparation stage of JICA loan agreement to the completion of the commissioning test on-site.

As for the implementation schedule of the Project, it would take some time of around 8 months for the completion of the model test of turbine. According to the hearing from the several manufacturers in Japan, they predict that it takes time of 24 months for the design and manufacturing works per unit.

Disassembling of existing equipment and the following erection works at the site will start after arrival of all necessary equipment.

Both the erection bays of Unit 1 and Unit 10 will be used for erection works to reduce the erection period.

It was tentatively envisaged that the schedule for the procurement of consultant, preparation of detailed design report and tender documents, and tendering and contract with the contractor would be implemented during the following period:

- Procurement of Consultant : 12.0 months
- Preparation of Detailed Design Report and Tender Documents : 7.5 months
- Tendering and Contract with Contractor : 10.5 months

To be added Schedule for Scenario-A1

To be added Schedule for Scenario-A2

To be added Schedule for Scenario-B1

To be added Schedule for Scenario-B2

7.3 Quality Control Plan

(1) Quality Control of Equipment and Materials to be Supplied

The consultant will check the quality control manuals submitted by the contractor to determine if manufacturing products meet the quality standard or followed the needed procedures. The consultant will either instruct or reject the contractor to take over the materials. The consultant and WAPDA engineers will witness shop tests for major equipment to be procured under the Project.

(2) Quality Control during Construction

1) Contractor's Documents

The contractor shall submit the construction schedule, shop drawings, design calculations, test procedures, test reports, O&M manuals, quality control plans and safety plans for approval of WAPDA and/or consultant.

2) Control of Site Works

During the construction works, the consultant and WAPDA inspectors will check damages on equipment and materials, and order the repair or replacement of the damaged equipment and materials. Prior to the issuance of payment certificates to the contractors, the consultant and/or WAPDA inspectors will inspect not only the progress but also the quality of all facilities claimed by the contractors in their application for payment.

3) Commissioning Tests

The consultant and WAPDA representative will check the test report, and function and performance of substation equipment before the energizing.

7.4 Operation and Maintenance Plan

- 1) The WAPDA, being a semi-autonomous body, is controlled by the GOP through MoWP. The WAPDA, being an independent authority, is responsible for the O&M of the projects/power houses in light of government instructions/directives.
- 2) The WAPDA arranges budget (both foreign and local) for O&M of the projects through MoWP and the Ministry of Finance or utilizes its own resources as much as possible.¹
- 3) The WAPDA has its own staff for the operation and maintenance of the power houses/projects.
- 4) Operation of the hydropower stations is carried out according to the intent of water

¹ WAPDA has covered the O&M cost of Mangla Power Station entirely by use of its own financial resources since its commissioning in 1967. However, WAPDA has never carried out overhaul of turbines & generators in consideration of the next reasons: 1) prolonged power crisis across the country, and 2) saving the many steps and a lot of time required for obtaining the approval from the Government of Pakistan.

releases issued by IRSA who put their consolidated demand on the leases as per requirement of irrigation departments of the provinces.

- 5) The WAPDA is also responsible for arranging spare parts and other materials required for the smooth running of the projects.
- 6) The MoWP oversees the performance of WAPDA during the implementation and O&M in light of the government instructions/directives.
- 7) The WAPDA is also responsible for the security of all hydropower stations/installation and performs this activity through a dedicated security staff.

7.5 Payment Procedure to the Contractor

The payment to the contractor shall be made in Foreign Currency (F/C) and Local Currency (L/C).

And, an advance payment shall be paid to the contractor for mobilization and design, when the contractor submits a guarantee in accordance with the contract agreement.

7.5.1 Civil Works

The basic payment procedure for the civil works to the contractor is described below:

1. The contractor shall submit eight copies of the application for payment signed by the representative of the contractor to the project manager of the PMU of WAPDA at the end of each month.
2. After preliminary review by the project manager, the application for payment will be sent to the consultants for review and certification.
3. Within 7 to 28 days (or as mentioned in the contract agreement) of receipt of the application for payment, the consultant shall determine the amount of payment and issue a certificate herein called "interim payment certificate" (IPC) to WAPDA and the contractor.
4. The project manager of the PMU, after thorough evaluation, will approve the IPC and place a demand of approved amount of payment to the general manager (finance) of the Power Wing of WAPDA.
5. The general manager (finance) of the Power Wing will release the approved amount of payment to the project manager of the PMU and transfer the funds into his official bank account.
6. The project manager of the PMU will issue a cheque to the contractor on receipt of funds from the general manager (finance) of Power Wing.

7. The maximum period within which the payment is to be made to the contractor is 30 to 60 days (or as agreed in the contract agreement), from the first submission of application for payment to the project manager of the PMU.

7.5.2 Electrical and Mechanical Works

The basic payment procedure for the electrical and mechanical works to the contractor is described below:

1. The contractor shall submit eight copies of the application for payment signed by the representative of the contractor to WAPDA at the end of each month.
2. The application for payment on the delivery of any plant and erection equipment shall also be accompanied by the following:
 - Copies of the contractor's invoice showing plant description, quantity, unit price, total price;
 - Copies of packing list identifying contents of each package;
 - Contractor's guaranty certificate;
 - Inspection certificate issued by the consultant and the manufacturer's factory inspection report;
 - Clean on board, bill of lading or air waybill;
 - Certificate that the plant complies with specification;
 - Certificate of origin, issued by the contractor;
 - Marine insurance policies;
 - Consultant's permission to deliver; and
 - Any other documents as considered necessary by the consultant.
3. Within 14 days (or as prescribed in the contract agreement) of receipt of the monthly statement, the consultant shall determine the amount of payment to the contractor and issue to WAPDA and the contractor a certificate of payment.
4. The amount of payment to the contractor under any payment certificate issued by the consultant shall be paid by WAPDA to the contractor within 58 days (foreign component) and within 49 days (local component) after the contractor's monthly statement has been submitted to the consultant for certification. (These periods can vary as per contract agreement.)

7.6 Security Regulation in the Project Site

The Ministry of Interior (MOI) stipulates the security regulation for government-sponsored

project. Their security is the main responsibility of the government. The sponsoring ministry or department must be made responsible to coordinate and ensure the safety and security of their foreign guests in collaboration with the law enforcing agencies (LEAs). The sponsor must deputize an officer to look after the security aspects and the whole blame and responsibility must not be thrown to the LEAs alone.

The security regulation in the project site and camp site stipulated by the MOI is described below:

Security in the Project Site

- 1) Responsibility of security rests with the sponsoring department, ministry, or private firm.
- 2) All security arrangements must be coordinated with the Foreigner's Security Cell (FSC), MOI.
- 3) Sponsors should submit the security plan to FSC, MOI and get its approval prior to the arrival of foreigners.
- 4) Only one agency should be made responsible for security. All other security agencies must function under its command.
- 5) Project site should be isolated from local habitation.
- 6) Project site must be well cordoned possibly with only one entry and exit point.
- 7) Nobody should be allowed to enter the project area without a security pass or valid permission issued by an appropriate, responsible, and competent authority.
- 8) Security arrangements should be directly proportional to the level of threat being anticipated.
- 9) Required number of security towers should be built on the perimeter of the project site.
- 10) Good and reliable communication within the project site and with the outside agency, such as sponsor and LEAs, should be ensured.
- 11) Sufficient security staff should be hired or assigned to the project site.
- 12) Security must remain active round the clock.
- 13) Security staff must work in three shifts for this purpose.
- 14) Security staff must get proper rest after their duty.
- 15) Security staff must not be overworked. Overwork can hamper their efficiency.
- 16) Efficiency and state of mind of security staff should be given due consideration.
- 17) Security staff should be cleared security-wise from intelligence agencies before assigning security duty with the foreigners.

- 18) All local labor must be cleared security-wise before employing them to the Project.

Security in the Camp Site

In addition to the abovementioned points, the following should be considered:

- 1) All-out efforts should be made to keep the camp within the parameters of the project site so that an integrated security arrangement will work.
- 2) If it is not possible, then the camp should be kept as close to the project site as possible.
- 3) In this case, a separate security plan should be made and submitted to FSC, MOI for approval prior to the arrival of foreigners.
- 4) Foreigners must stay within the camp site and should not be allowed to move out freely for security reasons.
- 5) They must be provided all facilities and items of daily use inside the camp site.
- 6) If camp site is not within the project site, then a separate commander should be made responsible for the security of the camp site.

7.7 Required Permission for Foreigner to Enter the Project Site

The following procedures are stipulated by MOI in acquiring permission of foreigner to enter the project site in Mangla. The said permission is named as non-objection certificate (NOC).

- 1) The consultant or the contractor will apply to WAPDA for an issuance of NOC.
- 2) WAPDA requests to MOI for issuance of NOC for the consultant or the contractor.
- 3) MOI instructs the Administration of AJ&K, Inspected General Police (IGP) for arrangement of the security for the consultant or the contractor during their transfer to the project site in Mangla and their stay at the site.
- 4) MOI issues the NOC to WAPDA, and WAPDA informs the consultant and the contractor.

CHAPTER 8
PROJECT COST ESTIMATION

CHAPTER 8 PROJECT COST ESTIMATION

8.1 Estimation of Project Costs

8.1.1 Basis of Estimates

The estimates of the project cost were prepared based on the following conditions:

(1) Direct Construction Cost

a) Equipment and material cost

The unit costs of equipment and materials were collected directly from several manufacturers, and these costs were evaluated through experiences and references to similar projects.

b) Installation cost

Installation cost to be adopted will be 9% to 25% of the equipment price, excluding civil works, based on the recommendations of the manufacturers and previous experiences.

c) Transportation including insurance

Transportation cost for shipping and insurance was included in the equipment and material cost, and the inland transportation cost to be adopted will be 5% of the equipment cost.

(2) Exchange Rate

The exchange rate was estimated based on a monthly average rate of November 2012. The following exchange rates were adopted:

USD 1	=	JPY 80.9
USD 1	=	PRs 96.1
JPY 1	=	PRs 0.84

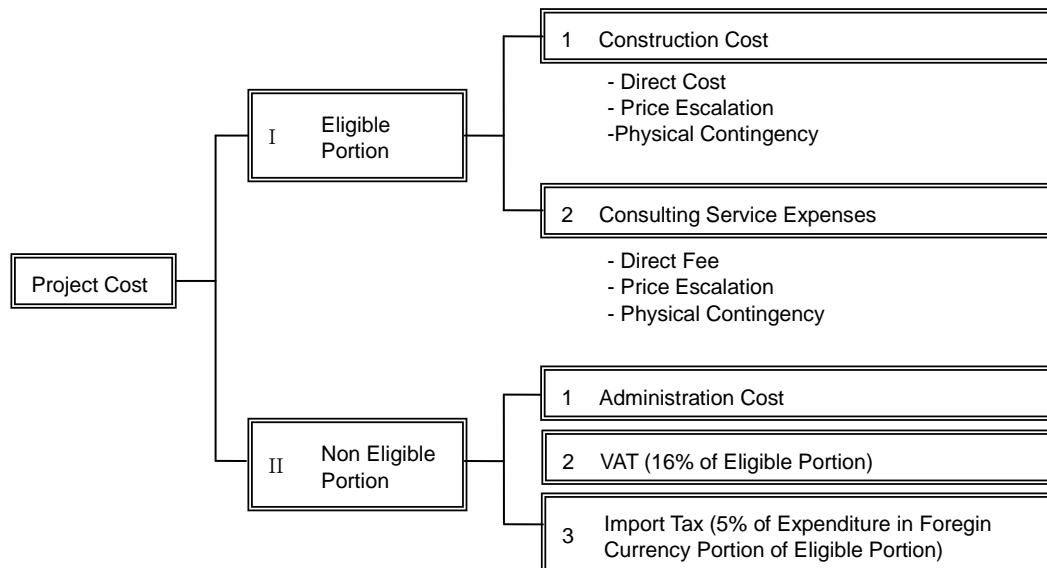
(3) Allocation of Foreign and Local Currencies

The foreign currency portion (F/C) includes the cost of insurance and freight (CIF) of equipment and materials to be imported and administration fee at the site. The local currency portion (L/C) includes the costs of labor, customs clearance duty, and inland transportation cost of imported equipment and materials.

(4) Composition of the Project Implementation Cost

The project cost composed of an eligible portion and non-eligible portion is shown in Figure

8-1. The eligible portion consists of the construction cost and consulting service expenses, while the non-eligible portion is made up of administration cost, value added tax (VAT) and custom duty.



Source: Prepared by the Survey Team

Figure 8-1 Composition of the Project Cost

(5) Price Escalation Rates of Foreign and Local Currencies

Price escalations were assumed to be 2.1% of the direct cost for foreign currency, and 5.7% of the direct cost for local currency, referring to similar projects.

(6) Physical Contingency

Physical contingency was assumed to be 5% of the sum of the direct cost and price escalation for construction works and consulting services.

(7) Consulting Service Expenses

The consulting service fee consisting of engineering services was estimated based on the number of man-month (MM) required for the service.

(8) Administration Cost

The administration cost was estimated based on the number of man-month (MM) required for Project Management Unit (PMU) as shown in Table 7-1.

(9) Value Added Tax (VAT)

The VAT was assumed at 16 % of the sum of both of the foreign currency portion and local

currency portion of the eligible portion.

(10) Custom Duty

For national projects, the import tax of 5% was applied to the CIF prices of the costs for the procurement of materials and equipment abroad.

8.1.2 Estimated Direct Construction Cost

The estimated direct construction costs for each item are shown in Tables 8-1 and 8-2. The said costs are estimated based on the generator with 135MW at the rated power factor.

Table 8-1 Direct Construction Cost at Scenario-A (Units 1-4)

item	Direct Construction Cost		Total
	Foreign	Local	yen
	yen	PRs	
Turbine	3,215,840,141	159,515,880	3,349,833,480
Generator	4,967,827,200	246,420,000	5,174,820,000
Balance of Plant	4,144,466,051	205,578,673	4,317,152,136
Transformer	1,103,961,600	54,760,000	1,149,960,000
Circuit Breaker	951,246,912	47,184,867	990,882,200
Civil Works	19,648,309	974,618	20,466,988
Total	14,402,990,213	714,434,038	15,003,114,804

Source: Prepared by the Survey Team

Table 8-2 Direct Construction Cost at Scenario-B (Units 1-6)

item	Cost		Total
	Foreign	Local	yen
	yen	PRs	
Turbine	5,809,045,939	288,147,120	6,051,089,520
Generator	8,920,009,728	442,460,800	9,291,676,800
Balance of Plant	6,213,377,318	308,203,240	6,472,268,040
Transformer	1,655,942,400	82,140,000	1,724,940,000
Circuit Breaker	1,423,190,496	70,594,767	1,482,490,100
Civil Works	50,013,876	2,480,847	52,097,788
Total	24,071,579,757	1,194,026,774	25,074,562,248

Source: Prepared by the Survey Team

8.1.3 Estimated Consulting Service Fee

(1) Consulting Service Fee

Based on the implementation schedule, the proposed consulting service and its estimated costs were prepared on the following basis:

- The proposed consulting service involves the provision of engineering services as detailed in Table 8-3.
- The tentative TOR of consulting services was prepared based on the results of the feasibility study.
- The assignment schedule for engineering staff is prepared based on the different stages of detailed design, preconstruction, and construction.
- Billing rates were assumed from the rates commonly used for Japanese ODA Loan projects.

The TOR of consulting services is listed in Table 8-3.

Table 8-3 Summary of the TOR of Consulting Services

1.	CONSULTING SERVICES at the DESIGN STAGE
1.1	Review of Previous Related Studies
1.2	Preparation of Necessary Project Documents
1.3	Determination of Design Standards and Criteria
1.4	Detailed Design Works
1.5	Preparation of Bill of Quantity and Specifications
1.6	Preparation of Construction Plan and Schedule
1.7	Preparation of Cost Estimates
1.8	Preparation of Pre-qualification Documents
1.9	Preparation of Tender Documents
2.	CONSULTING SERVICES at the TENDERING STAGE
2.1	Assistance during the Pre-qualification
2.2	Assistance during the Bidding Stage
2.3	Assistance during the Contract Award Stage
3.	CONSULTING SERVICES at the CONSTRUCTION STAGE
3.1	Preparatory Works/Mobilization
3.2	Review of the Contractor's Drawings and Specifications
3.3	Review of the Construction Plan
3.4	Control of Quantity and Quality
3.5	Monitoring and Control of Work Progress
3.6	Environmental Monitoring during the Construction Period
3.7	Control of Payment
3.8	Supervising the Preparation of As-built Drawings and Completion Report
3.9	Supervising the Preparation of Operations and Maintenance Manuals
3.10	Final Inspection and Issuance of Completion Certificate
3.11	Assistance in Institutional Development
3.12	On-the-Job Training (OJT) based on Transfer of Technical Knowledge

Source: Prepared by the Survey Team

In line with the assumed TOR above, the required input of competent engineers for each scenario is shown in Tables 8-4 and 8-5 respectively.

The definition of scenarios is as below:

- Scenario-A1: Units 1-4, double units stoppage
- Scenario-A2: Units 1-4, single unit stoppage
- Scenario-B1: Units 1-6, double units stoppage
- Scenario-B2: Units 1-6, single unit stoppage

Table 8-4 Input of Required Engineers at Scenario-A1 and Scenario-A2

Phase	Scenario-A1 (Unit 1- 4, double units stoppage)		Scenario-A2 (Unit 1- 4, single unit stoppage)	
	Foreign Engineers (M/M)	Local Engineers (M/M)	Foreign Engineers (M/M)	Local Engineers (M/M)
1. Design Stage	39	49	39	49
2. Tendering Stage	7	7	7	7
3. Construction Stage	164	217	224	223
Total	210	273	270	279

Source: Prepared by the Survey Team

Table 8-5 Input of Required Engineers at Scenario-B1 and Scenario-B2

Phase	Scenario-B1 (Unit 1- 6, double units stoppage)		Scenario-B2 (Unit 1- 6, single unit stoppage)	
	Foreign Engineers (M/M)	Local Engineers (M/M)	Foreign Engineers (M/M)	Local Engineers (M/M)
1. Design Stage	59	83	59	83
2. Tendering Stage	7	7	7	7
3. Construction Stage	216	310	316	320
Total	282	400	382	410

Source: Prepared by the Survey Team

Based on the above assumptions of the required input of engineers, the consulting service fee at Scenario-A1 and A2 during the implementation period was estimated at JPY1,035 million and JPY1,287 million respectively. The total consulting service fees at Scenario-A1 and A2 correspond to about 6.9% and 8.6% of the total direct construction cost at Scenario-A as shown in Table 8-1.

As for Scenario-B1 and B2, the consulting service fee at the Scenario-B1 and B2 during the implementation period was estimated at JPY1,458 million and JPY1,897 million respectively. The total consulting service fees at Scenario-B1 and B2 correspond to about 5.8% and 7.6% of the total direct construction cost at Scenario-B as shown in Table 8-2.

8.1.4 Estimated Project Implementation Cost

(1) General Untied Japanese ODA Loans

1) Scenario-A1 and A2

The estimated project implementation cost at Scenarios-A1 and A2 under the condition of utilizing the general untied Japanese ODA loans, which is applied an interest rate 1.4%, is summarized in Tables 8-6 and 8-7 respectively. The grand totals of project cost at the Scenario-A1 and A2 are estimated to be about JPY23.8 billion and JPY24.6 billion respectively. The project implementation cost was largely divided into two portions, namely, eligible cost for Japanese ODA Loan scheme portion, and non-eligible cost for the Government of Pakistan portion as shown in the tables.

Table 8-6 Project Cost at Scenario-A1 (General Untied Japanese ODA Loans)

Item		Total		
		FC	LC	Total
A. ELIGIBLE PORTION		Mil. Yen	Mil. PRs	Mil. Yen
I)	Procurement / Construction	16,784	992	17,617
	UNIT 1-4	14,403	714	15,003
	Base cost for JICA financing	14,403	714	15,003
	Price escalation	1,582	230	1,775
	Physical contingency	799	47	839
II)	Consulting services	853	216	1,035
	Base cost	737	156	867
	Price escalation	76	50	118
	Physical contingency	41	10	49
Total (I + II)		17,637	1,208	18,652
B. NON ELIGIBLE PORTION				
a	Procurement / Construction	0	0	0
	Base cost for JICA financing	0	0	0
	Price escalation	0	0	0
	Physical contingency	0	0	0
b	Land acquisition	0	0	0
	Base cost	0	0	0
	Price escalation	0	0	0
	Physical contingency	0	0	0
c	Administration cost	0	173	145
d	VAT	2,822	193	2,984
e	Import tax	0	999	839
Total (a+b+c+d+e)		2,822	1,365	3,969
TOTAL (A+B)		20,459	2,573	22,621
C. Interest during Construction				
	Interest during Construction(Const.)	1,003	0	1,003
	Interest during Construction(Consul.)	1,002	0	1,002
	Interest during Construction (Consul.)	0	0	0
D. Commitment Charge		177	0	177
GRAND TOTAL (A+B+C+D)		21,639	2,573	23,800
E. Eligible Portion incl. IDC (A+C+D) for JICA Finance		18,817	1,208	19,831
F. of which, Ceiling Amount for JICA Finance		-	-	20,230

Source: Prepared by the Survey Team

Table 8-7 Project Cost at Scenario-A2 (General Untied Japanese ODA Loans)

Item		Total		
		FC	LC	Total
		Mil. Yen	Mil. PRs	Mil. Yen
A. ELIGIBLE PORTION				
I)	Procurement / Construction	17,015	1,029	17,879
	UNIT 1-4	14,403	714	15,003
	Base cost for JICA financing	14,403	714	15,003
	Price escalation	1,801	266	2,025
	Physical contingency	810	49	851
II)	Consulting services	1,094	230	1,287
	Base cost	930	161	1,065
	Price escalation	112	58	161
	Physical contingency	52	11	61
Total (I + II)		18,109	1,260	19,167
B. NON ELIGIBLE PORTION				
a	Procurement / Construction	0	0	0
	Base cost for JICA financing	0	0	0
	Price escalation	0	0	0
	Physical contingency	0	0	0
b	Land acquisition	0	0	0
	Base cost	0	0	0
	Price escalation	0	0	0
	Physical contingency	0	0	0
c	Administration cost	0	201	169
d	VAT	2,897	202	3,067
e	Import tax	0	1,013	851
Total (a+b+c+d+e)		2,897	1,415	4,086
TOTAL (A+B)		21,006	2,675	23,253
C. Interest during Construction				
		1,107	0	1,107
	Interest during Construction(Const.)	1,107	0	1,107
	Interest during Construction (Consul.)	1	0	1
D. Commitment Charge		203	0	203
GRAND TOTAL (A+B+C+D)		22,316	2,675	24,563
E. Eligible Portion incl. IDC (A+C+D) for JICA Finance		19,418	1,260	20,476
F. of which, Ceiling Amount for JICA Finance		-	-	20,878

Source: Prepared by the Survey Team

2) Scenario-B1 and B2

The estimated project implementation cost at Scenario-B1 and B2 under the condition of utilizing the general untied Japanese ODA loans is summarized in Tables 8-8 and 8-9 respectively. The grand totals of project cost at the Scenario-B1 and B2 are estimated to be about JPY 40.1 billion and JPY 42.0 billion respectively.

Table 8-8 Project Cost at Scenario-B1 (General Untied Japanese ODA Loans)

Item	Total		
	FC Mil. Yen	LC Mil. PRs	Total Mil. Yen
A. ELIGIBLE PORTION			
I) Procurement / Construction	28,347	1,705	29,779
UNIT 1-6	24,072	1,194	25,075
Base cost for JICA financing	24,072	1,194	25,075
Price escalation	2,925	430	3,286
Physical contingency	1,350	81	1,418
II) Consulting services	1,162	352	1,458
Base cost	997	250	1,207
Price escalation	110	85	182
Physical contingency	55	17	69
Total (I + II)	29,509	2,057	31,237
B. NON ELIGIBLE PORTION			
a Procurement / Construction	0	0	0
Base cost for JICA financing	0	0	0
Price escalation	0	0	0
Physical contingency	0	0	0
b Land acquisition	0	0	0
Base cost	0	0	0
Price escalation	0	0	0
Physical contingency	0	0	0
c Administration cost	0	195	164
d VAT	4,721	329	4,998
e Import tax	0	1,687	1,417
Total (a+b+c+d+e)	4,721	2,211	6,579
TOTAL (A+B)	34,230	4,269	37,816
C. Interest during Construction			
Interest during Construction(Const.)	1,911	0	1,911
Interest during Construction (Consul.)	1,910	0	1,910
	1	0	1
D. Commitment Charge	331	0	331
GRAND TOTAL (A+B+C+D)	36,473	4,269	40,059
E. Eligible Portion incl. IDC (A+C+D) for JICA Finance	31,752	2,057	33,480
F. of which, Ceiling Amount for JICA Finance	-	-	34,050

Source: Prepared by the Survey Team

Table 8-9 Project Cost at Scenario-B2 (General Untied Japanese ODA Loans)

Item	Total		
	FC	LC	Total
A. ELIGIBLE PORTION	Mil. Yen	Mil. PRs	Mil. Yen
I)			
Procurement / Construction	28,982	1,812	30,504
UNIT 1-6	24,072	1,194	25,075
Base cost for JICA financing	24,072	1,194	25,075
Price escalation	3,530	531	3,977
Physical contingency	1,380	86	1,453
II)			
Consulting services	1,575	383	1,897
Base cost	1,319	259	1,537
Price escalation	181	106	270
Physical contingency	75	18	90
Total (I + II)	30,557	2,195	32,401
B. NON ELIGIBLE PORTION			
a			
Procurement / Construction	0	0	0
Base cost for JICA financing	0	0	0
Price escalation	0	0	0
Physical contingency	0	0	0
b			
Land Acquisition	0	0	0
Base cost	0	0	0
Price escalation	0	0	0
Physical contingency	0	0	0
c			
Administration cost	0	241	202
d			
VAT	4,889	351	5,184
e			
Import Tax	0	1,725	1,449
Total (a+b+c+d+e)	4,889	2,317	6,836
TOTAL (A+B)	35,446	4,512	39,236
C. Interest during Construction			
Interest during Construction(Const.)	2,379	0	2,379
Interest during Construction (Consul.)	2,377	0	2,377
	1	0	1
D. Commitment Charge	417	0	417
GRAND TOTAL (A+B+C+D)	38,242	4,512	42,032
E. Eligible Portion incl. IDC (A+C+D) for JICA Finance	33,353	2,195	35,196
F. of which, Ceiling Amount for JICA Finance	-	-	35,727

Source: Prepared by the Survey Team

(2) Climate Change Program Loan

1) Scenario-A1 and A2

In case of utilizing the Climate Change Program Loan which is applied an interest rate 0.3%, the estimated project costs at Scenario-A1 and A2 are summarized in Tables 8-10 and 8-11. The grand totals of project cost at the Scenario-A1 and A2 are estimated to be about JPY23.0 billion and JPY23.7 billion respectively.

Table 8-10 Project Cost at Scenario-A1 (Climate Change Program Loan)

Item	Total		
	FC Mil. Yen	LC Mil. PRs	Total Mil. Yen
A. ELIGIBLE PORTION			
I) Procurement / Construction	16,784	992	17,617
UNIT 1-4	14,403	714	15,003
Base cost for JICA financing	14,403	714	15,003
Price escalation	1,582	230	1,775
Physical contingency	799	47	839
II) Consulting services	853	216	1,035
Base cost	737	156	867
Price escalation	76	50	118
Physical contingency	41	10	49
Total (I + II)	17,637	1,208	18,652
B. NON ELIGIBLE PORTION			
a Procurement / Construction	0	0	0
Base cost for JICA financing	0	0	0
Price escalation	0	0	0
Physical contingency	0	0	0
b Land Acquisition	0	0	0
Base cost	0	0	0
Price escalation	0	0	0
Physical contingency	0	0	0
c Administration cost	0	173	145
d VAT	2,822	193	2,984
e Import Tax	0	999	839
Total (a+b+c+d+e)	2,822	1,365	3,969
TOTAL (A+B)	20,459	2,573	22,621
C. Interest during Construction			
Interest during Construction(Const.)	211	0	211
Interest during Construction (Consul.)	211	0	211
	0	0	0
D. Commitment Charge	170	0	170
GRAND TOTAL (A+B+C+D)	20,840	2,573	23,002
E. Eligible Portion incl. IDC (A+C+D) for JICA Finance	18,018	1,208	19,033
F. of which, Ceiling Amount for JICA Finance	-	-	19,552

Source: Prepared by the Survey Team

Table 8-11 Project Cost at Scenario-A2 (Climate Change Program Loan)

Item		Total		
		FC	LC	Total
A. ELIGIBLE PORTION		Mil. Yen	Mil. PRs	Mil. Yen
I)	Procurement / Construction	17,015	1,029	17,879
	UNIT 1-4	14,403	714	15,003
	Base cost for JICA financing	14,403	714	15,003
	Price escalation	1,801	266	2,025
	Physical contingency	810	49	851
II)	Consulting services	1,094	230	1,287
	Base cost	930	161	1,065
	Price escalation	112	58	161
	Physical contingency	52	11	61
Total (I + II)		18,109	1,260	19,167
B. NON ELIGIBLE PORTION				
a	Procurement / Construction	0	0	0
	Base cost for JICA financing	0	0	0
	Price escalation	0	0	0
	Physical contingency	0	0	0
b	Land Acquisition	0	0	0
	Base cost	0	0	0
	Price escalation	0	0	0
	Physical contingency	0	0	0
c	Administration cost	0	201	169
d	VAT	2,897	202	3,067
e	Import Tax	0	1,013	851
Total (a+b+c+d+e)		2,897	1,415	4,086
TOTAL (A+B)		21,006	2,675	23,253
C. Interest during Construction				
		233	0	233
	Interest during Construction(Const.)	232	0	232
	Interest during Construction (Consul.)	1	0	1
D. Commitment Charge		194	0	194
GRAND TOTAL (A+B+C+D)		21,433	2,675	23,680
E. Eligible Portion incl. IDC (A+C+D) for JICA Finance		18,535	1,260	19,593
F. of which, Ceiling Amount for JICA Finance		-	-	20,128

Source: Prepared by the Survey Team

2) Scenario-B1 and B2

In case of utilizing the Climate Change Program Loan which is applied an interest rate 0.3%, the estimated project costs at Scenario-B1 and B2 are summarized in Tables 8-12 and 8-13. The grand totals of project cost at the Scenario-B1 and B2 are estimated to be about JPY38.5 billion and JPY40.1 billion respectively.

Table 8-12 Project Cost at Scenario-B1 (Climate Change Program Loan)

Item	Total		
	FC	LC	Total
A. ELIGIBLE PORTION	Mil. Yen	Mil. PRs	Mil. Yen
I) Procurement / Construction	28,347	1,705	29,779
UNIT 1-6	24,072	1,194	25,075
Base cost for JICA financing	24,072	1,194	25,075
Price escalation	2,925	430	3,286
Physical contingency	1,350	81	1,418
II) Consulting services	1,162	352	1,458
Base cost	997	250	1,207
Price escalation	110	85	182
Physical contingency	55	17	69
Total (I + II)	29,509	2,057	31,237
B. NON ELIGIBLE PORTION			
a Procurement / Construction	0	0	0
Base cost for JICA financing	0	0	0
Price escalation	0	0	0
Physical contingency	0	0	0
b Land Acquisition	0	0	0
Base cost	0	0	0
Price escalation	0	0	0
Physical contingency	0	0	0
c Administration cost	0	195	164
d VAT	4,721	329	4,998
e Import Tax	0	1,687	1,417
Total (a+b+c+d+e)	4,721	2,211	6,579
TOTAL (A+B)	34,230	4,269	37,816
C. Interest during Construction			
Interest during Construction(Const.)	401	0	401
Interest during Construction (Consul.)	1	0	1
D. Commitment Charge	316	0	316
GRAND TOTAL (A+B+C+D)	34,948	4,269	38,534
E. Eligible Portion incl. IDC (A+C+D) for JICA Finance	30,227	2,057	31,955
F. of which, Ceiling Amount for JICA Finance	-	-	32,754

Source: Prepared by the Survey Team

Table 8-13 Project Cost at Scenario-B2 (Climate Change Program Loan)

Item		Total		
		FC Mil. Yen	LC Mil. PRs	Total Mil. Yen
A. ELIGIBLE PORTION				
I)	Procurement / Construction	28,982	1,812	30,504
	UNIT 1-6	24,072	1,194	25,075
	Base cost for JICA financing	24,072	1,194	25,075
	Price escalation	3,530	531	3,977
	Physical contingency	1,380	86	1,453
II)	Consulting services	1,575	383	1,897
	Base cost	1,319	259	1,537
	Price escalation	181	106	270
	Physical contingency	75	18	90
Total (I + II)		30,557	2,195	32,401
B. NON ELIGIBLE PORTION				
a	Procurement / Construction	0	0	0
	Base cost for JICA financing	0	0	0
	Price escalation	0	0	0
	Physical contingency	0	0	0
b	Land Acquisition	0	0	0
	Base cost	0	0	0
	Price escalation	0	0	0
	Physical contingency	0	0	0
c	Administration cost	0	241	202
d	VAT	4,889	351	5,184
e	Import Tax	0	1,725	1,449
Total (a+b+c+d+e)		4,889	2,317	6,836
TOTAL (A+B)		35,446	4,512	39,236
C. Interest during Construction				
		497	0	497
	Interest during Construction(Const.)	496	0	496
	Interest during Construction (Consul.)	1	0	1
D. Commitment Charge		395	0	395
GRAND TOTAL (A+B+C+D)		36,337	4,512	40,128
E. Eligible Portion incl. IDC (A+C+D) for JICA Finance		31,448	2,195	33,292
F. of which, Ceiling Amount for JICA Finance		-	-	34,109

Source: Prepared by the Survey Team

8.1.5 Project Cost Reduction Plan

(1) Assembling turbine and generator

There are two erection bays at both sides of Unit 1 and Unit 10 in powerhouse which have enough space for assembling turbine and generator at the same time.

Therefore, it is expected to shorten the construction schedule by use of two erection bays effectively.

(2) Centering method

By introducing the actual centering method at the installation of turbine and generator, it is expected to shorten the construction schedule as compared to the piano wire method which is a conventional method for installation of turbine and generator.

Actual centering method is to assemble from the lower parts to upper parts with setting and confirming the vertical center line on the assembled parts, and this method can eliminate tentative assembly of the parts such as upper bracket, guide vane and so on.

CHAPTER 9

FINANCIAL AND ECONOMIC ANALYSES

CHAPTER 9 FINANCIAL AND ECONOMIC ANALYSES

9.1 Objectives and Methodology

The financial and economic analyses aim to examine the viability of the project by calculating the internal rate of return (IRR) and the net present value (NPV).

9.1.1 Financial Analysis

Financial analysis is conducted to evaluate the profitability of the project from the viewpoint of the implementing organization. To obtain the financial internal rate of return (FIRR) and the financial net present value (FNPV), net benefit of the project is derived considering 1) the benefit (incremental revenue of bulk supply tariff) and 2) the cost based on the market price.

Financial cost excludes price contingencies, interest during construction (IDC), and other financial charges against the project cost. FIRR and FNPV are calculated based on the cash flow before tax and interest payments.

9.1.2 Economic Analysis

Economic analysis is conducted to evaluate the viability of the project from the viewpoint of the national economy. To obtain the economic internal rate of return (EIRR) and the economic net present value (ENPV), the benefit of the project is derived considering 1) the increased benefit based on the saved cost by replacing the alternative energy sources (e.g., diesel generators) and 2) the economic costs.

In the calculation of EIRR and ENPV, the cost of the project is converted to the economic cost in order to evaluate the actual cost for the national economy. In this regard, transfer payment within the national economy (e.g., tax) is excluded from the calculation as it is neither benefit nor cost for the country.

9.1.3 Methodology

The cash flow of the Project was prepared to calculate the IRR and NPV. These figures were calculated based on the following formula. The IRR is equal to the discount rate that results in zero NPV.

$$\sum_{t=1}^n \{(B - C)_t \div (1 + r)^t\} = 0$$

Where, C=cost, B=Benefit, t=#th year (1,2,3...n), n=project life, r=internal rate of return

For the calculation of both the IRR and NPV, two cases of “with project” and “without project” were considered to determine the net incremental benefit and cost. For the calculation of the

NPV, the predetermined discount rate was used.

9.2 Assumptions

This section lists and describes the assumptions that were used for calculating IRR and NPV.

9.2.1 Project Life, Salvage Value, and Price Base

The Project was assumed to have a useful economic life of 35 years after the commencement of the Project.¹² At the end of the economic life, the Project was assumed to have no salvage value. Benefits and costs were expressed in terms of 2012 constant prices.

9.2.2 Physical Contingency and Price Escalation

Physical contingency is defined as the monetary value of additional resources that may be needed beyond the base cost to complete the project. It is estimated as a percentage of the base cost. Physical contingency generally varies, depending on the source of the base cost. It was assumed in the analysis to be 5% of the base cost.

Price escalation allows for any fluctuation in the foreign exchange and commodity price, between the time of the cost estimate and loan approval. Price escalation was assumed at 2.1% and 5.7% for foreign cost and local cost, respectively.

Price escalation was excluded from the financial and economic analyses due to the uncertainty of price fluctuations in the future and the application of the 2012 constant price.

9.2.3 Operation and Maintenance (O&M) Cost

According to WAPDA Power Wing Annual Report 2011, the percentage of the operational and maintenance expenditure in relation to property, plant, and equipment was approximately 1.5%.

Table 9-1 Percentage of O&M Cost in Relation to the Capital Cost (Unit: PRs million)

	FY 2009-2010	FY 2010-2011
Property, plant, and equipment	164,737	186,803
Total cost of operation and maintenance in "cost of electricity"	2,188	2,980
1) Salaries, wages & benefits	1,510	1,952
2) Repairs & maintenance	418	692
3) Dams inspection & monitoring cost	260	336
Percentage of O&M cost to property, plant & equipment	1.3%	1.6%

¹ The project life of a hydropower station is normally set at around 50 years, which is longer than 35 years used in this report. However, as explained later, due to the application of a relatively high discount rate (12%), the value after 35th year becomes insignificant, where the value of PRs 100 today will be equal PRs 1.7 at the 36th year. The assumption of 35 years was also the same with what was used in the "Feasibility Study for Up-gradation and Refurbishment of Generation Units of Mangla Power Station", December 2011.

² WAPDA assumed the economic useful life of generation unit is 29 years in its accounting standard.

Source: WAPDA Power Wing, "Annual Account 2011", p. 37

Note: Two expenditure items of "salaries, wages & benefits" and "repairs & maintenance" appeared twice in the income statement, one in the "cost of electricity" and another in the "operating expenses". The former was included in the above table as it was directly related to the operation and maintenance of hydropower stations. The latter was not included in the table as it was assumed to be the general administration cost.

Based on the above calculation and assumption that the capital cost of the Project is proxy to the value of fixed asset, the annual O&M cost of the Project was assumed to be 1.5% of the total capital cost. Operation and maintenance related to the Project were assumed to commence after the completion of construction. The O&M cost did not include any costs from potential forced outages.

WAPDA has enough technical and financial capacity for the operation and maintenance of the power plant. The present technical ability and number of the staff at Mangla Power Station is enough and does not require the assignment of additional staff according to the observation of the Survey Team.

According to the annual report 2011 of WAPDA (Power Wing), the cost of electricity (12.8 PRs billion), which is the direct cost for the operation and maintenance of the power plant, is covered by the revenue (33.5 PRs billion). In addition, the grant from the government reduced from 1.08 PRs billion in 2010 to 0.68 PRs billion in 2011, which resulted in the less dependence on the grant.³

Therefore, it can be concluded that WAPDA is internally generating the cash necessary for the operation and maintenance and does not need to obtain the additional cash for the operation and maintenance from the outside.

9.2.4 Water Use Charges

WAPDA is obliged to pay water use charges (WUC) of Mangla Power Station to the Government of Azad Jammu and Kashmir (AJ&K) at a rate of PRs 0.15/kWh.⁴ Therefore, the incremental WUC was included as a cost in the calculation of FIRR and FNPV. Since this was treated as transfer payment within a country, it was not counted as a cost in calculating EIRR and ENPV.

9.2.5 Bulk Supply Tariff

The National Transmission and Dispatch Company (NTDC) purchases electricity from the hydropower stations including Mangla Power Station as a single buyer and pays the bulk

³ It should be noted that the grant is not necessarily for the operation and maintenance. The annual report does not clarify the detail of the grant.

⁴ NEPRA, "Determination of Tariff Petition filed by WAPDA Hydroelectric", No. NEPRA/TRF-173/WAPDA (Hydro)-2011

supply tariff, which is approved by National Electric Power Regulatory Authority (NEPRA).⁵

The tariff has two components: 1) fixed charge and 2) variable charge. The fixed charge is based on the plant's capacity to cover the fixed portion of the O&M cost, debt service payment, and the fixed return on the equity investment. The variable charge is based on the actual volume of electricity transmitted to NTDC to cover WUC and the variable portion of the O&M cost. The NTDC pays the fixed and variable charge monthly to WAPDA.

The following tariff has been approved by NEPRA for WAPDA hydroelectric for FY 2011-12. The current tariff was applied for quantifying the benefit (i.e., incremental revenue of Mangla Power Station) in calculating FIRR and FNPV.

Table 9-2 Bulk Supply Tariff

	Fixed charge (PRs/kW/Month)	Variable charge (Paisa/kWh)
Regular tariff	482.340	6.771
Recovery of revenue gap	66.702	0.936
Total tariff	549.042	7.707

Source: National Electric Power Regulatory Authority (NEPRA), "Determination of Tariff Petition filed by WAPDA Hydroelectric", No. NEPRA/TRF-173/WAPDA Hydro-2011

Note: 100 Paisa = 1 Rupee.

9.2.6 Exchange Rate

The exchange rate of JPY 0.84 to PRs 1 was used for converting foreign currency to its local equivalent. Exchange rate of PRs 96.1 to USD 1 was used as well.

9.2.7 Conversion Factor

The standard conversion factor (SCF) is an indicator to estimate the level of distortion in the market due to policies, duties, or subsidies of the government. The SCF is applied in the economic analysis when the domestic cost, which is assumed to be distorted, is to be converted into the economic cost in order to eliminate distortion.

The SCF was calculated as 0.97 based on the following formula, and figures from the recent terms of trade and duties.⁶ As shown in Table 9-3, this figure is nearly equal to one. It can be assumed that there was not much distortion in the price of commodities.

$$SCF = \frac{[\text{Import (CIF)} + \text{Export (FOB)}]}{[(\text{Import} + \text{Import duty}) + (\text{Export} + \text{Export tax} - \text{Export subsidy})]}$$

⁵ "Power Purchase Agreement between National Transmission and Dispatch Company and the Pakistan Water and Power Development Authority"

⁶ The standard conversion factor of 0.91 was applied in ADB's "Report and Recommendation of the President to the Board of Directors: Proposed Loan for Indus Hydropower Project (Pakistan)" September 2011. SCF of 0.97 in this report can be regarded as reasonable figure, considering the figure of the ADB's recent report.

Table 9-3 Terms of Trade (Unit: PRs million)

Import	Export	Import duty	Export tax	Export subsidy
2,910,990	1,640,928	164,900	0	0

Source: Pakistan Statistical Year Book 2011, 9.1 Foreign Trade, 18.1 Revenue Receipts of the Federal Government

Regarding the labor cost, it was assumed that there were no significant distortions in the wage of skilled labor. However, in the case of unskilled labor, underemployment may exist in Pakistan.

Monthly minimum wages in Pakistan are recommended by the federal government under the labour policies and set by the provincial minimum wages boards under the Minimum Wages Ordinance, 1961. Pakistan's first minimum wage was introduced in 1992 when it was set at PRs 1500 per month. Then, it was set at PRs 4000 in 2006 and PRs 7000 in 2010.

Table 9-4 below shows that a significant number of workers were working below the 2001 minimum wage.

Table 9-4 Percentage of Wage Earners Earning Below the Minimum Wage of 2001 (PRs 2500 per month)

Year	Regular Worker	Non-regular Worker	All Workers
1997/98	11.6	32.7	18.0
2001/02	14.7	43.0	29.4
2003/04	14.1	39.2	25.8

Source: Dr. Mohammad Irfa, "Pakistan's Wage Structure during 1990/01-2006/07", December 2008, p.29

The figures in the above tables implied that the opportunity cost of unskilled labor is likely to be less than the minimum wage rate.

Table 9-5 Monthly Wages of Regular and All Workers by Type of Enterprise 2003-04 (Unit: PRs/month)

	All Workers	Regular Workers
Government	6,585	6,656
Formal	4,501	5,596
Informal	2,875	3,027

Source: Dr. Mohammad Irfa, "Pakistan's Wage Structure during 1990/01-2006/07", December 2008, p.9

The average wage of workers in the informal sector is nearly half of that of the formal sector as shown in Table 9-5. Therefore, the conversion factor of 0.5 was applied to the cost of unskilled labor when it is converted to economic cost.

Labor cost was assumed to share 100% of the installation, testing, and training expenses.

9.2.8 Cut-off Rate

The cut-off rate is used to evaluate and judge whether the project is viable from the viewpoint of the implementing organization and the national economy, by comparing it with FIRR and EIRR, respectively.

In principle, the cut-off rate adopted in the financial analysis was calculated based on the concept of opportunity cost of capital. Loans from JICA will be extended to the Government of

Pakistan, and will be reloaned to WAPDA. The interest rate of the recent loan provided to WAPDA is 15-17%.

Table 9-6 Recent Foreign Loan Lent to WAPDA

Loan	Interest Rate	Loan Period	Outstanding Loan (PRs million)	
			2010	2011
IDB-PAK-0117	17%	2008/2016	4,565.4	6,674.0
AFD Credit Facility	15%	2011/2028	-	458.7
Kuwait Fund Loan No. 742	17%	2011/2025	-	110.7
Saudi Fund Loan No. 10/479	17%	2011/2025	-	218.8

Source: Pakistan WAPDA Power Wing (Hydroelectric), Annual Account 2011, p.23

However, the interest rate of the loan to WAPDA is not equal to the opportunity cost of capital. The recent interest rate of the treasury bill of Pakistan, which can be regarded as the opportunity cost of capital, is approximately 12%. In this report, the cut-off rate of 12% was used for judging the viability in terms of the FIRR and also used as the discount rate for calculating the FNPV.

Table 9-7 Interest Rate of the Treasury Bills

Treasury Bill	Weighted Average Rate
3 months	11.7980%
6 months	11.8677%
12 months	11.9211%

Source: State Bank of Pakistan, 352nd auction as of March 7, 2012, <http://www.sbp.org.pk/departments/stats/NDSP.htm#b>

The ADB used 10-12% as the social discount rate for the economic analysis, and the rate was regarded as the social opportunity cost of capital in Pakistan.⁷

Although it is difficult to find the theoretical justification for the social discount rate used by development partners, a rate of 12% was applied for the calculation of EIRR as this was adopted by major international financial institutions.⁸

9.2.9 Auxiliary Consumption and Transmission and Distribution Loss

Based on the updated figure in Electricity Marketing Data (2011), the percentage of auxiliary consumption was assumed to be 2% of the total amount of generation.⁹

The transmission and distribution loss (T&D loss) was applied to the economic analysis, but not to the financial analysis, as the amount of electricity sold and the revenue based on bulk supply tariff were decided by the amount of electricity transmitted to NTDC, and not on the amount the end-users receive.

⁷ ADB, Report and Recommendation of the President to the Board of Directors: Proposed Loan Patind Hydropower Project (Pakistan), September 2011

⁸ According to the World Bank, the discount rate lower than 10% is difficult to justify. Research has shown that the cost of capital for the developing countries is higher than 10% (World Bank, "Handbook on Economic Analysis of Investment Operations", May 1996, p.146).

⁹ Electricity Marketing Data 36th Issue, "Statistics at Glance: PEPCO (Public and Private)", June 2011

From the recent figure of Electricity Marketing Data, 20% of T&D loss was applied to calculate the net incremental generation and benefit in the economic analysis.

9.2.10 Remaining Life of the Existing Units

The incremental benefit is calculated by quantifying the difference in the amount of revenue (financial analysis) and economic benefit (economic analysis) between the existing units (without project) and the new units (with project). Assumption on the remaining life of the existing units was made in order to calculate the generation, revenue, and benefit of the existing units.

Table 9-8 Remaining Useful Life of Existing Units

	Year of Starting Operation	Age at the End of 2012	Remaining Life	Assumption Used for Analysis
Unit 1	1967	45	5	5
Unit 2	1967	45	5	5
Unit 3	1968	44	6	5
Unit 4	1969	43	7	5
Unit 5	1973	39	11	5
Unit 6	1974	38	12	5

Source: Prepared by the Survey Team

Although the life of generation plant and equipment is 29 years in WAPDA's accounting standard, the units are maintained in a relatively good condition despite their age. Taking into consideration the current condition of operation and maintenance, the life of the unit was assumed at 50 years as the base case in the financial and economic analyses and the remaining life was calculated for each unit as shown in Table 9-8.

In the case of Units 5 and 6, the remaining life was estimated to be shorter than the other units (45 years) by considering the frequency of occurrence of technical problem and repair. In the sensitivity analysis, the case of shorter life (45 years) will be examined to check the impact of the change of this assumption to the IRR and NPV.

9.2.11 Overhaul

The overhaul of the equipment of each unit is scheduled to be conducted every ten years. It takes five months to complete the overhaul. The cost of the equipment for overhaul per unit is estimated 460 million PRs. The units are required to stop the generation during the overhaul period (five months).

9.2.12 Clean Development Mechanism (CDM)

Chapter 6 estimates GHG emission reduction in both cases of Scenario A and B. Based on the figures in "6.2.6 GHG Emission Reduction after Project Activity", the additional potential

benefit of CDM per year/GWh is calculated to conduct the sensitivity analysis of IRR and NPV on the trial basis.

Table 9-9 Calculation of CDM benefit

Item	Unit 1-4	Unit 1-6	Unit
Generation/year	1,532.50	1,588.30	GWh
GHG emission reduction	1,334,527	1,383,118	t-CO ₂ /y
CO ₂ rate	8.3	8.3	US\$/ton
CO ₂ rate	797.63	797.63	PRs/ton
Estimated CDM benefit	1,063	1,103	PRs million/year
Consultant registration cost @15% of CDM benefits	160	165	PRs million
Net CDM benefit/year	905	938	PRs million/year
Net CDM benefit/year/GWh	0.590	0.590	PRs million/year/GWh

Source: "Bloomberg New Energy Finance", Press Release, April 5, 2012 for more detailed information.

Note: The cost of consultant for registration is estimated to be 15% of the total CDM benefit based on the assumption used for the similar hydro power plant project. CO₂ rate is based on the weighted average market price (6.6 Euro) in the first quarter of 2012. See

Due to the uncertainty on the possibility of realizing CDM benefit and with reference to the feasibility study report of the similar hydro power plant project in Pakistan,¹⁰ the duration of receiving CDM benefit is assumed to be ten years after the completion of the Project.

9.2.13 Scenarios of Rehabilitation and Enhancement

The financial and economic analyses were conducted for the following four scenarios that were proposed in Chapter 5 as well as for individual unit.

Table 9-10 Scenarios of Rehabilitation and Enhancement

Scenario	Unit	Stoppage
Scenario A1	Unit 1,2,3,4	Double units
Scenario A2	Unit 1,2,3,4	Single unit
Scenario B1	Unit 1,2,3,4,5,6	Double units
Scenario B2	Unit 1,2,3,4,5,6	Single unit

Source: Prepared by the Survey Team

9.3 Identification and Quantification of Financial and Economic Costs

Financial and economic costs were identified and quantified based on the estimation of project costs explained in Chapter 8. Financial costs and economic costs were used for calculating FIRR/FNPV and EIRR/ENPV, respectively.

9.3.1 Financial Cost

The financial cost was derived from the project cost, which was indicated in the estimation of project costs. Financial cost consists of 1) initial investment cost and 2) O&M cost.

Project cost includes equipment and construction cost, inland transportation, consulting

¹⁰ Phandar Hydro Consultants, "Phandar Hydropower Project Detailed Engineering Design Report: Economic and Financial Evaluation", April 2012

services and physical and price contingencies. On the other hand, financial cost is used to estimate the performance of the project from the viewpoint of the implementing organization and excludes price escalation and IDC.

Table 9-11 Financial Cost of the Project upon Completion of Construction (Scenario A) (Unit: PRs million)

Items	Financial Cost (Scenario A1)			Financial Cost (Scenario A2)		
	F/C	L/C	Total	F/C	L/C	Total
Equipment & appliance	17,146	714	17,861	17,146	714	17,861
Price escalation	0	0	0	0	0	0
Physical contingency	1,000	58	1,058	1,027	60	1,087
IDC/commitment charge	0	0	0	0	0	0
Consulting services	877	156	1,033	1,107	161	1,268
Eligible Portion Total	19,023	928	19,951	19,280	936	20,215
Non- Eligible Portion Total	3,359	1,365	4,725	3,449	1,415	4,865
Grand Total	22,383	2,293	24,676	22,729	2,351	25,080

Note: The total did not match due to rounding. This principle on rounding is applicable to all the tables on costs and benefits.

The cost of erection, repair, civil works and commissioning test is included in the local cost of equipment and appliance.

Source: Prepared by the Survey Team

Table 9-12 Financial Cost of the Project upon Completion of Construction (Scenario B) (Unit: PRs million)

Items	Financial Cost (Scenario B1)			Financial Cost (Scenario B2)		
	F/C	L/C	Total	F/C	L/C	Total
Equipment & appliance	28,657	1,194	29,851	28,657	1,194	29,851
Price escalation	0	0	0	0	0	0
Physical contingency	1,673	98	1,771	1,732	105	1,837
IDC/commitment charge	0	0	0	0	0	0
Consulting services	1,187	250	1,437	1,570	259	1,830
Eligible Portion Total	31,516	1,542	33,058	31,959	1,558	33,517
Non- Eligible Portion Total	5,620	2,211	7,831	5,820	2,317	8,138
Grand Total	37,136	3,753	40,889	37,780	3,875	41,655

Source: Prepared by the Survey Team

Table 9-13 Annual Allocation of Financial Cost (Scenario A) (Unit: PRs million)

Year	Financial Cost (Scenario A1)			Financial Cost (Scenario A2)		
	F/C	L/C	Total	F/C	L/C	Total
Year 1	0	0	0	0	0	0
Year 2	162	29	191	205	30	235
Year 3	18	2	20	22	2	25
Year 4	2,221	222	2,442	1,536	157	1,692
Year 5	5,125	511	5,636	3,310	334	3,644
Year 6	6,610	666	7,276	5,049	512	5,562
Year 7	5,613	586	6,199	5,967	611	6,577
Year 8	2,630	278	2,908	4,110	436	4,546
Year 9	0	0	0	2,260	242	2,502
Year 10	0	0	0	270	27	298
Total	22,383	2,293	24,676	22,729	2,351	25,080

Source: Prepared by the Survey Team

Table 9-14 Annual Allocation of Financial Cost (Scenario B) (Unit: PRs million)

Year	Financial Cost (Scenario B1)			Financial Cost (Scenario B2)		
	F/C	L/C	Total	F/C	L/C	Total
Year 1	0	0	0	0	0	0
Year 2	261	55	316	283	52	335
Year 3	24	3	26	16	3	18
Year 4	2,929	269	3,198	2,042	193	2,236
Year 5	6,474	608	7,082	4,240	389	4,628
Year 6	9,894	971	10,865	6,195	604	6,799
Year 7	9,558	975	10,533	6,770	682	7,453
Year 8	5,661	610	6,271	6,879	724	7,603
Year 9	2,336	262	2,598	5,567	596	6,163
Year 10	0	0	0	3,793	410	4,203
Year 11	0	0	0	1,994	223	2,217
Total	37,136	3,753	40,889	37,780	3,875	41,655

9.3.2 Economic Cost

Economic cost was derived from the project cost, which was indicated in the estimation of project cost. Costs of project items in local currency were converted to economic costs by applying the corresponding SCF. Costs of items that were already at border price need not be adjusted.

Economic cost is used to estimate the performance of the project from the viewpoint of national economy, and excludes price escalation, duty and taxes, and IDC. Duty and taxes are excluded from the economic cost as they are transfer payments within the economy of a country and are not real cost to the national economy.

Table 9-15 Economic Cost of the Project upon Completion of Construction (Scenario A) (Unit: PRs million)

Items	Economic Cost (Scenario A1)			Economic Cost (Scenario A2)		
	F/C	L/C	Total	F/C	L/C	Total
Equipment & appliance	17,146	357	17,504	17,146	357	17,504
Price escalation	0	0	0	0	0	0
Physical contingency	1,000	56	1,056	1,027	58	1,085
IDC/commitment charge	0	0	0	0	0	0
Consulting services	877	151	1,018	1,107	156	1,263
Eligible Portion Total	19,023	564	19,587	19,280	572	19,852
Non- Eligible Portion Total	0	168	168	0	195	195
Grand Total	19,023	732	19,755	19,280	767	20,047

Source: Prepared by the Survey Team

Table 9-16 Economic Cost of the Project upon Completion of Construction (Scenario B) (Unit: PRs million)

Items	Economic Cost (Scenario B1)			Economic Cost (Scenario B2)		
	F/C	L/C	Total	F/C	L/C	Total
Equipment & appliance	28,657	597	29,254	28,657	597	29,254
Price escalation	0	0	0	0	0	0
Physical contingency	1,673	95	1,768	1,732	101	1,834
IDC/commitment charge	0	0	0	0	0	0
Consulting services	1,187	243	1,429	1,570	252	1,822
Eligible Portion Total	31,516	935	32,451	31,959	950	32,909
Non- Eligible Portion Total	0	189	189	0	234	234
Grand Total	31,516	1,124	32,640	31,959	1,184	33,143

Source: Prepared by the Survey Team

Table 9-17 Annual Allocation of Economic Cost (Scenario A) (Unit: PRs million)

FY	Economic Cost (Scenario A1)			Economic Cost (Scenario A2)		
	F/C	L/C	Total	F/C	L/C	Total
Year 1	0	0	0	0	0	0
Year 2	162	28	190	205	29	234
Year 3	18	2	20	22	2	24
Year 4	1,885	66	1,950	1,294	46	1,340
Year 5	4,327	141	4,468	2,792	97	2,889
Year 6	5,602	198	5,800	4,247	145	4,392
Year 7	4,773	195	4,968	5,044	188	5,231
Year 8	2,252	102	2,354	3,507	158	3,664
Year 9	0	0	0	1,941	95	2,036
Year 10	0	0	0	227	8	235
Total	19,023	732	19,755	19,280	767	20,047

Source: Prepared by the Survey Team

Table 9-18 Annual Allocation of Economic Cost (Scenario B) (Unit: PRs million)

FY	Economic Cost (Scenario B1)			Economic Cost (Scenario B2)		
	F/C	L/C	Total	F/C	L/C	Total
Year 1	0	0	0	0	0	0
Year 2	261	53	314	283	50	333
Year 3	24	2	26	16	3	18
Year 4	2,545	81	2,626	1,771	62	1,833
Year 5	5,528	159	5,687	3,658	108	3,766
Year 6	8,386	265	8,651	5,293	179	5,472
Year 7	8,069	283	8,352	5,732	201	5,933
Year 8	4,733	186	4,920	5,734	205	5,939
Year 9	1,970	95	2,065	4,627	171	4,797
Year 10	0	0	0	3,162	125	3,287
Year 11	0	0	0	1,684	82	1,766
Total	31,516	1,124	32,640	31,959	1,184	33,143

Source: Prepared by the Survey Team

9.4 Identification and Quantification of Financial and Economic Benefits

Financial and economic benefits were identified and quantified in this section. These benefits

were gained from incremental generation, which will be achieved through the implementation of the Project. Firstly, the calculation methodology of incremental generation was explained. Secondly, the financial benefit was quantified based on the incremental power generation and the incremental revenue by selling electricity to NTDC. Thirdly, the economic benefit was calculated based on the saved cost by replacing the alternative energy sources (e.g., uninterrupted power supply (UPS) equipment and diesel generators).

9.4.1 Financial Benefit

The financial performance of the Project was evaluated from the viewpoint of the direct beneficiary (i.e., WAPDA). Financial benefit was identified as the increased revenue from electricity sales to NTDC. If the Project is implemented, more electricity will be sold and revenues will be added to WAPDA. Project outputs are valued by the bulk supply tariff.

$$\text{Generation (GWh)} = \text{Capacity (MW)} \times 24 \text{ hours} \times 365 \text{ days} \times \text{Plant factor (\%)} / 1000$$

The benefit can be calculated until the end of the project life (35 years). For financial analysis, the benefit of incremental revenue can be calculated in a particular year, by multiplying the incremental electricity generated with the rate of bulk supply tariff. The bulk supply tariff consists of 1) fixed charge and 2) variable charge, as explained in Section 9.2.6.

$$\text{Revenue} = \text{Capacity (MW)} \times \text{Fixed charge} + \text{Generation (GWh)} \times \text{Variable charge (PRs/kWh)}$$

In order to calculate the financial benefit as the net incremental revenue (revenue “with project” minus revenue “without project”), the benefits of both “with project” and “without project” were calculated.

The revenue of “without project” is the opportunity cost of the Project. It is also recognized as the benefit foregone while the existing units stop their operation due to the construction and installation of new units.

It should be noted, however, that no existing units were assumed to stop operation within the first two years of the project period as this period covers the stage of designing and manufacturing the equipment.

Table 9-19 Financial Benefit of the Project before Discounting (Scenario A1) (Unit: PRs million)

FY	Unit 1	Unit 2	Unit 3	Unit 4
Year 1	0	0	0	0
Year 2	0	0	0	0
Year 3	(811)	(811)	(811)	(811)
Year 4	(811)	(811)	(811)	(811)
Year 5	(811)	(811)	(811)	(811)
Year 6	0	0	0	0
Year 7	571	0	0	0
Year 8	952	952	571	0
Year 9	952	952	952	952
Year 10 onward	952	952	952	952

Source: Prepared by the Survey Team

Note: Figures in parenthesis are deficit balance.

Table 9-20 Financial Benefit of the Project before Discounting (Scenario A2) (Unit: PRs million)

FY	Unit 1	Unit 2	Unit 3	Unit 4
Year 1	0	0	0	0
Year 2	0	0	0	0
Year 3	(811)	(811)	(811)	(811)
Year 4	(811)	(811)	(811)	(811)
Year 5	(811)	(811)	(811)	(811)
Year 6	0	0	0	0
Year 7	571	0	0	0
Year 8	952	638	0	0
Year 9	952	952	714	0
Year 10	952	952	952	790
Year 11 onward	952	952	952	952

Source: Prepared by the Survey Team

Note: Figures in parenthesis are deficit balance.

The remaining life of the existing units were assumed to be five years until Year 5 and no additional electricity and revenue will be produced by the new units during construction period. The deficit (i.e., the foregone revenue of the existing units) will be recognized from Year 3 to Year 5 for both Scenario A and B.

Table 9-21 Financial Benefit of the Project before Discounting (Scenario B1) (Unit: PRs million)

FY	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6
Year 1	0	0	0	0	0	0
Year 2	0	0	0	0	0	0
Year 3	(811)	(811)	(811)	(811)	(811)	(811)
Year 4	(811)	(811)	(811)	(811)	(811)	(811)
Year 5	(811)	(811)	(811)	(811)	(811)	(811)
Year 6	0	0	0	0	0	0
Year 7	0	0	0	0	571	0
Year 8	571	0	0	0	952	952
Year 9	952	952	571	0	952	952
Year 10 onward	952	952	952	952	952	952

Source: Prepared by the Survey Team

Table 9-22 Financial Benefit of the Project before Discounting (Scenario B2) (Unit: PRs million)

FY	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6
Year 1	0	0	0	0	0	0
Year 2	0	0	0	0	0	0
Year 3	(811)	(811)	(811)	(811)	(811)	(811)
Year 4	(811)	(811)	(811)	(811)	(811)	(811)
Year 5	(811)	(811)	(811)	(811)	(811)	(811)
Year 6	0	0	0	0	0	0
Year 7	0	0	0	0	571	0
Year 8	0	0	0	0	952	638
Year 9	714	0	0	0	952	952
Year 10	952	790	0	0	952	952
Year 11	952	952	866	0	952	952
Year 12 onward	952	952	952	952	952	952

Source: Prepared by the Survey Team

9.4.2 Economic Benefit

In determining the economic benefit of the project, two types of benefit are normally identified. The value of economic benefit of electricity consumption are based on 1) the induced market, which is brought about from the increased electricity consumption (i.e., incremental benefits) and 2) the diverted market, which is the current energy consumption in which electricity replaces alternative energy sources such as kerosene lamps, UPS, and/or diesel generators (i.e., non incremental benefits).¹¹

With the huge deficit of electricity supply and prolonged load shedding in Pakistan, the electricity produced by the Mangla Power Station was not assumed to increase the electricity consumption or replace the existing generation capacity, but simply a substitute to the alternative energy source. Thus, the entire output of the Mangla Power Station was

¹¹ See Appendix 13, p. 42, ADB, "Project Completion Report: Ghazi Barotha Hydropower Project (Loan 1424 PAK) in Pakistan, August 2005 for the explanation of this concept.

considered non-incremental.

In identifying the level of the economic benefit, the saved cost was calculated using the economic cost of alternative energy sources as the upper limit and the economic price of bulk supply tariff as the lower limit.

(1) Economic Price of Tariff

Electricity is the only product generated from the Project. Electricity is assumed to be a non-tradable output as it is produced only for domestic economy and not exported to neighboring countries.¹² The economic price of the tariff resulting to PRs 6.0625/kWh was calculated using the SCF of 0.97 as follows.

Table 9-23 Economic Price of Tariff

Average Tariff	Calculation	Economic Price
PRs 6.25/kWh	PRs 6.25/kWh x 0.97	PRs 6.0625/kWh

Source: Electricity Marketing Data, "Statistics at a glance: PEPCO (Public and Private)", 36th Issue, 2011

(2) Avoided Cost of Alternative Energy

There are two major sources of energy that can be saved by the incremental supply of electricity, which is made possible by the Project. Table 9-17 shows that the diesel generators are mainly used by industrial and agricultural users and the UPS is used by commercial and domestic (residential) users as alternative source of lighting and for use of electric appliances such as television, radio and computers.

Table 9-24 Assumption on the Alternative Energy Source Based on the Types of Consumers

Alternative Source	Type of Consumers
UPS	Domestic, commercial users
Diesel generator	Industrial, agricultural, others

Table 9-25 shows the current average consumption of the users in each category.

Table 9-25 Average Electricity Consumption per Consumer (Unit: kWh)

	Domestic	Commercial	Industrial	Agricultural	Others
Annual	1,778	1,934	64,819	31,529	760,440
Monthly	148	161	5,402	2,627	63,370

Source: Electricity Marketing Data, "Table D-5: Electricity consumption per consumer", 36th Issue, 2011

Note: "Others" include public lighting (374 GWh/year), bulk supply (3,544 GWh/year), traction (2 GWh/year), and supply to KESC (5,499 GWh/year).

The UPS is selected as an alternative energy source instead of kerosene lamp, which is often used for calculating the saved cost, since the latter is not widely used in Pakistan. Table 9-19

¹² Indeed, the demand is not met by the current supply of electricity, resulting in the significant number (256,980 as of June 2011) of pending applications to eight distribution companies (Electricity Marketing Data, Table D-11: Number of pending applications, 36th Issue). Based on this fact, it is assumed in this report that the incremental supply of electricity generated by the project will be consumed in Pakistan.

shows that nearly half of the expenditure on energy is spent on the electricity bill. On the other hand, less than 3% is spent on kerosene. Furthermore, load shedding is widespread in Pakistan, leading electricity consumers to prepare for scheduled (and unscheduled) load shedding by using the UPS.¹³

Table 9-26 Household Expenditure on Energy (Unit: PRs, %)

	Pakistan	Urban	Rural
Average monthly expenditure	713	904	622
Firewood	22.1%	7.5%	32.1%
Kerosene	2.8%	0.8%	4.2%
Charcoal	0.1%	0.0%	0.1%
Coal	0.1%	0.0%	0.2%
Dung cakes	3.6%	0.8%	5.5%
Natural gas	9.1%	20.3%	1.4%
LPG	3.8%	3.6%	3.9%
Electricity	50.4%	63.1%	41.7%
Candles	2.0%	1.7%	2.3%
Agricultural residues	4.5%	0.7%	7.1%
Accessories (bulbs, etc.)	1.5%	1.5%	1.6%

Source: USAID Pakistan, "Energy Sector Assessment for USAID/Pakistan", Table 9: Average Monthly Expenditure in Rupees on Energy in Pakistan Households (Winrock 2007), June 2007

Electricity users tend to utilize the alternative energy sources due to load shedding and unstable power supply. They are replaced as soon as uninterrupted stable power is supplied. The cost of alternative energy source, which is normally higher than the retail tariff, is regarded as the upper limit to calculate the saved cost, which is explained in the following section.

Diesel generators

Diesel generators, one of the major alternative sources of power supply, can be replaced using incremental power supply from the increased capacity of generation. The saved cost of diesel generators can be regarded as economic benefit.

More than 80% of crude oil is imported from overseas.¹⁴ As the Government of Pakistan regulates the price of petroleum products and imposes tax and market margin, such transfer payment within a country is deducted from the prescribed price in order to calculate the true cost to the country.

Table 9-27 Economic Cost of Hi-Speed Diesel Oil (H.S.D) (Unit: PRs/litter)

Prescribed Price	98.82
- Petroleum Levy	(5.18)
Net Price of H.S.D. (excluding transfer payment)	93.64

Source: Oil & Gas Regulatory Authority, Press Release, December 31, 2011

¹³ For example, Lahore Electric Supply Company (LESCO) has increased the hours of load shedding from 10 hours to 12 hours per day, according to the article of Daily Times on May 27, "Citizens in agony as load shedding increases by 2 hours".

¹⁴ Adeel Ahmad, Mithilesh Kumar Jha, "Status of Petroleum Sector in Pakistan - A Review", Oil and Gas Business, 2007

The cost of generation by a diesel generator consists of fixed and variable costs. Fixed cost (i.e., purchase cost of equipment) was excluded in the calculation as it is regarded as a sunk cost at the time of calculation.

Table 9-28 Variable Cost of Diesel Generation

Item		Figure	Unit
Installed capacity	$A = \text{kVA} \times \text{Power Factor}$	9.2	kW
Power factor	Power factor = 0.8	0.8	
Load factor	Load factor = 0.4	0.4	
Net generation	$B = \text{kW} \times 8760 \times \text{Load factor}$	32,237	kWh/year
Economic cost of diesel oil	$C = \text{Market price-tax\& margin}$	93.64	PRs/L
Fuel consumption	$D = \text{Web site info}$	2.40	L/hour
Fuel cost	$E = \text{Fuel consumption (liter per hour)} \times 8760 \times \text{Load factor} \times \text{Fuel price per liter}$	787,475	PRs/year
Variable O&M cost	$F = \text{Fuel cost} \times 1\%$	7,875	PRs/year
Total cost	$G = E + F$	795,350	PRs/year
Variable cost per kWh	$H = G/B$	24.67	PRs/kWh

Source: Prepared by the Survey Team

As a result of the calculation, PRs 24.67/kWh was decided as the upper limit of the economic cost of diesel generators.

UPS

The domestic and commercial customers tend to use the UPS as a back-up in case of load shedding. Since the life of UPS is relatively short, both fixed and variable costs per kWh were calculated.

Table 9-29 Fixed and Variable Costs of UPS

Items		Figure	Unit	Remark
Price of UPS	$A = \text{survey}$	23,500	PRs	Quotation from UPS dealer
Capacity of UPS	$B = \text{survey}$	1,400	VA	Quotation from UPS dealer
Economic life	$C = \text{assumption}$	5	year	
Annualized cost	$D = A/C$	4,700	PRs/year	
Equivalent wattage	$E = B \times \text{power factor}$	1,120	watt	Capacity (VA) \times power factor (0.8)
Hours of use per day	$F = \text{assumption}$	10	hours	
Equivalent kWh per year	$G = E \times F \times 365/1000$	4,088	kWh/year	
Fixed cost per unit (kWh-Value)	$H = D/G$	1.1	PRs/kWh	
Unit price of battery	$I = \text{survey}$	7,500	PRs/unit	Quotation from UPS dealer
Necessary no. of battery	$J = \text{survey}$	3	unit/year	Quotation from UPS dealer
Cost of battery per year	$K = I \times J$	22,500	PRs/year	
Tariff	$L = \text{assumption}$	6.06	PRs/kWh	Economic cost of tariff
Efficiency	$M = \text{assumption}$	0.5		
Recharging cost	$N = G \times L/M$	49,567	PRs/year	
Variable cost per unit (kWh-Value)	$O = (K+N)/G$	17.6	PRs/kWh	
Total cost of UPS	$P = H+O$	18.8	PRs/kWh	

Source: Prepared by the Survey Team

As a result of the calculation above, PRs 18.8/kWh was the upper limit of the economic cost of

the UPS.

(3) Saved Cost

The saved cost represents the economic value of electricity consumption of the electricity users. This is not equal to the retail tariff of electricity for a number of factors. As it is often the case, the retail tariff rate tends to be subsidized and does not adequately reflect economic benefit. In the economic analysis, economic benefits were equated with the savings from using electricity for lighting, irrigation, industrial, and other works, by utilizing UPS and diesel generators as major source of alternative energy.

It was assumed in the analysis that the difference between 1) the weighted average retail tariff and 2) what consumers are actually paying for the alternative source of energy was the saved cost.

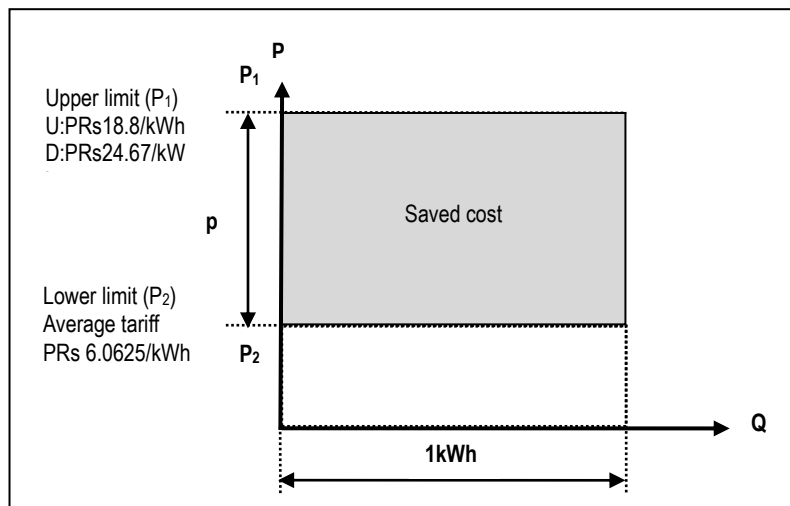


Figure 9-1 Saved Cost

Note: "U" represents "UPS", while "D" represents diesel generation.

Domestic consumers were assumed to be using the UPS. Irrigation users were assumed to be using diesel-powered irrigation pumps as backup for their electric-powered pumps. Commercial users were assumed to be using mainly the UPS as backup for electric lighting while very few utilize diesel generators. Industrial users were assumed to be using diesel generators, although there were some who do not own such equipment.

Table 9-30 Calculation of Saved Cost of Alternative Energy Source

Tariff Category	Alternative Source	Consumption (GWh)		Economic Price (PRs/kWh)		Difference (Saved Cost)	Weighted Saved Cost
				Upper Limit	Lower Limit		
		(a)	(b)	(c)	(d)=(b)-(c)	(e)=(a)*(d)	
Domestic	UPS	29,507	43%	18.78	6.0625	12.72	5.45
Commercial	UPS	4,466	6%	18.78	6.0625	12.72	0.82
Industrial	Diesel generator	16,371	24%	24.67	6.0625	18.61	4.42
Agricultural	Diesel generator	9,585	14%	24.67	6.0625	18.61	2.59
Public lighting	UPS	372	1%	18.78	6.0625	12.72	0.07
Others	Diesel generator	8,577	12%	24.67	6.0625	18.61	2.32
		68,878	100%			Total	15.67

Source: Prepared by the Survey Team

Based on the share of consumption of each tariff category, the weighted saved cost was calculated at PRs 15.67/kWh.

4) Economic Benefit

Based on the calculated saved cost (PRs 15.67/kWh), the economic benefit of the Project was calculated as shown in Tables 9-24 and 9-25.

As explained in the section of financial benefit, the first two years produce zero benefit because the existing units are not stopped during this period and there is no foregone benefit.

Table 9-31 Economic Benefit of the Project before Discounting (Scenario A1) (Unit: PRs million)

FY	Unit 1	Unit 2	Unit 3	Unit 4
Year 1	0	0	0	0
Year 2	0	0	0	0
Year 3	(8,413)	(8,413)	(8,413)	(8,413)
Year 4	(8,413)	(8,413)	(8,413)	(8,413)
Year 5	(8,413)	(8,413)	(8,413)	(8,413)
Year 6	0	0	0	0
Year 7	5,926	0	0	0
Year 8	9,876	9,876	5,926	0
Year 9	9,876	9,876	9,876	9,876
Year 10 onward	9,876	9,876	9,876	9,876

Source: Prepared by the Survey Team

Table 9-32 Economic Benefit of the Project before Discounting (Scenario A2) (Unit: PRs million)

FY	Unit 1	Unit 2	Unit 3	Unit 4
Year 1	0	0	0	0
Year 2	0	0	0	0
Year 3	(8,413)	(8,413)	(8,413)	(8,413)
Year 4	(8,413)	(8,413)	(8,413)	(8,413)
Year 5	(8,413)	(8,413)	(8,413)	(8,413)
Year 6	0	0	0	0
Year 7	5,926	0	0	0
Year 8	9,876	6,617	0	0
Year 9	9,876	9,876	7,407	0
Year 10	9,876	9,876	9,876	8,197
Year 11 onward	9,876	9,876	9,876	9,876

Source: Prepared by the Survey Team

Table 9-33 Economic Benefit of the Project before Discounting (Scenario B1) (Unit: PRs million)

FY	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6
Year 1	0	0	0	0	0	0
Year 2	0	0	0	0	0	0
Year 3	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)
Year 4	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)
Year 5	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)
Year 6	0	0	0	0	0	0
Year 7	0	0	0	0	5,926	0
Year 8	5,926	0	0	0	9,876	9,876
Year 9	9,876	9,876	5,926	0	9,876	9,876
Year 10 onward	9,876	9,876	9,876	9,876	9,876	9,876

Source: Prepared by the Survey Team

Table 9-34 Economic Benefit of the Project before Discounting (Scenario B1) (Unit: PRs million)

FY	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6
Year 1	0	0	0	0	0	0
Year 2	0	0	0	0	0	0
Year 3	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)
Year 4	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)
Year 5	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)	(8,413)
Year 6	0	0	0	0	0	0
Year 7	0	0	0	0	5,926	0
Year 8	0	0	0	0	9,876	6,617
Year 9	7,407	0	0	0	9,876	9,876
Year 10	9,876	8,197	0	0	9,876	9,876
Year 11	9,876	9,876	8,987	0	9,876	9,876
Year 12 onward	9,876	9,876	9,876	9,876	9,876	9,876

Source: Prepared by the Survey Team

9.5 Conclusion of Financial and Economic Analyses

Based on the assumptions, costs and benefits calculated and described so far, the financial

and economic IRRs and NPVs were calculated and presented in this section.

9.5.1 FIRR and FNPV

(1) Base Case

Benefit and cost were compiled and calculated considering the 2012 prices in order to obtain FIRR and were discounted using the opportunity cost of capital (12%) for attaining the FNPV.

Both Scenarios (Unit 1-4 and Unit 1-6) showed negative NPV and an FIRR which is lower than the cut-off rate. This is mainly caused by the assumption on the remaining life of the existing units as explained in the next section.

Table 9-35 FIRR and FNPV (Scenario A1)

Case	FIRR	FNPV (PRs million)	FNPV (US\$ million)
Unit 1	5.9%	(2,292)	(24)
Unit 2	5.7%	(2,259)	(24)
Unit 3	5.6%	(2,192)	(23)
Unit 4	5.4%	(2,211)	(23)
Total	5.7%	(8,954)	(95)

Source: Prepared by the Survey Team

Table 9-36 FIRR and FNPV (Scenario A2)

Case	FIRR	FNPV (PRs million)	FNPV (US\$ million)
Unit 1	5.8%	(2,320)	(25)
Unit 2	5.5%	(2,279)	(24)
Unit 3	5.2%	(2,233)	(24)
Unit 4	4.9%	(2,198)	(23)
Total	5.4%	(9,030)	(96)

Source: Prepared by the Survey Team

Table 9-37 FIRR and FNPV (Scenario B1)

Case	FIRR	FNPV (PRs million)	FNPV (US\$ million)
Unit 1	5.5%	(2,294)	(24)
Unit 2	5.2%	(2,308)	(24)
Unit 3	5.2%	(2,241)	(24)
Unit 4	5.0%	(2,253)	(24)
Unit 5	4.2%	(3,295)	(35)
Unit 6	4.0%	(3,259)	(34)
Total	4.8%	(15,651)	(166)

Source: Prepared by the Survey Team

Table 9-38 FIRR and FNPV (Scenario B2)

Case	FIRR	FNPV (PRs million)	FNPV (US\$ million)
Unit 1	5.1%	(2,308)	(24)
Unit 2	4.8%	(2,264)	(24)
Unit 3	4.5%	(2,218)	(23)
Unit 4	4.2%	(2,208)	(23)
Unit 5	4.1%	(3,357)	(36)
Unit 6	3.8%	(3,209)	(34)
Total	4.4%	(15,565)	(165)

Source: Prepared by the Survey Team

The incremental generation and revenue were the same among the units as well as the

capacity of the existing units and new units. The schedule of construction and installation and the resulting difference in timing for starting electricity generation are the factors that significantly differentiate the level of FIRR and FNPV between the units.

The FIRR of Units 5 and 6 were lower than those of Units 1-4 despite the earlier completion of the former as the capital costs of the former were larger than those of the latter though the installed capacity and expected benefit were the same for all the units.

(2) Sensitivity Analysis

Sensitivity analysis was conducted for the financial analysis as the actual condition may be different from those assumed for the base case. In the sensitivity analysis, 1) tariff increase (10%), 2) cost increase (10%), 3) delay in construction (1 year), 4) shorter life of existing units (45 years), and 5) CDM benefit were considered.

Table 9-39 Sensitivity Analysis for Scenario A1 (FIRR & FNPV)

Case	Benefit	Cost	FIRR (%)	FNPV (Mil PRs)	FNPV (Mil US\$)
Base case	No change	No change	5.7%	(8,954)	(95)
Tariff increase (+10%)	+10%	No change	6.5%	(8,256)	(87)
Cost increase (+10%)	No change	+10%	5.0%	(10,347)	(109)
Delay in construction (1 yr)	No change	No change	5.5%	(8,564)	(91)
Shorter life of existing unit (45 yrs)	No change	No change	9.2%	(2,745)	(29)
With CDM benefit	+CDM benefit	No change	8.2%	(5,591)	(58)

Source: Prepared by the Survey Team

Table 9-40 Sensitivity Analysis for Scenario A2 (FIRR & FNPV)

Case	Benefit	Cost	FIRR (%)	FNPV (Mil PRs)	FNPV (Mil US\$)
Base case	No change	No change	5.4%	(9,030)	(96)
Tariff increase (+10%)	+10%	No change	6.2%	(8,416)	(89)
Cost increase (+10%)	No change	+10%	4.7%	(10,357)	(110)
Delay in construction (1 yr)	No change	No change	5.1%	(8,778)	(93)
Shorter life of existing unit (45 yrs)	No change	No change	8.9%	(2,821)	(30)
With CDM benefit	+CDM benefit	No change	7.8%	(6,038)	(63)

Source: Prepared by the Survey Team

Table 9-41 Sensitivity Analysis for Scenario B1 (FIRR & FNPV)

Case	Benefit	Cost	FIRR (%)	FNPV (Mil PRs)	FNPV (Mil US\$)
Base case	No change	No change	4.8%	(15,651)	(166)
Tariff increase (+10%)	+10%	No change	5.6%	(14,712)	(156)
Cost increase (+10%)	No change	+10%	4.1%	(17,869)	(189)
Delay in construction (1 yr)	No change	No change	4.5%	(15,046)	(159)
Shorter life of existing unit (45 yrs)	No change	No change	7.8%	(6,337)	(67)
With CDM benefit	+CDM benefit	No change	7.3%	(10,597)	(112)

Source: Prepared by the Survey Team

Table 9-42 Sensitivity Analysis for Scenario B2 (FIRR & FNPV)

Case	Benefit	Cost	FIRR (%)	FNPV (Mil PRs)	FNPV (Mil US\$)
Base case	No change	No change	4.4%	(15,565)	(165)
Tariff increase (+10%)	+10%	No change	5.2%	(14,822)	(157)
Cost increase (+10%)	No change	+10%	3.7%	(17,603)	(186)
Delay in construction (1 yr)	No change	No change	4.1%	(14,969)	(158)
Shorter life of existing unit (45 yrs)	No change	No change	7.5%	(6,251)	(66)
With CDM benefit	+CDM benefit	No change	6.7%	(11,566)	(120)

Source: Prepared by the Survey Team

It is clear from the figures above that the change in the level of benefit and cost and the delay in construction did not significantly change the IRR (less than 1%).

On the contrary, the impact of the change in the assumption on the remaining life of the existing units was evident and more significant than the change in the level of benefit and cost and the delay in construction.

The reason for this can be explained from the formula of calculating net incremental benefit. As explained in the previous section, the generation and tariff revenues of the existing units during the construction and installation period are recognized as forgone benefits when they are forced to stop operation. If the remaining life of the existing units is assumed to be shorter, the foregone benefit will become smaller accordingly.

Additional CDM benefit can increase the IRR by more than 1%. However, as mentioned earlier, there is uncertainty that the Project is eligible for this benefit at this stage.

9.5.2 EIRR and ENPV

(1) Base Case

The benefit and cost were compiled and calculated using the economic cost, in order to obtain EIRR and were discounted using the social discount rate (12%) for attaining the ENPV.

In contrast with the FIRR, EIRR was higher than the cut-off rate in the base case of all cases. This difference is explained by the huge gap between 1) the level of the economic benefit (i.e., PRs 15.67/kWh) in economic analysis and 2) the incremental tariff revenue in financial analysis.

Table 9-43 EIRR and ENPV (Scenario A1)

Case	EIRR (%)	ENPV (PRs million)	ENPV (US\$ million)
Unit 1	20.7%	18,246	193
Unit 2	19.3%	15,781	167
Unit 3	18.6%	14,424	153
Unit 4	17.4%	12,185	129
Total	19.0%	60,636	642

Source: Prepared by the Survey Team

Table 9-44 EIRR and ENPV (Scenario A2)

Case	EIRR (%)	ENPV (PRs million)	ENPV (US\$ million)
Unit 1	20.7%	18,231	193
Unit 2	18.6%	14,543	154
Unit 3	17.0%	11,342	120
Unit 4	15.6%	8,380	89
Total	17.9%	52,496	556

Source: Prepared by the Survey Team

Table 9-45 EIRR and ENPV (Scenario B1)

Case	EIRR (%)	ENPV (PRs million)	ENPV (US\$ million)
Unit 1	18.5%	14,397	152
Unit 2	17.4%	12,159	129
Unit 3	16.8%	10,950	116
Unit 4	15.8%	8,951	95
Unit 5	20.1%	17,305	183
Unit 6	18.7%	14,853	157
Total	17.9%	78,615	832

Source: Prepared by the Survey Team

Table 9-46 EIRR and ENPV (Scenario B2)

Case	EIRR (%)	ENPV (PRs million)	ENPV (US\$ million)
Unit 1	17.0%	11,335	120
Unit 2	15.6%	8,375	89
Unit 3	14.4%	5,781	61
Unit 4	13.4%	3,381	36
Unit 5	20.1%	17,269	183
Unit 6	18.1%	13,680	145
Total	16.4%	59,821	633

Source: Prepared by the Survey Team

ENPV of each unit showed positive benefit. While the FNPV of both scenarios showed deficit, it can be concluded that the economic benefit of the Project is robust as the people in Pakistan are paying very high costs for alternative energy sources (i.e. diesel generators and UPS) due to insufficient supply of electricity and the Project can be justified from the viewpoint of the national economy.

(2) Sensitivity Analysis

The sensitivity analysis was conducted for economic analysis. Similar to the financial analysis, increase in economic benefit, cost overrun of construction, delay in construction, change in the assumption of the remaining life of the existing units, and CDM benefit were considered.

The results of sensitive analysis for EIRR and ENPV were similar to those of FIRR and FNPV. The impact on EIRR and ENPV of the change in the level of benefit and cost was relatively small. Delay in construction increased the figures of EIRR and ENPV slightly. The change in the assumption on the remaining life of the existing units drastically increased the figures of EIRR and ENPV. Unlike financial analysis, the impact of additional CDM benefit is limited as it is small compared with the huge economic benefit (saving of the cost for alternative energy source).

Table 9-47 Sensitivity Analysis for Scenario A1 (EIRR & ENPV)

Case	Benefit	Cost	EIRR (%)	ENPV (PRs million)	ENPV (US\$ million)
Base case	No change	No change	19.0%	60,636	642
Benefit increase (+10%)	+10%	No change	19.1%	67,882	718
Cost increase (+10%)	No change	+10%	18.8%	59,487	629
Delay in construction (1 yr)	No change	No change	19.3%	62,066	657
Shorter life of existing unit (45 yrs)	No change	No change	80.7%	125,070	1,323
With CDM benefit	+CDM benefit	No change	19.2%	63,260	669

Source: Prepared by the Survey Team

Table 9-48 Sensitivity Analysis for Scenario A2 (EIRR & ENPV)

Case	Benefit	Cost	EIRR (%)	ENPV (PRs million)	ENPV (US\$ million)
Base case	No change	No change	17.9%	52,496	556
Benefit increase (+10%)	+10%	No change	18.1%	58,873	623
Cost increase (+10%)	No change	+10%	17.8%	51,404	544
Delay in construction (1 yr)	No change	No change	18.2%	53,935	571
Shorter life of existing unit (45 yrs)	No change	No change	80.3%	116,931	1,237
With CDM benefit	+CDM benefit	No change	18.1%	54,830	580

Source: Prepared by the Survey Team

Table 9-49 Sensitivity Analysis for Scenario B1 (EIRR & ENPV)

Case	Benefit	Cost	EIRR (%)	ENPV (PRs million)	ENPV (US\$ million)
Base case	No change	No change	17.9%	78,615	832
Benefit increase (+10%)	+10%	No change	18.0%	88,356	935
Cost increase (+10%)	No change	+10%	17.7%	76,783	813
Delay in construction (1 yr)	No change	No change	18.1%	80,825	855
Shorter life of existing unit (45 yrs)	No change	No change	72.8%	175,266	1,855
With CDM benefit	+CDM benefit	No change	18.1%	82,557	874

Source: Prepared by the Survey Team

Table 9-50 Sensitivity Analysis for Scenario B2 (EIRR & ENPV)

Case	Benefit	Cost	EIRR (%)	ENPV (PRs million)	ENPV (US\$ million)
Base case	No change	No change	16.4%	59,821	633
Benefit increase (+10%)	+10%	No change	16.5%	67,532	715
Cost increase (+10%)	No change	+10%	16.2%	58,139	615
Delay in construction (1 yr)	No change	No change	16.6%	61,888	655
Shorter life of existing unit (45 yrs)	No change	No change	71.5%	156,472	1,656
With CDM benefit	+CDM benefit	No change	16.6%	62,940	666

Source: Prepared by the Survey Team

9.6 Risk Analysis

This section presents the risk factors that may significantly influence the financial situation of the Project and WAPDA.

9.6.1 Accumulating Receivables and Revision of Tariff

As mentioned in the previous chapter, accumulating receivables is caused by 1) the low level of tariff of the distributing companies, which is lower than the full cost recovery and 2) the failure of payment of subsidy to the distribution companies by the government for filling the gap

of the difference. Facing the fuel price hike, the Government of Pakistan has notified the increase of tariff and plans to notify the further increase.¹⁵ However, the situation on the level of the tariff needs to be carefully watched.

9.7 Operation and Effect Indicators

Envisaged operation and effect indicators of the Project are as follows:

- 1) Operation indicators
 - Maximum output of Mangla Power Station [MW]
 - Average annual power generation of Mangla Power Station [GWh]
 - Average plant factor of Mangla Power Station [%]
- 2) Effect indicators
 - Increase in the earnings of WAPDA
 - Contribution to the reduction of carbon dioxide by decreasing the usage of kerosene and diesel oil etc.

Table 9-51 shows operation and effect indicators to measure the quantitative effects of the Project including target values at the time after completion of the Project.

¹⁵ Daily Times, "Massive increase in power tariff", May 18, 2012

Table 9-51 Operation and Effect Indicators

Indicators	Present Conditions in 2012	Target	
		Scenario-A (for 4 units) The target year is 2021	Scenario-B (for 6 units) The target year is 2023
Maximum output	1,150 [MW]	1,230 [MW]	1,270 [MW]
Average annual power generation	2,753[GWh] (for 4 units)	3,232 [GWh]	-
	4,130[GWh] (for 6 units)	-	4,848 [GWh]
Average plant factor	49.6 [%]	60.6 [%]	59.2 [%]
Increase in the earnings of WAPDA	3,243 [PRs Mil/year] (for 4 units)	3,807 [PRs Mil/year]	-
	4,864 [PRs Mil/year] (for 6 units)	-	5,710 [PRs Mil/year]
Contribution to the reduction of carbon dioxide	-	1,334,527 [t-CO2/year]	1,383,118 [t-CO2/year]

Note: The figures of power generation and earnings are based on those of financial analysis.
Source: Prepared by the Survey Team

CHAPTER 10

CONCLUSION AND RECOMMENDATIONS

CHAPTER 10 CONCLUSIONS AND RECOMMENDATIONS

10.1 Conclusions

10.1.1 Project Outline

The project outline based on the recommendation of enhancement of generator's output up to 135 MW is as below.

1) Rehabilitation and Enhancement

The scenarios for rehabilitation and enhancement project of Mangla Power Station with enhanced generator's output 135 MW are summarized in Table 10-1.

Table 10-1 Recommended Scenarios

Scenarios	Subject Unit	No. of Units of Stoppage	Project Cost		Economic IRR	Financial IRR
			General Untied Japanese ODA	Climate Change Program		
Scenario-A1	Units 1-4 (4 units)	Double units	USD 294.2 mil. (JPY 23,800 mil.)	USD 284.3 mil. (JPY 23,002 mil.)	19.0 %	5.7 %
Scenario-A2		Single unit	USD 303.6 mil. (JPY 24,563 mil.)	USD 292.7 mil. (JPY 23,680 mil.)	17.9 %	5.4 %
Scenario-B1	Units 1-6 (6 units)	Double units	USD 495.2 mil. (JPY 40,059 mil.)	USD 476.3 mil. (JPY 38,534 mil.)	17.9 %	4.8 %
Scenario-B2		Single unit	USD 519.6 mil. (JPY 42,032 mil.)	USD 496.0 mil. (JPY 40,128 mil.)	16.4 %	4.4 %

Source: Prepared by the Survey Team

USD 1= JPY 80.9

2) Implementation Period of the Project

The implementation period of the Project from the signing of the Loan Agreement (L/A) up to completion of the Project at all scenarios is shown in Table 10-2.

Table 10-2 Project Implementation Period

Stage	Scenarios				Remarks
	Scenario-A1	Scenario-A2	Scenario-B1	Scenario-B2	
Pre-construction Stage	30 months	30 months	30 months	30 months	Procurement of Consultant, Preparation of Tender Documents and Tendering Stage
Construction Stage	65 months	80 months	77 months	102 months	Rehabilitation and Enhancement Works
Total	95 months	110 months	107 months	132 months	-

Source: Prepared by the Survey Team

4) Project Cost

4)-1. General Untied Japanese ODA Loans

i) Scenario-A1 and A2

The estimated project cost at Scenario-A1 and A2 under the condition of utilizing the general untied Japanese ODA loans is summarized in Table 10-3.

Table 10-3 Project Cost at Scenario-A1 and A2

	Scenario-A1			Scenario-A2		
	FC	LC	Total	FC	LC	Total
1. Construction Cost	USD 207.5 mil. (JPY 16,784 mil.)	USD 10.3 mil. (JPY 833 mil.)	USD 217.8 mil. (JPY 17,617 mil.)	USD 210.3 mil. (JPY 17,015 mil.)	USD 10.7 mil. (JPY 864 mil.)	USD 221.0 mil. (JPY 17,879 mil.)
2. Consulting Services Cost	USD 10.5 mil. (JPY 853 mil.)	USD 2.2 mil. (JPY 182 mil.)	USD 12.8 mil. (JPY 1,035 mil.)	USD 13.5 mil. (JPY 1,094 mil.)	USD 2.4 mil. (JPY 193 mil.)	USD 15.9 mil. (JPY 1,287 mil.)
3. Interest during Construction, Commitment Charge	USD 14.6 mil. (JPY 1,180 mil.)	0	USD 14.6 mil. (JPY 1,180 mil.)	USD 16.2 mil. (JPY 1,310 mil.)	0	USD 16.2 mil. (JPY 1,310 mil.)
4. Others (Administration Cost, VAT, Import Tax)	USD 34.9 mil. (JPY 2,822 mil.)	USD 14.2 mil. (JPY 1,147 mil.)	USD 49.1 mil. (JPY 3,969 mil.)	USD 35.8 mil. (JPY 2,897 mil.)	USD 14.7 mil. (JPY 1,189 mil.)	USD 50.5 mil. (JPY 4,086 mil.)
Total Cost	USD 267.5 mil. (JPY 21,639 mil.)	USD 26.7 mil. (JPY 2,161 mil.)	USD 294.2 mil. (JPY 23,800 mil.)	USD 275.8 mil. (JPY 22,316 mil.)	USD 27.8 mil. (JPY 2,247 mil.)	USD 303.6 mil. (JPY 24,563 mil.)

USD 1= JPY 80.9

Note: 1) Items No. 1, 2 and 3 shall be borne by JICA Finance.

2) Item No. 4 shall be borne by WAPDA or the Government of Pakistan depending upon approval by the Planning Commission of Pakistan.

Source: Prepared by the Survey Team

ii) Scenario-B1 and B2

The estimated project cost at Scenarios-B1 and B2 under the condition of utilizing the general untied Japanese ODA loans is summarized in Table 10-4.

Table 10-4 Project Cost at Scenario-B1 and B2

	Scenario-B1			Scenario-B2		
	FC	LC	Total	FC	LC	Total
1. Construction Cost	USD 350.4 mil. (JPY 28,347 mil.)	USD 17.7 mil. (JPY 1,432 mil.)	USD 368.1 mil. (JPY 29,779 mil.)	USD 358.2 mil. (JPY 28,982 mil.)	USD 18.8 mil. (JPY 1,522 mil.)	USD 377.1 mil. (JPY 30,504 mil.)
2. Consulting Services Cost	USD 14.4 mil. (JPY 1,162 mil.)	USD 3.7 mil. (JPY 296 mil.)	USD 18.0 mil. (JPY 1,458 mil.)	USD 19.5 mil. (JPY 1,575 mil.)	USD 4.0 mil. (JPY 322 mil.)	USD 23.4 mil. (JPY 1,897 mil.)
3. Interest during Construction, Commitment Charge	USD 27.7 mil. (JPY 2,242 mil.)	0	USD 27.7 mil. (JPY 2,242 mil.)	USD 34.6 mil. (JPY 2,796 mil.)	0	USD 34.6 mil. (JPY 2,796 mil.)
4. Others (Administration Cost, VAT, Import Tax)	USD 58.4 mil. (JPY 4,721 mil.)	USD 23.0 mil. (JPY 1,858 mil.)	USD 81.3 mil. (JPY 6,579 mil.)	USD 60.4 mil. (JPY 4,889 mil.)	USD 24.1 mil. (JPY 1,947 mil.)	USD 84.5 mil. (JPY 6,836 mil.)
Total Cost	USD 450.8 mil. (JPY 36,473 mil.)	USD 44.3 mil. (JPY 3,586 mil.)	USD 495.2 mil. (JPY 40,059 mil.)	USD 472.7 mil. (JPY 38,242 mil.)	USD 46.8 mil. (JPY 3,790 mil.)	USD 519.6 mil. (JPY 42,032 mil.)

USD 1= JPY 80.9

Note: 1) Items No. 1, 2 and 3 shall be borne by JICA Finance.

2) Item No. 4 shall be borne by WAPDA or the Government of Pakistan depending upon approval by the Planning Commission of Pakistan.

Source: Prepared by the Survey Team

4)-2. Climate Change Program Loan

i) Scenario-A1 and A2

The estimated project cost at Scenario-A1 and A2 under the condition of utilizing the climate change program loan is summarized in Table 10-5.

Table 10-5 Project Cost at Scenario-A1 and A2

	Scenario-A1			Scenario-A2		
	FC	LC	Total	FC	LC	Total
1. Construction Cost	USD 207.5 mil. (JPY 16,784 mil.)	USD 10.3 mil. (JPY 833 mil.)	USD 217.8 mil. (JPY 17,617 mil.)	USD 210.3 mil. (JPY 17,015 mil.)	USD 10.7 mil. (JPY 864 mil.)	USD 221.0 mil. (JPY 17,879 mil.)
2. Consulting Services Cost	USD 10.5 mil. (JPY 853 mil.)	USD 2.2 mil. (JPY 182 mil.)	USD 12.8 mil. (JPY 1,035 mil.)	USD 13.5 mil. (JPY 1,094 mil.)	USD 2.4 mil. (JPY 193 mil.)	USD 15.9 mil. (JPY 1,287 mil.)
3. Interest during Construction, Commitment Charge	USD 4.7 mil. (JPY 381 mil.)	0	USD 4.7 mil. (JPY 381 mil.)	USD 5.3 mil. (JPY 427 mil.)	0	USD 5.3 mil. (JPY 427 mil.)
4. Others (Administration Cost, VAT, Import Tax)	USD 34.9 mil. (JPY 2,822 mil.)	USD 14.2 mil. (JPY 1,147 mil.)	USD 49.1 mil. (JPY 3,969 mil.)	USD 35.8 mil. (JPY 2,897 mil.)	USD 14.7 mil. (JPY 1,189 mil.)	USD 50.5 mil. (JPY 4,086 mil.)
Total Cost	USD 257.6 mil. (JPY 20,840 mil.)	USD 26.7 mil. (JPY 2,162 mil.)	USD 284.3 mil. (JPY 23,002 mil.)	USD 264.9 mil. (JPY 21,433 mil.)	USD 27.8 mil. (JPY 2,247 mil.)	USD 292.7 mil. (JPY 23,680 mil.)

USD 1= JPY 80.9

Note: 1) Items No. 1, 2 and 3 shall be borne by JICA Finance.

2) Item No. 4 shall be borne by WAPDA or the Government of Pakistan depending upon approval by the Planning Commission of Pakistan.

Source: Prepared by the Survey Team

ii) Scenario-B1 and B2

The estimated project cost at Scenario-B1 and B2 under the condition of utilizing the climate change program loan is summarized in Table 10-6.

Table 10-6 Project Cost at Scenario-B1 and B2

	Scenario-B1			Scenario-B2		
	FC	LC	Total	FC	LC	Total
1. Construction Cost	USD 350.4 mil. (JPY 28,347 mil.)	USD 17.9 mil. (JPY 1,452 mil.)	USD 368.3 mil. (JPY 29,799 mil.)	USD 358.2 mil. (JPY 28,982 mil.)	USD 18.8 mil. (JPY 1,522 mil.)	USD 377.1 mil. (JPY 30,504 mil.)
2. Consulting Services Cost	USD 14.4 mil. (JPY 1,162 mil.)	USD 3.7 mil. (JPY 296 mil.)	USD 18.0 mil. (JPY 1,458 mil.)	USD 19.5 mil. (JPY 1,575 mil.)	USD 4.0 mil. (JPY 322 mil.)	USD 23.4 mil. (JPY 1,897 mil.)
3. Interest during Construction, Commitment Charge	USD 8.9 mil. (JPY 717 mil.)	0	USD 8.9 mil. (JPY 717 mil.)	USD 11.0 mil. (JPY 892 mil.)	0	USD 11.0 mil. (JPY 892 mil.)
4. Others (Administration Cost, VAT, Import Tax)	USD 58.4 mil. (JPY 4,721 mil.)	USD 23.0 mil. (JPY 1,858 mil.)	USD 81.3 mil. (JPY 6,579 mil.)	USD 60.4 mil. (JPY 4,889 mil.)	USD 24.1 mil. (JPY 1,947 mil.)	USD 84.5 mil. (JPY 6,836 mil.)
Total Cost	USD 432.0 mil. (JPY 34,948 mil.)	USD 44.3 mil. (JPY 3,586 mil.)	USD 476.3 mil. (JPY 38,534 mil.)	USD 449.2 mil. (JPY 36,337 mil.)	USD 46.9 mil. (JPY 3,791 mil.)	USD 496.0 mil. (JPY 40,128 mil.)

USD 1= JPY 80.9

Note: 1) Items No. 1, 2 and 3 shall be borne by JICA Finance.

2) Item No. 4 shall be borne by WAPDA or the Government of Pakistan depending upon approval by the Planning Commission of Pakistan.

Source: Prepared by the Survey Team

10.2 Recommendations Prior to Implementation

As previously stated, after the conclusion of the L/A, it will take at least 30 months to secure a contract with a contractor for the rehabilitation and enhancement works. The recommendations for maintenance are to be done by the implementation agency prior to the implementation of the Project as stated below:

- To clean up erection bays;
- To confirm the operating conditions of the lifting beam, lifting device, and wire;
- To confirm the operating conditions of overhead traveling crane with inching operation; and
- To clean up the inside of water pits and generator rooms.

10.3 Recommendations for Monitoring System Using Japanese Technology

10.3.1 Hydraulic Consideration

According to the result of the field survey in this study, the monitoring systems for sedimentation in the reservoir, water level of the reservoir, movement of the power house and seepage model analysis data since 1968 are manually operated. These systems are not reliable and precise. Consequently, the improvement of the existing monitoring systems is strongly recommended by the use of GIS technology.

The upgrading monitoring systems recommended by the Survey Team are as follows:

- 1) Rehabilitation of sedimentation monitoring system at the dam;
- 2) Rehabilitation of water level monitoring system at the dam;
- 3) Rehabilitation of seepage monitoring system at the power house;
- 4) Rehabilitation of movement monitoring system at the power house;
- 5) Rehabilitation of crack observation at the power house;
- 6) Rehabilitation of existing meteorological and river observation stations for tributaries; and
- 7) Centralized control panel monitoring system.

10.3.2 Monitoring System for Sedimentation Using Japanese Technology

The sedimentation of Mangla Dam is being surveyed every three to five years since the 1970's and its volume is shown in Table 4-25. The annual average sedimentation is 36.13 million m³. If the situation of sedimentation and its volume are observed in an earlier time, the appropriate counter measures against sedimentation may be considered and implemented for each river properly. Therefore, the reservoir will be effectively used for irrigation/hydraulic power after preventing sedimentation. In the past, the survey of sedimentation took more than two months. If the survey is conducted using GPS and multi-beam sonar sounding system by Japanese

technology, the period of survey would be shortened and accurate sedimentation volume would be obtained.

On the other hand, the movement monitoring system is being conducted at the power house but the existing equipment are old model and manually operated. The updated model shall be recommended for installation to obtain accurate monitoring. The updated equipment is very accurate and the data is transmitted by wireless to the centralized monitor station, which is useful during emergency period. Using the updated monitoring system, the movement of the dam body and power station and pore-water pressure shall be observed at the centralized monitor station in real time to prevent accidents.

Presently, the model systems of the meteorological stations upstream of the dam are also old. The stations are still manually operated and there is no real time monitoring. The stations must also be updated by using data logger and transmitter for sending data automatically to the centralized monitor station on time via 3G system. The meteorological and river data shall be accurately observed thru the internet in real time so that the dam shall be managed and observed properly.

Table 10-7 shows the number of equipment to be installed, the specification of equipment, and estimated cost for rehabilitation of the existing measurement and observation systems.

Table 10-7 Cost Estimate for Equipment and System

Location	Item	Nos.	Unit Price (USD 1,000)	Amount (USD 1,000)
Dam Site	Sediment monitoring system	1	1,600	1,600
	Telemeter dam water level gauge	2	25	50
Power House	Movement observation system	2	27	54
	Crack observation system	5	6	30
	Seepage monitoring system	6	15	90
Meteorological and River Observation Station Power House Monitoring Room	Telemetry water level gauge	6	90	540
	Telemetry river velocity gauge			
	Software			
	Solar panel/battery			
	Data transmission (GPRS)			
	CCTV			
	Data transmission (GPRS)			
Database				
Power House Monitoring Room	River cross-sectional survey	1	360	360
Total				2,724

Source: Prepared by the Survey Team

Note 1: Equipment/system cost including system development, software, programming, and training at the site.

Note 2: Equipment cost including installation guidance at the site, but not including civil works

The tentative implementation schedule is shown in Table 10-8.

Table 10-8 Implementation Schedule

Monitoring System	Work Item	Month				
		1	2	3	4	5
Sedimentation of Dam	Measurement	■	■			
	Arc-GIS			■	■	
	Training	■	■	■	■	
Movement of Power House	Installation		■			
	Training			■		
Seepage at Power House	Installation		■			
	Training			■		
Crack Displacement	Installation			■		
	Training				■	
Water Level of Dam	Installation		■			
	Training			■		
Meteorological and River Stations	Installation	■	■			
	Training			■		
Centralized Control Panel	Installation			■	■	
	Training				■	
-	Reinforcement of Cracks	■	■			

Source: Prepared by the Survey Team

10.4 Time Based Action Plan

The works to be done by WAPDA prior to the conclusion of L/A is summarised as the Time Based Action Plan in the table below:

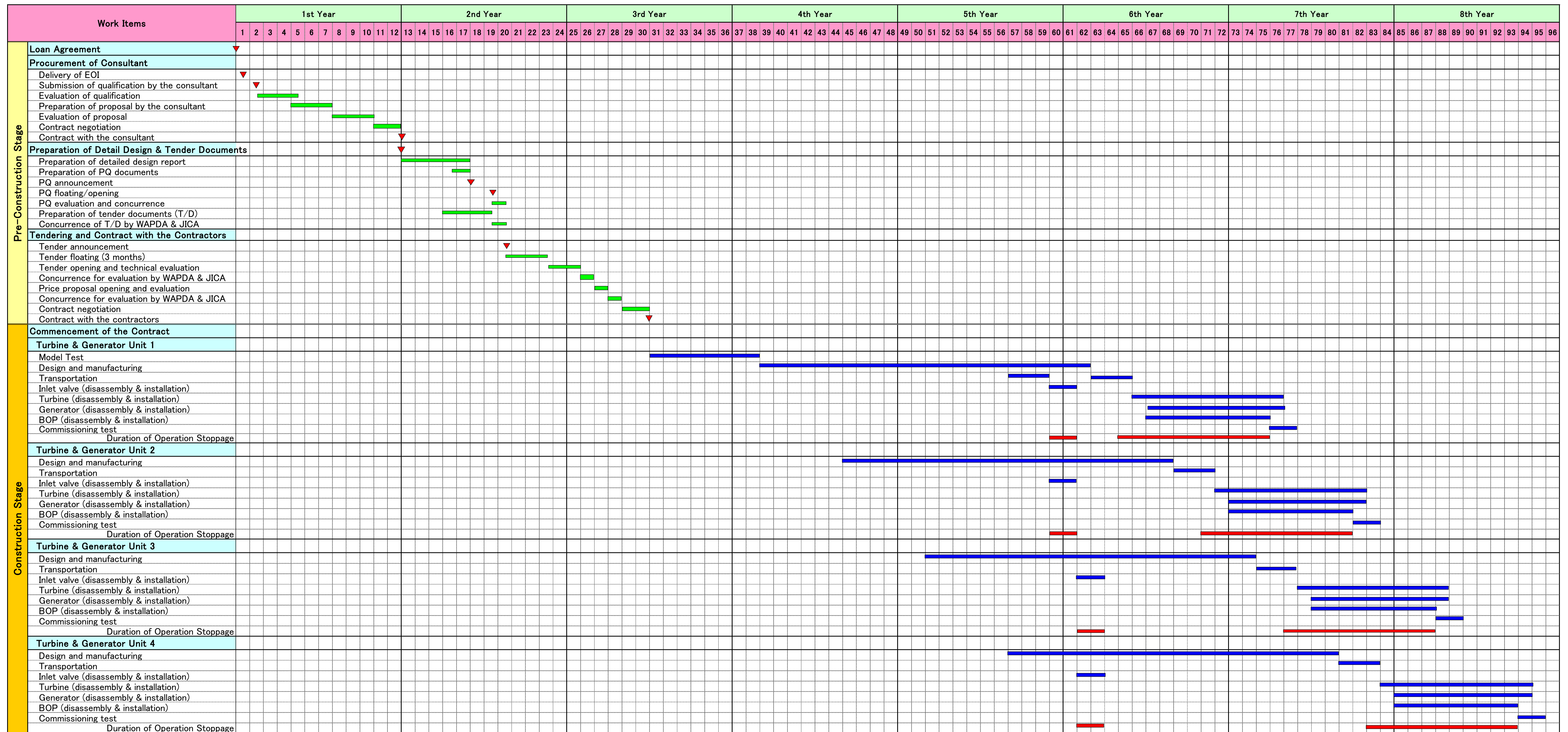
Table 10-9 Time Based Action Plan

No.	Work Items	Time Frame	Responsible Department of WAPDA
1	Preparation of PC-I by WAPDA/Consultant and its submission to Minister of Water and Power (MoWP)	1.0 month	General Manager (Hydel) Development
2	Minister of Water and Power (MoWP) examines PC-I and submit it to Planning Commission for obtaining their approval.	1.0 month	MoWP
3	Planning Commission examines the proposed project in depth by circulating it to all the stakeholders, the Provincial Governments (if involved) and Ministry of Finance for their comments / reservations (if any)	1.0 month	Planning Commission
4	After getting the comments of all the stakeholders a working paper would be prepared by the Planning Commission of Pakistan.	0.5 month	Planning Commission
5	As the value of the project is more than Rs 1,000 million, it is to be put up in Executive Committee of National Economic Council (ECNEC) for approval. ECNEC is	1.0 month	Planning Commission , Chairman WAPDA,

	headed by MOF and attended by EAD, Planning Commission of Pakistan, provincial governments, MoWP and WAPDA through its Chairman / Member Power and General Manager (Hydel) Development.		Member (P) and G.M. (Hydel) Development
6	Establishment of the Project Management Unit (PMU) of WAPDA at the project site to execute the project.	1.0 month	General Manager (Hydel) Development would obtain the approval of the WAPDA Authority.

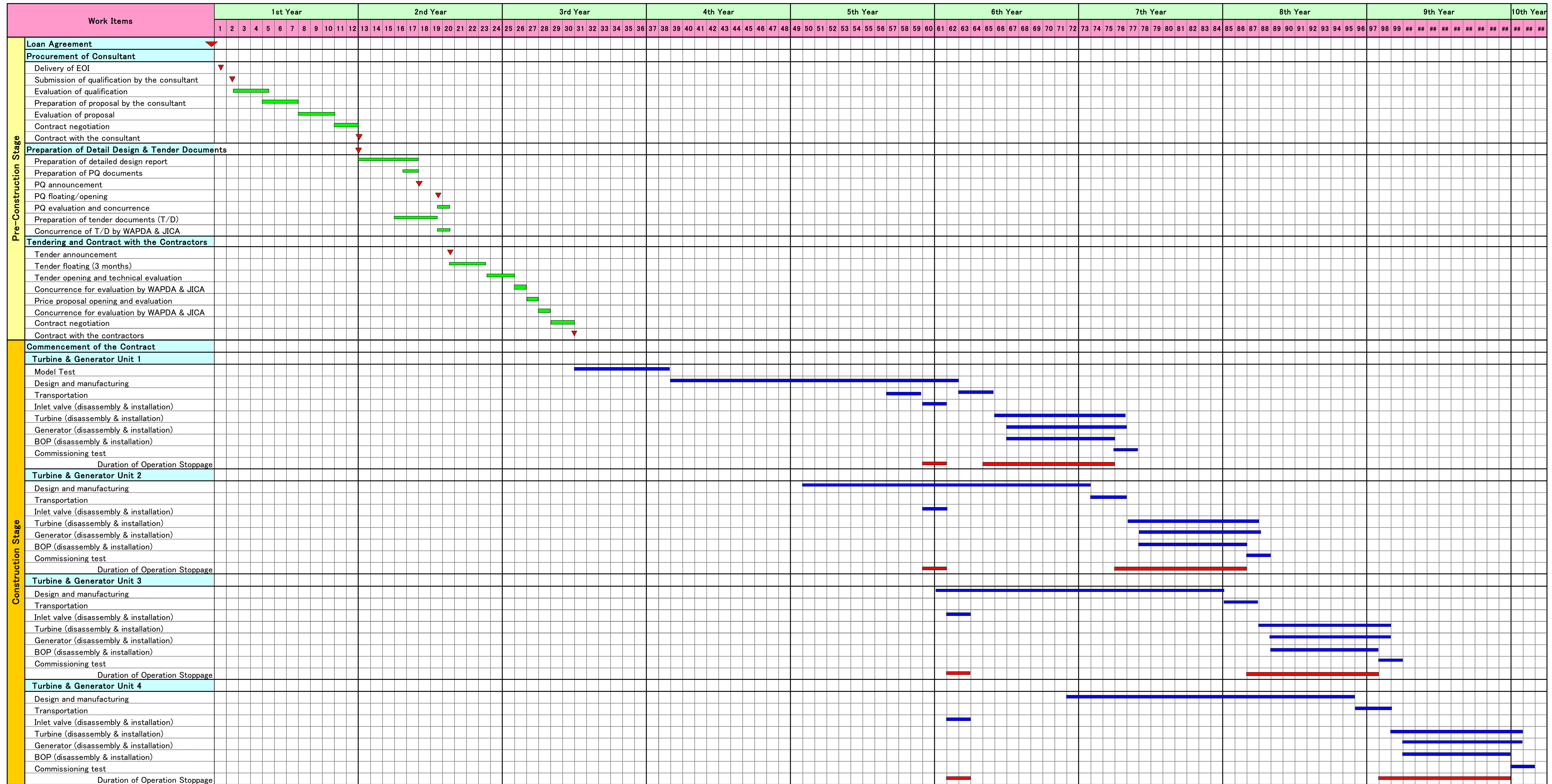
Source: Prepared by the Survey Team

Figure 7-3 Implementation Schedule for Scenario-A1



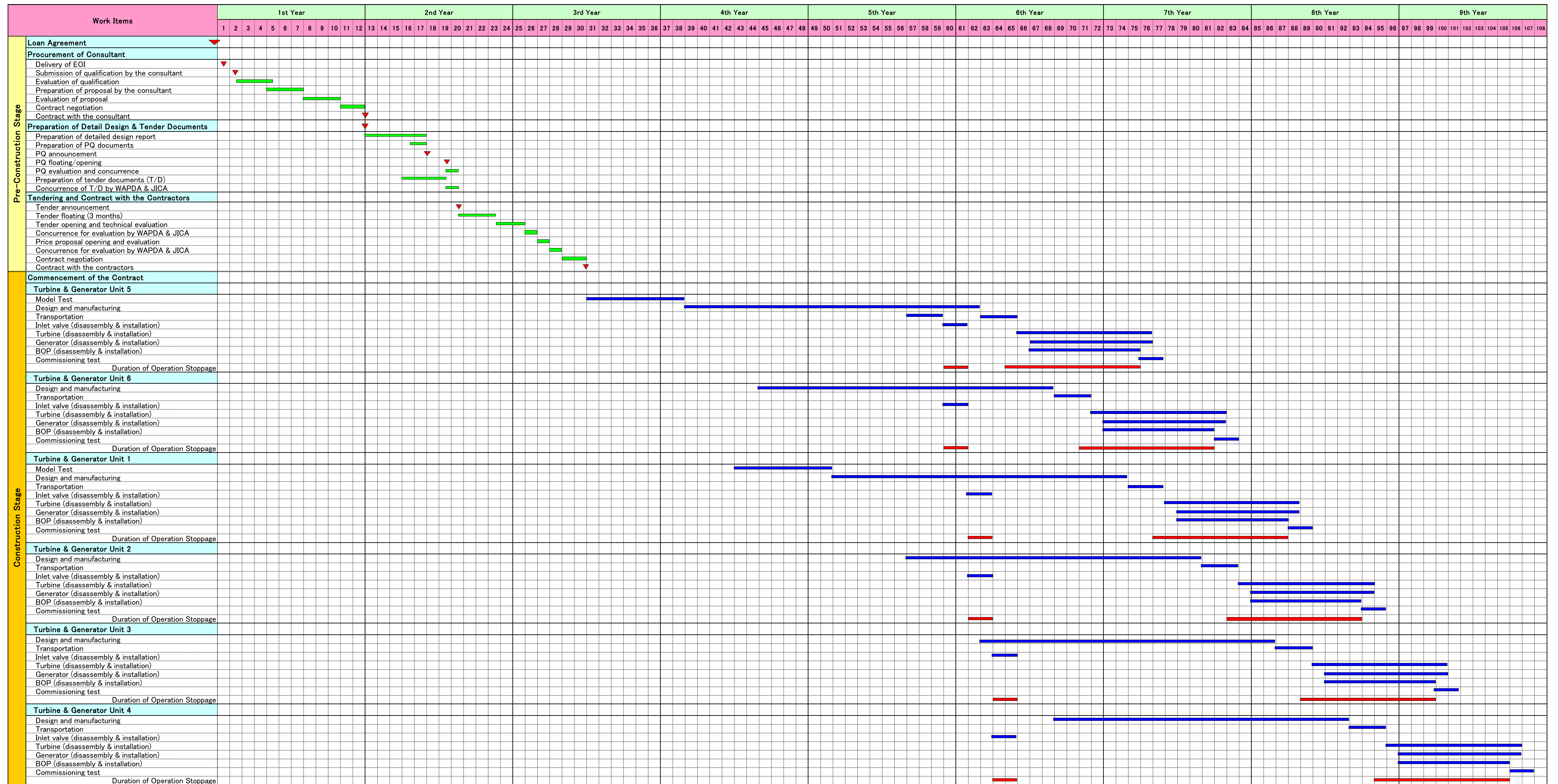
Note: Decreasing generating power caused by operational stoppage of 2 units during the construction stage of Scenario-A1 would be covered by increase of power generation of other 8 units. However, it seems to be difficult to avoid the large lowering of total power generation of Mangla Power Station at this scenario.

Figure 7-4 Implementation Schedule for Scenario-A2



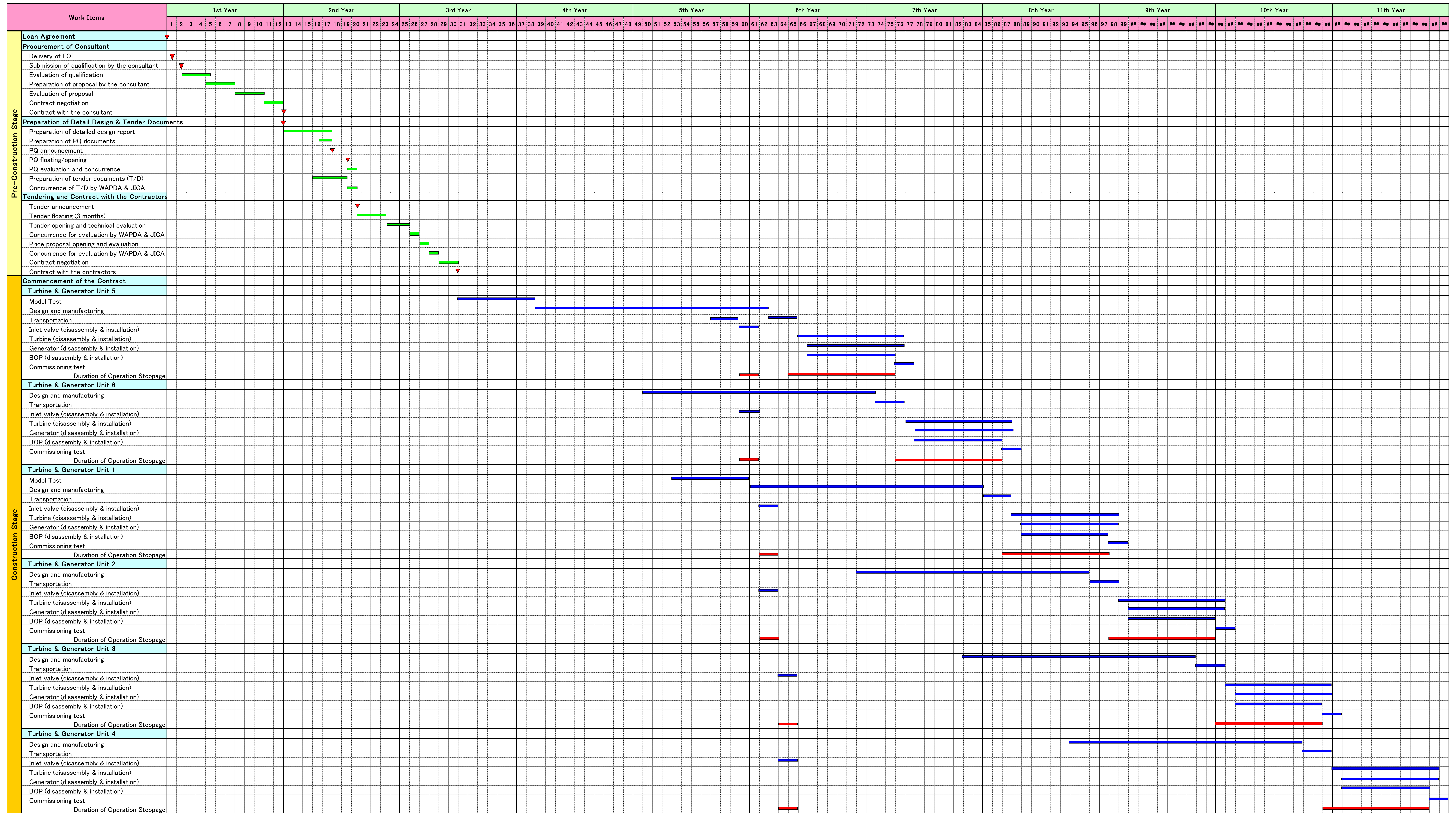
Note: Decreasing generating power caused by operational stoppage of 1 unit during the construction stage of Scenario-A2 would be minimized the total power generation of Mangla Power Station by increase of power generation of the other 9 units.

Figure 7-5 Implementation Schedule for Scenario-B1



Note: Decreasing generating power caused by operational stoppage of 2 units during the construction stage of Scenario-B1 would be covered by increase of power generation of other 8 units. However, it seems to be difficult to avoid the large lowering of total power generation of Mangla Power Station at this scenario.

Figure 7-6 Implementation Schedule for Scenario-B2



Note: Decreasing generating power caused by operational stoppage of 1 unit during the construction stage of Scenario-B2 would be minimized the total power generation of Mangla Power Station by increase of power generation of the other 9 units.