**Government of the Islamic
Republic of Pakistan**

**National Transmission and
Despatch Company**

Project for Least Cost Power Generation and Transmission Expansion Plan

Final Report

May 2016

Japan International Cooperation Agency (JICA)

International Institute of Electric Power, Ltd. (IIEP)

Project for Least Cost
Generation and Transmission Expansion Plan

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Abbreviation

Abbreviation	Word
AC	Alternative Current
ADB	Asian Development Bank
AEDB	Alternative Energy Development Board
AJK	Azad Jammu and Kashmir
AFC	Automatic Frequency Control
BTU	British Thermal Unit
CASA	Central Asia South Asia
COD	Commercial Operation Date
CP	Counterpart
CPP	Captive Power Plant
CPPAGL	Central Power Purchasing Agency Guarantee Limited
DC	Direct Current
D/C	Double Circuit
DF	Diversity Factor
DFR	Draft Final Report
DGGas	Directorate General of Gas
DGOil	Directorate General of Oil
DGPC	Directorate General Petroleum Concessions
DPC	Dispatching Power Control
DSM	Demand Side Management
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
FACTS	Flexible Alternating Current Transmission System
FIRR	Financial Internal Rate of Return
FR	Final Report
F/S	Feasibility Study
GDP	Gross Domestic Product
GENCOs	Generation Companies
GIS	Gas Insulated Switchgear
GHG	Green House Gas
GSO	Governmental Statistics Office
HDIP	Hydrocarbon Development Institute of Pakistan
HHV	High Heat Value
HPP	Hydropower Plant
HQ	Headquarter
IEA	International Energy Agency
IPP	Independent Power Producer
ISGS	Inter State Gas Systems Limited
Ic/R	Inception Report
It/R	Interim Report
JICA	Japan International Cooperation Agency
KE	K-Electric Limited
KPK	Khyber Pakhtunkhwa Province
LCP	Least Cost generation and transmission expansion Plan
LDC	Load Dispatch Center
LHV	Low Heat Value
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
LOLE	Loss of Load Expectation

Abbreviation	Word
LRMC	Long Run Marginal Cost
MENR	Ministry of Energy and Natural Resources
MOE	Ministry of Environment
MPNR	Ministry of Petroleum and Natural Resources
MPDR	Ministry of Planning, Development and Reform
MWP	Ministry of Water and Power
NEPRA	National Electric Power Regulatory Authority
NESPAK	National Engineering Services Pakistan
NPCC	National Power Control Center
NTDC	National Transmission and Despatch Company
OGRA	Oil and Gas Regulatory Authority
OJT	On the Job Training
OLTC	On-Load Tap Changer
O&M	Operation and Maintenance
PAEC	Pakistan Atomic Energy Commission
PC	Planning Commission
PDP	Power Development Plan
PDPAT	Power Development Planning Assist Tool (Software name)
PEPA	Pakistan Environment Protection Act / Agency
PEPCO	Pakistan Electric Power Company
PSS	Power System Stabilizer
PSS/E	Power System Simulator for Engineering (Software name)
PPIB	Private Power Infrastructure Board
PPS	Power Producer and Supplier
RFO	Residual Fuel Oil
SEA	Strategic Environmental Assessment
SHM	Stakeholder Meeting
SNGPL	Sui Northern Gas Pipelines Limited
SPP	Small Power Producer
SS	Switching Station
S/S	Substation
SSGCL	Sui Southern Gas Company Limited
S/Y	Switchyard
TAPI	Turkmenistan-Afghanistan-Pakistan-India
TCEB	Thar Coal & Energy Board
T/D	Transmission and Distribution
TDS	Tariff Differential System
T/L	Transmission Line
TOR	Terms of Reference
TOU	Time of Use
TPP	Thermal Power Plant
UNEP	United Nations Environment Programme
US$	United State Dollar
USAID	United States Agency for International Development
WAPDA	Water and Power Development Authority
WASP	Wien Automatic System Planning (Software name)
WB	World Bank
W/S	Workshop
WTI	West Texas Intermediate

Chapter 1 Introduction

1.1 Background of the Study

The Government of Pakistan started energy sector reform, as one of the priority issues in the Extended Funded Facility arrangement approved by IMF in September 2013. To promote the reform process, Energy Sector Reform Program is formulated in collaboration with JICA, World Bank and Asian Development Bank. The overall objective of the program is to support the implementation and goals of National Power Policy 2013 approved by the Government of Pakistan to develop an efficient and consumer oriented electric power system that meets the needs of its people and economy sustainably and affordably.

This program includes a broad range of issues such as tariff and subsidies management, improvement of sector performance and opening the market to private sector, and improving accountability and transparency of the energy sector. One of the key components among these reforms is an introduction of long-term least cost generation and transmission expansion plan (hereinafter referred to as "LCP"), which is to be drafted by National Transmission and Dispatch Company Limited (hereinafter referred to as "NTDC") . LCP is required to be approved by National Electric Power Regulatory Authority by December 2015 and its' periodic update as one of the indicative triggers to be achieved in the matrix of the Energy Sector Reform Program. NTDC formulated "National Power System Expansion Plan" in 2011 and is planning to update it into LCP for approval.

For this purpose, NTDC requested JICA to support NTDC in terms of technical expertise on formulating LCP especially for optimization method of power generation development plan and power system development plan. From this background, JICA decided to start this project which aims to support formulating draft LCP and capacity development of NTDC in order to acquire expertise on formulating LCP and update it in every three years.

1.2 Purpose and TOR

1.2.1 Purpose of the Project

Under the above background, the Project aims at building capacity of National Transmission and Dispatch Company Limited (NTDC) to enable periodic revision of LCP.

Meanwhile, according to the policy matrix of "Power Sector Reform Program", the long-term least cost generation and transmission expansion plan (LCP) which is to be drafted by NTDC is required to be approved by National Electric Power Regulatory Agency by December 2015 and its' periodic update in every three years by NTDC is also required.

Accordingly, achievement of the Project is expected to contribute significantly to the steady implementation of the power sector reforms. In order to reduce the electric power generation cost, the Project supports to formulate LCP draft targeting next twenty years and transfers the technology to NTDC on formulating and updating LCP.

1.2.2 Area in Which to Conduct the Project

The whole country (Including Lahore and Karachi), Pakistan

1.2.3 Conducting Organizations of the Partner Country

<u>Counterpart of the Project:</u>

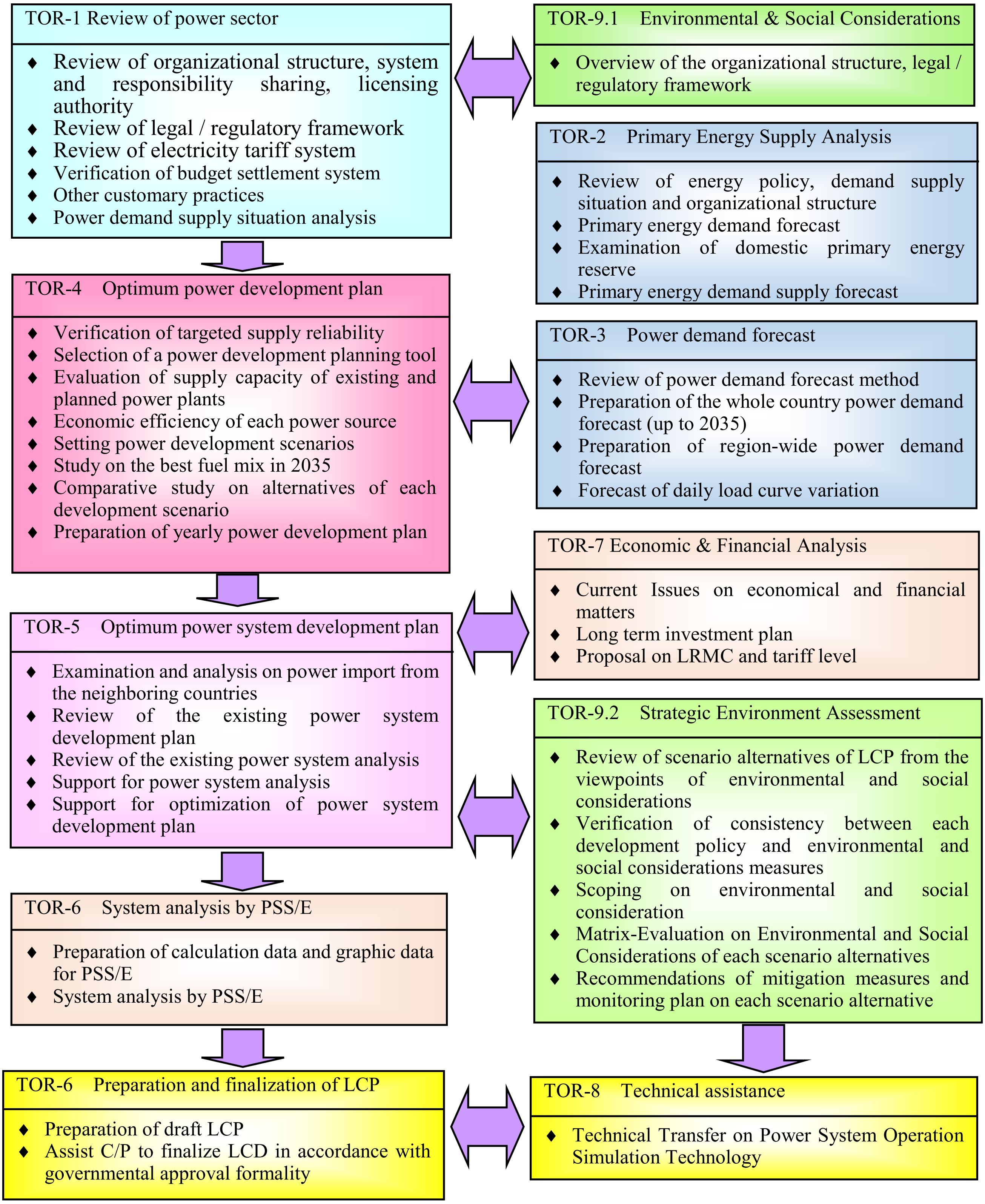
- NTDC: National Transmission and Despatch Company
- GENCOs: Generation Companies
- WAPDA: Water and Power Development Authority

The organizations related to the Project.

- MWP: Ministry of Water and Power
- MPNR: Ministry of Petroleum and Natural Resources
- NEPRA: National Electric Power Regulatory Authority
- GENCO Holding Company

1.2.4 TOR of the Project

Figure 1-1 shows the basic flow of work practices and Table 1-1 shows the yearly progress of the entire investigation work.



TOR-1 Review of power sector

- Review of organizational structure, system and responsibility sharing, licensing authority
- Review of legal / regulatory framework
- Review of electricity tariff system
- Verification of budget settlement system
- Other customary practices
- Power demand supply situation analysis

TOR-4 Optimum power development plan

- Verification of targeted supply reliability
- Selection of a power development planning tool
- Evaluation of supply capacity of existing and planned power plants
- Economic efficiency of each power source
- Setting power development scenarios
- Study on the best fuel mix in 2035
- Comparative study on alternatives of each development scenario
- Preparation of yearly power development plan

TOR-5 Optimum power system development plan

- Examination and analysis on power import from the neighboring countries
- Review of the existing power system development plan
- Review of the existing power system analysis
- Support for power system analysis
- Support for optimization of power system development plan

TOR-6 System analysis by PSS/E

- Preparation of calculation data and graphic data for PSS/E
- System analysis by PSS/E

TOR-6 Preparation and finalization of LCP

- Preparation of draft LCP
- Assist C/P to finalize LCD in accordance with governmental approval formality

TOR-9.1 Environmental & Social Considerations

- Overview of the organizational structure, legal / regulatory framework

TOR-2 Primary Energy Supply Analysis

- Review of energy policy, demand supply situation and organizational structure
- Primary energy demand forecast
- Examination of domestic primary energy reserve
- Primary energy demand supply forecast

TOR-3 Power demand forecast

- Review of power demand forecast method
- Preparation of the whole country power demand forecast (up to 2035)
- Preparation of region-wide power demand forecast
- Forecast of daily load curve variation

TOR-7 Economic & Financial Analysis

- Current Issues on economical and financial matters
- Long term investment plan
- Proposal on LRMC and tariff level

TOR-9.2 Strategic Environment Assessment

- Review of scenario alternatives of LCP from the viewpoints of environmental and social considerations
- Verification of consistency between each development policy and environmental and social considerations measures
- Scoping on environmental and social consideration
- Matrix-Evaluation on Environmental and Social Considerations of each scenario alternatives
- Recommendations of mitigation measures and monitoring plan on each scenario alternative

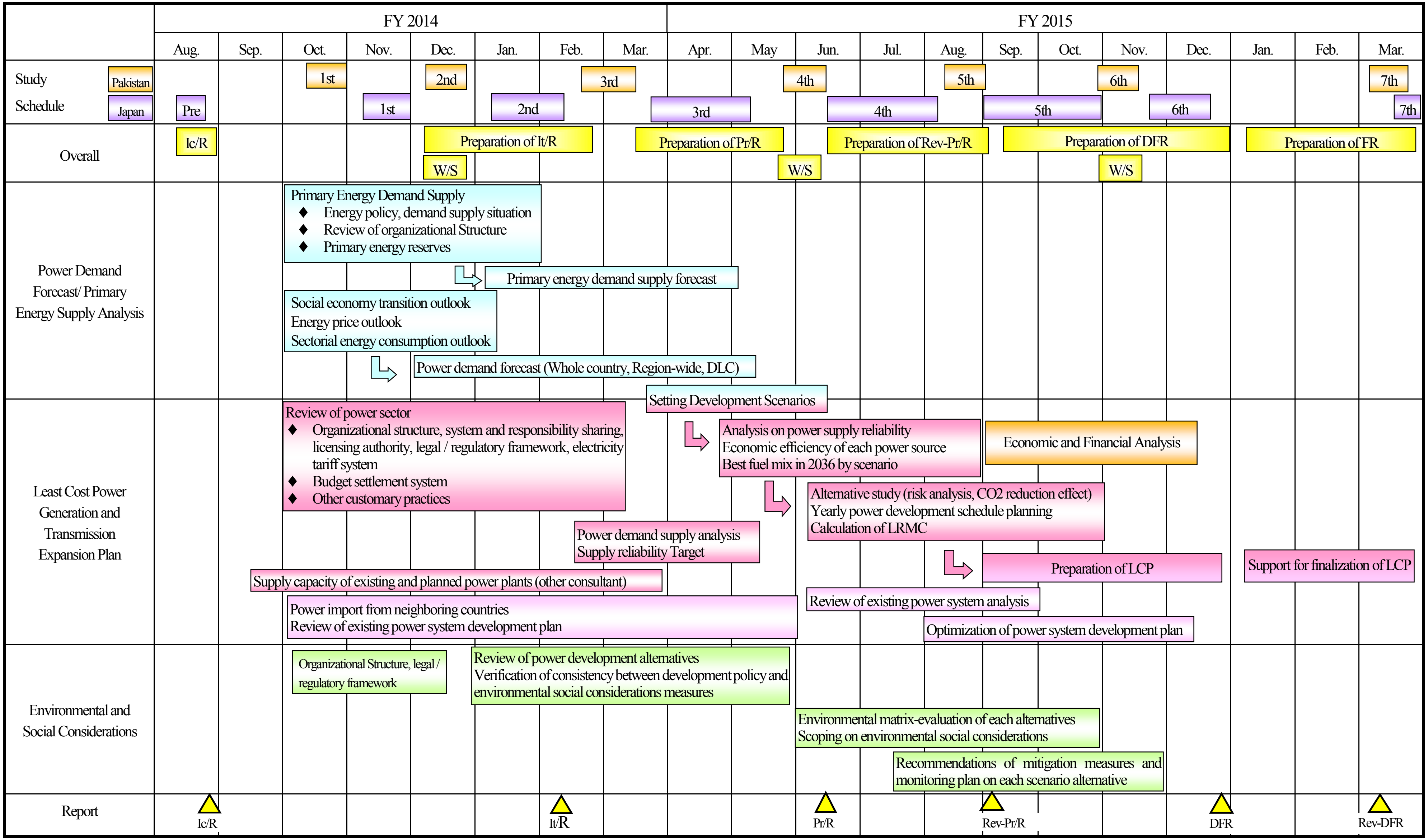
TOR-8 Technical assistance

- Technical Transfer on Power System Operation Simulation Technology

(Source: JICA Project Team)

Figure 1-1 Basic Work Flow (TOR correlation chart)

Table 1-1 Basic Work Flow Schedule



	FY 2014: Aug., Sep., Oct., Nov., Dec., Jan., Feb., Mar. FY 2015: Apr., May, Jun., Jul., Aug., Sep., Oct., Nov., Dec., Jan., Feb., Mar.
Study Schedule – Pakistan	1st 2nd 3rd 4th 5th 6th 7th
Study Schedule – Japan	Pre 1st 2nd 3rd 4th 5th 6th 7th
Overall	Ic/R Preparation of It/R W/S Preparation of Pr/R W/S Preparation of Rev-Pr/R Preparation of DFR W/S Preparation of FR
Power Demand Forecast/ Primary Energy Supply Analysis	Primary Energy Demand Supply ◆ Energy policy, demand supply situation ◆ Review of organizational Structure ◆ Primary energy reserves Primary energy demand supply forecast Social economy transition outlook Energy price outlook Sectorial energy consumption outlook Power demand forecast (Whole country, Region-wide, DLC) Setting Development Scenarios
Least Cost Power Generation and Transmission Expansion Plan	Review of power sector ◆ Organizational structure, system and responsibility sharing, licensing authority, legal / regulatory framework, electricity tariff system ◆ Budget settlement system ◆ Other customary practices Analysis on power supply reliability Economic efficiency of each power source Best fuel mix in 2036 by scenario Economic and Financial Analysis Alternative study (risk analysis, CO2 reduction effect) Yearly power development schedule planning Calculation of LRMC Power demand supply analysis Supply reliability Target Preparation of LCP Support for finalization of LCP Supply capacity of existing and planned power plants (other consultant) Power import from neighboring countries Review of existing power system development plan Review of existing power system analysis Optimization of power system development plan
Environmental and Social Considerations	Organizational Structure, legal / regulatory framework Review of power development alternatives Verification of consistency between development policy and environmental social considerations measures Environmental matrix-evaluation of each alternatives Scoping on environmental social considerations Recommendations of mitigation measures and monitoring plan on each scenario alternative
Report	Ic/R It/R Pr/R Rev-Pr/R DFR Rev-DFR

Legend Ic/R: Inception Report, It/R: Interim Report, DFR: Draft Final Report, FR: Final Report, W/S: Workshop

1.3 Basic Policy of the Project

1.3.1 Basic Policy

The basic policy of the Project is as follows.

(1) Support for developing LCP considering energy and power situation thoroughly, fitting local natural social environment, and excelling economically
(2) Primary energy demand supply analysis and power demand forecast
(3) Support for preparing optimum power generation development plan
(4) Support for preparing optimum power system expansion plan
(5) Mitigation of the environmental negative impact through alternative comparison study by Strategic Environmental Assessment (hereinafter referred to as "SEA") from the viewpoints of low carbon, climate change, greenhouse gas emissions, etc.
(6) Technical transfer on LCP technology through the Study

1.3.2 Outline Flow of the Survey

Figure 1-2 shows outline flow of the Study. The Study Team is divided into three groups of "Power Demand Forecast / Primary Energy Supply Analysis", "LCP Development Group", and "Environmental & Social Consideration Group" and conduct works individually. Outcomes of each group is not intended to be evaluated alone, of course, the reports are finalized by sharing and binding organically the outcomes of each group. In addition, outcomes of other consultants employed separately are also utilized efficiently and effectively by sharing information and cooperating closely each other.

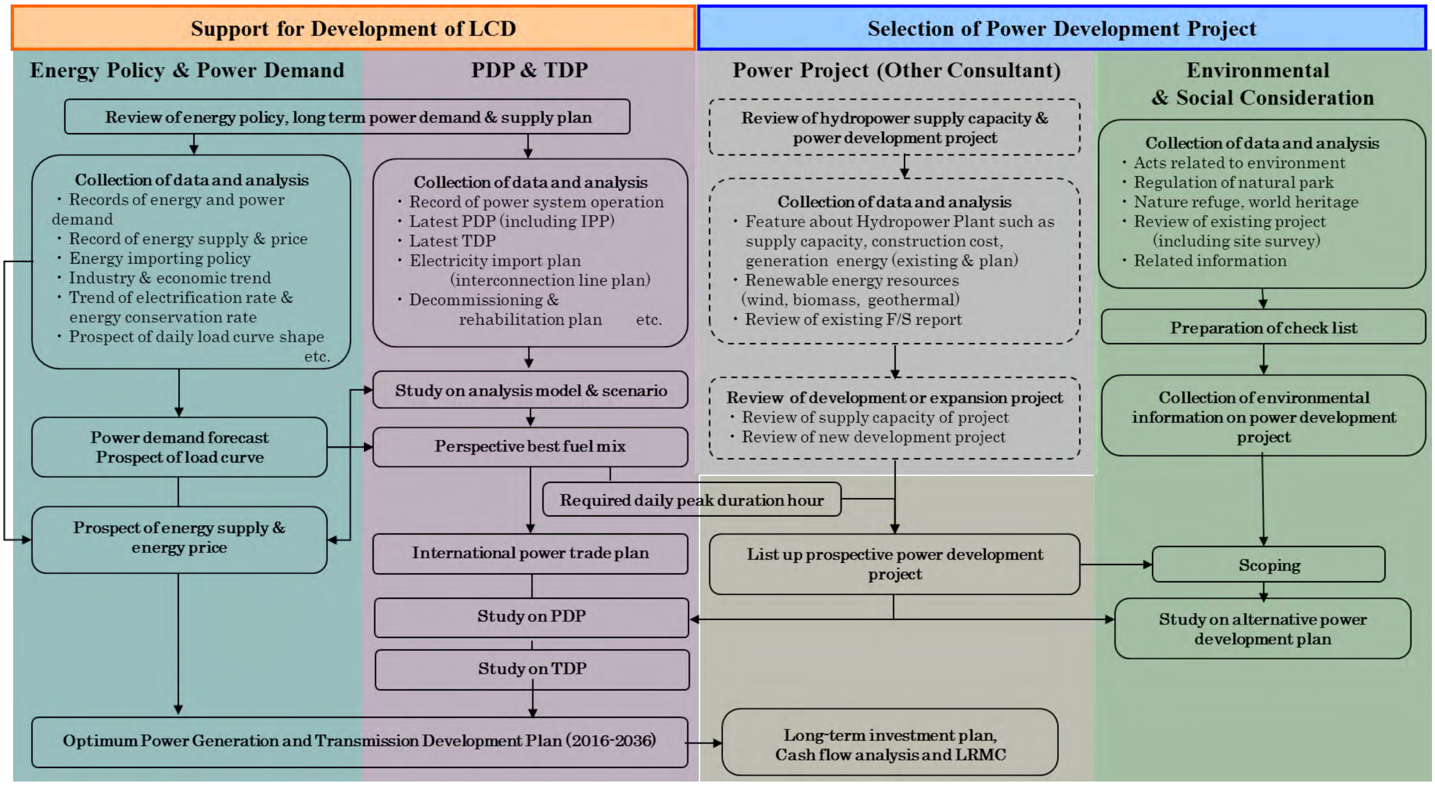
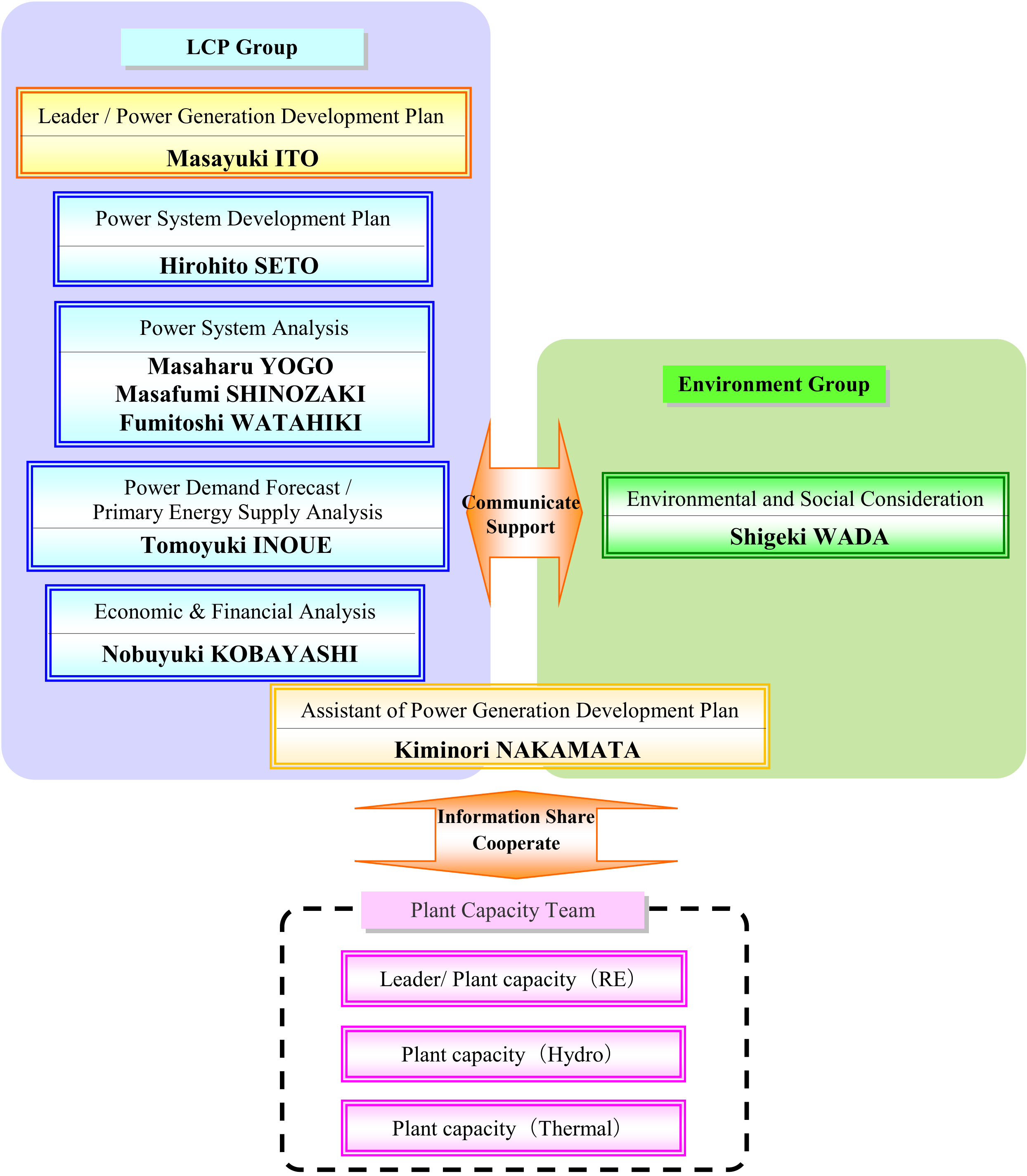


Figure 1-2 Outline Flow of the Study (Study Concept)

1.4 Project Organization Structure and Performance

1.4.1 JICA Project Team Composition

This Survey will be executed with the following members and system as shown in Figure 1-3.



(Source: JICA Project Team)

Figure 1-3 Study Team Composition

1.4.2 Conducted Studies in Pakistan

The JICA Project Team had conducted studies in Pakistan two times as of 31 Jan., 2015. During its stay in Pakistan, the JICA Project Team studied the following technical subjects through cordial discussions with Pakistani counterparts and relevant authorities / organizations.

First Mission	Major Research and Discussions in the First Mission
October 18, 2014 to November 1, 2014	➢ The Project Team submitted the inception report to Pakistani counterparts and explained the project overview. ➢ The Project Team visited and requested NTDC counterparts and the relevant Governmental Authorities / Organizations to provide information and data related to the project through the questionnaire. ➢ The NTDC counterparts and the Study team organized the structure for the Project ➢ The Project Team concluded the contract with a local consultant of NEC to facilitate collection of required information and data for the LCP.

Second Mission	Major Research and Discussions in Second Mission
December 11, 2014 to December 25, 2014	➢ 1st Workshop was held at the Islamabad Club in Islamabad on 17th Dec. 2014 organized by NTDC. Number of participants was 58 excluding JICA Project Team from the Pakistani authorities and organizations relevant to the LCP and the donor organizations such as JICA, WB, ADB and USAID. The JICA project team made presentations. ➢ The Project Team visited the relevant governmental authorities / organizations which were not able to be visited in the 1st mission and collected information and data.

Third Mission	Major Research and Discussions in Third Mission
March 7 2015 to March 26 2015	➢ The Project Team submitted and explained the Interim Report. ➢ Growth rates of GDP in the Base and High cases were set. ➢ The DISCO-wise hourly power demand data in 2014 were obtained. ➢ Features of Hydropower development projects were collected. ➢ Socio-environmental information such as natural environment protected area and social impacts of hydropower projects was collected. ➢ The Project Team visited Mangla HPP and Thar coal Block II sites.

Fourth Mission	Major Research and Discussions in Fourth Mission
May 30 2015 to June 13 2015	➢ The Project Team submitted and explained the Progress Report. ➢ 2nd Workshop was held at the Faletti's Hotel in Lahore on 9th June. 2015 organized by NTDC. Number of participants was 84 excluding JICA Project Team from the Pakistani authorities and organizations relevant to the LCP and the donor organizations such as JICA, WB and USAID. The JICA project team made presentations. ➢ The development scenarios were set. ➢ The necessary data in 2011-12 for PSS/E were provided by NTDC. ➢ The Project Team transferred the usage of the power development planning assist tool (PDPAT II) software to the counterparts through a seminar.

Fifth Mission	Major Research and Discussions in Fifth Mission
August 15 2015 to August 29 2015	➢ The Project Team submitted and explained the Revised Progress Report. ➢ The Project Team visited and requested the relevant Governmental Authorities / Organizations to provide information and data related to the economic and financial analysis. ➢ Power and energy demand forecast tool (Simple.E) were transferred to the C/P through a seminar. ➢ The Project Team transferred the technology and methodology of the power development planning assist tool (PDPAT II) software to the counterparts through a seminar.

Sixth Mission	Major Research and Discussions in Sixth Mission
October 31 2015 to November 14 2015	➢ The Project Team submitted and explained the draft of Draft of Draft Final Report to NTDC, MWP, PC and Donor agencies. ➢ 2nd Workshop was held at the Hotel Margala in Islamabad on 5th November 2015 organized by NTDC. Number of participants was 51 excluding JICA Project Team from the Pakistani authorities and organizations relevant to the LCP and the donor organizations such as JICA, WB, USAID and KfW. The JICA project team made presentations.

Seventh Mission	Major Research and Discussions in Seventh Mission
March 12 2016 to March 26 2016	➢ The Project Team submitted and explained the Revision of Draft Final Report to NTDC, MWP, NEPRA and Donor agencies. ➢ The Project Team supported NTDC to optimize LCP and receive Governmental Approval.

Chapter 2 Review of Power Sector

2.1 Socio-Economic Situation in Pakistan

2.1.1 Overview of Current Socio-Economic Situation

The official name of Pakistan is "The Islamic Republic of Pakistan", the country was independent from British-ruled India in 1947. And East Pakistan area was spun off from Pakistan as Bangladesh in 1971. Pakistan is bordered by India to the east, Afghanistan to the west, Iran to the southwest and China in the far northeast.

The overview of current Socio-Economic Situation of Pakistan is as the following table.

Table 2-1 Social Economic outlines of Pakistan

Items	Contents
Country area	796,000 km^2（Around 2 times to Japan）
Population	180 million (Growth rate 2.03％/ year) in 2011-2012
Capital	Islamabad
Races	Punjabis, Sindhi, Pakhtun, Baluchi
Languages	Urdu (Native language), English (Official language)
Religion	Islam (State religion)
Foreign exchange rate	Exchange rate =101.6 Rs per US$ (period average in 2013) Purchasing power parity (PPP) rate = 26.77 Rupees per US$
GDP	Nominal GDP = 236.6 billion US$ in 2013. 22.9 trillion Rupees.
Growth rate of GDP	3.5% (5 year average from 2008 to 2013) 3.7% in 2011-2012
GDP per capita	1,299 US$ per capita
Unemployment rate	6.0 % in 2010-2011
Main industries	Agriculture and Textile industries
Foreign trade	Total foreign trade in 2011-2012 1) Export 23.64 billion US$ 2) Import 44.91 billion US$ Main products for trading 1) Export Apparel and Agro products 2) Import Oil products, Crude oil, Machines, Iron & Steel, Foods and palm Main trading partner countries 1) Export USA, UK, Afghanistan, UAE and China 2) Import UAE, Saudi Arabia, Kuwait and China

(Source: Annual report of Pakistan Central Bank, Country database of World bank, HP of Ministry of Foreign Affairs, Japan)

2.1.2 Transition of Population

Pakistan population increased to 184.5 million in 2012-2013 around 5 times of 32.5 million in 1950-1951. As of 2014, the population growth rate shows 2 % / annum and the Government has been implementing population control measures since 1960. The future country population, the growth rates and the population ratio between urban and rural areas estimated by "National Institute of Population Studies in Pakistan" from 2013-14 to 2020-21 are described in the following table. The growth rate of population is estimated to decrease up to 1.7% in 2020-21.

Table 2-2 Transition of Population in Pakistan

	Population			Growth rate			Share	
Fiscal	Urban	Rural	Total	Urban	Rural	Total	Urban	Rural
year	million	million	million	%	%	%	%	%
1999–00	48.0	92.3	140.4				34.2	65.8
2000–01	49.0	94.2	143.2	2.0	2.0	2.0	34.2	65.8
2001–02	50.2	96.5	146.8	2.5	2.5	2.5	34.2	65.8
2002–03	51.2	98.4	149.7	2.0	2.0	2.0	34.2	65.8
2003–04	52.7	101.3	154.0	2.9	2.9	2.9	34.2	65.8
2004–05	53.7	103.1	156.8	1.8	1.8	1.8	34.2	65.8
2005–06	54.7	105.1	159.9	2.0	2.0	2.0	34.2	65.8
2006–07	55.8	107.2	163.0	1.9	1.9	1.9	34.2	65.8
2007–08	57.0	109.5	166.5	2.2	2.2	2.2	34.2	65.8
2008–09	60.7	109.3	170.0	6.5	−0.2	2.1	35.7	64.3
2009–10	63.0	110.5	173.5	3.8	1.1	2.1	36.3	63.7
2010–11	65.4	111.7	177.1	3.8	1.1	2.1	36.9	63.1
2011–12	67.5	113.1	180.7	3.3	1.3	2.0	37.4	62.6
2012–13	69.2	115.1	184.5	2.5	1.7	2.0	37.6	62.4
2013–14	70.9	116.9	187.9	2.5	1.6	1.9	37.8	62.2
2014–15	72.6	118.8	191.5	2.4	1.6	1.9	37.9	62.1
2015–16	74.4	120.7	195.0	2.4	1.6	1.9	38.1	61.9
2016–17	76.1	122.5	198.6	2.3	1.5	1.8	38.3	61.7
2017–18	77.9	124.3	202.2	2.3	1.5	1.8	38.5	61.5
2018–19	79.6	126.1	205.7	2.3	1.4	1.8	38.7	61.3
2019–20	81.4	127.9	209.3	2.2	1.4	1.7	38.9	61.1
2020–21	83.2	129.6	212.8	2.2	1.4	1.7	39.1	60.9

(Source : World bank database and The Survey of National Institute of Population Studies in 2013)

2.1.3 Transition of Gross Domestic Product

The averaged GDP growth rate during the past 11 years was 4.0% as shown in Table 2-3. The growth rate from 2002-03 to 2004-05 recorded over 7%, however, that was as low as 1.6% - 2.8% from 2007-08 to 2010-11 due to the negative impacts such as the Lehman shock in 2008 and the large flood damage in Aug. 2010.

Table 2-3 Transition of Gross Domestic Product

Fiscal Years	Nominal GDP		Real GDP		Real GDP		PPP GDP	
	Values	Growth	at 2005-06 price	Growth	at 2005-06 price	Growth	at US$ PPP factor	Growth
Units	Billion Rs	%	Billion Rs	%	Billion USD	%	Billion USD	%
2000-01	4,210	10.0	6,185	2.0	88	2.0	494	2.0
2001-02	4,453	5.8	6,384	3.2	90	3.2	510	3.2
2002-03	4,876	9.5	6,694	4.8	95	4.8	534	4.8
2003-04	5,641	15.7	7,187	7.4	102	7.4	574	7.4
2004-05	6,500	15.2	7,738	7.7	110	7.7	618	7.7
2005-06	8,216	26.4	8,216	6.2	116	6.2	656	6.2
2006-07	9,240	12.5	8,613	4.8	122	4.8	688	4.8
2007-08	10,638	15.1	8,760	1.7	124	1.7	699	1.7
2008-09	13,200	24.1	9,008	2.8	127	2.8	719	2.8
2009-10	14,867	12.6	9,153	1.6	130	1.6	731	1.6
2010-11	18,285	23.0	9,408	2.8	133	2.8	751	2.8
2011-12	20,091	9.9	9,785	4.0	138	4.0	781	4.0

(Note) PPP : Purchasing Power Parity (Source : World bank database)

2.2 Organizational Structure

2.2.1 Power Sector

An electricity law (Electricity Act 1910) was enacted in 1910. KE was established in 1913, and Electricity Rule (Execution bylaw of 1910 Act) was established in 1922 and 1937. The Pakistan became independent in 1947. Generation, transmission and distribution companies had existed in each region at the stage from 1947 to 1958.

WAPDA consisting of three Wing (Hydropower (water resource development), electricity and services) was established by the WAPDA Act in 1958. Decentralization and privatization program of WAPDA were started in 1990, aiming at the efficiency by introducing the power supply based on a market mechanism with the competitiveness. The electricity policy was simultaneously published in 1994 for resolving power shortage problem.

PEPCO (Pakistan Electric Power Company) was founded by WAPDA law revision of 1998 for the purpose of introducing private capital through disintegrate of generation, transmission and distribution. WAPDA was disintegrated that the Power Wing of WAPDA was separated into GENCO which owns and operates thermal power plants (GENCO becomes four companies afterwards), WAPDA which has charge of waterpower plants and water resources management, NTDC in charge of the transmission and 8 DISCOs (DISCOs become ten companies afterwards).

The electricity policy in 1994 (Policy Framework and Package of Incentives for Private Sector Power Generation Projects in Pakistan) gave the incentive that is advantageous to investors and called in much investment in the Pakistani power sector. The characteristics of this policy is to have offered an attractive electricity price of 6.5 cents/kWh to investors using "cost plus method" to decide an electricity price. Furthermore, in the policy in 2002, the power purchase price by the government was raised more and guaranteed very high IRR of 17%.

As for the situation of power sector as of 2013, the distribution companies are with deficit operation due to politically decided electricity tariff cutting into cost and low collection rate of electricity bill. A loss was made up by government subsidy before, but now the subsidy is reduced through the economic crisis in 2008. In addition, in the face of the steep rise of the international crude oil price, the payment for the transmission company (NTDC / CPPAGL) by the distribution companies (DISCOs) is delayed and falls into a situation to hold a debt for a transmission company. Furthermore, the transmission company has a debt for the generation companies and the generation companies have a debt for the fueling companies, that is, the serious problem of so-called "circulation debt issue (Circular debt)" occurs.

The present organizational structure of the power sector is shown in Figure 2-1, and Ministry of Water and Power (MWP) has supervised and managed each state own companies for generation, transmission and distribution. In addition, there are Provincial/AJK bureau supervising provincial development of power sources as a subordinate organization of MWP, AEDB supervising renewable energy generation, PPIB supervising independent power producers and PAEC supervising nuclear power generation.

In addition, there is the regulatory authority of NEPRA which issues business licenses and sets electricity tariff and constitutes Grid Code as an independent organization.

(1) Generation Company

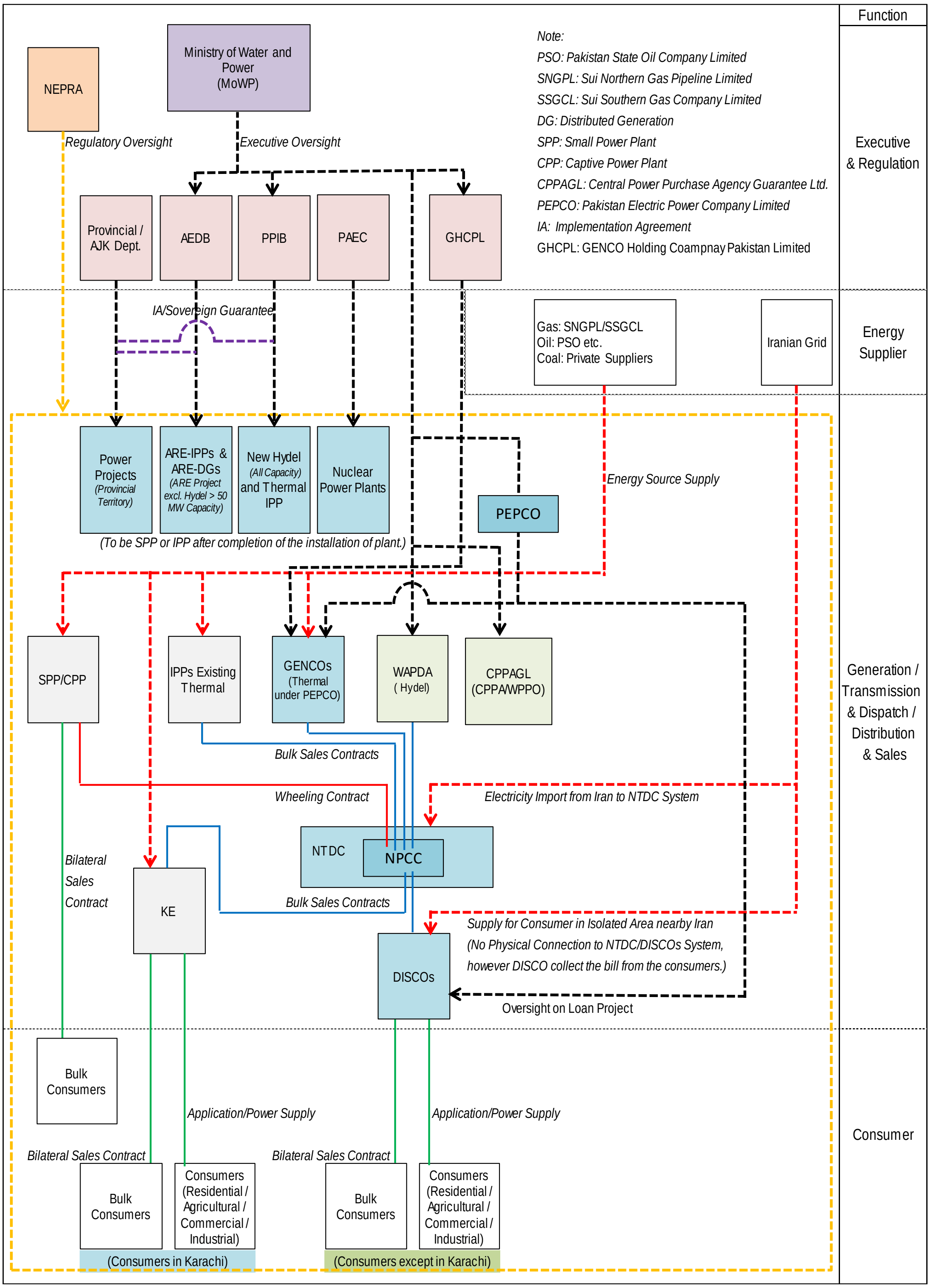
There are WAPDA for hydropower, five GENCOs for thermal power as the state own generation companies, and there are IPP (Independent Power Producer) for both hydropower and thermal power, SPP (Small Power Producer) and CPP (Capital Power Producer) as the private generation companies supervised by PPIB.

(2) Transmission Company

NTDC transmits electricity as the sole transmission company, however, in the Karachi district, KE (K-Electricity Limited) operates all of generation, transmission and distribution.

(3) Distribution Company

The number of DISCOs becomes ten after 2012. DISCOs have local franchise-like character of NTDC, and the counting such as their performance and the short term prospect is conducted by PEPCO. A name and the position of each DISCO is show in Table 2-4 and the geographical position is shown in Figure 2-2.



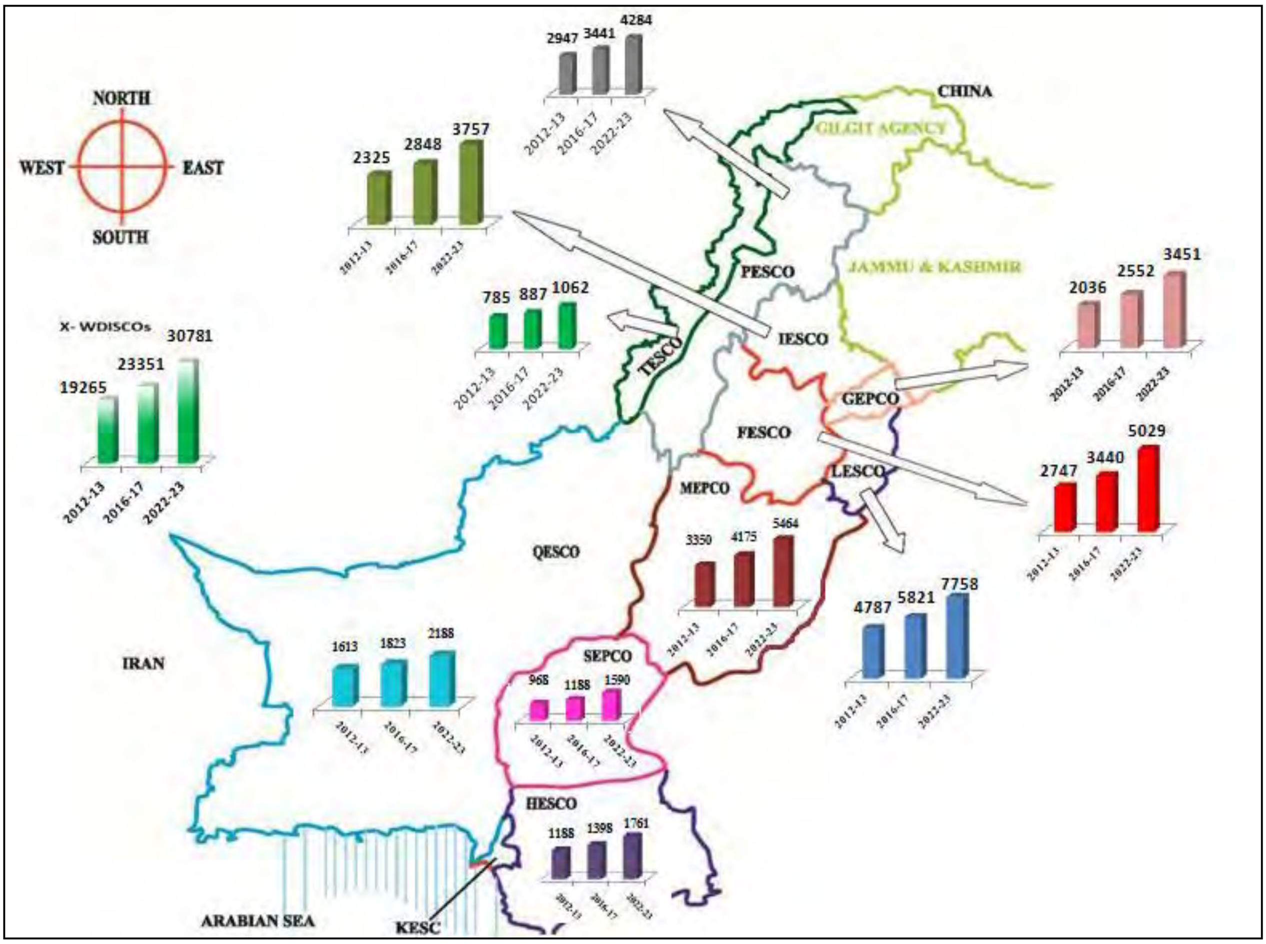
(Source : JICA Project Team)

Figure 2-1 Organizational Structure of Power Sector

Table 2-4 Name and Location of DISCOs

DISCO	Location	Province
IESCO	Islamabad	Islamabad
LESCO	Lahore	Punjab
GEPCO	Gujranwala	
FESCO	Faisalabad	
MEPCO	Multan	
PESCO	Peshawar	KPK
HESCO	Hyderabad	Sindh
SEPCO	Sukkur	
QESCO	Quetta	Baluchistan
TESCO	Tribal	Tribal area

(Source : PEPCO Power Market Survey 2012-2013)



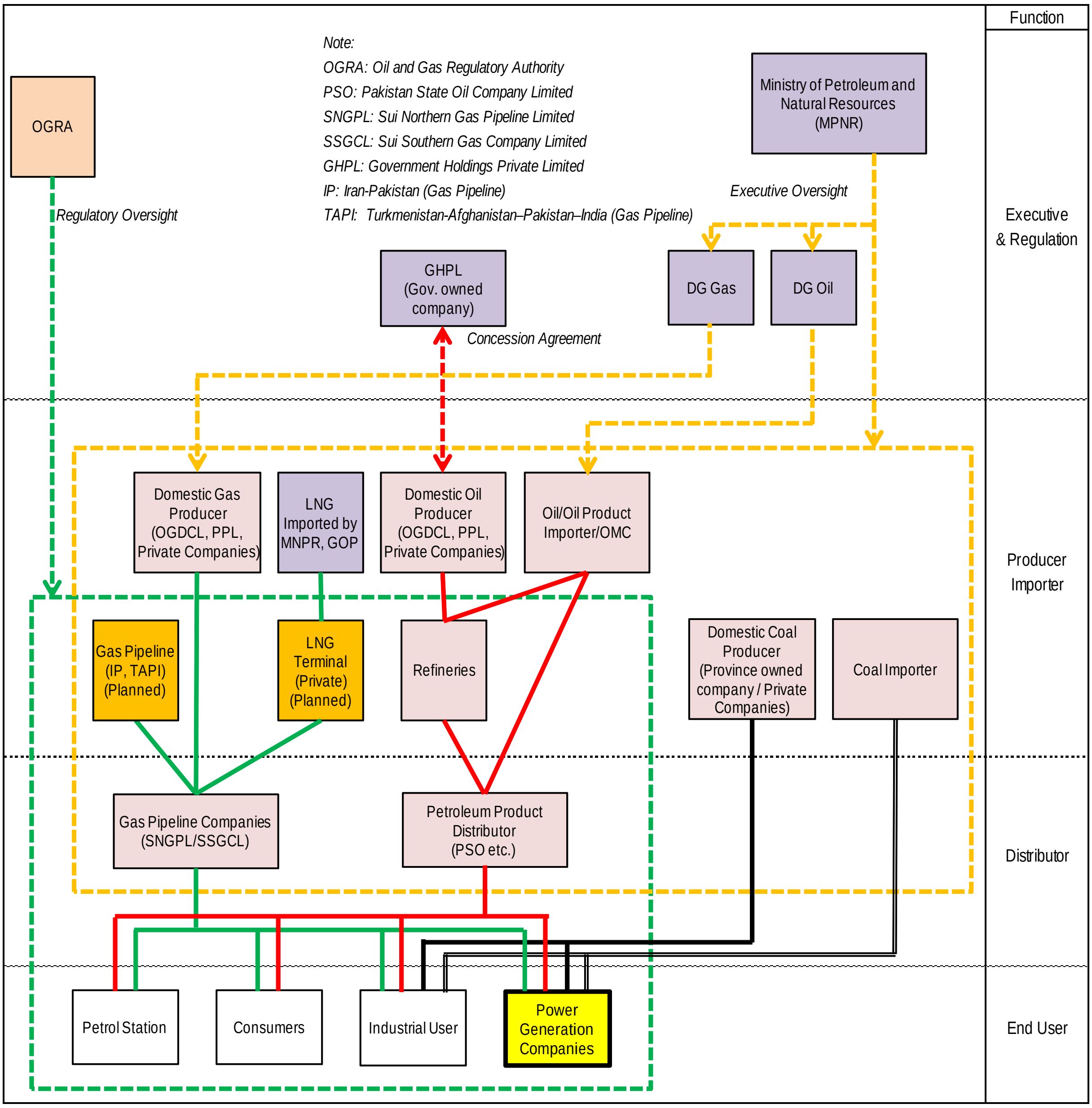
(Source : PEPCO Power Market Survey 2012-2013)

Figure 2-2 Geographical Position of DISCOs

2.2.2 Energy Sector

The organizational structure of the energy sector is shown in Figure 2-3. Ministry of oil natural resources (MPNR) has supervised the primary energy, and DGOil about the oil and DGGas about the gas are organized respectively in the ministry. In addition, MPNR control directly about the LNG import.

In addition, there is the regulatory authority of OGRA which issues business licenses and gives approval of the prices as an independent organization.

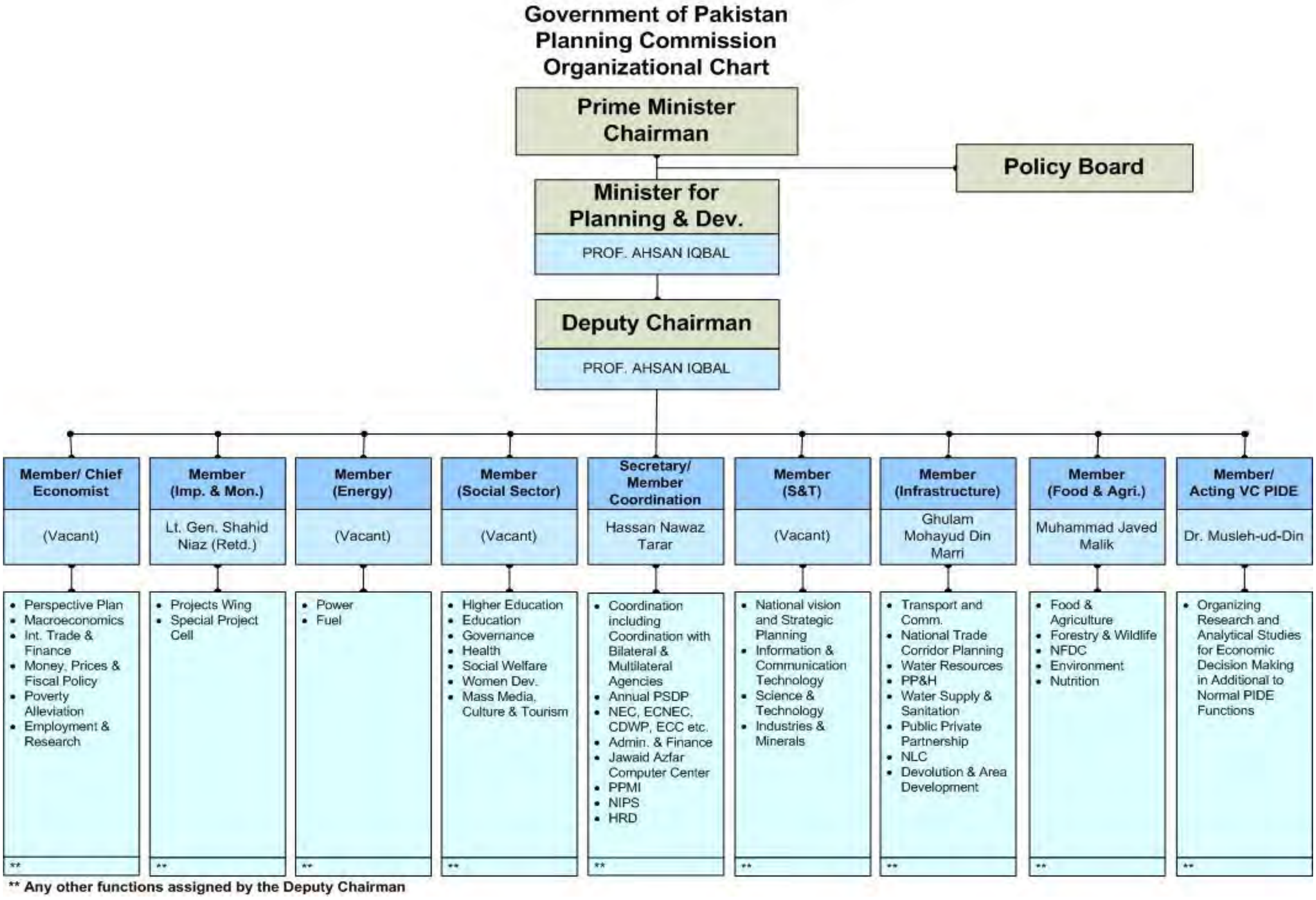


(Source : JICA Project Team)

Figure 2-3 Organizational Structure of Energy Sector

2.2.3 Planning Commission

There is Ministry of Planning, Development & Reform (MPDR) which coordinates with relevant ministries and agencies about the national development plan. In addition, there is the planning commission which chairperson is the prime minister and committee members consists of every sectoral members as an coordination organization of the whole ministries and government offices as shown in Figure 2-4, and Minister of MPDR acts as the secretary general. Particularly, Member Energy has jurisdiction over the Power and Energy sector.



(Source : Planning Commission HP as of Dec. 2014)

Figure 2-4 Organizational Structure of Planning Commission

2.3 Power and Energy Policy

Ministry of Water and Power (MWP) published "National Power Policy 2013" in July 2013. The following Vision is mentioned in the Policy.

"Pakistan will develop the most efficient and consumer centric power generation, transmission, and distribution system that meets the needs of its population and boosts its economy in a sustainable and affordable manner."

The following 5 targets are set in the Policy.

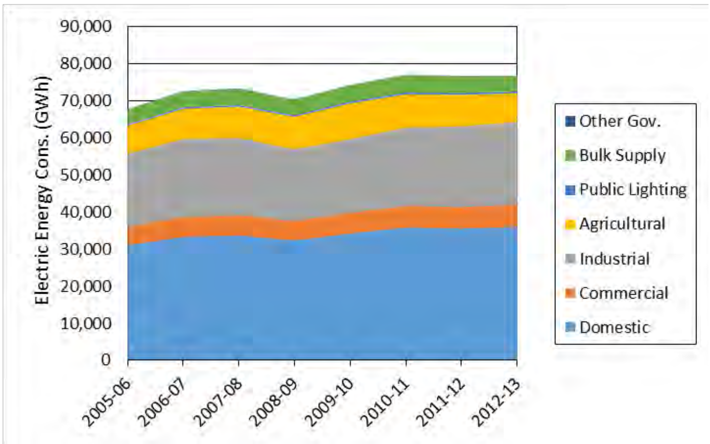
1) Supply - Demand Gap
    Decrease supply demand gap from 4500 -5000 MW today to 0 by 2017
2) Affordability
    Decrease cost of generation from 12 cents/unit today to ~10 cents/unit by 2017
3) Efficiency
    Decrease transmission and distribution losses from 23-25% to ~16% by 2017
4) Financial Viability / Collection
    Increase collection from ~85% to 95% by 2017
5) Governance
    Decrease decision making processing time at the Ministry, related departments and regulators from long to short durations

2.4 Current Situation of Power Demand and Supply

2.4.1 Transition of Electricity Consumption

(1) Electricity consumption by sector

Electricity consumption by sector in Pakistan is shown in Table 2-5 and in Figure 2-5. Domestic, Industrial Commercial and Public lighting have grown but Agricultural and Bulk supply have not grown. Total growth rate during 2005-06 and 2012-13 is 1.8%. This low growth is deemed to be caused by shortage of power supply capacity.



(Source : Power System Statistics 2012-13)

Figure 2-5 Electricity Consumption by Sector

Table 2-5 Electricity Consumption by Sector

(Unit : GWh)

Fiscal Year	Domestic	Commercial	Industrial	Agricultural	Public Lighting	Bulk Supply	Other Gov,	Total
2005-06	31,084	5,001	19,644	7,624	361	3,959	118	67,802
2006-07	33,335	5,363	21,066	8,176	387	4,246	127	72,712
2007-08	33,704	5,572	20,729	8,472	415	4,342	158	73,400
2008-09	32,282	5,252	19,330	8,795	430	4,177	101	70,372
2009-10	34,272	5,605	19,823	9,689	458	4,417	81	74,347
2010-11	35,885	5,782	21,207	8,971	456	4,715	82	77,099
2011-12	35,589	5,754	21,801	8,548	478	4,502	88	76,761
2012-13	36,116	6,007	22,313	7,697	457	4,137	61	76,788
2013/2006	2.2%	2.7%	1.8%	0.1%	3.4%	0.6%	-9.0%	1.8%

(Source : Power System Statistics 2012-13)

(2) Electricity consumption by region

Pakistan is divided into 4 provinces, Punjab, Sindh, KPK (Khyber Pakhtunkhwa province), Balochistan province and AJK (Azad Jammu and Kashmir autonomous state). Karachi belongs to Sindh province. Electricity consumption of KE accounts for 65% of that of Sindh province and accounts for 15% of that of the whole country (NTDC and KE) in 2013.

Table 2-6 Electricity Consumption by Sector

(Unit : GWh)

Years	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	Growth rate (%)
Punjab	42,236	45,294	45,040	43,465	45,906	47,638	46,981	46,467	1.4%
Sindh	13,242	14,201	14,726	14,518	15,293	15,876	16,325	17,193	3.8%
KPK	7,888	8,459	8,223	7,560	8,259	8,712	8,528	8,455	1.0%
Balochistan	3,697	3,965	4,089	4,110	4,099	4,048	4,086	3,812	0.4%
AJK	739	792	1,322	719	790	825	841	862	2.2%
Country total	67,802	72,711	73,400	70,372	74,347	77,099	76,761	76,789	1.8%
Consumption in Karachi	9,233	10,136	10,933	10,100	10,677	10,876	11,077	11,744	3.5%
Consumption in NTDC	58,569	62,575	62,467	60,272	63,670	66,223	65,684	65,045	1.5%

Note: KPK: Khyber Pakhtunkhwa province in northern area (Old name :North-West Frontier Province)
AJK: Azad Jammu and Kashmir autonomous state in northern area of Pakistan

(Source : Power System Statistics 2012, 2013)

(3) Recorded power demand of the whole country

There are 10 DISCOs in the NTDC system, and other than that, there is KE (K-Electric Limited) in charge of the power supply in the Karachi city. NTDC transmits electricity to 10 DISCOs and KE, but KE supplies electricity at the same time from its own power stations. Table 2-7 shows the power demand records (peak power demand (at sending end), sales energy, generated energy (at sending end), annual load factor) of DISCOs. The peak demand (at sending end) includes the latent peak power demand. As well as that, Table 2-8 shows the power demand records of KE and Table 2-9 shows the power demand records of the whole country, respectively.

The annual load factor[1] of DISCOs has been undergone a transition around 65%, on the contrary, the annual load factor of KE has been lowered year by year. This is deemed to be caused by mainly decrease of T/D loss rates of KE from 37% in 2009-10 to 28% in 2013-14.

In addition, the total of the peak power demand of KE and the peak power demand of the whole country are different from DISCOs. This is caused by the time gap when peak power demand occurs in between NTDC power system and KE power system. It is so-called as "Diversity". The diversity factor[2] is assumed as 1.02.

Table 2-7 Power Demand Records of DISCOs

Items	Unit	2009-10	2010-11	2011-12	2012-13	2013-14	G.R.
Peak Demand	MW	17,847	17,901	18,280	18,227	19,966	2.84
Sales Energy	GWh	63,660	66,213	65,638	64,987	71,055	2.79
Generated Energy	GWh	83,829	85,192	84,103	82,847	89,607	1.68
Generated Energy Demand	GWh	98,644	106,421	108,154	109,173	112,288	3.29
T/D kWh Loss	GWh	20,169	18,979	18,465	17,860	18,552	-2.07
T/D Loss Rate	%	24.1	22.3	22.0	21.6	20.7	
Load Factor	%	63.1	67.9	67.5	68.4	64.2	

(Source : Power System Statistics 39th, JICA Project Team revised)

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[1] Load factor = (electric energy consumption + T/D loss) / annual maximum power demand / 8760 hr

[2] Diversity factor (D.F.) = (Peak demand of DISCOs + Peak demand of KE) / The whole country peak demand

Table 2-8 Power Demand Records of KE

	Unit	2009-10	2010-11	2011-12	2012-13	2013-14	G.R.
Peak Demand	MW	2,562	2,565	2,596	2,778	2,929	3.40
Sales Energy	GWh	9,905	10,071	10,277	10,942	11,453	3.70
Generated Energy	GWh	15,806	15,431	15,259	15,823	15,991	0.29
Generated Energy Demand	GWh	15,806	15,431	15,259	15,823	15,991	0.29
T/D kWh Loss	GWh	5,901	5,360	4,982	4,881	4,538	-6.35
T/D Loss Rate	%	37.3	34.7	32.6	30.8	28.4	
Load Factor	%	70.4	68.7	67.1	65.0	62.3	

(Source : Power System Statistics 39th, JICA Project Team revised)

Table 2-9 Power Demand Records of Whole Country

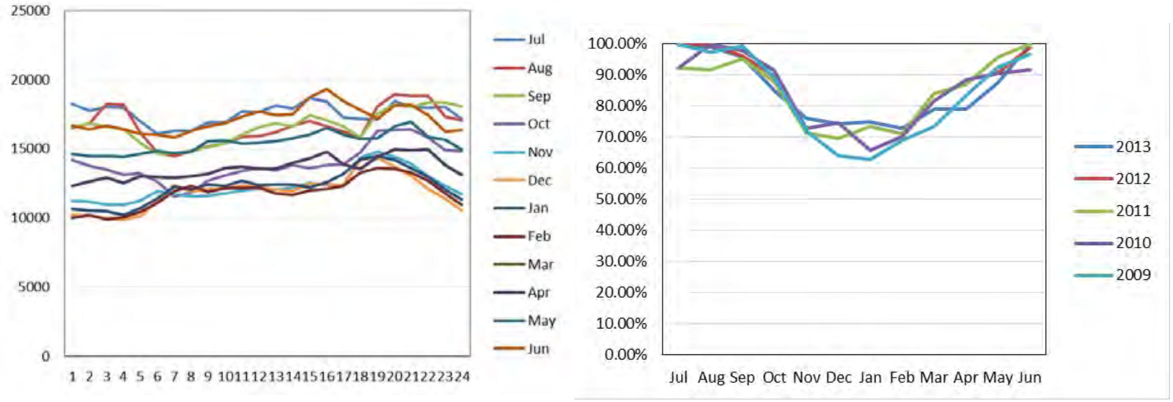
Items	Unit	2009-10	2010-11	2011-12	2012-13	2013-14	G.R.
Peak Demand *	MW	20,009	20,065	20,467	20,544	22,407	2.87
Peak Demand **	MW	20,409	20,466	20,876	20,955	22,855	-
Sales Energy	GWh	73,565	76,284	75,915	75,929	82,508	2.91
Generated Energy	GWh	99,635	100,623	99,362	98,670	105,810	1.51
Generated Energy Demand	GWh	114,450	121,852	123,413	124,996	128,279	2.89
T/D kWh Loss	GWh	26,070	24,339	23,447	22,741	23,302	-2.77
T/D Loss Rate	%	26.2	24.2	23.6	23.0	22.0	
Load Factor	%	65.3	69.3	68.8	69.5	65.4	

Note * : Total of peak power demand of DISCOs and KE
Note ** : Peak power demand of the whole country
Diversity Factor : Diversity factor (time gap between DISCOs peak demand and KE peak demand)
=Total peak power demand / Peak power demand of the whole country=1.02 is assumed

2.4.2 Difference of Daily Load Curve between Seasons

The daily load curve of NTDC system when the peak load occurred in every month in 2012-13 and the monthly peak load from 2009-10 to 2012-13 are shown in Figure 2-6. Meanwhile, the peak load includes the latent peak power demand.

The electricity use pattern is clearly different between the summer and the winter. The late-night power demand in the summer did not fall down and the daily peak load occurred at 17:00 or 20:00 - 22:00, however, the daily load curve in winter is common shape and the power demand falls down in the middle of the night (around 70 % of the peak load) and, the peak load occurs from 18:00 to 19:00. Furthermore, the peak load in the winter is around 70 % of that in the summer.



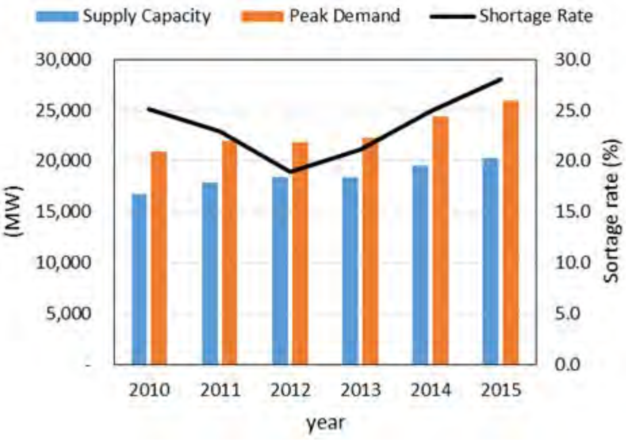
(Source : NTDC, JICA Project Team)

Figure 2-6 Difference of Power Demand between Summer and Winter

2.4.3 Power Demand and Supply Balance

The right figure shows the transition of the peak load and supply capacity. The growth rate of peak load is 4 % / annum during these 5 years, meanwhile, it is hard to say that the supply capacity increased based on the deliberate development plan, the growth rate of supply capacity is 4% / annum, which cannot dissolve the power shortage. The supply capacity is 20GW that is 6GW (28%) less than the peak load of 26GW as of 2014-15.

The following three points are mentioned as the main causes.



(Source : JICA Project Team)

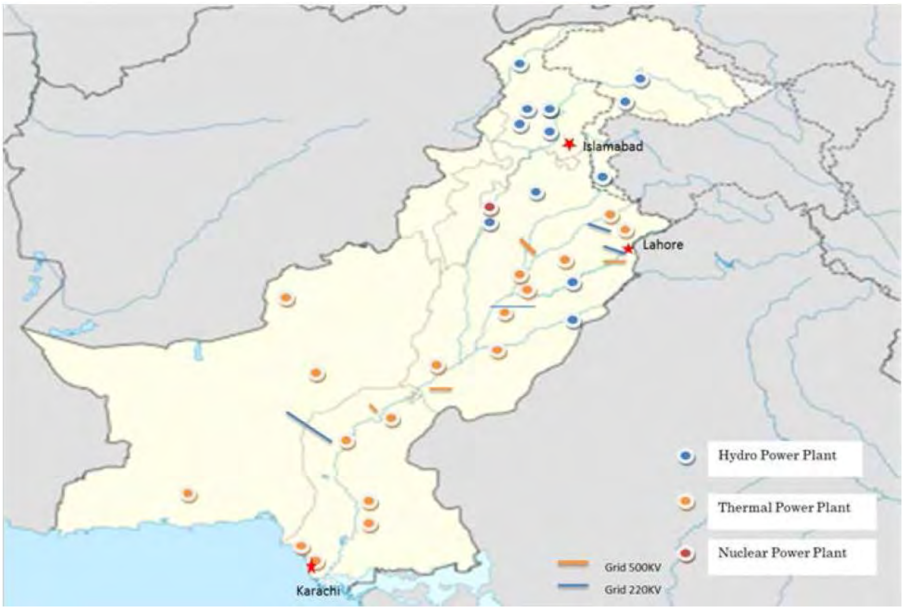
Figure 2-7 Transition of Peak Load and Supply Capability

- Despite the total installed capacity of hydropower plants is 7GW, the total supply capacity in summer that is the wet season is 4.5GW, since main purpose of water control of hydropower plants with large reservoir is not generation but irrigation.
- Although the total installed capacity of thermal power plants is 17.7GW, the supply capacity is only 14.9GW due to aging of equipment.
- The generated energy produced by oil-fired thermal power plant accounts for about one-third of the whole generated energy, however, the procurement of petroleum fuel has become difficult due to the financial difficulties of GENCOs in line with the circular debt and soaring fuel costs.

2.4.4 Existing Generation Facilities

(1) Locations of the existing power plants

The power system in Pakistan can be divided into the northern part and the southern part, and the power sources composition is largely different from each other due to uneven distribution of the primary energy. The locations of the main existing power plants are shown in the below figure, and the hydropower plants concentrates in the northern mountainous area and the thermal power plants are distributed over the middle and southern parts that is a production area of the primary energy of Oil and Gas. Therefore, the electricity is supplied from the northern part to the southern part in the wet season, meanwhile, from the middle and southern parts to the northern part in the dry season.



(Source : JICA study on information gathering and confirmation of the power sector reform)

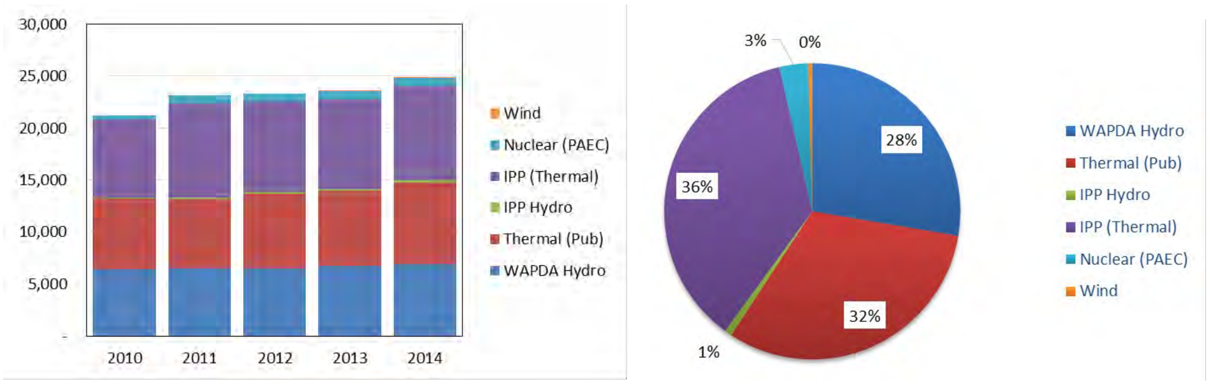
Figure 2-8 Locations of Main Existing Power Plants

(2) Existing power plants

Installed capacity by power source and power sources configuration as of 2013-14 are shown in Table 2-10 and Figure 2-9. In addition, generated energy results by power source are shown in Figure 2-10. The total installed capacity increases 3,700MW in four years from 2009-10 to 2013-14, and the increase of thermal power installed capacity was the largest with 2,700 MW and the hydropower installed capacity increased with 500MW. In addition, the installed capacity ratio and generated energy ratio of public generation are 63% and 52% respectively.

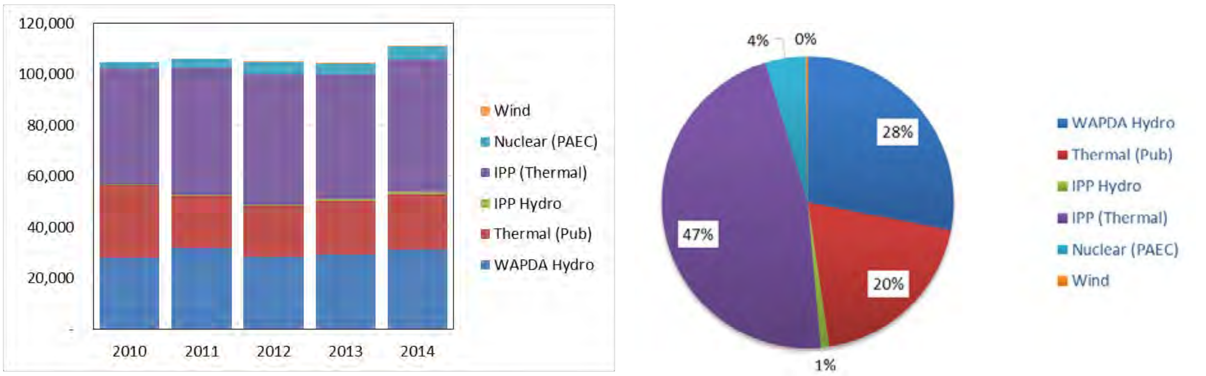
Table 2-10 Installed Capacity and Generated Energy Records by Power Source

Fiscal Year	2010	2011	2012	2013	2014
Installed Capacity (MW)					
WAPDA Hydro	6,444	6,516	6,516	6,733	6,902
Thermal (Pub)	6,784	6,650	7,222	7,182	7,880
IPP Hydro	111	111	111	195	195
IPP (Thermal)	7,456	9,103	8,666	8,670	9,083
Nuclear (PAEC)	462	787	787	787	787
Wind	-	-	-	50	106
Total	21,257	23,167	23,302	23,617	24,953
System Gen. Energy (GWh)					
WAPDA Hydro	27,927	31,685	28,206	29,326	31,204
Thermal (Pub)	28,432	20,633	20,222	21,005	21,750
IPP Hydro	565	305	436	707	1,035
IPP (Thermal)	45,279	49,880	51,237	48,950	51,935
Nuclear (PAEC)	2,523	3,503	4,872	4,100	4,943
Wind	-	-	6	6	272
Total	104,726	106,006	104,979	104,094	111,139



(Source : JICA Project Team)

Figure 2-9 Power Sources Configuration at the end of Jun. 2014



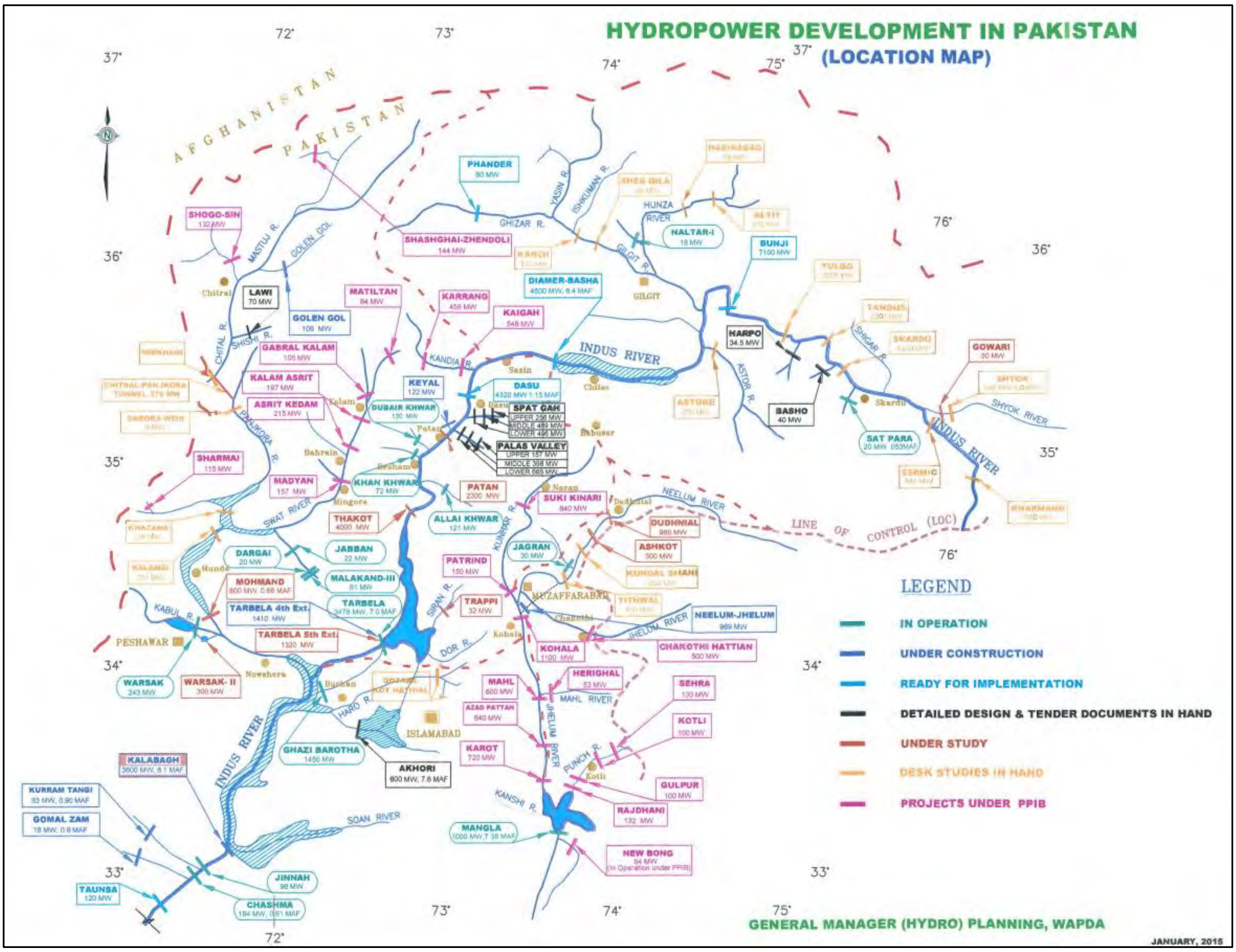
(Source : JICA Project Team)

Figure 2-10 Generated Energy Results by Power Sources until the end of Jun. 2014

(3) Existing power plant profile

(a) Hydropower plant

The Locations of existing and planned hydropower plants as of Jan. 2015 are shown in Figure 2-11. The amount of installed capacity at the end of 2013-14 is 7,097 MW as shown in Table 2-11, and the total available capacity of hydropower plants owned by WAPDA is 6,951 MW in the summer and 3,856 MW in the winter.



(Source : General Manager (Hydro) Planning, WAPDA, Jun. 2015)

Figure 2-11 Location of Hydropower Plant (Existing and Planned) as of Jun. 2015

Table 2-11 List of Existing Hydropower Plant

As of Jun 2014

Source	Power Plant Name	Location	Source and Type	Commissioning Year	No. ×Unit Cap.(MW)	Installed Capacity	Available Capacity	
							Summer	Winter
						(MW)	(MW)	(MW)
WAPDA Hydel (Existing)	Tarbela	Indus River	Daily-base regulating	1977-85 '1992-93	10×175 4× 432	3,478	3,702	1,874
	Warsak	Kabul River, Peshawar	Daily-base regulating	1960-81	4×40 2×41.5	243	200	20
	Mangla	Jehlum River, Mirpur	Daily-base regulating	1967-94	10×100	1,000	1,120	450
	Ghazi Barotha	Indus River, Attack	Power Channel	2003-04	5×290	1,450	1,030	1,160
	Chashma	Indus River, Chashma	Power Channel	2001	8×23	184	157	67
	Khan Khwar	Shangla, K.P.K	Run-of-river	2010	2×34 1×4	72	72	15
	Allai Khwar	Shangla, K.P.K	Run-of-river	2013	2×60.5	121	121	60
	Dubair Khwar	Shangla, K.P.K	Run-of-river	2013	1×130	130	130	65
	Jinnah	Mianwall, K.P.K	Power Channel	2012-14	8×12	96	96	40
	Small Hydro (<25MW)		Run-of-river	-	-	128	81	26
	Sub-total					6,902	6,756	3,792
Hydro IPP	Jagran (AJK)	Jagran、A.J.K	Run-of-river	2000	5×6	30	30	10
	Malakand-III	Malakand, K.P.K	Run-of-river	2008	4×20.25	81	81	20
	Laraib/New Bong Esc.	Laraib, A.J.K	Run-of-river	2013	4×21	84	84	34
	Sub-total					195	195	64

(Source : Power System Statistics 39th)

(b) Thermal power plant

The list of existing thermal power plants owned by GENCOs in the NTDC system is shown in Table 2-12. The amount of installed capacity of GENCOs as of the end of Jun. 2014 is 5,402MW, but the available capacity is 4,312MW which is around 20 % below of the installed capacity due to mainly aging. Meanwhile, the amount of installed capacity of IPPs is 9,444MW, but the available capacity is 8,592MW which is around 10 % below of the installed capacity as shown in Table 2-13.

Besides, Lakhra power plant is the only one coal fired thermal power plant which available capacity is only 30MW. GENCO V was newly established and 1 GT of Nandipur thermal power plant was put into operation in 2014 by GENCO V.

Table 2-12 List of Existing Thermal Power Plant (GENCOs)

As of Jun 2014

	Power Plant Name	Location	Type	Commissioning Year	No. ×Unit Cap.(MW)	Installed Capacity (MW)	Dependable Capacity (MW)	Fuel Type
GENCO-I	Jamshoro	Jamshoro, Sindh	Steam	1989-91	1×250 3×200	850	2×180 2×170	1×FO 3×Gas/FO
	Kotri	Kotri, Sindh	G.T CCGT	1979-81 1994	2×25 1×44	144	4×20 1×40	Gas/HSD
GENCO-II	Guddu	Guddu, Sindh	Steam	1974 1980, 1985	2×110 2×210	640	50, 75 2×150	Gas/FO
			GT	1985-86 1992 2014	4×100 2×136 2×243	1,158	3×75 2×80 1×115 2×243	Gas
			CCGT	1987-88 1994 2014	2×100 1×143 1×261	604	70, 65 95 261	Gas
	Quetta	Quetta, Baluchistan	GT	1984	35	35	25	Gas
GENCO-III	Musaffargarh	Musaffargarh, Punjab	Steam	1993-97	3×210 3×200 1×320	1,350	185,200,160 245, 170 170	Gas/FO
	Faisalabad	Faisalabad, Punjab	Steam	1967	2×66	132	2×50	FO
			GT	1975	8×25	200	4×19 4×23	HSD
			CCGT	1994	1×44	44	1×42	Gas
GENCO-IV	Lakhra	Lakhra, Sindh	Steam	1995-96	3×50	150	30	Coal
GENCO-V	Nandipur	Nandipur, Punjab	GT	2014	1×96	95	95	FO/HSD
Sub-total w/o Isolated Gen.						5,402	4,312	

(Source : Power System Statistics 39th)

Table 2-13 List of Existing Thermal Power Plant (IPP, including NUPP and Bagasse)

As of Jun 2014

	Power Plant Name	Location	Type	Commissioning Year	No. ×Unit Cap.(MW)	Installed Capacity (MW)	Dependable Capacity (MW)	Fuel Type
Thermal IPP	Kot Addu	Kot Addu, Musaffargarh, Punjab	GT	1987-89 1995 1997	2×110 2×96 4×94.4 2×114 1×137	1,214.6	1,342	Gas/FO
			CCGT	1991 1994	2×112 2×100	424		Gas/HSD
	HUBCO	Hub, Baluchistan	Steam	1996-97	4×323	1,292	1,200	RFO
	Kohinoor(KEL)	Raiwind near Lahole, Punjab	Deisel	1997	8×15.68	131.4	124	RFO
			Steam	1997	1×6			RFO
	AES Lalpir	Mahmoodkot, Muzaffargarh, Punjab	Steam	1997	1×362	362	350	RFO
	AES Pak Gen.	Mahmoodkot, Muzaffargarh, Punjab	Steam	1998	1×365	365	349	RFO
	SEPCOL	Ralwind near Lahole, Punjab	Deisel	1999	5×23.4 1×18.9	135.9	110	Gas
	Habibullah Coastal (HCPC)	Quetta, Baluchistan	GT	1999	3×37	111	129	Gas/HSD
			CCGT		1×29	29		
	Rousch	Abdul Hakeem-Khanewal, Punjab	GT	1999	2×152	450	395	Gas/HSD
			CCGT		1×146			
	Saba Power	Farooqabad-Shelkhura, Punjab	Steam	1999	1×134	134	126	RFO
	Fauji Kabirwala	Kabirwala-Khanewal, Punjab	GT	2000	2×48.8	97.6	151	Gas/HSD
			CCGT		1×59.4	59.4		
	Japan Power	Raiwind Lahole, Punjab	Deisel	2000	24×5.625	135	107	RFO
	Uch Power	Dera Murad Jamali, Baluchistan	GT	2000	3×130	390	551	Gas/HSD
			CCGT		1×196	196		
	Altern Energy Ltd.	Fatehjang-Attock, Punjab	G.E	2001	3×10.3	31	27	Gas
	TNB Liberty Power	Dharki, Sindh	GT	2001	1×156	156	212	Gas/HSD
			CCGT		1×79	79		
	Attock Gen Ltd (AGL)	Rawalpindi, Punjab	Deisel	2009	9×17	153.3	156.2	RFO
			Steam		1×12	12		
	Atlas Power	Sheikhupura, Punjab	Reci. Engine	2009	11×18.4	202.7	213.9	RFO
			Steam		1×16.5	16.5		
	Nishat Power	Multan Rd., Lahole, Punjab	Reci. Engine	2010	11×17.1	187.8	195.3	RFO
			Steam		1×14.3	14.3		
	Orient Power	Baloki, Punjab	GT	2010	2×75.8	151.6	212.7	Gas/HSD
			Steam		1×77.5	77.5		
	Engro Energy	Dharki, Sindh	GT	2010	1×116.7	116.7	213.8	Gas/HSD
			Steam		1×116.7	116.7		
	Saif Power	Shahiwal, Punjab	GT	2010	2×75.9	151.8	205.3	Gas/HSD
			Steam		1×76.7	76.7		
	Hubco Narowal	Narowal, Punjab	D. Engine	2011	11×18.4	202.7	213.8	RFO
			Steam		1×16.5	16.5		
	Halmore	Sheikhupura, Punjab	GT	2011	2×75.8	151.6	206.8	Gas/HSD
			Steam		1×77.0	77.0		
	Saphire	Muridkey, Punjab	GT	2010	2×75.8	151.6	212.1	Gas/HSD
			Steam		1×77.0	77.0		
	Nishat Chunian	Multan Rd., Lahole, Punjab	D. Engine	2010	11×17.1	187.8	195.7	RFO
			Steam		1×14.3	14.3		
	Liberty Power Tech.	Faisalabad, Punjab	D. Engine	2011	11×17.1	187.8	196.1	RFO
			Steam		1×14.3	14.3		
	Foundation Power	Dharki, Sindh	GT	2011	1×114.9	114.9	178.2	Gas
			Steam		1×114.9	114.9		
	Uch Power - II	Dera Murad Jamali, Baluchistan	Steam	2014	1×386.2	386.2	375	Gas
	JDW Sugar Mill - II	Rahim Yar Khan, Punjab	Steam	2014	26.4	26.4	23	Baggase
	JDW Sugar Mill - III	Ghotki, Sindh	Steam	2014	26.4	26.4	23	Baggase
	Chashma Unit 1-2	Chashma (PAEC)	Nuclear	2000	325	325	300	NUC
			Nuclear	2011	325	325	300	NUC
Sub-total w/o Isolated Gen.						9,470	8,594	

(Source : Power System Statistics 39th)

The existing thermal power plants and nuclear power plant in the KE power system are listed in Table 2-14. The amount of installed capacity at the end of Jun. 2014 is 2,638MW, but the available capacity is 2,050 MW which is around 20 % below of the installed capacity. This is caused by fuel conversion of Unit #3 and #4 (2 x 210MW) of TPS Bin Quasim-1. When taking into account this, the gap becomes below 10%.

Table 2-14 List of Existing Thermal Power Plant (incl. IPP and NUPP) in KE

As of Jun 2014

	Power Plant Name	Location	Type	Commissioning Year	No. ×Unit Cap.(MW)	Installed Capacity (MW)	Dependable Capacity (MW)	Fuel Type
KE	TPS Bin Qasim II	Sindh	CCGT	2012	3×125 1×185	560	517	GAS/HSDO
	Korangi CCPS	Sindh	CCGT	2008-09	4×48 1×27	220	192	GAS/HSDO
	SGTPS-2	Sindh	Engine	2009	32×2.8	88	88	Gas
	KGTPS-2	Sindh	Engine	2009	32×2.9	88	88	Gas
	TPS Bin Qasim I	Sindh	GT	1983-97	6×210	1260	755	Gas/HFO
Public and IPP	Gul Ahmad Energy	Sindh	Engine	1997	9×14.2	127.5	127.5	HFO
	Tapal Energy	Sindh	Engine	1997	12×10.3	123.5	123.5	HFO
	Otners	Sindh	Engine			34.0	34	Gas/HFO
	KANUPP Unit 1	Krachi, Sindh (PAEC)	Nuclear	1972	137	137.0	100	NUC
Sub-total						2,638	2,025	

(Source : KE)

(c) Wind power plant

Wind power plants have been developed since 2012, the installed capacity of wind power at the end of Dec. 2014 is 156 MW.

Table 2-15 Existing Wind Power Plant List

As of Dec 2014

Source	Power Plant Name	Location	Type	Commissioning Year	No. ×Unit Cap.(MW)	Installed Capacity (MW)	Derated Capacity (MW)	Fuel Type
Wind	Fauji Fertilizer Co. Ener.	Jimpir, Sindh	Wind	2012		49.5	49.5	Wind
	Zorlu Enerji Pakistan	Jimpir, Sindh	Wind	2013	5×1.2 28×1.8	56.4	56.4	Wind
	Three Gorges Wind Firm	Jimpir, Sindh	Wind	2014		50.0	50	Wind
Sub-total w/o Isolated Gen.						155.9	156	

(Source : JICA Project Team (Supply capacity analysis group))

(d) Power trade

Power import has been executed by NTDC a bit from only Iran by the end of Jun. 2014. Besides, not power exchange but power trade has been carried out between NTDC and KE power system.

Table 2-16 Power Trade Results by NTDC

Country / Agency	2009-10	2010-11	2011-12	2012-13	2013-14
Import					
Iran	249	269	296	375	419
KE	20	26	0	0	0
Total Electricity Imported	269	295	328	375	419
Export					
KE	5,208	5,449	5,684	5,463	5,441
Any other Country / Region	0	10	43	0	0
Total Electricity Exported	5,208	5,459	5,727	5,463	5,441

(Source : NEPRA "State of Industry Report 2014")

CASA-1,000 connecting Central Asia and South Asia is the plan that surplus power 1,300MW from the Kyrgyz Republic and Tajikistan is transmitted via Afghanistan, which power consumption of 300MW is expected, hence, 1,000MW is transmitted to Pakistan. Memorandum of understanding among 4 governments was signed in Kabul on November 16, 2007, but any progress has not seen then. Meanwhile, the total investment is estimated as 1.0 billion US$.

(Source : http://tribune.com.pk/story/559377/project-financing-adb-to-pull-out -of-casa-1000MW-import//)

2.4.5 Existing Transmission and Distribution Facilities

The transmission voltage of the Pakistan is 132 / 220 / 500kV, the frequency is 50Hz. NTDC which is a state-own transmission company executes operation and maintenance of transmission and substation facilities of 500kV and 220kV and transmission line outgoing feeder of 132kV. Bulk transmission line of 500kV connects with double circuits between Peshawar substation in the north and Hubco power station in the south at total length of around 1,700km.

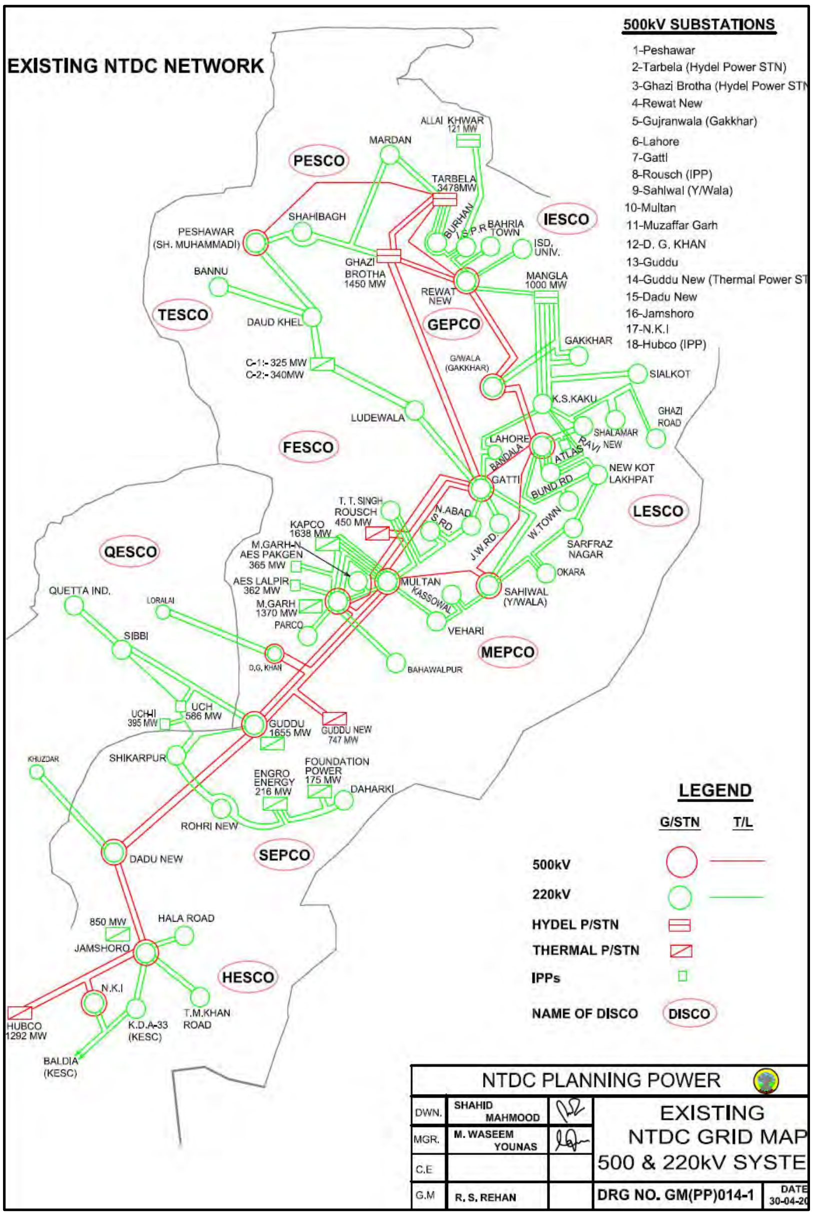
The looped bulk power system exists in northern part system where the capital Islamabad and Lahore are located, but transmission line in some sections is a single circuit. In addition, the loop is not formed in the system of the southern side from the Multan. Meanwhile, in the population crowd areas such as Lahore, the 220 kV power system forms a loop.

Some areas are supplied power with a 132kV transmission line from Iran. Because the area is several hundred kilos away from the bulk transmission line of NTDC, it is managed as an independent power system.

On the other hand, KE power system located in the southern part of Pakistan is connected with NTDC power system by 220 kV transmission lines, and KE had received power interchange of 20 GWh temporarily until 2010, but it has been supplied power from NTDC in after 2011.

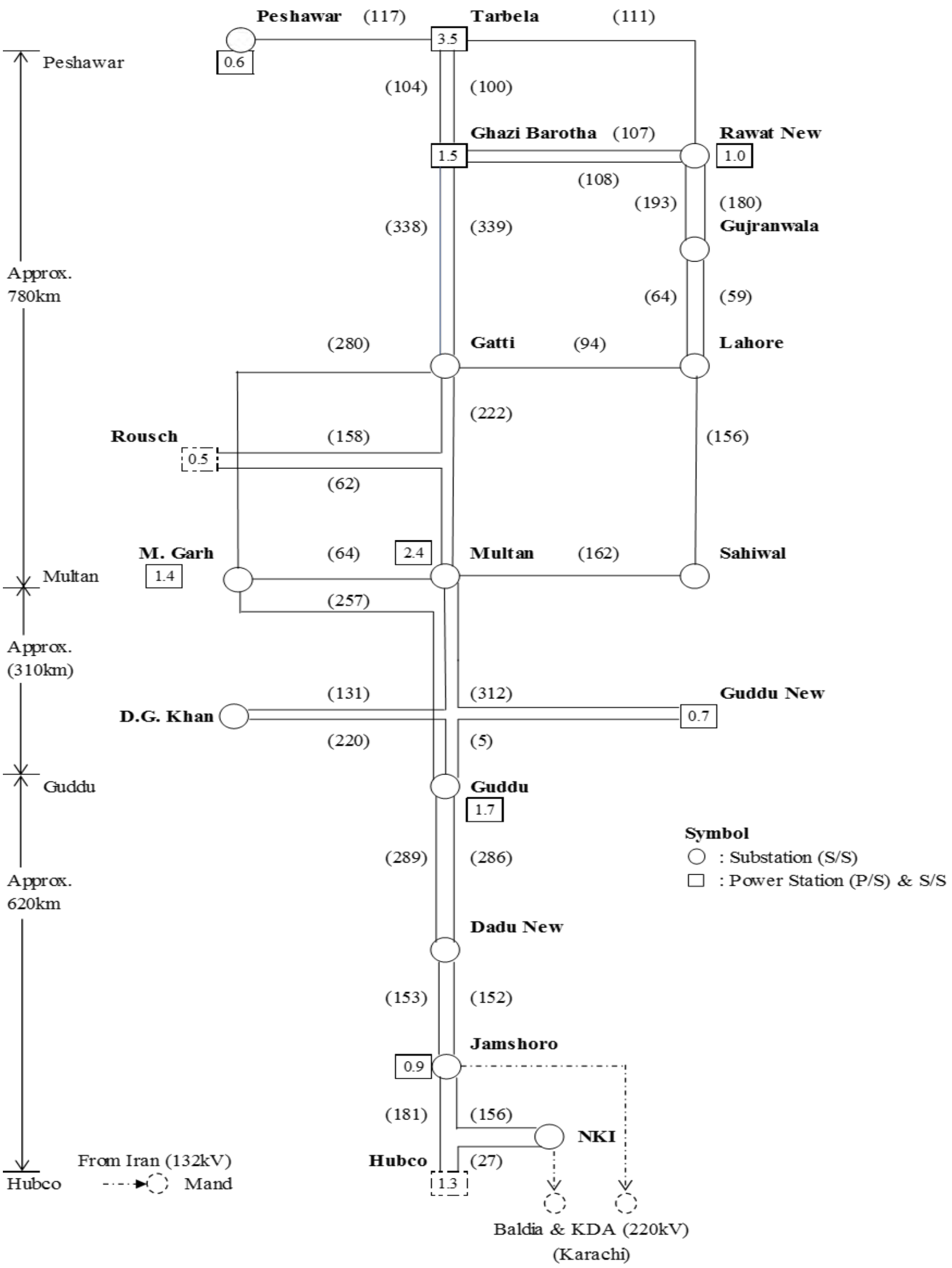
Besides, the National Dispatch Center is located in Islamabad and the Local Dispatch Center of 132kV is located in Jamshoro.

Route of the existing 500 kV and 220 kV transmission lines operated by NTDC as of the end of Apr. 2015 is shown in Figure 2-12, and the outline of 500 kV transmission lines is shown in Figure 2-13.



(Source : NTDC)

Figure 2-12 Existing 220/500kV Transmission Line Route



Remarks:
1 ☐ means Approx. output of P/S in [GW]
2 ⬚ means 500kV S/S operated by IPP.
3 ( ) means Approx. distance of 500kV transmission line in [km].

(As of End of Aug. 2015)

(Source : JICA Project Team)

Figure 2-13 Outline of 500kV Transmission Line

(1) Transmission development plan

NTDC prepared National Power System Expansion Plan 2011-2030 in 2011 to resolve the power shortage and to meet the demand growth, and the expansion program has been proceeded on the basis of that. As a future bulk power system, adoption of DC 600 kV is planned in the expansion plan. In addition, CASA-1000 project that the surplus electric power of hydropower plants in the summer in Tajikistan is transmitted to Pakistan via Afghanistan with DC 500kV (maximum output is 1,000MW) is in progress as an international power trade. However, the power supply by CASA-1000 is limited to do for 5 months from May to October. Besides, according to the press on November 8, 2015, receiving price would be 9.41 UScent/kWh.

Meanwhile, the 1,000MW power import plan is underway, which is transmitted through the year by DC 500kV of 678km between Zahedan in Iran and Quetta in Pakistan (585km long is constructed in Iran and 93km is in Pakistan).

Related to the above, Pakistan targets "the formulation of the cutting edge transmission system" in National Power Policy 2013, and NEPRA (National Electric Power Regulatory Authority) sets a goal to reduce current transmission loss from 3 % to 2.5 % in 2017.

(2) Current status of transmission system

The voltage of the bulk power system is 500kV and it connects approximately 1,700km with double circuits from Peshawar substation in the north to the Hubco power station (IPP) in the south via Multan substation. Nos. of circuits is 32 and the total length is 5,187km as of the end of May 2015. In addition, the transmission lines are looped from the Tarbela power station to Multan substation via Rawat, Lahore and Sahiwal substations, however, the following 4 intervals consist of a single circuit.

1) Tarbela HPS and Rawat new substation
2) Lahore substation and Gatti substation
3) Lahore substation and Sahiwal substation
4) Multan substation and Sahiwal substation

Single-phase reclosing at the time of transmission accidents is not applied to either 220kV or 500kV system.

Double circuits transmission lines are adopted for all the 220kV power systems, and the transmission lines less than 132kV are operated and maintained by each DISCO. The transmission lines of 132kV are partially looped.

NTDC transmits electricity to KE by the double circuits transmission lines of 220kV from Jamshoro TPS and NKI substation respectively. The maximum power transmitted has been 650MW but is planned to reduce up to 350MW near future, since KE has formulated its power system development plan aiming at independence.

There is the independent system that QESCO manages in the west of Karachi. This area is connected with a 132kV transmission line between Mand substations and Iran and the power transmitted is supplied to the neighboring areas. Since this independent system is several 100km away from the national grid of Pakistan, connection to the national grid is not planned currently. Besides, there are some districts in this area, which receive electricity from Iran with 11kV distribution line

On the other hand, the examination of the present transmission loss is carried out by NTDC based on the information from National Power Control Center (NPCC) which is a branch of NTDC.

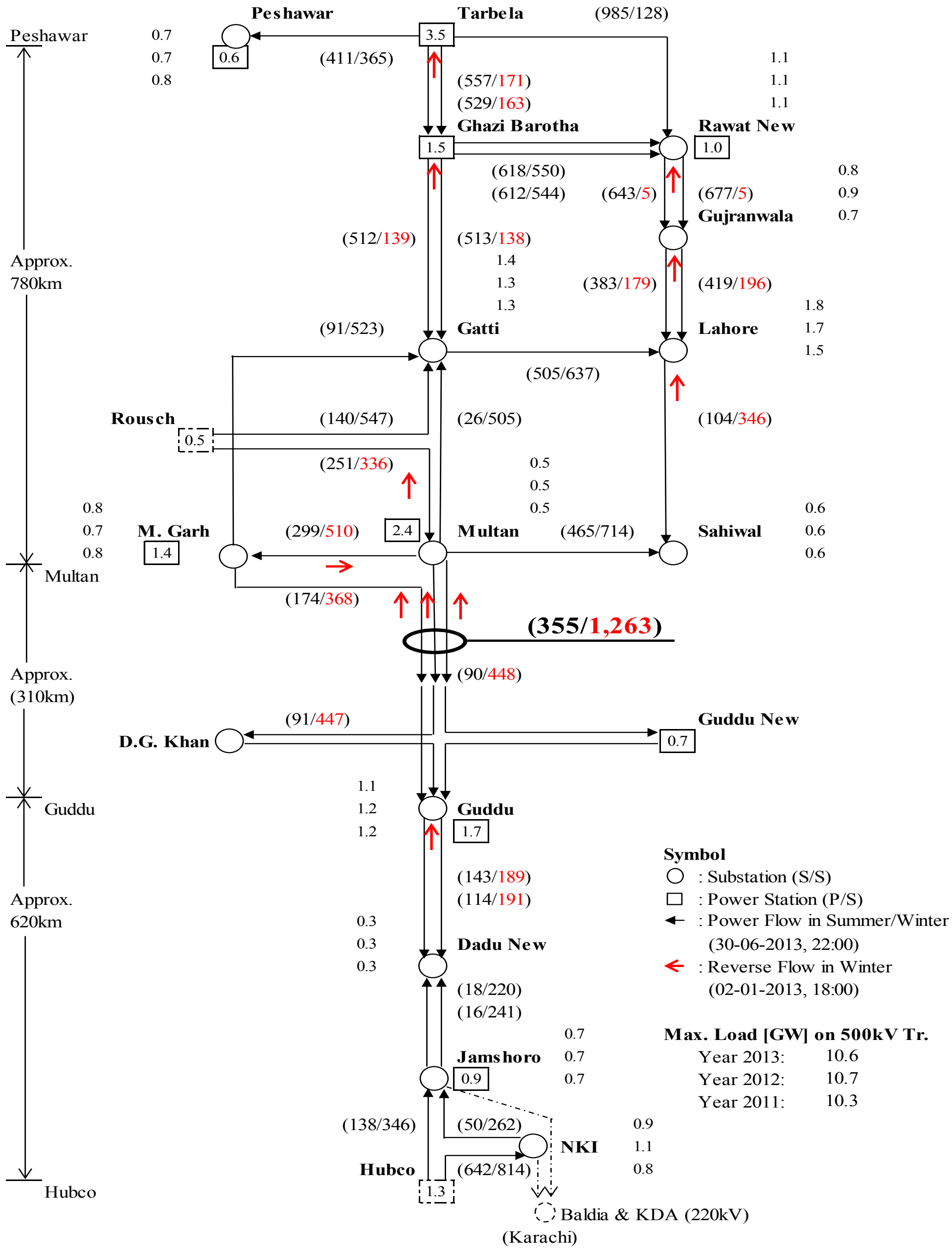
Since there are some intervals which the phase advance reactive power runs short in some 500kV transmission lines in accordance with the system analysis results on peaking time in the summer and winter, there are some substations which bus voltage is less than 500kV.

The power system analysis for the future plan is carried out by using PSS/E, the analysis software, based on the power demand for 220 / 132kV substation that NTDC manages, which is estimated based on the power demand forecast of each DISCO.

Besides, the power flow direction of the 500kV system in the summer becomes reverse in the winter in line with the output drop of the hydropower plants in the winter. The transmission line that the biggest power flow occurred is between Lahore substation and Gujranwala substation and the gap was recorded as 1.6GW in 2013. Meanwhile, the reversal of the power flow direction during Peak time and Off-peak time does not occur in the same season. Based on the above conditions of power sources and load forecast, NPC formulates power system operation plan and directs operation of the power plants and the bulk substations by phone, etc. The operator of bulk substations makes tap of transformer and breaker on and off manually following the directs.

Figure 2-14 shows the sum of maximum power of the bulk transformers (500 / 220kV) in every substation in 2012 - 13, and the power flow of the 500 kV system at the time of the peak load recorded in the summer at 22:00 of Jun. 30, 2013 and in the winter at 18:00 of Jan. 2, 2013. The maximum power has recorded as 1.8GW in Lahore and 1.4GW in Gatti.

Besides, the blackout occurred in the metropolitan area in Jan. 2015 was caused due to defects of protection system of the some aged bulk transformers.



Remarks:

(As of End of Aug. 2015)

1 □ means Approx. output of P/S in [GW]
2 ⬚ means 500kV S/S operated by IPP.
3 ( ) means Max. Load (Summer/Winter) in [MW].
4 Max. Load is calculated besed on reading of actual current on 500/220kV Tr. feeder and assumed voltage as 220kV and power factor as 0.9.

(Source : JICA Project Team)

Figure 2-14 Power Flow of 500kV Transmission Line in Summer and in Winter (2012-13)

(3) Current status of transmission facility

The number of 500kV transmission lines that are the bulk power system was 30 at the end of Jun., 2010 and the total length was approximately 5,147km and expanded 70km longer for four years and became 5,144 km long at the end of Jun., 2014, but there is little construction of new transmission line during the above period. In addition, the 220kV transmission line was 7,367km long at the end of Jun., 2010 and 8,605km at the end of Jun., 2014, that is, approximately 1,300km were expanded.

Two kinds of ACSR and AAAC-469mm^2 are adopted for 500kV transmission line, 32 circuits and 5,190km in total as of May 2015, and the type of 3 or 4 conductors per phase is applied to them. OPGW-24C is adopted for the overhead ground wire. Besides, a part of transmission lines has passed over around 30 years since the commissioning.

The transition of length of 132 / 220 / 500 kV transmission lines for these 5 years is shown in Table 2-17. The outline of the 500 kV transmission line at the end of May 2015 is shown in Table 2-18.

Table 2-17 Transition of Length of 132 / 220 / 500 kV Transmission Line

(As of End of Jun. 2014)

No.	Voltage	2010	2011	2012	2013	2014	AAIR [%]	Remarks
1	500kV	5,078	5,078	5,078	5,144	5,147	0.3	
2	220kV	7,367	7,427	7,948	8,358	8,605	3.3	
3	132kV	23,995	25,359	25,646	26,161	27,108	3.0	

Remarks:

1 The data of 132kV is being provided by DISCOs.

2 AAIR: Annual Average Increasing Rate

(Source : NTDC-Power System Statistics 2013-14, 39th Edition)

Table 2-18 Outline of 500kV Transmission Line

(As of End of Aug. 2015)

No.	From	To	Length [km]	Specification of Conductor & No.				Line Capacity [MVA]	Commissioning Year	Remarks
				Type	Size (mm^2)	No. of Conductor	Current [A]			
1	Peshawar	Tarbela P/S (*1)	117	ACSR	469	4	800	2,700	Dec. 1985	(*1) 3,478MW
2	No.1, Tarbela P/S	Barotha P/S	100	AAAC	469	3	806	2,000	Apr. 2003	
3	No.2, Tarbela P/S	Barotha P/S	104	AAAC	469	3	806	2,000	May 2003	
4	Tarbela P/S	Rawat	111	ACSR	469	4	800	2,700	Feb. 1997	
5	No.1, Barotha P/S (*2)	Rawat CCT-1	107	ACSR	469	4	800	2,700	Nov. 2008	(*2) 1,450MW
6	No.2, Barotha P/S	Rawat CCT-2	108	ACSR	469	4	800	2,700	Nov. 2008	
7	No.1, Barotha P/S	Gatti	339	AAAC	469	3	806	2,000	Apr. 2003	
8	No.2, Barotha P/S	Gatti	338	AAAC	469	3	806	2,000	May 2003	
9	No.1, Rawat	Ghakhar (*3)	180	ACSR	469	4	800	2,700	Nov. 2008	(*3) Gujranwala
10	No.2, Rawat	Ghakhar	193	ACSR	469	4	800	2,700	Oct. 2009	
11	No.1, Ghakhar	Lahore	59	ACSR	469	4	800	2,700	Oct. 2009	
12	No.2, Ghakhar	Lahore	64	ACSR	469	4	800	2,700	Oct. 2009	
13	Gatti	Lahore	94	ACSR	469	4	800	2,700	Oct. 1993	
14	Sahiwal	Lahore	156	ACSR	469	4	800	2,700	Jun. 1992	
15	Gatti	Multan	222	ACSR	469	4	800	2,700	Jun. 1996	
16	Sahiwal	Multan	162	ACSR	469	4	800	2,700	Jun. 1992	
17	Gatti	Rousch P/S (*4)	158	ACSR	469	3	800	2,000	Nov. 1986	(*4) IPP:450MW
18	Rousch P/S	Multan	62	ACSR	469	3	800	2,000	Nov. 1986	
19	Gatti	Muzaffargarh	280	ACSR	469	4	800	2,700	Nov. 2008	
20	Multan	Muzaffargarh	64	ACSR	469	3	800	2,000	Mar. 2000	
21	Guddu	Muzaffargarh	257	ACSR	469	3	800	2,000	Dec. 1986	
22	Multan	G.D. Khan	131	ACSR	469	4	800	2,700	Jan. 1997	Partial New
23	Multan	Guddu New	312	ACSR	469	4	800	2,700	May 1997	Partial New
24	G.D. Kahn	Guddu	220	ACSR	469	4	800	2,700	May 1997	Partial New
25	Guddu New	Guddu	5	ACSR	469	4	800	2,700	May 1997	Partial New
26	No.1, Guddu	Dadu	286	AAAC	469	3	806	2,000	Feb. 1987	
27	No.2, Guddu	Dadu	289	AAAC	469	4	806	2,700	Aug. 1995	
28	No.1, Jamshoro	Dadu	152	AAAC	469	3	806	2,000	Jul. 1987	
29	No.2, Jamshoro	Dadu	153	AAAC	469	4	806	2,700	Oct. 1994	
30	Jamshoro	N. K. I	156	AAAC	469	4	806	2,700	Apr. 2006	
31	N. K. I.	Hubco P/S (*5)	27	AAAC	469	4	806	2,700	Apr. 2006	(*5) IPP:1,292MW
32	Jamshoro	Hubco P/S	181	AAAC	469	4	806	2,700	Oct. 1996	
		Total	**5,187**							

(Source : NTDC)

(4) Current status of substation facility

NTDC operates and maintains substations of 500 / 220kV and 220 / 132kV and DISCOs operate and maintain substations of less than 132kV. Besides, KE operates and maintains substations of 220 / 132kV, too.

The number of 500 / 220kV substation at the end of May, 2015 is 18 places and out of them, NTDC operates 13 places, WAPDA operates 2 places, IPP operates 2 places and GENCO operates 1 place. In addition, single phase transformer type is adopted for all 500 / 220kV and single phase or triple phase transformer type is adopted for 220 / 132kV substations that NTDC operates.

The operator of substations makes tap of OLTC and breaker on and off manually following the directs by telephone. The periodic check is executed every month and annual inspection of transformer is planned.

Meanwhile, the total bank capacity of 500 / 220kV transformer that NTDC operates is about 17 GVA, unit bank capacity is standardized as 450MVA, 600MVA or 750MVA. The total bank capacity of 220 / 132kV transformer is about 22GVA, unit bank capacity is standardized as 160MVA or 250MVA. And direct earthing system is adopted for all transformers. Besides, some substations have passed over 30 years or more after commissioning.

The overview of the bulk substations of 500kV as of the end of May 2015 is shown in Table 2-19 and that of 220 / 132kV at the end of Jun. 2015 is shown in Table 2-20 .

Table 2-19 Overview of 500kV Bulk Substation

(As of End of Aug. 2015)

No.	Name of Grid Station	Province	Commissioning Year	500/ 220 kV Trf.			220/ 132 kV			No. of 500kV Line	Remarks
				Capacity of Bank [MVA]			Capacity of Bank [MVA]				
				No.	Unit	Total	No.	Unit	Total		
1	Dadu New	Sindh	Sep. 1993	2	450	900	3	160	480	4	
2	D. G. Khan	Punjab	Jul. 2014	2	600	1,200	2	250	500	2	
3	Gujranwala	Punjab	Apr. 2009	2	600	1,200	3	160	480	4	Gakkhar/Nokhar
4	Gatti	Punjab	Jun. 1979	4	450	1,800	---	---	---	6	
5	Ghazi Barotha	K.P.K	2003	2	600	1,200				6	WAPDA
6	Guddu	Sindh	Feb. 1987	3	450	1,350	1	285	285	5	*1
							1	160	160		
7	Guddu New	Sindh	Feb. 2014							2	GENCO
8	Hubco	Sindh	1996							2	IPP
9	Jamshoro	Sindh	1988	2	450	900	2	160	320	4	
10	Lahore	Punjab	Jun. 1992	4	600	2,400	3	160	480	4	Sheikhupura
11	Muzaffargarh	Punjab	Jul. 1997	2	600	1,200	2	160	320	3	
12	Multan	Punjab	Nov. 1986	2	450	900	3	160	480	6	
13	NKI	Sindh	Mar 2006	2	600	1,200	---	---	---	2	
14	Peshawar	K.P.K	Dec. 1995	3	450	1,350	3	160	480	1	Shaikh Muhammadi
							1	250	250		Replaced: 3M/2014
15	Rawat New	Punjab	May 1997	3	450	1,350	1	160	160	5	
							2	250	500		
16	Rousch	Punjab	1986							2	IPP
17	Sahiwal	Punjab	Aug. 1987	2	600	1,200	4	160	640	2	Yousafwala
18	Tarbela	K.P.K	1985	2	237	474				4	WAPDA *2
	Total			37		18,624	31		5,535	64	

Remarks: 5-S/S are belonging to 2-WAPDA, 2-IPP & 1-GENCO including operation.

*1: 220/132kV Trf. Is belong to GENCO. *2: 500kV Trf. Is NTDC, Operation by WAPDA.

(Source : NTDC)

Table 2-20 Overview of 220/132 kV Substation

(As of End of Aug. 2015)

No.	Name of Substation	Date of Commissioning	Province	DISCO	Capacity of Transformer [MVA]			Year of Manufacturing	Remarks
					No.	Unit	Total		
1	AES Lalpir								IPP
2	AES Pakgen								IPP
3	Atlas Power								IPP
4	Bahawalpur	28.Feb.03	Punjub	MEPCO	1	160	160		
					2	250	500		
5	Bahria Town				1	63	63		Private (BTPL)
6	Bandala	26.Jun.14	Punjub	FESCO	1	250	250		
7	Bannu New	18.Jul.99	K.P.K.	PESCO	3	160	480		
8	Bund Road	24.Jun.88	Punjub	LESCO	4	250	1,000		
9	Burhan	1977	Punjub	IESCO	3	160	480		
					1	250	250	(Feb.15)	
10	Chashma Nuclear								IPP
11	Daharki	04.Aug.09	Sindh	SEPCO	1	160	160		
					1	250	250		
12	Daud Khel	25.Sep.91	Punjub	FESCO	2	160	320		
13	Ghakkar	11.Jun.82	Punjub	GEPCO	4	160	640		
14	GZR (Ghazi Road)	Jul. 2014	Punjub	LESCO	1	160	160		Temporary
15	Hala Road	02.Jun.90	Sindh	HESCO	3	160	480		
16	ISU Road	2004	Punjub	IESCO	2	250	500		Islamabad Univ.
17	Jaranwala	17.Dec.82	Punjub	FESCO	4	160	640		
18	Kala Shah Kaku	1970	Punjub	LESCO	3	160	480		
19	Kapco	Feb. 1987	Punjub	MEPCO	5	100	500		IPP
20	Khuzdar	09.Jun.14	Baluchistan	QUESC	2	160	320		
21	Kassowal	17.Apr.15	Punjub	MEPCO	2	160	320		
22	Kot Lakhpot New	1974	Punjub	LESCO	3	250	750		
23	Loralai	03.Aug.14	Punjub	QUESC	2	250	500		
24	Ludewala	01.Jan.05	Punjub	FESCO	3	160	480		
25	Mangla	Jul. 1969	Punjub	IESCO	3	138	414		WAPDA
26	Mardan	27.Jun.90	K.P.K.	PESCO	2	160	320		
					1	250	250		
27	NGPS Multan	May-60	Punjub	MEPCO	1	63.3	63.3		
					2	160	320		
28	Nishatabad	1960	Punjub	MEPCO	3	63.5	190.5		
					1	160	160		
29	Okara	03.Jul.14	Punjub	MEPCO	1	250	250		
30	Quetta Industrial	02.Sep.95	Baluchistan	QUESC	3	160	480		
31	Ravi LHR	1994	Punjub	LESCO	3	250	750		
32	PARCO								Private
33	Rohri	21.Sep.13	Sindh	SEPCO	2	250	500		
34	Sammandri Road	10.Jan.95	Punjub	FESCO	3	160	480		
35	Sangjani.	Dec.95	Punjub	IESCO	3	160	480		
36	Sarfaraz Nagar	17.Apr.95	Punjub	LESCO	3	160	480		
37	Shahi Bagh New	27.Feb.06	K.P.K.	PESCO	3	160	480		
38	Shalimar	05.May 14	Punjub	LESCO	3	160	480		
39	Shikarpur	21.Mar.01	Sindh	HESCO	3	160	480		
40	Sialkot	1999	Punjub	GEPCO	3	160	480		
41	Sibbi	02.Feb.82	Baluchistan	QUESC	2	160	320		
42	T.M. Khan	16.Jul.06	Sindh	HESCO	2	160	320		
43	T.T Singh	18.Nov.14	Punjub	FESCO	1	250	250		
44	Uch-I								IPP
45	Uch-II								IPP
46	Vehari	29.Mar.98	Punjub	MEPCO	3	160	480		
47	WAPDA Town	06.Jul.11	Punjub	FESCO	3	160	480		
	Sub-total				**115**		**18,590.8**	977	MVA by others

Remarks: 10-S/S are belonging to 1-WAPDA, 7-IPP and 2-Private.

(Source：NTDC)

(5) Bulk power system loss

The bulk power system loss rate in 2013-14 was 2.48% according to Power System Statistics 39th (NTDC). Meanwhile, the transmission loss rate in 2013-14 was 0.77% according to the NEPRA state of industry report 2014 as shown in Table 2-21. Accordingly, the substation loss rate was estimated as 1.7% which included station own use.

In addition, the accuracy of electric energy meter for transaction between NTDC and DISCOs is 0.2 grade and is installed at the low voltage side of 220 / 132kV transformer and at the high voltage side of 220 / 66kV.

Besides, the power factor of 220kV and 500kV transmission line is operated at around 0.9. Transition of the transmission loss (500 / 220kV) in the last 5 years is show in the below table.

Table 2-21 Transition of Transmission Loss

No.	Description	Unit	2009-10	2010-11	2011-12	2012-13	2013-14	Remarks
A: Transmission Lines								
1	**Received Energy**							
1)	500kV	[GWh]	87,072	89,795	63,687	78,797	90,489	
2)	220kV	[GWh]			66,481	90,359	99,208	
2	**Delivered Energy**							
1)	500kV	[GWh]	84,356	87,096	63,534	78,031	89,806	
2)	220kV	[GWh]			66,298	90,216	98,437	
3	**Energy Losses**							
1)	500kV	[GWh]			154	766	683	
2)	220kV	[GWh]	2,716	2,699	183	142	772	
4	**% Losses**							
1)	500kV	[%]			0.24	0.97	0.76	
2)	220kV	[%]	3.12	3.01	0.27	0.16	0.78	
5	**Overall Losses**	[GWh]	2,716	2,699	336	909	1,455	
		[%]	3.12	3.01	0.26	0.54	0.77	
B: Substation (S/S)								
1	Consumption	[%]	0.03	0.02	2.56	2.51	1.71	
	(This is including S/S losses and station use.)							
C: Transmission System Loss (Item A+B)								
1	Loss	[%]	3.15	3.03	2.82	3.05	2.48	*1

Source: NEPRA; State of Industry Report 2014 and *1: NTDC Power System Statistics 2013-2014

(Source : NEPRA ; State of Industry Report 2014)

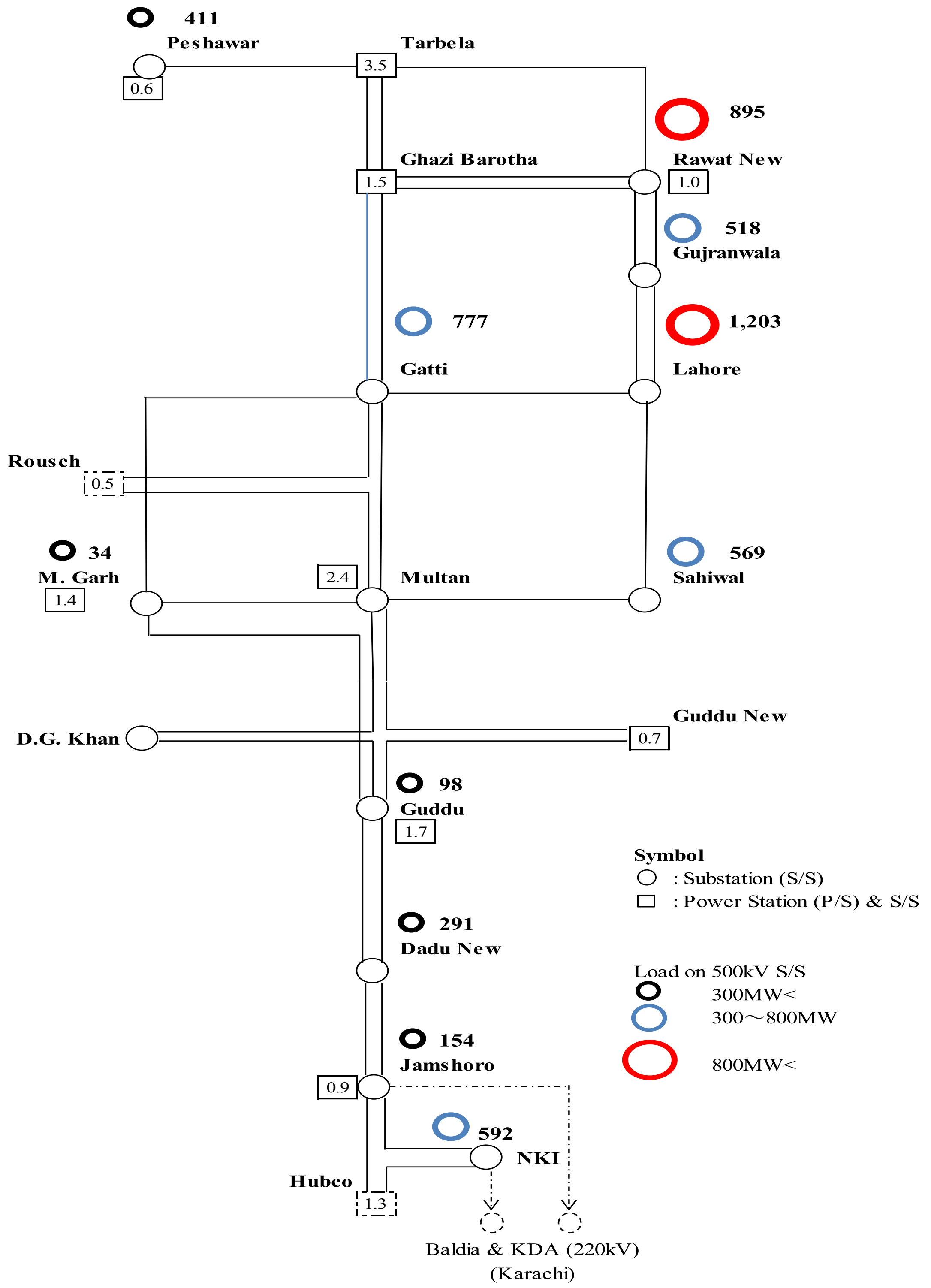
(6) Load map of 500kV substations

13 substations out of 18 substations of 500kV are for power receiving and the Lahore 500 / 220kV transformer recorded the maximum load of 1.2GW in the summer of 2012-13.

The loads of the primary substations were as follows;

1) Lahore :1,203MW
2) Rawat New : 895MW
3) Gatti : 777MW

The load map of the 500 / 220kV transformer of 500kV system is shown in Figure 2-15



Remarks:
1 □ means Approx. output of P/S in [GW]
2 ⬚ means 500kV S/S operated by IPP.
3 Load on 500kV S/S is Summer peak in Year 2012-13.

(Source : JICA Project Team)

Figure 2-15 Load Mao of 500kV Substations

(7) Distribution and Interconnection

Medium power voltage of 11 / 33 / 66 kV and low power voltage of 400 / 230V are adopted for the distribution system, and 10 DISCOs and KE operate. In addition, there is Bahria Town (Pvt) Limited (BTPL) for power distribution in the IESCO service area, but distributing power capacity is very small as less than 10MW.

The southwestern part of the QESCO's service area, an area in the west in the western side of Karachi, is supplied power by the 132kV transmission line from Iran which is planned to upgrade to 220kV (100MW). QESCO has some districts where electricity is supplied through the 11kV distribution line from Iran, that is planned to be 20kV distribution line.

Distribution area, number of the customers and main service area of DISCOs at the end of Jun., 2015 are shown in Table 2-22.

Table 2-22 Overview of DISCOs

(As of Jun. 2014)

No.	DISCO	Area [km^2]	No. of Consumers	Service Area
1	PESCO	74,521	2,867,778	Whole Province of Khyber Pakhtunkhwa, except tribal areas
2	TESCO	27,220	441,480	Federally Administrated Tribal Areas (FATA) (comprising of Bajaur, Mohmand, Khyber, Ourakzai, Kurrum, North Wazirstan, South Waziristan agencies) and Frontier Regions (FRs) (i.e. FR Peshawar, FR Kohat, FR Bannu, FR Tank and FR DI Khan
3	IESCO	23,160	2,379,302	Islamabad, Rawalpindi, Attock, Jhelum, Chakwal
4	GEPCO	17,207	2,824,053	Gujranwala, Sialkot, Mandi Bahauddin, Hafizabad, Narowal, Gujrat
5	LESCO	19,054	3,712,586	Lahore, Sheikhupura, Kasur, Okara, Nankara
6	FESCO	36,122	3,288,930	Faisalabad, Sargodha, Khushab, jhang, Toba Tek Singh, Bhalwal, Mianwali,Bhakkar
7	MEPCO	105,505	4,860,296	Multan, Rahim Yar Khan, Khanewal, Sahiwal, Pakpattan, Vehari, Muzaffargarh, Dera Ghazi Khan, Leiah, Rajan Pur, Bahawalpur, Lodhran, Bahawalnagar,
8	HESCO	81,087	952,263	All Province of Sindh except Karachi, Sukkur, Ghotki, Khairpur, Kashmore, Kandhkot, Jacobabad, Shikarpur, Larkana, Kambar, Shahdadkot, Dadu and some portions of Jamshoro, Naushehro, Feroze, Shaheed Banazirabad and Rahimyar Khan
9	SEPCO	56,300	712,196	Sukkur, Ghotki, Khairpur, Kashmore, Kandhkot, Jacobabad, Shikarpur, Larkana, Kambar, Shahdadkot, Dadu and some portions of Jamshoro, Naushehro, Feroz, Shaheed Banazirabad and Rahimyar Khan
10	QUESCO	334,616	548,980	Whole Province of Balochistan, except Lasbela where K-Eelectric is responsible for distribution of power
11	K-Electric	6,500	2,111,336	Entire Karachi and its suburbs upto Dhabeji and Gharo in Sindh and over Hub, Uthal Vindhar and Bela in Balochistan
	Total		**24,699,200**	

(Source：NEPRA-State of Industry Report 2014)

(8) Issues and considerations

The following issues concerning NTDC are pointed out at present.

1) Maintaining the facilities ledger

The facilities ledger is not maintained, which describes the specifications of the transmission lines and the main transformer as well as the year of manufacture and short-circuit capacity, etc. In addition, the accident history and maintenance records are not maintained, too. Therefore, appropriate renewal plan of equipment or instrument can not be developed.

2) Securing communication system concerning the latest information

Since the information on the new transmission lines and the transformers is not centrally managed, unification of the name and data sharing are not performed.

3) Optimizing the power factor of the bulk substations

Power factor of 0.95 as stipulated in the grid code is not maintained. Therefore, the voltage of substations is not maintained properly and reduction of transmission loss is not executed properly.

4) Establishing monitoring and control of the bulk substations

Since full-scale operation of the SCADA does not start, the system operation and data and information control are not performed appropriately.

5) Integration of 220kV transmission lines

Although power loss of a section where number of 220kV transmission lines is plural can be reduced by replacing with 500kV transmission line, such examination is not carried out.

6) Location of new thermal power plants

When selecting new thermal power plants, it is deemed that the distance from the power demand centers is not considered.

2.5 Electricity Tariff System

2.5.1 Electricity Tariff Table

Electricity tariff table revised in Oct. 2013 is shown in the below table. The categories of the electricity tariff are classified into 10 from A to K and A-1 is a supply tariff for residential. The residential electricity tariff is the only electric energy rate basically, in addition there is a subsidy from the government. On the other hand, for commercial and industrial, the tariff consists of the fixed charge and variable charge and TOU (Time of Use) is adopted for the both categories. Furthermore, the minimum charge when no using electricity is determined.

Besides, the mean electricity charge of DISCOs and KE in 2013-14 were 10.35 Rs/kWh and 12.15 Rs/kWh respectively.

Table 2-23 Electricity Tariff Table

Sr. No.	TARIFF CATEGORY/PARTICULARS	FIXED CHARGES RS/kW/M	VARIABLE CHARGES Rs/kWh		GOVERNMENT SUBSIDY			
						FIXED CHARGES RS/kW/M	VARIABLE CHARGES Rs/kWh	
A-1 GENERAL SUPPLY TARIFF - RESIDENTIAL								
a)	For Sanctioned Load Less Than 5 kW							
i	Up to 50 Units	-		4.00		-		2.00
	For Consumption exceeding 50 Units			11.00		-		-
ii	001-100 Units	-						
					101-200 Units	-		5.21
iii	101-300 Units	-		15.00	201-300 Units	-		6.89
						-		2.91
iv	301-700 Units	-		17.00		-		1.00
v	Above 700 Units	-		18.00		-		-
b)	For Sanctioned Load 5kW & above	-	Peak	Off-Peak			Peak	Off-Peak
	Time of Use		18.00	12.50				
A-2 GENERAL SUPPLY TARIFF - COMMERCIAL								
a)	For Sanctioned Load Less Than 5 kW			18.00				
b)	For Sanctioned Load 5kW & above	400.00		16.00				
			Peak	Off-Peak		-	Peak	Off-Peak
	Time of Use	400.00	18.00	12.50				
B INDUSTRIAL SUPPLY TARIFF - COMMERCIAL								
B1	Up to 25kW (at 400/230 Volts)			14.50				
B2	exceeding 25-500kW (at 400 Volts)	400.00		14.50				
	Time of Use		Peak	Off-Peak			Peak	Off-Peak
B1(b)	Up to 25kW		18.00	12.50				
B2(b)	exceeding 25-500kW (at 400 Volts)	400.00	18.00	12.30				
B3	For All Loads up to 5000kW(at 11,33kV)	380.00	18.00	12.20				
B4	For All Loads (at 66, 132kV)	360.00	18.00	12.10				
C SINGLE-POINT SUPPLY FOR PURCHASE IN BULK								
abridgement								
D AGRICULTURE TARIFF								
abridgement								
E TEMPORARY SUPPLY TARIFFS								
abridgement								
F SEASONAL INDUSTRIAL SUPPLY TARIFF								
abridgement								
G PUBLIC LIGHTING								
abridgement								
H RESIDENTIAL COLONIES ATTACHED TO INDUSTRIAL PREMISES								
abridgement								
K SPECIAL CONTRACTS								
abridgement								

(Source : No. NEPRA/TRF-100/11280-11282 October 11, 2013, JICA Project Team revised)

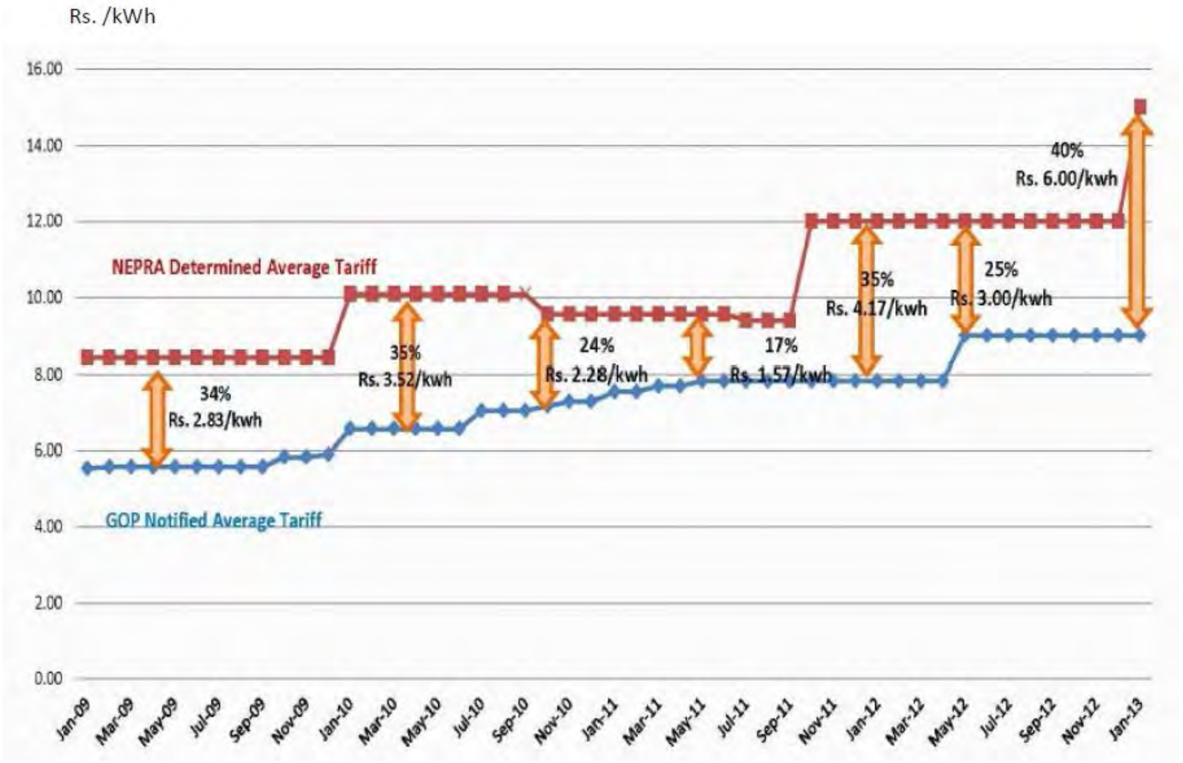
2.5.2 Determined Tariff by NEPRA and Notified Tariff by GOP

NEPRA decides the electricity tariff in consideration of economy and service quality according to the standard tariff and a procedure rule established in 1998. NEPRA Determined Tariff is set for every DISCO, however, GOP Notified Tariff is decided separately from it by Government of Pakistan and is applied to the actual electricity charge collection. After DISCOs applied their electricity tariff for NEPRA, NEPRA examined them and determined the tariffs after a public hearing (NEPRA Determined Tariff).

The government sets the GOP Notified Tariff in reference to the tariff that the most effective DISCO applied among the DISCOs. This gap between NEPRA Determined Tariff and GOP Notified Tariff is TDS (Tariff Differential Subsidy).

Differential Tariff has been applied for the DISCOs since 2007, however, Uniform Tariff not Differential Tariff is applied for the actual electricity charge collection to the end users continuously nationwide. The scale of the company, the geographical condition, the social political background, the population density of the user and user constitution, basic facilities and the differences such as in driving maintenance costs, a technique and an administrative loss and the management capability are different among DISCOs. Therefore, Different Tariff is imposed on every DISCO.

TDS has been transited with having some distance as shown in the below figure.



(Source : Energy Sector Crisis Issues & Reforms Way Forward by SHAHID SATTAR Member (Energy) Planning Commission May 23rd, 2013)

Figure 2-16 Transition of TDS

2.6 Corporation Situation to the Power Sector by Donor Organizations

(1) World Bank (WB)

WB has enforced with JICA and ADB and expressed assistance of approximately 6 billion dollars as "First Power Sector Reform Development Policy Credit" in April, 2014. In addition, WB has assisted CASA-1000 that a surplus electric power in the summer in Tajikistan is transmitted to Pakistan via Afghanistan with DC 500kV. Besides, WB has assisted the expansion of power network and the reduction of transmission and distribution losses.

In the late years, WB has assisted the facilitation of private sector investment in power sector as well.

(2) Asian Development Bank (ADB)

ADB has enforced "Sustainable Energy Sector Reform Program – Subsprgram-1" with JICA and WB. ADB has assisted the rehabilitation of the existing power plants and power networks, in addition, development of the renewable energy.

(3) U. S. Agency for International Development (USAID)

USAID has implemented Power Distribution Program (PDP) which is the part of the assistance and support to overcome the current energy crisis in Pakistan since Apr. 2010 for five year scheme. The Program aims at working with Pakistan's DISCOs to improve their operational and financial performance by reducing losses. The Program also works with the MWP and NEPRA to improve governance, and the regulatory framework and management of the power sector.

Chapter 3 Power Demand Forecast

3.1 Social Economic Outlook

The preconditions such as population, GDP growth rate, foreign exchange rate, inflation rate and crude oil price are as follows.

3.1.1 Growth rate of Population

The past growth rates of population in Pakistan were 2.2 % per year from 1999-2000 to 2004-05 and 2.0 % per year from 2004-05 to 2009-10. It can be considered that the future growth rate of the population will decrease gradually by comparing to the past trends. Therefore, the population growth rates are assumed as follows.

Table 3-1 Prediction of Population and Growth Rate in Pakistan

Population		2005	2010	2015	2020	2025	2030	2035	2040
Urban	Million	54	63	73	81	90	100	109	119
Rural	Million	103	110	119	128	136	144	151	158
Total	Million	157	174	191	209	227	244	261	277
Growth Rate		2005/00	2010/05	2015/10	2020/15	2025/10	2030/25	2035/30	2040/35
Urban	%	2.2	3.3	2.9	2.3	2.1	2.0	1.8	1.7
Rural	%	2.2	1.4	1.5	1.5	1.3	1.1	1.0	0.8
Total	%	2.2	2.0	2.0	1.8	1.6	1.5	1.3	1.2

Note: The population is at the end of June of the year

Note: In regards to the future growth rate of Pakistan, the Study of "National Institute of Population Studies, Pakistan" is referred.

(Source : JICA Project team)

The number of population by DISCO from the above population growth rate was estimated as shown in the following table. The population by district was estimated by NIPS (National Institute of Population Studies), and it was used for estimating population by DISCO up to 2021. The population by DISCO is summed up based on the district-wise population of NIPS. And, the DISCO-wise population was adjusted so as to coincide with the total national population forecasted.

Table 3-2 Forecast Population by DISCO

Unit : 1000persons

	2005	2010	2015	2020	2025	2030	2035	2040
LESCO	17,300	19,400	21,500	23,900	26,000	28,000	29,900	31,700
GEPCO	15,400	16,700	17,900	19,300	20,900	22,400	24,000	25,400
FESCO	18,800	21,000	23,400	26,000	28,300	30,500	32,500	34,500
IESCO	8,700	9,600	10,400	11,200	12,100	13,000	13,900	14,800
MEPCO	28,300	30,700	33,000	35,500	38,400	41,300	44,100	46,800
PESCO	18,200	20,200	21,900	23,800	25,800	27,700	29,600	31,400
HESCO	11,500	13,000	14,800	16,800	18,400	19,800	21,100	22,400
QESCO	6,700	7,400	8,200	9,000	9,800	10,500	11,200	11,900
TESCO	7,600	8,400	9,200	10,000	10,800	11,700	12,400	13,200
SEPCO	13,200	14,900	16,800	19,000	20,700	22,300	23,800	25,200
KE	11,500	12,500	13,400	14,500	15,600	16,800	18,000	19,100
Total	157,200	173,800	190,500	209,000	226,800	244,000	260,500	276,400

(Source : National Institute of Population Studies by 2020 and JICA Project Team after 2020)

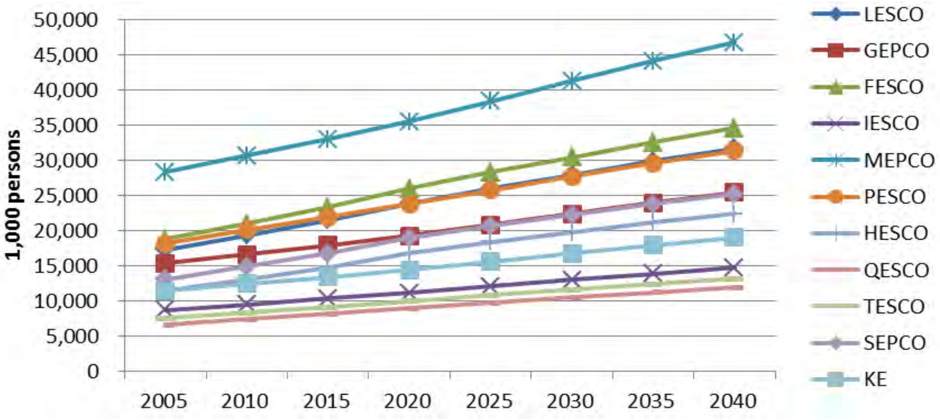


Figure 3-1 Prediction of Population Growth by DISCO

3.1.2 Economic Outlook

(1) GDP growth rate outlook

The average real GDP growth rate was 4.3 % / annum from 2000-01 to 2011-12. In addition, if Pakistan could realize political stability, reduction of energy supply constraints, improvement of labor productivity and increase of FDI as stated in Vision 2025, future GDP growth rate could be expected to be around 8%. The future real GDP growth rates were set in consideration of the followings.

(a) After 2014-15, it can be expected to enforce Vision 2025 under stable political circumstance.
(b) Pakistan's economic growth rate is predicted to be around 5 %~6 % / annum by the authorities (like MOF) and the international development institutes.
(c) The shortage problem of natural gas supply will be resolved in the near future in line with implantation of the National Energy Policy as described in Section 4.1.2, and Pakistan will be able to import electric power from neighboring countries.
(d) It is expected that the real GDP growth rate which is described in Vision 2025 may be realized in the near future.

Table 3-3 Prediction of GDP Growth Rate

Fiscal Year	Nominal GDP (billion Rs)	Real GDP at 2005-06 price (billion Rs)	Nominal GDP G.R. (%)	Real GDP G.R. (%)
2011-12	20,100	9,800	9.9	4.0
2012-13	21,800	10,100	8.6	3.6
2013-14	23,700	10,600	8.4	4.1
2014-15	25,700	11,000	8.5	4.3
2015-16	27,600	11,500	7.6	4.5
2016-17	29,900	12,100	8.2	5.0
2017-18	32,300	12,700	8.2	5.0
2018-19	34,900	13,300	8.2	5.0
2019-20	37,800	14,000	8.2	5.0
2024-25	55,900	17,800	8.2	5.0
2029-30	82,700	22,800	8.2	5.0
2034-35	122,400	29,100	8.2	5.0
2039-40	181,100	37,100	8.2	5.0

(Source: JICA Project Team)

(2) Foreign exchange rate forecast

The fluctuation in foreign exchange rates may be affected by FDI and inflation rate. It is assumed that the current exchange rate of 100 Pakistan rupees (Rs) per US$ will be maintained.

(3) Crude oil price outlook

As of April 2015, WTI (West Texas Intermediate) in New York market is kept around 60 US$/bbl. The crude oil exporting countries such as Saudi Arabia expect to increase crude oil price to compensate benefits from US$ devaluation (it equals to US inflation rate of 2 %). However, according to some oil experts, when looking at recent shale oil & gas supply situation, they predict that the near future crude oil price will remain at the current level or decreased until 2020, but the crude oil price may gradually increase again. Accordingly, WTI price was assumed as shown in the following table.

Table 3-4 Prediction of WTI Price

	Unit	2014	2015	2020	2025	2030	2035	2040
WTI price	US$/bbl	90	60	70	80	85	90	95

Note : Crude oil price is 2014 price

Note: Arabian light price produced in Saudi Arabia is 5~10 US$ / bbl less than WTI.

3.1.3 Economic Scenarios

The above mentioned GDP growth rate prediction is set as “Base case”. In addition, if the un-stability factors of Pakistani economy could be reduced and foreign trade between Pakistan and the neighboring countries could be expanded, Pakistani economy would reach higher growth than the above table. Therefore, the case when the GDP growth rate keeps 6.5% per year after 2018-19 was set as “High case”.

Table 3-5 GDP and Growth Rate (High case)

Fiscal Year	Nominal GDP (billion Rs)	Real GDP at 2005-06 price (billion Rs)	Nominal GDP G.R. (%)	Real GDP G.R. (%)
2011-12	20,100	9,800	9.9	4.0
2012-13	21,800	10,100	8.6	3.6
2013-14	23,700	10,600	8.7	4.3
2014-15	25,800	11,000	8.7	4.5
2015-16	27,900	11,600	8.2	5.0
2016-17	30,300	12,200	8.7	5.5
2017-18	33,100	13,000	9.2	6.0
2018-19	36,300	13,800	9.7	6.5
2019-20	39,800	14,700	9.7	6.5
2024-25	63,200	20,200	9.7	6.5
2029-30	100,400	27,600	9.7	6.5
2034-35	159,400	37,800	9.7	6.5
2039-40	253,200	51,900	9.7	6.5

(Source : JICA Project Team)

3.2 Methodology for Energy and Power Demand Forecast

3.2.1 Required Functions of Demand Forecast

In order to forecast the power and energy demand, the transition of the past power and energy consumption and the current situation of the consumption should be figured out. The social economic activities and the demand structure of energy and electric power should be analyzed. After that, the structures of energy and electric power demand forecast model should be designed. The following functions are required for the demand forecast model used in this project.

- Social economic changes be linked to the model
- Impact of energy price trend and energy conversion trend be considered
- Final energy demand and power demand by sector (Agriculture, Industrial, Commercial, Transportation, Public services and Residential) be analyzed
- Region-wise power demand forecasts be given
- International comparison of energy and electric power demand be given

3.2.2 Structure of Demand Forecast Model

At first, the demand forecast model predicts the sectoral final energy and electric power demand, then calculate electric power consumption and energy consumption for generation, and primary energy consumption. The outline of the model flow is shown in the below figure.

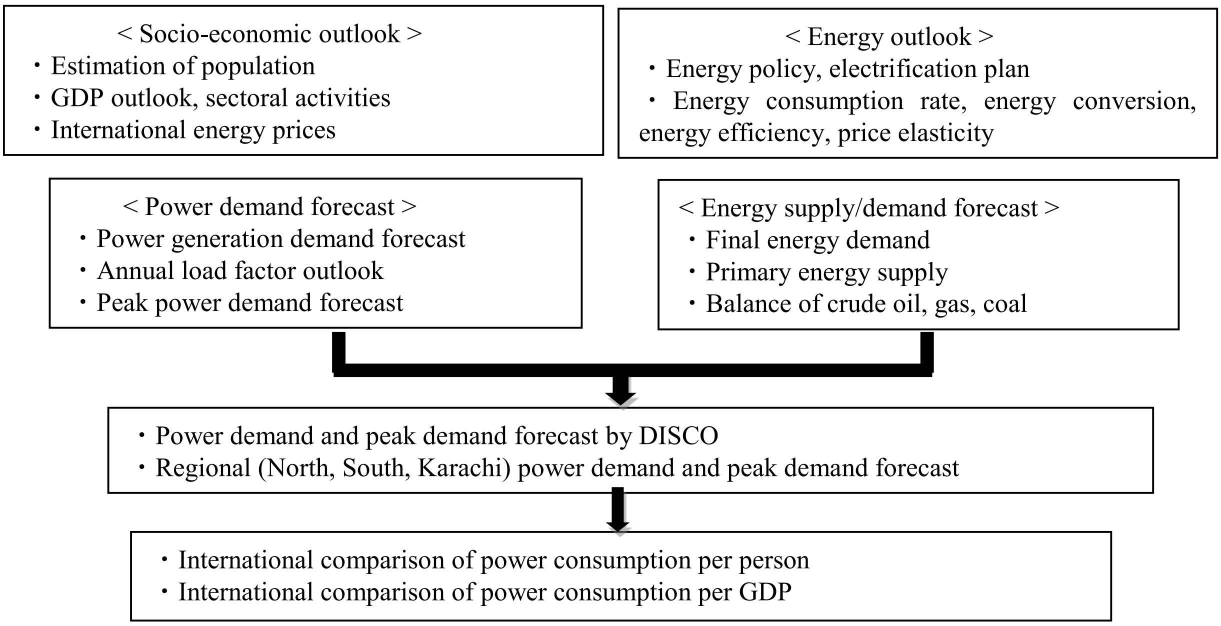


Figure 3-2 Power Demand Forecast Flow

In accordance with the above power demand forecast flow, power demand forecast model will be developed. Energy supply / demand flow defined by IEA is used in the model and the econometric model methodology is used. MS-EXCEL add-in software so-called “Simple.E” is used to develop the model . The outline of the energy and electric power demand forecast model is shown in the below figure.

Economic Block

(1) Socio-economic index
- Population
- GDP
- Price and foreign exchange rate

(2) Energy supply destination and its activity and policy
- Activity of agricultural sector
- Industrial activity
- Commercial service sector activity

(3) Energy price
- Crude oil price
- Electricity price
- Oil product price

(4) Prerequisite values
- Electrification rate
- Energy conversion

(5) Power generation plan
- Hydro
- Oil, gas, coal fire
- Renewable energy

Energy demand forecast block

(1) Sectoral final energy demand
- Agricultural - Industrial
- Transportation - Commercial service
- Governmental - Residential

(2) Sectoral power demand
- Agricultural - Industrial
- Transportation - Commercial service
- Governmental - Residential

(3) Final demand by energy source
- Coal - Natural gas
- LPG - Oil products
- Electricity - Renewable energy

(4) Power generation amount
- Hydro - Coal, crude oil,
- Gas powered fire generation
- Renewable energy

(5) Energy consumption of power sector
- Coal – Gas - Oil – Others

(6) Domestic energy consumption
- Final energy - Primary energy

(7) Demand by DISCO
- Electric energy demand
- Peak power demand

(8) Regional demand
- Electric energy demand
- Peak power demand

Figure 3-3 Outline of Energy and Electric Power Demand Forecast Model Structures

3.2.3 Procedures of Power and Energy Demand Model

For creating forecasting formula, energy intensities are estimated by using the past energy consumption per sectoral GDP (energy per population for Residential sector). The procedures of the demand forecasts are as follows;

Step 1 Sectoral total energy consumption by sector (Ai)
= Sectoral total energy consumption intensity of sector (i)
x Sectoral GDP (i) (Population is used for Residential sector)

Definition of Sectoral total energy consumption by sector (Ai)
A1: Agriculture, A2: Industry, A3: Transportation, A4: Commercial & services, A5: Government, A6: Residential
Definition of Sectoral total energy consumption intensity of sector (i)
Sectoral energy consumption / Sectoral GDP for business sectors (A1, A2, A3, A4, A5)
Residential sector energy consumption / population (A6)
Future intensity is estimated by auto correlation analysis

Step 2 Sectoral power demand (Bi)
= Sectoral total energy consumption (Ai) x Electrification rate[3] (i)
x Power tariff elasticity (i) x Energy Efficiency & Conservation index (i)
Definition of Sectoral electrification rate (Bi)
B1: Agriculture, B2: Industry, B3: Transportation, B4: Commercial & services, B5: Government, B6: Residential
Future electrification rate is estimated by auto correlation analysis.

---

[3] Electrification Rate is defined as “Electric Energy Consumption / Total Energy Consumption”

The sectors have upper limits that are estimated based on experiences of developed countries. The elasticity of power tariff and EE&C policy effectiveness are set here.

Step 3 Sectoral fuel demand (Ci)
= (Sectoral total energy consumption (Ai) – Sectoral power demand)
x Energy price elasticity (i) x EE&C indicator (i)

Definition of Sectoral fuel demand (Ci)
Ci: Agriculture, C2: Industry, C3: Transportation, C4: Commercial & services, C5: Government, C6: Residential
Definition of fuel demand
='Sectoral total energy demand – Power demand'
The elasticity of energy costs and EE&C policy effectiveness are set here.

Step 4 Power demand as final energy demand (Di)
= Sum sectoral power demand of Agriculture (B1), Industry (B2), Transportation (B3), Commercial & service (B4), Government (B5) and Residential (B6)

The power demand as a final energy demand is not dispatched power demand. TD loss is required to be added for the dispatched demand.

Step 5 Fuel demand as final energy demand (Ei)
= Sum Fuel demand of Agriculture (C1), Industry (C2), Transportation (C3), Commercial & service (C4), Government (C5) and Residential (C6)

Fuel demand as a final energy demand equals to the energy consumed by end users. Generally, Power, Natural gas, Oil products, Coal, Coal products and Woods / charcoal are used.

Step 6 Generated energy demand (Fi)
= Sales energy demand as final energy demand (D) + T/D loss

T/D loss is determined by T/D loss rate. The rate is set by the governmental target and/or Power sector targets.

Step 7 Peak power demand forecast (G)
＝Generated energy demand (F) / 24hours / 365 days / Load factor

Definition of Peak demand (MW)
Generated energy demand / 24 hours/ 365days / Load factor

Definition of Load factor (%)
Annual average load (MW) / Annual peak load (MW) x 100

3.3 Preconditions for Power Demand Forecast

3.3.1 Computed Electric Energy Demand

The electric energy demand is defined as Computed sales energy demand, which is a sum of Recorded sales energy demand and Load shedding (latent demand). In this section, the computed generated energy demand is forecasted.

The following tables show the recorded electricity sales energy (excluding the T/D loss).

Table 3-6 Recorded Electricity Sales Energy by DISCO

(Unit : GWh)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
PESCO	5,221	6,105	6,440	6,406	5,900	6,503	6,977	7,062	7,162	7,471
TESCO	2,514	2,150	2,019	1,817	1,660	1,756	1,735	1,466	1,295	1,366
IESCO	6,437	6,270	7,065	7,232	7,197	7,572	7,674	7,534	7,764	8,192
GEPCO	5,279	5,827	6,110	6,077	5,957	6,220	6,439	6,178	5,920	6,828
LESCO	11,832	13,090	13,947	13,766	13,168	13,881	14,741	14,467	14,285	15,948
FESCO	7,122	7,890	8,600	8,578	8,089	8,317	8,596	8,580	8,586	9,682
MEPCO	7,849	8,941	9,571	9,388	9,051	9,916	10,189	10,218	9,913	11,437
SEPCO							2,478	2,666	2,726	2,702
HESCO	4,006	4,446	4,843	5,105	5,128	5,396	3,336	3,381	3,524	3,685
QESCO	3,490	3,829	3,965	4,089	4,110	4,099	4,048	4,086	3,812	3,744
DISCOs	53,750	58,548	62,560	62,458	60,260	63,660	66,213	65,638	64,987	71,055
KE	8,416	9,059	9,367	10,052	9,396	9,905	10,071	10,276	10,942	11,453
Total	62,166	67,607	71,927	72,510	69,656	73,565	76,284	75,914	75,929	82,508

(Source : Power System Statistics 38th and 39th)

3.3.2 Electrification Rate

The electrification rate is defined as the share of electricity sales energy demand in the final energy demand including electricity, fossil fuel and woods & charcoal. The actual electrification rates of several countries and areas are shown in the below table. The electrification rate can be defined sector-wise such as Industrial, Commercial service, Governmental, Transportation and Residential sectors, and in general, the electrification rate grows year by year. As Industrial and Transportation sectors consume high fossil energies, the electrification rate is lower than the other sectors. On the other hand, since Government and Commercial service sectors consume mainly electric power due to high electric power demands of buildings such as offices, hospitals and schools, the electrification rate is high.

Table 3-7 Actual Electrification Rates of Counties and Area

(Unit : %)

Countries and Area	1980	1990	2000	2009
USA	13.3	17.5	19.5	21.4
Japan	19.0	21.5	23.5	25.6
Africa (Average)	14.9	17.7	19.9	20.8
Asia (Average)	11.7	14.0	18.4	21.7

Note: Electrification rate(%)＝Electricity consumption (toe) / Final energy consumption (toe)

(Source : “Energy and Economic Statistics Abstract 2012” by The Institute of Energy economics, Japan)

The prediction of electrification rates in the following table are calculated by autocorrelation analysis based on the past records.

Meanwhile, since the Government sector’s energy consumption is mostly electric energy and Transportation sector’s electric energy consumption is scarce, the electrification rates for both sectors are not considered.

Table 3-8 Sectoral Electrification Rate Prediction

<Base case> (Unit : %)

Sector	2014	2020	2025	2030	2035	2040
Industry	18.1	20.8	23.0	25.4	26.7	28.0
Commercial	38.1	39.0	40.0	41.0	42.1	43.1
Residential	12.6	14.6	17.1	20.2	23.8	28.2

<High case> (Unit : %)

Sector	2014	2020	2025	2030	2035	2040
Industry	18.1	21.8	24.0	26.4	27.7	29.0
Commercial	38.1	40.0	41.0	42.0	43.1	44.1
Residential	12.6	15.6	18.1	21.2	24.8	29.2

(Source : JICA Study team)

3.3.3 Other Important Factors

The prerequisites for other important factors are as follows;

1) According to the other country's energy efficiency policies, 20 % reduction in 20 years by final energy consumption and primary energy consumption is expected. However, the energy conservation measures are not considered in the model.

2) The hike of energy prices and power tariffs discourage the power demand. However, in the country that power shortage continues, consumers that require electricity are deemed to purchase electricity from DISCOs even though the tariff increased, when the tariff is cheaper than self-generation cost. Since it is considered that the prices hike does not affect growth of the power demand, the small elasticity of "-0.1" between energy price and power demand was set.

3) For the transmission kWh loss rate, NTDC aims to improve it from the current rate of 3.1 % to 2.5%. In addition, the distribution kWh loss rate will be improved up to the distribution loss rate of other developing countries of around 10%. Therefore, the T/D kWh loss of DISCOs is assumed as decrease by -0.5% every year and 12.5% after 2030-31. Similarly, the T/D kWh loss of KE is assumed as decrease by -1.0% every year and 12.5% after 2029-30.

4) Since the bulk consumers such as industrial park which generate power for themselves will become to receive electricity from the national grid in the future, the self- generation energy, which is equal to around 10% of the computed sales energy, is to be added as a part of potential electric energy demand.

3.4 Power Demand Forecast

3.4.1 Power Demand Forecast (Base Case)

(1) Sector-wise electric energy demand forecast (Base Case)

Sector-wise electric energy demands (Including T/D loss) in Base case are shown in the below table. The growth rate of the electricity sales energy demand is 5.8 % per year from 2014-15 to 2039-40, when GDP growth rate is 5.0 % per year during the same period (Elasticity: 1.16). In addition, the growth rate of the generated energy (at sending end) demand is estimated as 5.3% due to decrease of the T/D loss.

Table 3-9 Sector Wise Electric Energy Demand Forecasts（Base case）

		Unit	2010	2015	2020	2025	2030	2035	2040
Power demand by Sector	Total	GWh	126,945	161,411	222,579	299,395	397,969	511,920	656,868
	Agriculture.Fishery	GWh	12,800	16,200	21,500	25,500	28,900	32,300	35,800
	Industry	GWh	33,900	48,900	80,500	121,500	174,900	235,600	315,700
	Commercial & Services	GWh	8,700	10,900	16,600	23,900	33,100	45,000	60,600
	Public Government	GWh	87	76	97	124	158	202	258
	Public Street light	GWh	458	534	682	871	1,111	1,418	1,810
	Residentials	GWh	44,500	58,500	72,500	90,100	110,100	133,400	160,600
	T/D loss	GWh	26,500	26,300	30,700	37,400	49,700	64,000	82,100
Share	Total	S%	100.0	100.0	100.0	100.0	100.0	100.0	100.0
	Agriculture.Fishery	S%	10.1	10.0	9.7	8.5	7.3	6.3	5.5
	Industry	S%	26.7	30.3	36.2	40.6	43.9	46.0	48.1
	Commercial & Services	S%	6.9	6.8	7.5	8.0	8.3	8.8	9.2
	Public Government	S%	0.1	0.0	0.0	0.0	0.0	0.0	0.0
	Public Street light	S%	0.4	0.3	0.3	0.3	0.3	0.3	0.3
	Residentials	S%	35.1	36.2	32.6	30.1	27.7	26.1	24.4
	T/D loss	S%	20.9	16.3	13.8	12.5	12.5	12.5	12.5

(Source : JICA Project Team)

Table 3-10 Sector Wise Power Demand Growth Rate (Base case)

(Unit : %)

	2015/10	2020/15	2025/20	2030/25	2035/30	2040/35	2035/15
Total	4.9	6.6	6.1	5.9	5.2	5.1	5.8
Agriculture.Fishery	4.8	5.8	3.5	2.5	2.2	2.1	3.2
Industry	7.6	10.5	8.6	7.6	6.1	6.0	7.7
Commercial & Services	4.6	8.8	7.6	6.7	6.3	6.1	7.1
Public Government	-2.6	5.0	5.0	5.0	5.0	5.0	5.0
Public Street light	3.1	5.0	5.0	5.0	5.0	5.0	5.0
Residentials	5.6	4.4	4.4	4.1	3.9	3.8	4.1
T/D loss	-0.2	3.1	4.0	5.9	5.2	5.1	4.7

(Source : JICA Project Team)

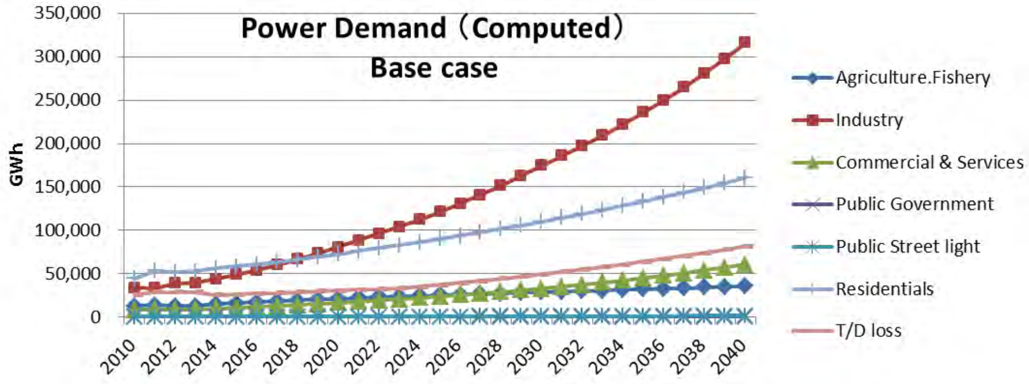


Figure 3-4 Sector Wise Electric Energy Demand Forecast（Base case）

(2) Estimation of region wise electric energy demand records

In this study, NTDC power system is divided into two power systems, North and South, taking into account geographical condition of long from North to South and uneven distribution of primary energy sources. And also KE power system is considered as another power system interconnected.

The north power system is composed of 6 DISCOs, PESCO, TESCO, IESCO, GEPCO, LESCO, FESCO, and the south power system is composed of 4 DISCOs, MEPCO, SEPCO, HESCO, QESCO.

Region wise electric energy demand records for the past 5 years were estimated based on the hourly computed power demand records for one year in 2014 as shown in the below table.

Table 3-11 Region Wise Electric Energy Demand (Past 5 Years)

System		Unit	2009-10	2010-11	2011-12	2012-13	2013-14
North	Computed energy demand	GWh	63,513	68,520	69,636	70,292	72,298
	T/D loss rate	%	24.1	22.3	22.0	21.6	20.7
	Sales energy	GWh	48,232	53,256	54,348	55,139	57,330
	Self-generation	GWh	4,823	5,326	5,435	5,514	5,733
	Sales energy demand	GWh	53,055	58,581	59,782	60,653	63,063
	Generated energy demand	GWh	69,864	75,373	76,600	77,322	79,528
South	Computed energy demand	GWh	35,131	37,900	38,518	38,881	39,990
	T/D loss rate	%	24.1	22.3	22.0	21.6	20.7
	Sales energy	GWh	26,678	29,457	30,061	30,499	31,711
	Self-generation	GWh	2,668	2,946	3,006	3,050	3,171
	Sales energy demand	GWh	29,346	32,403	33,067	33,549	34,882
	Generated energy demand	GWh	38,644	41,691	42,370	42,769	43,989
Karachi	Computed energy demand	GWh	15,806	15,431	15,259	15,823	15,991
	T/D loss rate	%	37.3	34.7	32.6	30.8	28.4
	Sales energy	GWh	9,905	10,071	10,277	10,942	11,453
	Self-generation	GWh	991	1,007	1,028	1,094	1,145
	Sales energy demand	GWh	10,896	11,078	11,305	12,036	12,598
	Generated energy demand	GWh	17,387	16,974	16,785	17,405	17,590
Total Generated Energy Demand		GWh	125,895	134,037	135,755	137,496	141,107

(3) Region wise electric energy demand forecast (Base case)

Sales energy demand is forecasted in the manner that the above (2) region wise sales energy demand records are multiplied by the above (1) sector wise power demand growth rate. Furthermore, generated energy (at sending end) demand is forecasted by adding T/D loss energy. The forecast results are shown in Table 3-12 and Figure 3-5. In 2034-2035 (20 year later), the generated energy (at sending end) demand will reach 425TWh, which is around 3 times of that in 2013-14.

Table 3-12 Region Wise Generated Energy (at Sending End) Demand Forecast (Base case)

		Unit	2014	2015	2020	2025	2030	2035	2040
NTDC T/D loss rate		%	20.7	20.2	17.7	15.2	12.7	12.5	12.5
KE T/D loss rate		%	28.4	27.4	22.4	17.4	12.5	12.5	12.5
System	North	GWh	79,528	84,261	113,841	148,823	192,208	247,172	317,811
	South	GWh	43,989	46,219	60,448	79,090	102,888	132,491	170,382
	Karachi	GWh	17,590	18,461	23,767	29,651	36,334	45,747	57,588
Total		GWh	141,107	148,942	198,056	257,565	331,430	425,411	545,780

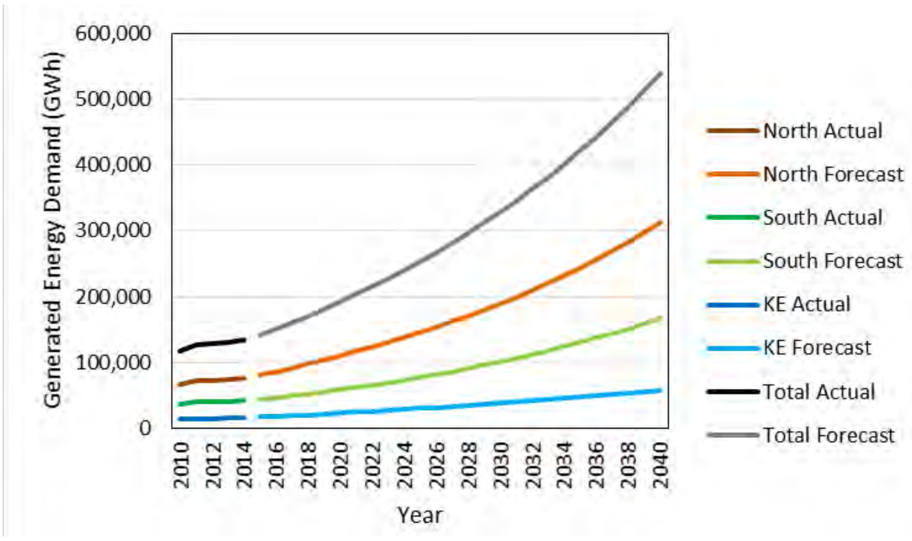


Figure 3-5 Region Wise Generated Energy (at Sending End) Demand Forecast (Base case)

(4) Region wise maximum power demand forecast (Base case)

Region wise maximum power demand is forecasted in the manner that (3) region wise generated energy demand is divided by annual load factor. Load factor is normally forecasted based on the trend of the record of load factor in the past. However, as shown in Table 3-13, since it is difficult to follow the trend of load factor or daily load curve from the records of region wise maximum demand and annual load factor (not including Self-generation), it is assumed that the future annual load factor will be the same as the latest one.

The reason why the annual load factor is predicted as no change is that annual load factor will increase in line with increase of power demand in the industrial sector, on the other hand, the gap of maximum power demand among seasons will become large in line with dissemination of air conditioner.

Region wise maximum power demand is forecasted based on the above generated energy demand forecast and the annual load factor forecast as shown in Table 3-13 and Figure 3-6. In 2034-35 (20 year later), the maximum power demand will reach 80GW, which is around 3 times of that in 2013-14.

Table 3-13 Estimation of Region Wise Maximum Demand and Load Factor Records

System		Unit	2009-10	2010-11	2011-12	2012-13	2013-14
North	Generated energy demand	GWh	65,820	71,632	72,908	73,728	76,119
	Load Factor	%	58.8	60.5	59.4	60.1	57.4
	Maximum demand	MW	12,333	12,922	13,378	13,346	14,389
South	Generated energy demand	GWh	36,407	39,621	40,327	40,781	42,103
	Load Factor	%	67.1	68.9	67.4	66.0	61.1
	Maximum demand	MW	5,977	6,276	6,519	6,720	7,470
Karachi	Generated energy demand	GWh	14,963	14,926	14,996	15,749	16,174
	Load Factor	%	70.4	68.7	67.1	65.0	62.3
	Maximum demand	MW	2,562	2,565	2,596	2,778	2,929
Total Maximum Demand 1)		MW	20,285	21,150	21,859	22,201	24,031

Note 1) : It is assumed that the diversity factor between North and South system is 1.01 and it between NTDC and KE system is 1.02

Table 3-14 Region Wise Maximum Demand Forecast (Base case)

System		Unit	2014	2015	2020	2025	2030	2035	2040
North	Generated Energy	GWh	79,528	84,261	113,841	148,823	192,208	247,172	317,811
	Load Factor	%	57.4	57.5	57.5	57.5	57.5	57.5	57.5
	Maximum Demand	MW	15,828	16,728	22,601	29,546	38,159	49,071	63,095
South	Generated Energy	GWh	43,989	46,219	60,448	79,090	102,888	132,491	170,382
	Load Factor	%	61.1	61.0	61.0	61.0	61.0	61.0	61.0
	Maximum Demand	MW	8,217	8,649	11,312	14,801	19,254	24,794	31,885
Karachi	Generated Energy	GWh	17,590	18,461	23,767	29,651	36,334	45,747	57,588
	Load Factor	%	62.3	62.0	62.0	62.0	62.0	62.0	62.0
	Maximum Demand	MW	3,222	3,399	4,376	5,459	6,690	8,423	10,603
Total Maximum Demand 1)		MW	26,499	27,966	37,209	48,399	62,289	79,958	102,591

Note 1) : It is assumed that the diversity factor between North and South system is 1.01 and it between NTDC and KE system is 1.02

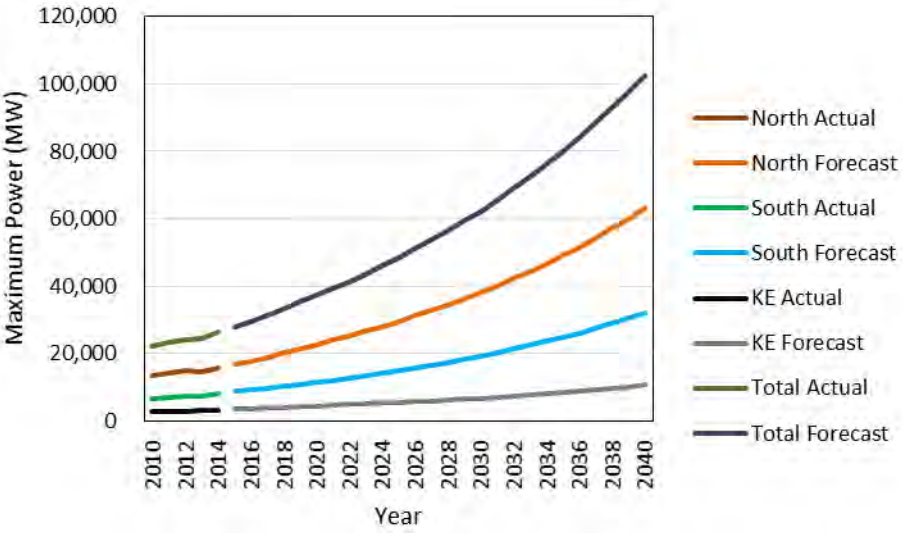


Figure 3-6 Region Wise Maximum Demand Forecast (Base case)

3.4.2 Power Demand Forecast (High Case)

(1) Sector wise electric energy demand forecast (High Case)

Sector wise electric energy demands (including T/D loss) in High case are shown in the below table. The growth rate of the dispatched power demand is 7.0 % per year from 2014-15 to 2039-40, when GDP growth rate is 6.5 % per year during the same period (Elasticity: 1.11). In addition, the growth rate of the generated energy (at sending end) demand is estimated as 6.6% due to decrease of the T/D loss.

Table 3-15 Sector Wise Electric Energy Demand Forecast（High case）

(Unit：GWh)

		Unit	2014	2015	2020	2025	2030	2035	2040
Power demand by Sector	Total	GWh	152,282	162,311	238,979	343,495	485,669	656,920	890,168
	Agriculture.Fishery	GWh	15,200	16,200	22,000	26,800	31,200	35,600	40,500
	Industry	GWh	44,400	49,000	88,400	142,500	216,700	311,500	445,300
	Commercial & Services	GWh	10,100	11,100	18,100	28,300	42,400	62,200	90,100
	Public Government	GWh	73	76	97	124	158	202	258
	Public Street light	GWh	509	534	682	871	1,111	1,418	1,810
	Residentials	GWh	56,400	58,900	76,700	102,000	133,400	163,900	200,900
	T/D loss	GWh	25,600	26,500	33,000	42,900	60,700	82,100	111,300
Share	Total	S%	100.0	100.0	100.0	100.0	100.0	100.0	100.0
	Agriculture.Fishery	S%	10.0	10.0	9.2	7.8	6.4	5.4	4.5
	Industry	S%	29.2	30.2	37.0	41.5	44.6	47.4	50.0
	Commercial & Services	S%	6.6	6.8	7.6	8.2	8.7	9.5	10.1
	Public Government	S%	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Public Street light	S%	0.3	0.3	0.3	0.3	0.2	0.2	0.2
	Residentials	S%	37.0	36.3	32.1	29.7	27.5	24.9	22.6
	T/D loss	S%	16.8	16.3	13.8	12.5	12.5	12.5	12.5

Table 3-16 Sector Wise Electric Energy Demand Growth Rate（High case）

(Unit ：%)

	2015/10	2020/15	2025/20	2030/25	2035/30	2040/35	2040/15
Total	5.0	8.0	7.5	7.2	6.2	6.3	7.0
Agriculture.Fishery	4.8	6.3	4.0	3.1	2.7	2.6	3.7
Industry	7.6	12.5	10.0	8.7	7.5	7.4	9.2
Commercial & Services	5.0	10.3	9.4	8.4	8.0	7.7	8.7
Public Government	-2.6	5.0	5.0	5.0	5.0	5.0	5.0
Public Street light	3.1	5.0	5.0	5.0	5.0	5.0	5.0
Residentials	5.8	5.4	5.9	5.5	4.2	4.2	5.0
T/D loss	0.0	4.5	5.4	7.2	6.2	6.3	5.9

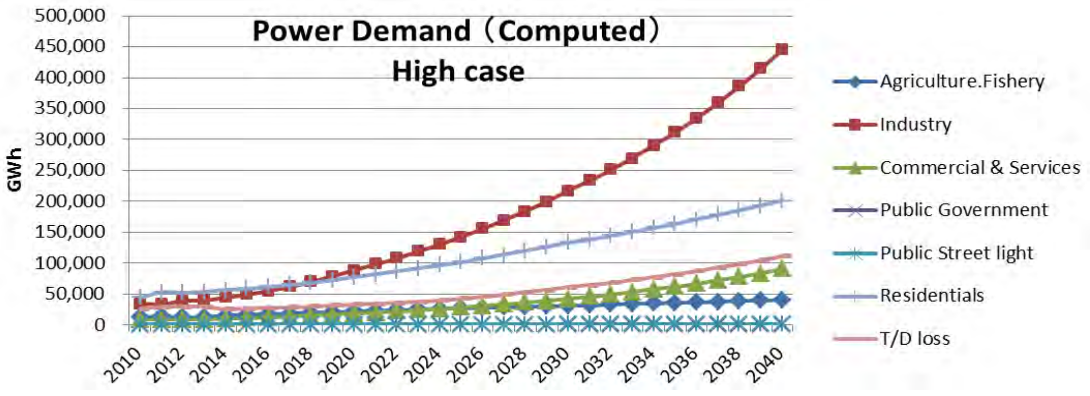


Figure 3-7 Sector Wise Electric Energy Demand Forecast（High case）

(2) Region wise electric energy demand forecast (High case)

Sales energy demand (High case) is forecasted as well as Base case in the manner that the above section 3.4.1 (2) region wise sales energy demand records are multiplied by the above (1) sector wise power demand growth rate. Furthermore, generated energy (at sending end) demand is forecasted by adding T/D loss energy.

The forecast results are shown in Table 3-17 and Figure 3-8. In 2034-2035, the generated energy (at sending end) demand will reach 544TWh, which is around 4 times of that in 2013-14.

Table 3-17 Region Wise Generated Energy (at Sending End) Demand (High case)

(Unit : GWh)

		Unit	2014	2015	2020	2025	2030	2035	2040
NTDC T/D loss rate		%	20.7	20.2	17.7	15.2	12.7	12.5	12.5
KE T/D loss rate		%	28.4	27.4	22.4	17.4	12.5	12.5	12.5
System	North	GWh	79,528	84,494	121,902	170,295	233,922	316,356	429,558
	South	GWh	43,989	46,347	64,727	90,501	125,217	169,574	230,290
	Karachi	GWh	17,590	18,512	25,450	33,929	44,220	58,553	77,838
Total		GWh	141,107	149,353	212,080	294,724	403,359	544,483	737,686

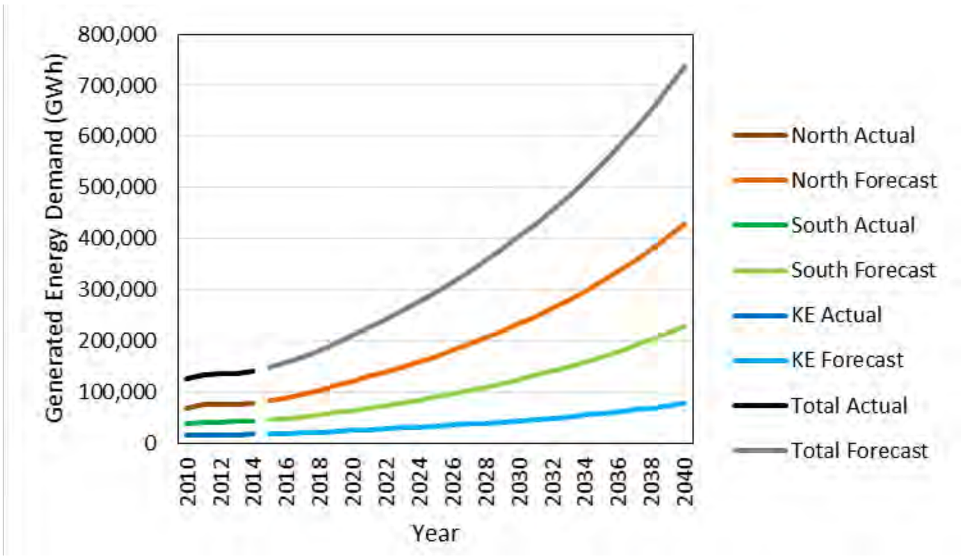


Figure 3-8 Region Wise Generated Energy (at Sending End) Demand Forecast (High case)

(3) Region wise maximum demand forecast (High case)

Region wise maximum demand forecast (High case) is forecasted as well as the Base case from generated energy demand (High case) and the annual load factor as shown in Table 3-12 and Figure 3-9. In 2034-35 (20 year later), the maximum power demand will reach 102GW, which is around 4 times of that in 2013-14.

Table 3-18 Region Wise Maximum Demand Forecast (High case)

Region		Unit	2014	2015	2020	2025	2030	2035	2040
North	Generated Energy	GWh	79,528	84,494	121,902	170,295	233,922	316,356	429,558
	Load Factor	%	57.4	57.5	57.5	57.5	57.5	57.5	57.5
	Maximum Demand	MW	15,828	16,775	24,201	33,809	46,441	62,806	85,281
South	Generated Energy	GWh	43,989	46,347	64,727	90,501	125,217	169,574	230,290
	Load Factor	%	61.1	61.0	61.0	61.0	61.0	61.0	61.0
	Maximum Demand	MW	8,217	8,673	12,113	16,936	23,433	31,734	43,096
Karachi	Generated Energy	GWh	17,590	18,512	25,450	33,929	44,220	58,553	77,838
	Load Factor	%	62.3	62.0	62.0	62.0	62.0	62.0	62.0
	Maximum Demand	MW	3,222	3,409	4,686	6,247	8,142	10,781	14,332
Total Maximum Demand 1)		MW	26,499	28,044	39,844	55,382	75,808	102,338	138,664

Note 1) : It is assumed that the diversity factor between North and South system is 1.01 and it between NTDC and KE system is 1.02

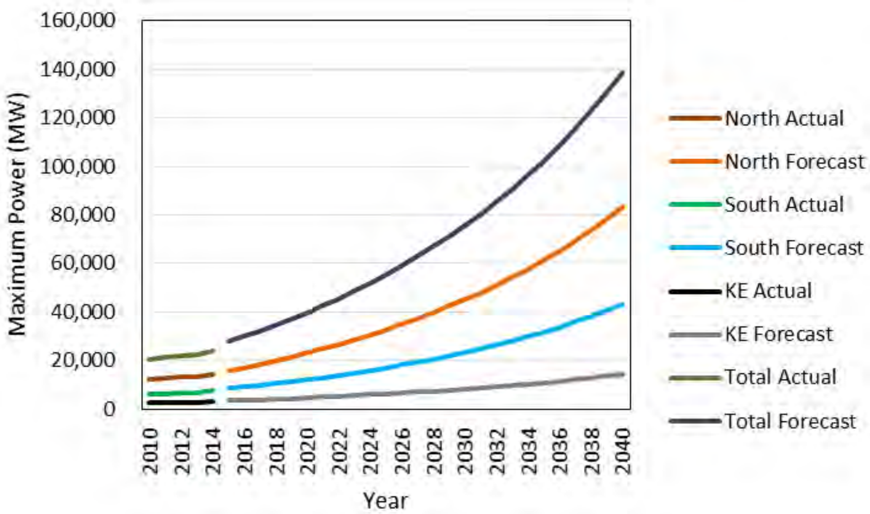


Figure 3-9 Region Wise Maximum Demand Forecast (High case)

3.5 Daily Load Curve Forecast

3.5.1 Methodology of Forecast

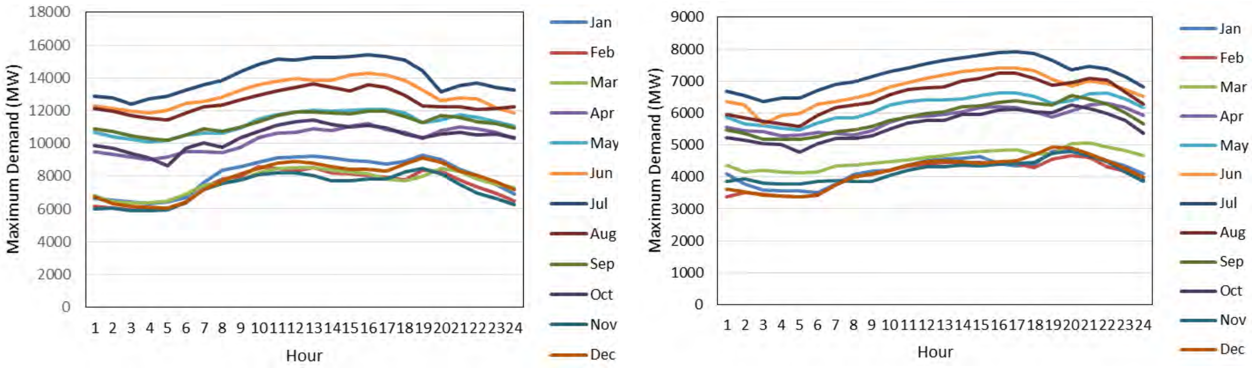
System wise, North, South and KE, daily load curves on maximum demand day, weekday and holiday are analyzed and arranged based on the DISCO wise hourly computed power demand data. Here, nothing but hourly computed power demand data in a year of 2014 could be obtained.

Future daily load curves are forecasted by assuming similar figure with the load curves in 2014 based on generated energy demand forecast and annual load curve forecast.

3.5.2 Region Wise Daily Load Curve Records

Region wise monthly daily load curves on the maximum demand day (top 3 days average), weekday and holiday in 2014 are shown in the following figures, respectively. There are big differences between daily load curve shapes in summer (from May to Sep.) and those in winter (from Nov. to Mar.) in the both North and South power system of NTDC. On the contrary, the daily load curves in KE power system except during winter season (from Dec. to Mar,) are similar and high power demand, it is deemed that power demand for air conditioning is large.

North System South System



KE System

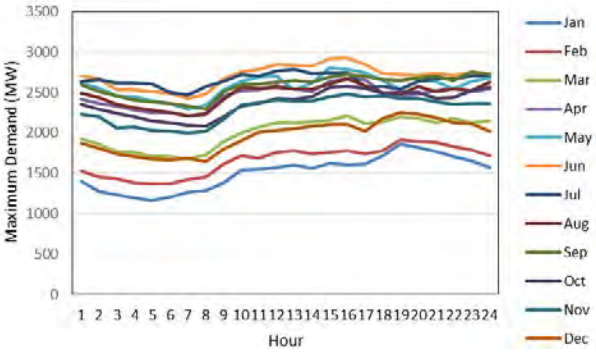


Figure 3-10 Region Wise Daily Load Curves on Maximum Demand Day

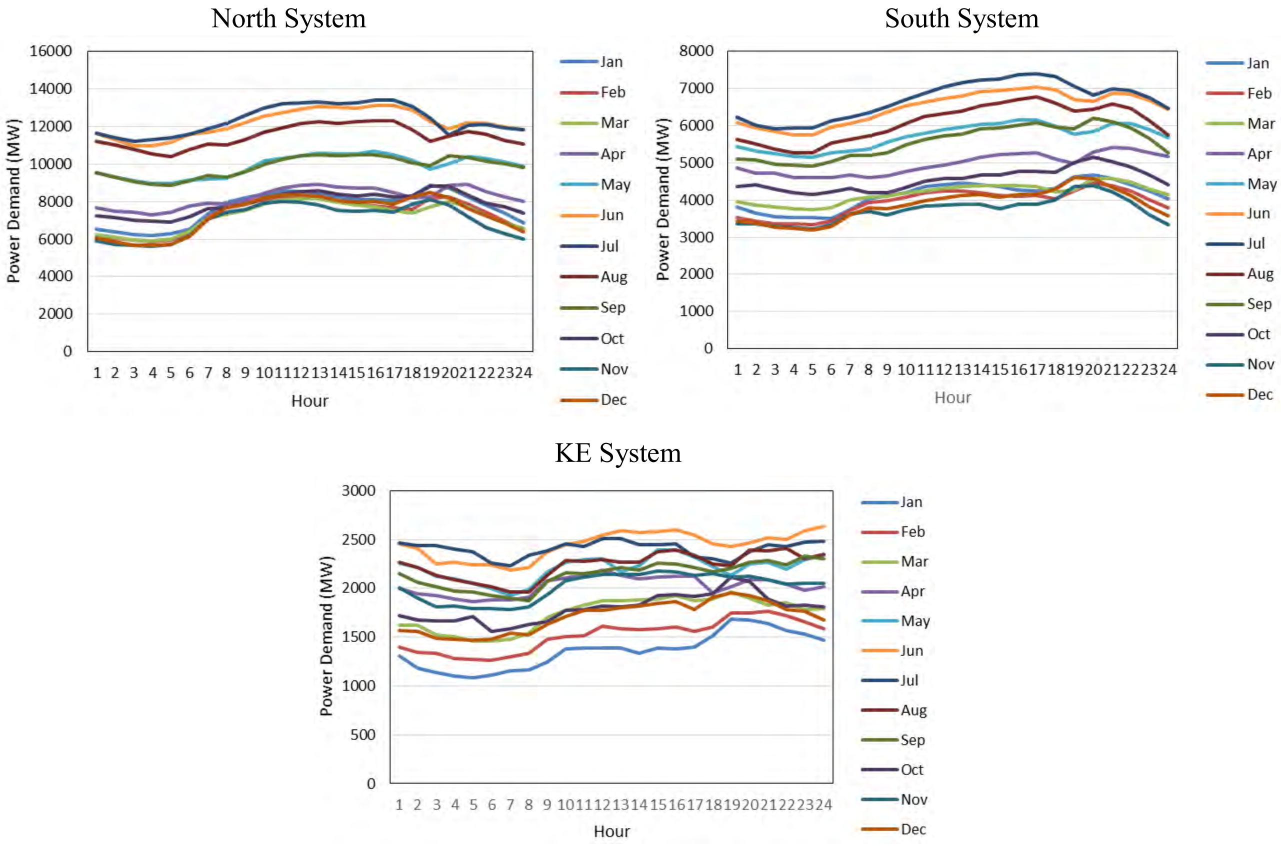


Figure 3-11 Region Wise Daily Load Curves on Weekday

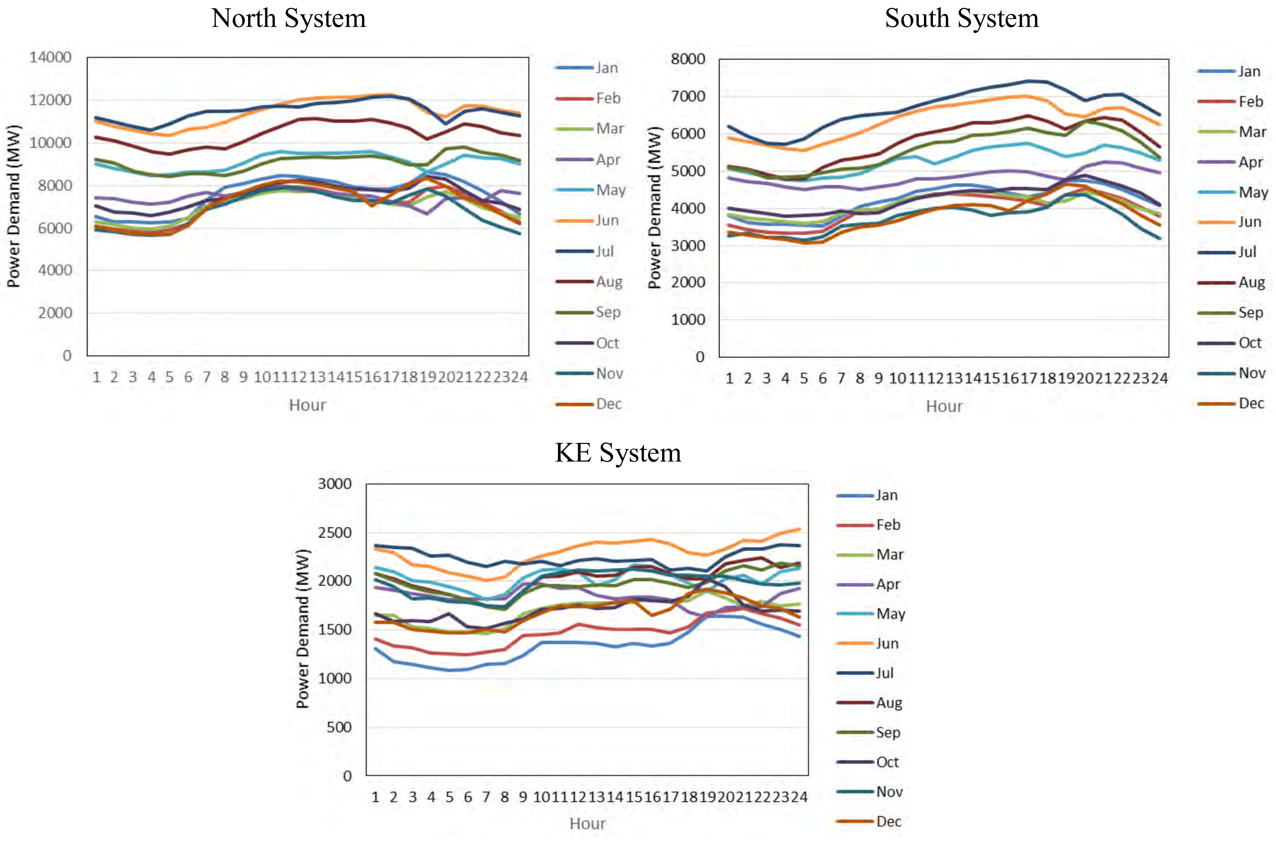


Figure 3-12 Region Wise Daily Load Curves on Holiday

3.5.3 Results of Daily Load Curve Forecast

Region wise daily load curves on maximum demand day (top 3 days average) of Base Case are forecasted as shown in the below figure.

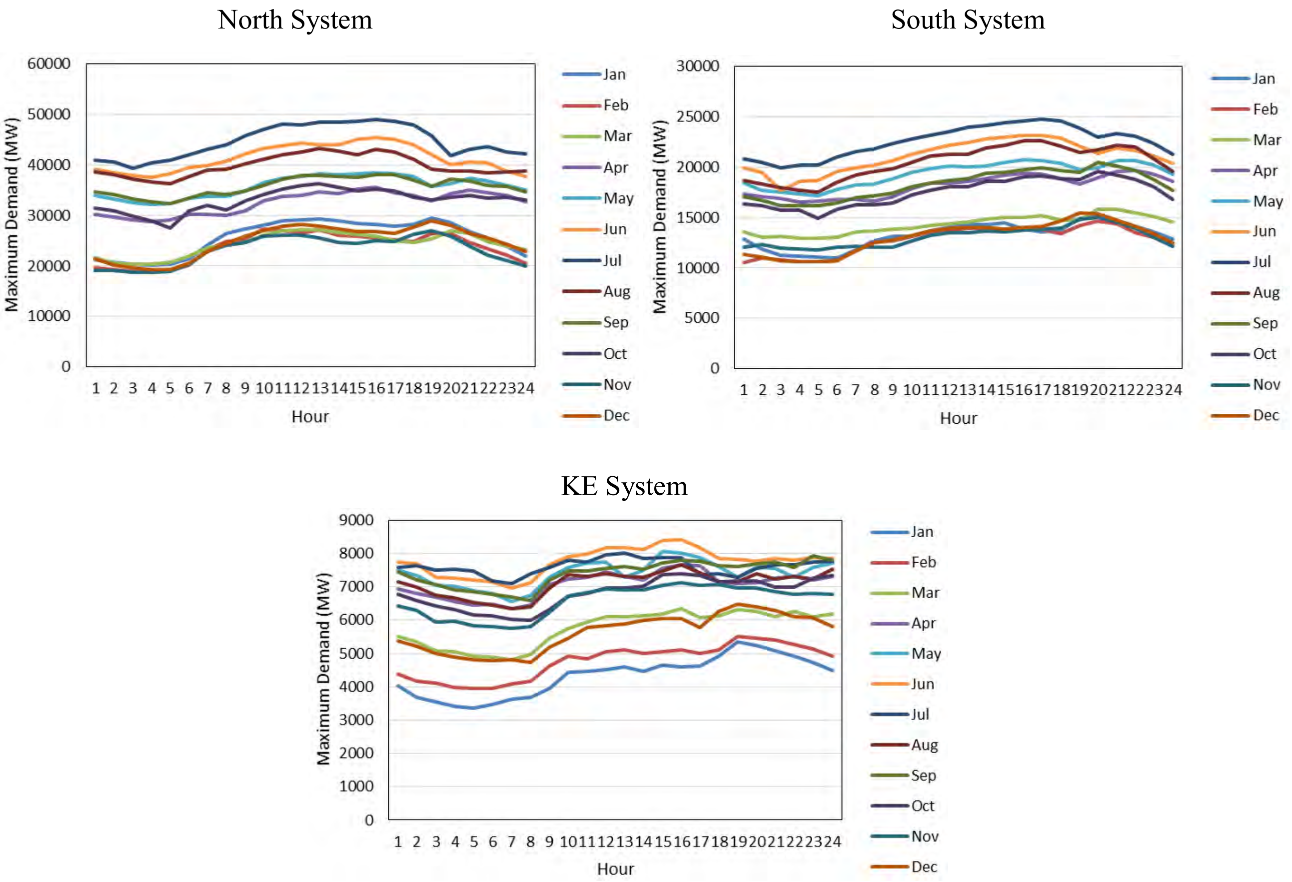


Figure 3-13 Region Wise Daily Load Curves on Maximum Demand Day in 2035

Chapter 4 Primary Energy

4.1 Current Status and Policy of Primary Energy

4.1.1 Current Demand and Supply Situation of Primary Energy

The natural gas accounts for over 50% of the total fossil fuel consumption in Pakistan. Most of the natural gas as final energy demand is used by Residential, Commercial, Industrial and Transportation sectors.

Table 4-1 Demand and Supply of Fossil Energies (as of 2012-13)

(Unit : 1000toe)

	Items	Natural gas	Crude oil	Imort Oil products	LPG	Coal	Fossil Total
Energy Supply	Production	31,152	3,735		236	1,422	36,546
	Import		7,652	10,624	74	2,441	20,791
	Export			−1,038			−1,038
	Stocks	−8	−44	63	0		11
	Net Supply total	31,144	11,343	9,650	310	3,863	56,309
Transformation	Gas processing	−2,595					−2,595
	Oil Refinery		−10,987	10,025	227		−736
	Power Station	−7,084		−7,561		−28	−14,674
	Power T/D losses	−972					−972
	Own use	−217		−159	−29		−405
	Non energy use	−2,755				−174	−2,929
	Statistic error		−356	288	26		−41
	Transformation total	−13,622	−11,343	2,593	224	−202	−22,351
Demand	Domestic	6,831		101	246		7,178
	Commercial	952			204		1,156
	Industry	7,393		1,384		3,661	12,439
	Agriculture			33			33
	Transportation	2,345		10,368			12,713
	Other & Government			333	79		412
	Demand total	17,522	0	12,220	528	3,661	33,931
as Reference	Brick					1,206	1,206
	Cement	14				2,455	2,469
	Fertilizer	728					728
	Steel mill	230		1,384			1,614
	General industry	6,422					6,422

Note : Natural gas includes non- associate gas and associate gas

(Source : Pakistan Energy Statistics 2013)

When looking at fossil fuel consumptions for power sector, natural gas and oil have been used fifty-fifty. According to the actual data for the past five years, the oil products has increased by an average rate of 1.8 % /year, while natural gas has decreased by an average rate of 3.6 % /year.

Table 4-2 Past Records of Primary Energies to Power Sector

Items	Energy	Unit	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	AGR(%)
Energy as Oil equivalence	Gas	1000 toe	8,491	7,830	7,107	6,494	6,733	7,084	−3.6
	Oil	1000 toe	6,910	7,384	8,602	7,933	7,410	7,561	1.8
	Coal	1000 toe	73	50	56	43	47	28	−17.2
	Total	1000 toe	15,474	15,264	15,765	14,470	14,190	14,673	−1.1
Contribution	Gas	%	54.9	51.3	45.1	44.9	47.4	48.3	−2.5
	Oil	%	44.7	48.4	54.6	54.8	52.2	51.5	2.9
	Coal	%	0.5	0.3	0.4	0.3	0.3	0.2	−16.3
	Total	%	100.0	100.0	100.0	100.0	100.0	100.0	0.0
Energy as usual unit	Gas	million cfd	1,163	1,073	974	890	922	970	−3.6
	Oil	1000 ton	7,274	7,773	9,055	8,350	7,800	7,959	1.8
	Coal	1000 ton	182	126	140	108	117	71	−17.2

(Source : Pakistan Energy Statistics 2013)

4.1.2 National Energy Policy

According to the survey of ISGS (Inter Sate Gas System) , the natural gas demand in 2012 (2011-2012） was 2,000 Bcfa, while the gas production in the same period was 1,500 Bcfa. That is, the gas supply shortage was 500 Bcfa. As the natural gas consumption of power sector was 360 Bcfa in 2012, and it is said that there are electric energy supply shortage of 30 % of electric energy demand in 2012, it means that the required natural gas amount for the power sector was inferred as 470 Bcfa in 2012, thus the natural gas shortage was 110 Bcfa. The reasons of the natural gas shortage to power sector are as follows;

1) Even though 50 % of primary energy in Pakistan is contributed by natural gas, the natural gas production has continued to decrease in recent years.
2) Since the gas demand continuously increase for Residential, Commercial, and Transportation (CNG) sectors along with economy growth, the gas could not be supplied sufficiently to Power sector and Industrial sector.

The Government is considering the following strategies against fuel shortage, especially, natural gas shortage.

- Natural gas import from neighboring countries
- LNG import
- Investment to rehabilitate the existing hydro power stations
- Promoting renewable energies
- Power import from neighboring countries
- Improvement of energy efficiency and conservation

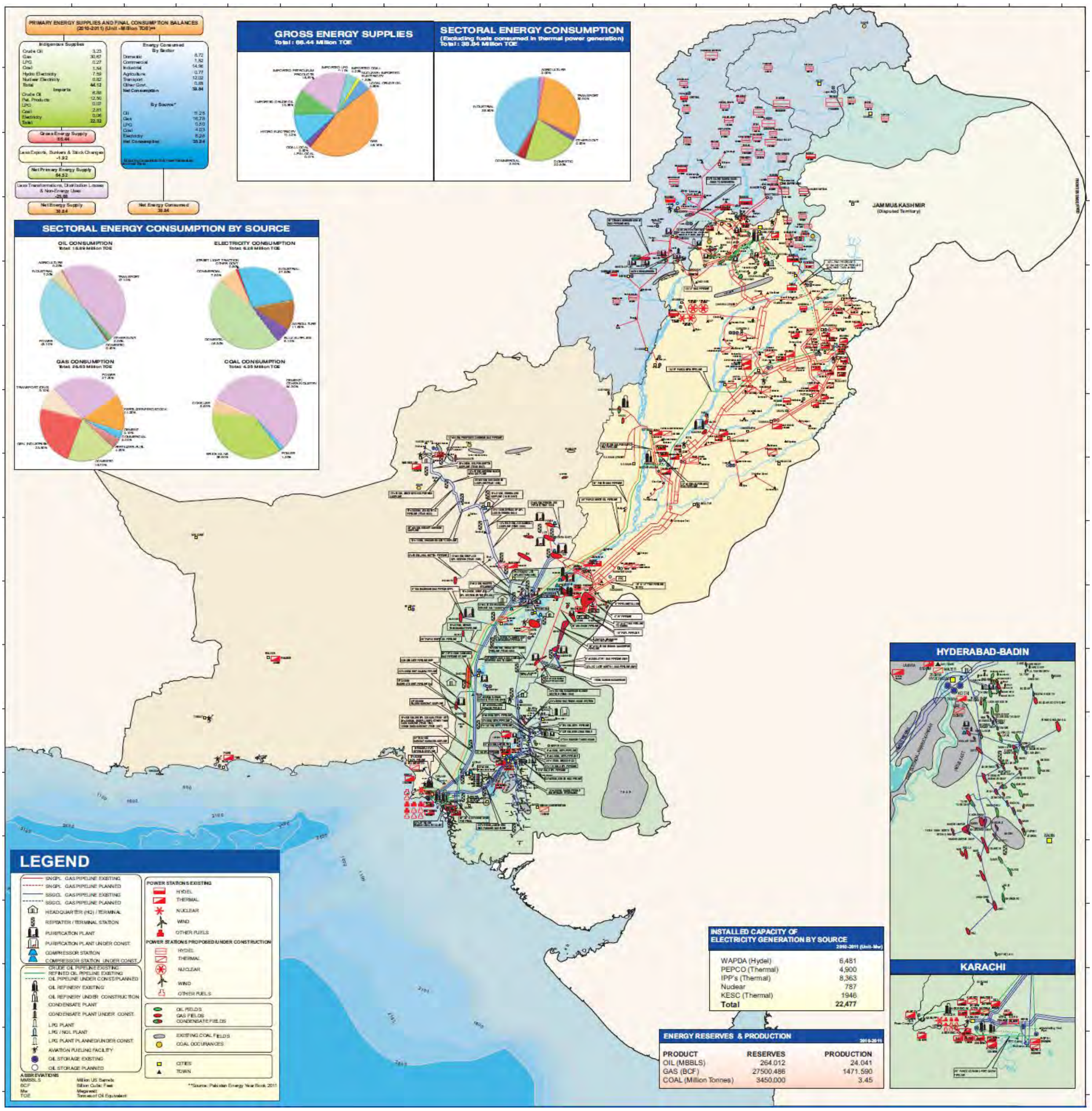
MPNR also has the following strategies against fuel shortage, considering that there is almost no possibility of increasing natural gas production from the existing gas fields.

- Domestic natural gas development (Onshore and Offshore)
- Natural gas import by pipeline
- LNG import
- Loss reduction and efficient natural gas consumption
- Coal import and development of coal mine

4.2 Primary Energy Development Plan

4.2.1 Current Status of Energy Infrastructure

Energy Infrastructure at the end of 2012-13 is shown in the below figure.



(Source : PPIS (Pakistan Petroleum Information Service))

Figure 4-1 Current Status of Energy Infrastructure

4.2.2 Natural Gas

(1) Natural gas reserves

The Non-associated gas (natural gas) reserves and association gas reserves are shown in the following table. As the natural gas production has already reached the peak out in Pakistan, the future production may be decreased unless new natural gas fields are discovered.

Table 4-3 Reserves of Natural Gas (As of 2013-14)

Type	Unit	Original Recoverable	Cumulative Production	Balance Recoverable	Heating Value
Non-associated Gas	Tcf	55.6	30.9	24.7	826 Btu/cf
	million Toe	1100.0	661.7	439.1	
Associated Gas	Tcf	1.5	1.1	0.4	
	million Toe	38.9	32.2	6.8	
Total	Tcf	57.1	32.0	25.1	
	million Toe	1138.9	693.9	445.9	

(Source: DGPC)

(2) Natural gas production

Although non-association gas and association gas are produced in Pakistan, the production of non- association gas remained flat from 2007-08 to 2012-13, and the production of association gas tends to decrease during the past few years. The production growth rate of non-association gas is 0.9 % per year from 2007-08 to 2012-13, and the growth rate of the total natural gas production is 0.7 % per year in the same period.

Table 4-4 Natural Gas Production

(Unit : Bcfa)

Type	Province	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	AGR(%)
Non-associated Gas	Balochistan	319.6	305.4	288.4	280.1	295.8	276.6	-2.8
	KPK	26.7	28.7	72.2	122.6	132.8	123.6	35.9
	Punjab	58.4	66.7	60.3	61.9	68.3	59.9	0.5
	Sindh	1014.2	1032.2	1034.7	988.3	1044.5	1027.4	0.3
	Total	1418.9	1433.0	1455.6	1452.9	1541.4	1487.5	0.9
Associated Gas	Balochistan							
	KPK	3.0	2.7	2.8	2.6	2.8	2.6	-2.8
	Punjab	13.4	9.6	9.2	7.4	7.5	9.3	-7.0
	Sindh	18.9	15.5	15.3	8.6	7.2	6.4	-19.5
	Total	35.3	27.8	27.3	18.6	17.5	18.3	-12.3
Total	Balochistan	319.6	305.4	288.4	280.1	295.8	276.6	-2.8
	KPK	29.7	31.4	75.0	125.2	135.6	126.2	33.6
	Punjab	71.8	76.3	69.5	69.3	75.8	69.2	-0.7
	Sindh	1033.1	1047.7	1050.0	996.9	1051.7	1033.8	0.0
	Total	1454.2	1460.8	1482.9	1471.5	1558.9	1505.8	0.7

Note: None-association gas : When hydrocarbon as gaseous state constantly exists in reservoir, the field is called as "Gas field". The heavy hydrocarbon becomes from gaseous state to liquid state (Condensate) on the ground. In the case of wet gas field, the heavy gas changes to liquid in field when the pressures of storage layer is reduced by progressing the gas production. When the gas production ratio is over 50 %, the field is called as "Gas field".

(Source: DGPC)

(3) Natural gas consumption in regional areas

The regional gas consumption in 2011-12 is shown in the following table. Sindh province has the largest share of over 50 % in the total gas consumption and the power sector is the biggest gas consumer which accounts for approximately 30% of the total gas consumption.

Table 4-5 Natural Gas Consumption by Region（As of 2012）

(Unit : Bcfa)

Sector	Subsector	Punjab	KPK	Sindh	Balochistan	Total
Domestic		156.4	26.8	95.8	13.0	292.0
Commercial		27.8	2.5	9.7	0.7	40.7
Industry	Steel Mills			9.8		9.8
	Cement		0.2	0.4		0.6
	Fertilizer(Feedstock)	104.4		44.3		148.7
	Fertilizer(Fuel)	25.2	0.1	13.9		39.2
	Power	57.7		235.6	69.0	362.3
	Transport	48.6	22.3	28.2	1.2	100.3
	Other industry	122.0	13.3	138.9	0.2	274.4
	The total	357.9	35.9	471.1	70.4	935.3
Total	Bcfa	542.1	65.2	576.6	84.1	1268.0
	Bcfd	1.49	0.18	1.58	0.23	3.47
	ktoe	11,717	1,525	12,898	1,220	27,360

(Source: DGGas)

(4) Gas supplier for power sector

The natural gas supply to power sector has tended to decrease for 5 years from 2007-08 to 2012-13. The supply in 2007-08 was 430 Bcfa, and it was 362 Bcfa in 2012-13. The supply in 2012-13 was only 84% comparing to that in 2008. The average decrease rate for those years was 3.4 % per year. SNGPL (Sui Northern Gas Pipeline Limited) was the biggest gas supplier for power sector, and their supply amount accounted for 33 % in 2012-13. Next biggest gas supplier was SSGCL (Sui Southern Gas Company Limited), and its supply amount accounted for 20 %. The supply amount of the two gas suppliers accounts for over 53 % of the total gas supply for power sector.

Table 4-6 Gas Suppliers to Power Sector

(Unit : Bcfa)

Companies	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	AGR(%)
SNGPL	134.8	105.9	100.6	117.1	121.2	118.6	−2.5
SSGCL	126.8	131.5	115.1	79.6	68.9	73.1	−10.4
Kandhkot gas field	35.8	36.2	37.1	36.3	38.2	25.5	−6.6
Mari Gas field	43.4	41.5	41.5	23.6	41.8	40.9	−1.2
Nandpanjpir Gas fields	12.0	16.9	14.6	11.7	18.2	13.9	3.0
Sara/Sui Gas fields	6.3	0.8	0.5	0.1	0.0	0.0	
Uch Gas field	70.7	71.2	67.5	69.0	70.2	61.3	−2.8
Qadirpur Gas field						29.0	
Total(Bcfa)	429.8	404.0	376.9	337.4	358.5	362.3	−3.4
Total (mm cfd)	1178	1107	1033	924	982	993	−3.36
Total (Ktoe)	8,492	7,830	7,107	6,494	6,733	7,084	−3.6

(Source: DGGas)

(5) Gas consumption by sector

The average growth rates of natural gas consumptions of Residential and Transportation sectors were 7.4 % and 6.8 %, respectively, for the past 5 years. Meanwhile, the consumption growth rates of Industry and Power sectors have decreased by an average rate of - 2.1 % and - 3.4 % per year from 2007-08 to 2012-13, respectively. Industry sector can change power supply from the grid power of DISCO to self-generation, but the power sector cannot but switch fuel to the oil. It leads to a decrease in power generation and at the same time suppresses the account balance of the power sector when hiking crude oil price.

Table 4-7 Natural Gas Consumption by Sector

(Unit : Bcfa)

Sector	Subsector	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	AGR(%)
Domestic		204.0	214.1	219.4	232.2	261.9	291.9	7.4
Commercial		33.9	35.5	37.0	36.5	39.6	40.7	3.7
Industry	Steel Mills	16.9	14.0	13.0	12.0	10.0	9.8	-10.3
	Cement	12.7	7.3	1.9	1.4	1.3	0.6	-45.7
	Fertilizer(Feedstc	160.1	162.0	175.6	175.9	168.7	148.8	-1.5
	Fertilizer(Fuel)	40.0	39.1	44.5	52.5	43.1	39.2	-0.4
	Power	429.9	404.1	366.9	337.4	358.4	362.3	-3.4
	Other industry	305.7	305.0	320.5	279.7	286.1	274.5	-2.1
	Industry total	965.3	931.5	922.4	858.9	867.6	835.2	-2.9
Transport		72.0	88.2	99.0	113.1	119.0	100.2	6.8
Total	Bcfa	1,275.2	1,181.1	1,178.8	1,127.6	1,169.1	1,167.8	-1.7
	Bcfd	3.49	3.24	3.23	3.09	3.20	3.20	-1.7
	ktoe	27,519	27,324	27,553	26,626	27,508	27,361	-0.1

(Source: DGGas)

(6) Consumer price of natural gas

The gas price are determined by user category. The natural gas price of residential sector becomes higher depending on the gas consumption volume, however, the gas price of "1.77-3.55 million Btu", the middle class category, for residential sector is comparatively cheap as 100 Rs / million Btu in 2012-13. The gas price for power sector in 2012-13 is 488 Rs / million Btu which is more than double of that in 2004-05.

Table 4-8 Natural Gas Consumer Prices

(Unit : Rs / million Btu)

	1.Jun 2005	1.Jun 2006	1.Feb 2007	1.Jan 2008	1.Jan 2009	1.Jan 2010	7.Aug 2011	1 Jun 2012	1 Jan 2013
Domestic use	73.95	80.96	82.07	82.07	86.17	99.48	107.87	100.00	100.00
Commercial use	234.67	271.07	268.23	283.05	393.33	463.80	526.60	600.00	636.83
Industry	208.56	240.91	238.38	251.55	339.43	382.37	434.18	460.00	488.23
Captive power	208.56	240.91	238.38	251.55	339.43	382.37	434.18	460.00	488.23
Cement	240.28	277.55	305.15	335.67	454.95	536.42	609.10	700.00	742.97
Fertilizer as fuel	208.56	240.91	238.38	251.55	339.43	382.37	434.18	460.00	488.23
Power use from SNGPL/SSGCL	208.56	240.91	238.38	251.55	349.56	393.79	447.14	460.00	488.23
Power use for IPP					295.03	332.36	377.39	460.00	488.23
Raw Gas for WAPDA from Mari	195.95	226.34	223.96	236.64	328.42	369.97	420.10	460.00	488.23

Domestic use: category with '1.77 - 3.55 million Btu prices' Commercial use: general use
Industry: general industry use

(Source: DGGas and OGRA)

(7) Domestic natural gas development

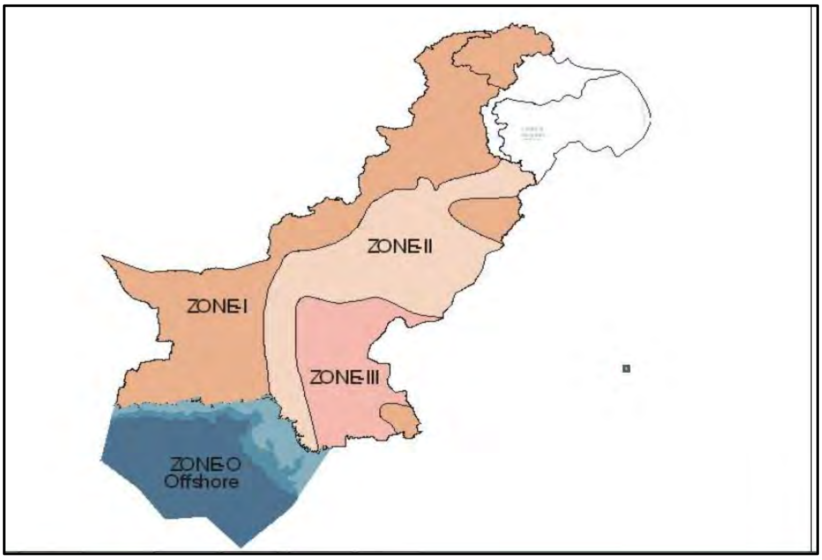
According to the data of DGGas (Directorate General of Gas), the natural gas reserve of Pakistan in 2013-14 is 24.7 Tcf. For aiming the development of on-shore and off-shore concessions, MPNR made tendering to IOC (International Oil Companies) in October 2012. However, it was postponed to March 2013. As of October 2014, MPNR and IOC are continuing the negotiation for the development, and the production amount is not clear yet. The following table shows risk and estimated cost by ZONE (development concession).

Table 4-9 Gas Concessions of On-shore and Off-shore, Risk and Production Cost

	Zone	Risk and cost	Estimated cost
On-shore	Existing wells		5.0 US$/MMBtu
	ZONE1 (35 blocks)	High risk & high cost	7.0 US$/MMBtu
	ZONE2 (18 blocks)	Medium risk & high to medium cost	6.5 US$/MMBtu
	ZONE3 (7 blocks)	Low risk & low cost	6.0 US$/MMBtu
Off-shore	Shallow		7.0 US$/MMBtu
	Deep		8.0 US$/MMBtu
	Ultra deep		9.0 US$/MMBtu

Note: The gas prices are Well Head Price, while it is assumed that the range of crude oil price is 70~110 US$/bbl.
Note: The gas prices of shallow and deep off-shore fields are estimated by JICA study team based on the gas price of Ultra deep sea estimated by the Government.
Note: Pakistan gas heat value (HHV) is 950 Btu/scf.

(Source : MPNR The ministry issued Invitation to Bid on October 2012)



(Source : Petroleum Exploration & Production Policy 2012)

Figure 4-2 Concession Blocks and Off-shore Gas Fields

(8) Iran - Pakistan (IP) gas pipeline

This project is to supply gas by pipeline from South Pars gas fields in Iran to Pakistan border. In 2009, the following contents are signed between Iran and Pakistan government.

1. In 2009, the governmental agreement was signed by the presidents of both Pakistan and Iran
2. The valid period of the natural gas trading agreement is 25 years, effective after 13th June 2010. Natural gas of 7.8 Bcma (750 MMcfd) would be supplied by December 2014.
3. Regarding natural gas price, Iran proposes 13.4% * Brent crude oil price and Pakistan requests 12 % * Brent crude oil price[4]. (it is still in negotiation stage)

Note: The total investment is 7.5 billion US$ to construct the gas pipeline, and Pakistan has to bear an expense of 1.5 billion US$ for the investment.

(Source: Natural Gas in Pakistan, Current issues and Trends by Oxford Institute)

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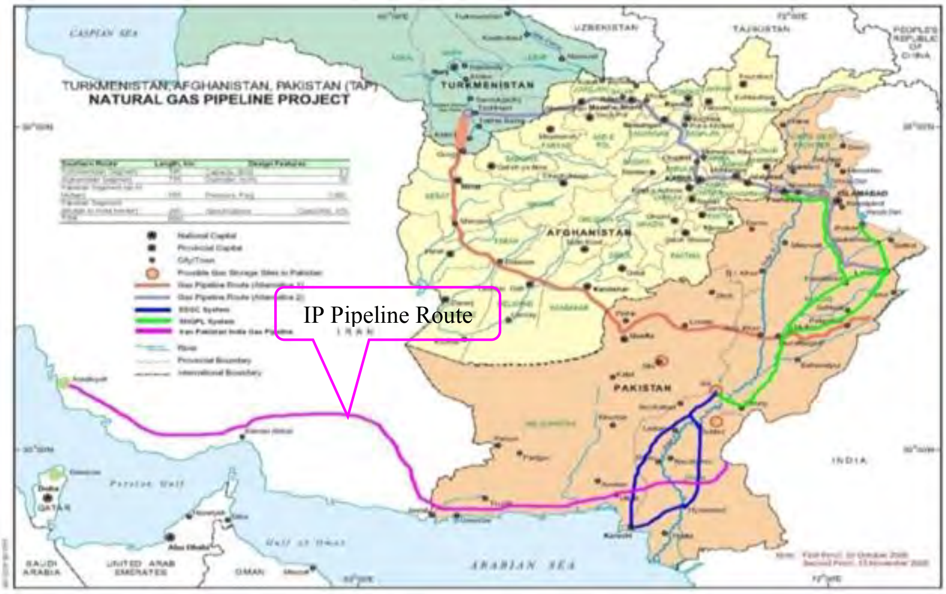
[4] Bent crude oil is one that occupies major position in the crude oil price market. And it is a low sulfur content light oil that is mined from the Brent oil field in the North Sea of the United Kingdom.

However, the project has not been realized due to political issues between Iran and Western countries, including USA, as of December 2014. The pipeline already has been constructed from gas production plant area in Assaluyeh to Shehr in Iran, which distance is 900 km. Meanwhile, the remaining pipeline length to be constructed is only about 100 – 200 km. The natural gas receiving base in Pakistan is located about 700km from the border but the pipeline and base facility have not constructed yet. The Pakistan government approved the budget of 1.5 billion US$ or the investment in January 2013. At the same time, Iran government proposed capital loan of 500 million US$ to Pakistan government. Both governments have agreed to complete the construction of pipeline by the end of 2015.

According to ISGS as of Dec. 2014, although all arrangement has completed, there is no progress of the project due to economic sanction by the western countries to Iran. Even if construction is commenced since 2015, it will spend 3 years by completion, hence, the start of operation will be the year of 2018 or 2019 at earliest.



Note: The pink line along Arabian Sea is Iran-Pakistan gas pipeline route.

(Source: ISGS)

Figure 4-3 Iran – Pakistan Gas Pipeline Route

(9) Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline

The TAPI gas pipeline project has been proposed in 2004 supported by ADB. The project is to supply natural gas produced in South Yolotan-Osman and the neighboring gas fields in Turkmenistan to Afghanistan, Pakistan and India. The contents of the agreement signed by the related countries in December 2010 are shown in the following table.

Table 4-10 Description of Business of TAPI

Items	Contents
Pipeline length	1,680 km
Transfer volume	33 Bcma
Investment （as of 2008）	7.6 billion US$
Diameter of the pipeline	56 inch
Gas supply term	30 years
Starting year of gas supply	From the year of 2017
Gas consumption (Afghanistan)	5 Bcma
Gas consumption （Pakistan）	14 Bcma
Gas consumption （India）	14 Bcma

(Source : Natural gas in Pakistan published by Oxford Institute)

After that, Turkmenistan has proposed to supply natural gas not from South Yolotan-Osman but from Dauletabad gas fields. Moreover, Turkmenistan gives the project status of “ East – West pipeline” and is thinking of further expansion. In May 2012, the sales agreement was signed among Turkmenistan, Pakistan and India.

Table 4-11 Estimated of TAPI Price (Crude Oil Price : 100 US$ / bbl)

Location at trading	Gas price
Turkmenistan Border Price	9.5 US$ / MMBtu
Transit fees	0.5 US$ / MMBtu
Pakistan border price	11.9 US$ / MMBtu

Note: Natural gas price at Pakistan border is estimated by 12 % Brent

Note: The pipeline length in Afghanistan is 735 km.

Note: Gas production in Turkmenistan is 84 Bcma, and 65 Bcma is exported to China

(Source : Natural gas in Pakistan published by Oxford Institute)

Since the pipeline route of the project is designed through Afghanistan, it is still unclear whether or not the project can be commenced from 2017. In the meeting with ADB in Islamabad, ADB officer’s affirmation was not obtained. According to the survey by Oxford Institute in 2013, the Institute predicts that the project will be started by 2020.

In addition, according to the information from ISGS, the two routes in the following map have been examined. As of December 2014, there is high possibility to select the south route (red line) due to the security problems in the north Afghanistan route (green line).

(Source : ISGS & Oxford Institute Studies)

Figure 4-4 Pipeline Route of TAPI

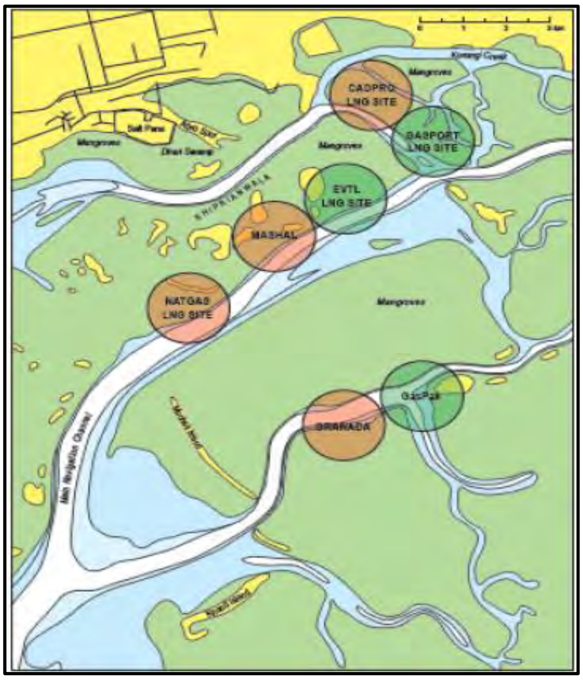
(10) LNG import

Until now, LNG import business has not progressed due to strict regulations of OGRA (Oil and Gas regulatory Authority), such as LNG purchasing price at receiving port, transfer cost and sales price to consumers. Especially, there was a big constraint due to price restrictions imposed by government regulations. From 2011, the Government started to alleviate regulations including the LNG purchasing price at the receiving port and transfer cost, whereas the regulation of sales price to consumers is still regulated. As of December 2014, the companies that have announced its participation in LNG import business are; Engro Elengy (EPTL), Global Energy Infrastructure (GEI). Pakistan Gasport, Daewoo(DSME) and Fauji Oil Terminal, etc. The licensed companies from OGRA are the three of above mentioned companies excluding Fauji Oil Therminal. The LNG floating terminals of three companies will be constructed in offshore wetland area of Port Qasim (35km Southeast from Karachi). The LNG business contents are described in the following table.

Table 4-12 LNG Import Business Company and Quantity of LNG

Engro Elengy (EPTL)	400 MMcfd (Start at March 2015)
Global Energy Infrastructure (GEI)	500 MMcfd (Starting date not announced)
Pakistan Gasport	400 MMcfd (Starting date not announced)

(Source: ISGS)



Note: Port Qasim is located 35 km away from Karachi

Note: The green parts in the above are wetland, and the white lines are creeks.

(Source : Port Qasim Authority)

Figure 4-5 LNG Floating Terminals at Off-shore of Port Qasim

According to SSGCL, Pakistan State Oil, SSGCL and ISGS had negotiated concerning the LNG import business with Qatar in May 2014. Consequently, Pakistan agreed with Qatar to start import LNG from March 2015. The contents are as follows;

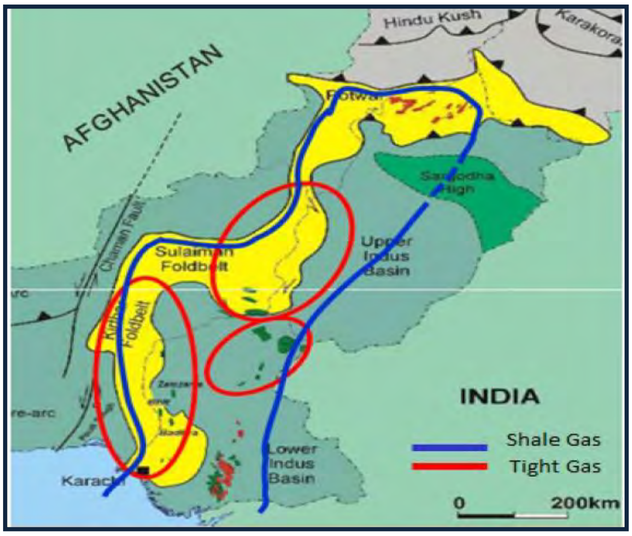
- Regasification Floating plant
- At the beginning, the LNG import will be 200mmcfd and may be increased to 400mmcfd in the end.
- The purchasing price will be spot price.
- LNG will sent to inland by SSGCL (1/3) and SNGPL (2/3)

By the governmental policy, bulk consumers will be given the highest priority concerning the LNG imported from Qatar. And the company importing LNG in Pakistan will be Elengy Terminal Pakistan Limited (Subsidiary company of Engro Corp). LNG will be sold across the country through SSGCL and SNGPL pipelines, however, the gas price for imported LNG is still not set as of October 2014. There is information that the price may be applied by the weighted average between domestic natural gas and LNG prices.

According to KE, the construction of LNG receiving base will take 3 years, therefore, the all planned LNG business companies may start supplying gas by 2019 or 2020. At that time, the quantity of LNG will be 1,200~1,300 MMcfd and increase to 1,700 MMcfd by 2022.

(11) Shale and tight gas

According to the survey conducted by Petroleum Institute Pakistan in 2011, there are shale gas reserves with 51 Tcf and tight gas reserves with 40 Tcf in Pakistan. The direction on tight gas development and production is published in 2011. As of April 2015, the tight gas is not produced in Pakistan.



(Source : Petroleum Institute Pakistan in 2011)

Figure 4-6 Reserves of Shale / Tight Gas

Under the circumstances, USAID supports for Pakistan to develop the shale and tight gas. Pakistan is developing shale gas wells in Sindh with the support of USAID. USAID deems the development of shale gas is successful. As of March 2015, the presumption of shale gas development in Sindh is as follows;

① The shale gas will be produced with 105 MMcfd in 2015.

② The business production in Sindh will be started after 2020.

According to “Shale Gas Resource and Technology Assessment in Middle & Lower Indus Basin of Pakistan Milestone 5 Report” published by USAID in August 2015, the following items are described.

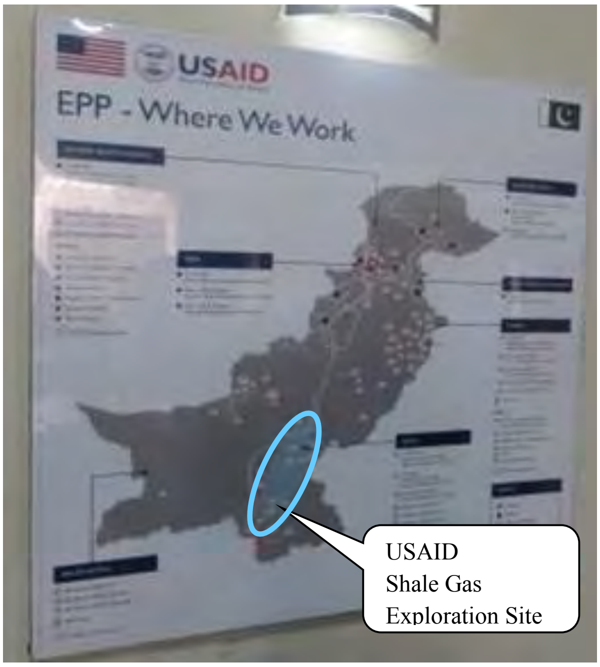
③ Useful technologies for Shale gas production

④ Useful infrastructure of roads, pipelines and water supply

⑤ Work plans for optimum shale gas exploration

⑥ Calculation of production costs

⑦ Current regulatory and capital expenditures



(Source : USAID)

Figure 4-7 Location of Shale / Tight Gas Development in Sindh

The shale gas production costs in Middle and Lower Indus Basins are calculated in the report. The costs are calculated for three cases that are short term (less than 5 years), middle term (5 to 10 years) and long term (more than 10 years) as shown in the below table.

Table 4-13 Shale gas production cost (Well head)

(Unit : US$/MMBtu)

Case	Short term	Middle term	Long term
Base case (Operator take 20%)	11.21	9.94	8.67
High case (Operator take 25%)	11.91	10.55	9.19
Low case (Tax and royalty holiday for 10years)	9.07	8.05	7.02

Note: The above costs are calculated under the precondition of shale gas promotion policy of Government

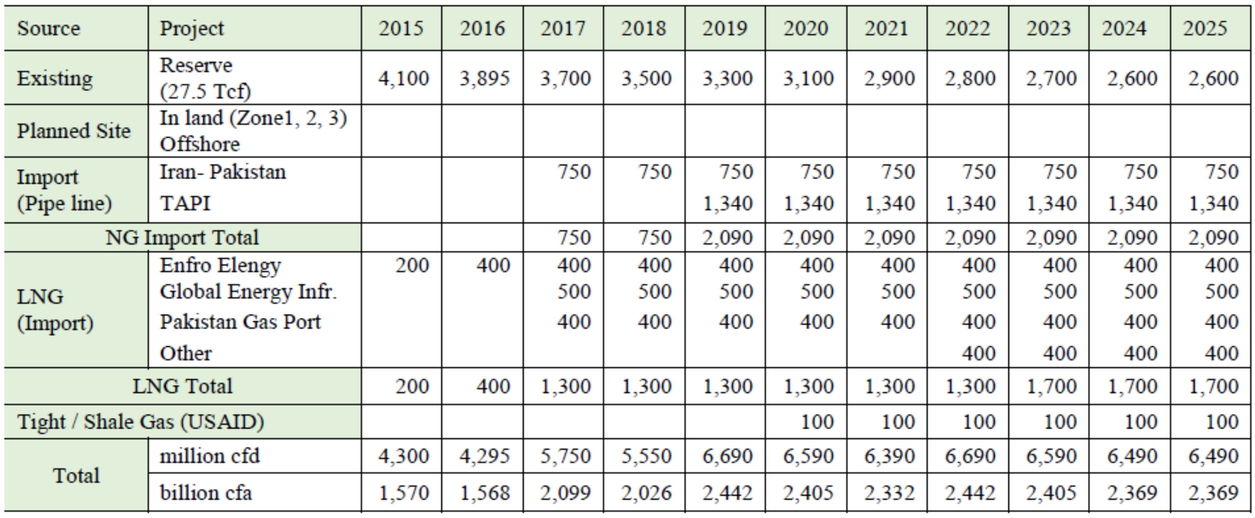
Note: In Low case, operator take is 20% and there are no tax and no royalty for 10 years

Note: Low case cost is suitable when comparing shale gas costs to the imported gas price.

(12) Future natural gas supply

The summary of natural gas supply plans in Pakistan as of March 2015 is shown in Table 4-14and Table 4-15.

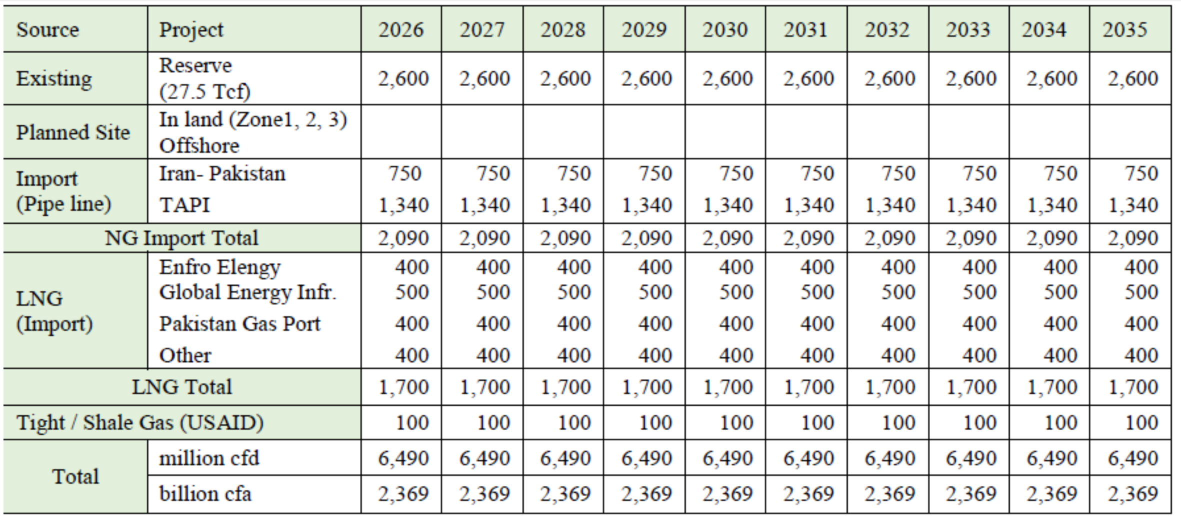
Table 4-14 Natural Gas Supply Plans (from 2015 to 2025)



Source	Project	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing	Reserve (27.5 Tcf)	4,100	3,895	3,700	3,500	3,300	3,100	2,900	2,800	2,700	2,600	2,600
Planned Site	In land (Zone1, 2, 3) Offshore											
Import (Pipe line)	Iran- Pakistan			750	750	750	750	750	750	750	750	750
	TAPI					1,340	1,340	1,340	1,340	1,340	1,340	1,340
NG Import Total				750	750	2,090	2,090	2,090	2,090	2,090	2,090	2,090
LNG (Import)	Enfro Elengy	200	400	400	400	400	400	400	400	400	400	400
	Global Energy Infr.			500	500	500	500	500	500	500	500	500
	Pakistan Gas Port			400	400	400	400	400	400	400	400	400
	Other								400	400	400	400
LNG Total		200	400	1,300	1,300	1,300	1,300	1,300	1,300	1,700	1,700	1,700
Tight / Shale Gas (USAID)							100	100	100	100	100	100
Total	million cfd	4,300	4,295	5,750	5,550	6,690	6,590	6,390	6,690	6,590	6,490	6,490
	billion cfa	1,570	1,568	2,099	2,026	2,442	2,405	2,332	2,442	2,405	2,369	2,369

(Source: JICA Project Team)

Table 4-15 Natural Gas Supply Plans (from 2026 to 2035)



Source	Project	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Existing	Reserve (27.5 Tcf)	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600	2,600
Planned Site	In land (Zone1, 2, 3) Offshore										
Import (Pipe line)	Iran- Pakistan	750	750	750	750	750	750	750	750	750	750
	TAPI	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340	1,340
NG Import Total		2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090	2,090
LNG (Import)	Enfro Elengy	400	400	400	400	400	400	400	400	400	400
	Global Energy Infr.	500	500	500	500	500	500	500	500	500	500
	Pakistan Gas Port	400	400	400	400	400	400	400	400	400	400
	Other	400	400	400	400	400	400	400	400	400	400
LNG Total		1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Tight / Shale Gas (USAID)		100	100	100	100	100	100	100	100	100	100
Total	million cfd	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490	6,490
	billion cfa	2,369	2,369	2,369	2,369	2,369	2,369	2,369	2,369	2,369	2,369

(Source: JICA Project Team)

4.2.3 Coal

(1) Coal reserve

The following table is regional coal reserves in Pakistan as of Jun. 2013. Thar coal takes a hold on 175 billion tons out of the total coal reserve in Pakistan of 186 billion tons. The future coal supply of Pakistan depends heavily on Thar coal development.

In addition, the sum of the measured reserves of 3.45 billion tons and the indicated reserves of 11,68 billion tons is around 15 billion tons. When it is assumed that the future annual mining volume is 200 million tons, the minable duration will be 75 years. Meanwhile, the fuel consumption volume per annum is 5.1 million tons in the case of coal fired thermal which the installed capacity is 1,000MW, annual plant factor is 75% and heat rate is 40%. Therefore, in the case that 90% of coal production of 200 million tons is used for coal thermal power plants, the installed capacity of 35GW can be developed.

Table 4-16 Coal Reserves in Pakistan (as of Jun. 2013)

(Unit : million ton)

Subsector	Total	Measured Reserves	Indicated	Inferred	Hypothetical
Balochistan	217	54	13	134	16
Punjab	235	55	24	11	145
Sindh	185,457	3,339	11,635	56,346	114,137
KPK	90	2	5	84	
Azad Kashmir	9	1	1	7	
Total	186,008	3,451	11,678	56,582	114,298
Thar	175,000				

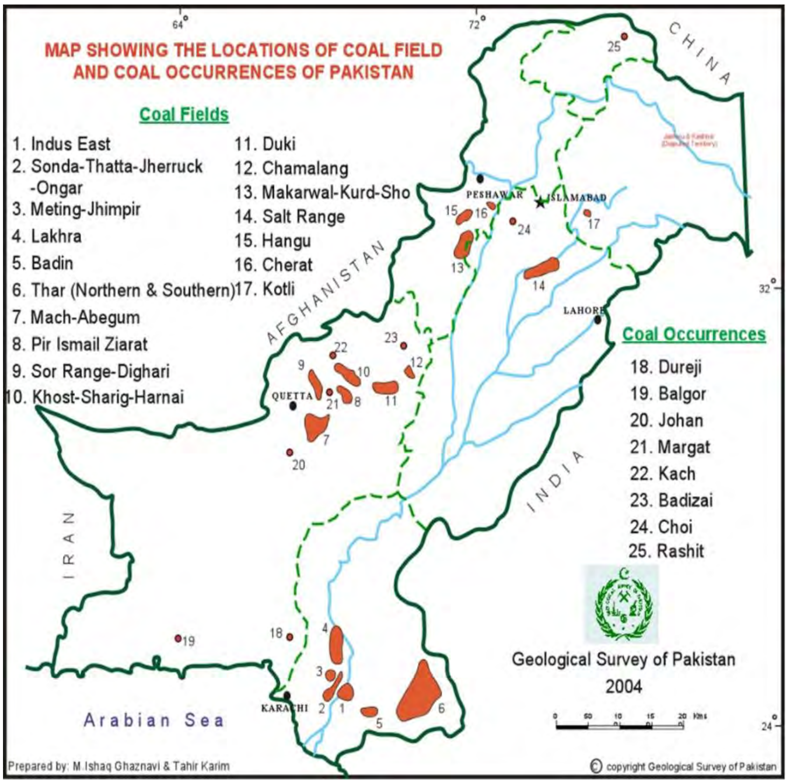
Measured: Coal has been determined within error margin less than 20 %

Indicated: Coal has been estimated from analyses and from reasonable geologic inferences.

Inferred: Coal has been estimated from geologic projections.

Hypothetical: Undiscovered coal to be reasonably expected to exist in known mining districts

(Source: Pakistan Energy Yearbook 2013)



(Source : TCEB)

Figure 4-8 Locations of Coal Fields

(2) Coal production and import performance

The coal production in Pakistan has decreased from 4.1 million tons in 2007-08 to 3.3 million tons in 2012-13. In addition, the coal import of Pakistan also has decreased from 6.0 million tons in 2008 to 3.7 million tons in 2012-13. Accordingly, the coal consumption during the same period has decreased minus 7.4 % / annum.

Table 4-17 Coal Production and Import

(Unit : 1000 tons)

Sector	Subsector	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	AGR(%)
Production	Balochistan	2,269	2,057	1,503	1,342	1,334	1,150	-12.7
	Punjab	554	572	591	620	624	605	1.8
	Sindh	1,059	841	1,200	1,101	1,258	1,158	1.8
	KPK/FATA	243	269	186	387	395	266	1.8
	Total : 1000ton	4,124	3,738	3,481	3,450	3,612	3,179	-5.1
	Total : 1000toe	1,845	1,672	1,557	1,544	1,616	1,422	-5.1
Import	Total : 1000ton	5,987	4,652	4,658	4,267	4,057	3,710	-9.1
	Total : 1000toe	3,939	3,060	3,064	2,807	2,669	2,441	-9.1
Supply	Total : 1000ton	10,111	8,390	8,138	7,717	7,669	6,889	-7.4
	Total : 1000toe	5,784	4,732	4,622	4,351	4,285	3,863	-7.8

Note: The reserves as of Jun. 2013

(Source : Pakistan Energy Yearbook 2013)

(3) Coal consumption

More than 90 % of the coal production in Pakistan is mainly consumed by brick and cement production, and the coal consumption of power sector in 2012-13 was only 1% of the total consumption. The coal consumption in power sector from 2007-08 to 2012-13 had decreased by 17 % / annum, and it was the maximum attrition rate among all coal consumers during that period. The coal consumption in steel industry had also decreased by an average rate of 10 % per year. The coal consumption in the whole country had decreased more than 7 % / annum during the same period.

Table 4-18 Coal Consumption by Sector

(Unit : 1000 tons)

Sector	Subsector	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	AGR(%)
Consumption	Domestic	1.0	0.8					
1000 tons	Brick kiln Industry	3,760.0	3,274.0	3,005.0	3,003.0	3,108.0	2,696.0	-6.4
	Cement /Other	5,721.0	3,801.8	4,577.0	4,187.9	4,181.9	3,865.9	-7.5
	Pak steel	466.0	1,200.0	430.8	429.1	275.0	264.0	-10.7
	Power(WAPDA)	162.2	112.5	125.5	96.5	104.6	63.0	-17.2
	Total	10,110.2	8,389.1	8,138.3	7,716.5	7,669.5	6,888.9	-7.4
Consumption	Domestic	0.4	0.4					
1000 toe	Brick kiln Industry	1,682.4	1,465.1	1,344.5	1,343.8	1,390.6	1,206.2	-6.4
	Cement /Other	3,721.7	2,427.5	2,937.5	2,681.7	2,667.1	2,455.0	-8.0
	Pak steel	306.6	789.4	283.4	282.3	180.9	173.7	-10.7
	Power(WAPDA)	72.6	50.3	56.1	43.2	46.8	28.2	-17.2
	Total	5,783.7	4,732.7	4,621.5	4,351.0	4,285.4	3,863.1	-7.8

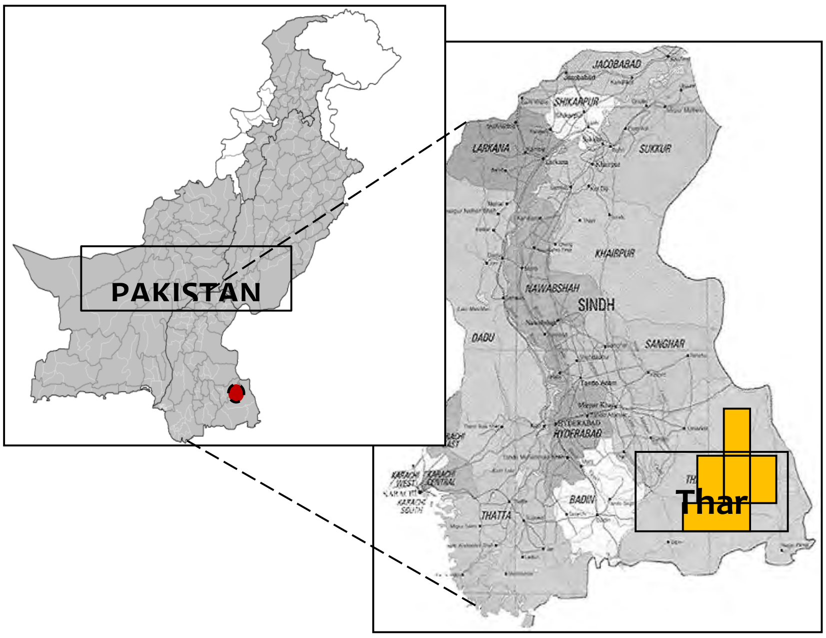
(Source : Pakistan Energy Yearbook 2013)

(4) Development situation of Thar coal concession

According to the TCEB (Thar Coal & Energy Board), Thar Coalfield is spread across the area of 9,000 sq km. Government of Sindh has developed 12 Blocks in part of this coalfield having approximately area of 1200 sq km. In addition, according to SECNC ((Sindh Engro Coal Mining Company) of Block II investor, the quality of coal is reported as shown in Table 4-19.

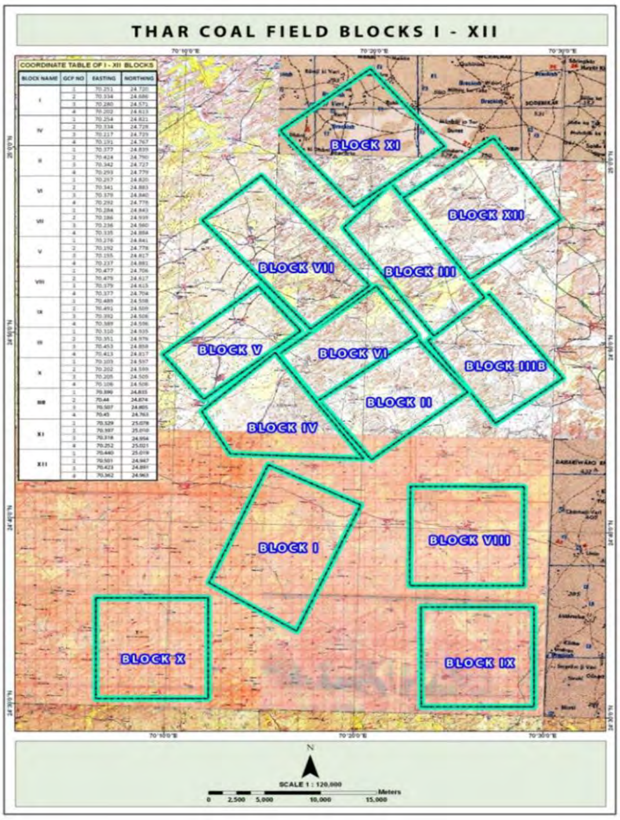
Table 4-19 Quality of Thar Coal (Lignite)

Heating Value (Net) (kcal/kg)	Sulfur (%)	Ash (%)	Moisture (%)
2,770	**1.07**	**7.8**	**47.46**



(Source : TCEB)

Figure 4-9 Location of Thar Coal



(Source : TCEB)

Figure 4-10 Coal Mine Concession Blocks in Thar

As of Mar. 2015, the power generation development plans by coal mine concession block are shown in the following table.

Table 4-20 Coal and Power Generation Development Plan by Mine Concession Block

Block	Investment Firm	Exploitable Coal Reserve (million tons)	Power Development Projects (MW)		Expected Commercial Operation Year
Block I	SSRL(China-Pakistan)	3,657	2 x 660	1,320	2018
Block II	SECMC Pakistan	1,584	2 x 330	660	2017-2018
			2 x 330	660	2019
			4 x 660	2,640	2021
Block III	Asia Power UK	2,007	2 x 660	1,320	2021-2022
Block IV	Harbin Electric China	2,572	2 x 660	1,320	2020-2021
Block V	UCG Project Pakistan	1,394	2 x 5	10	2021
Block VI	Oracle(China-UK)	1,423	2 x 600	1,200	2019
Block VII	FFC Pakistan	2,176	2 x 660	1,320	—

SSRL : The Sino-Sindh Resources (Pvt) Limited
SECMC : Sindh Engro Coal Mining Company
UCG : Underground Coal Gasification

(Source : TCEB)

As of October 2014, contracts with contractors including EPC (Engineering, Procurement and Construction) and financial open are underway for Block I, Block II and Block VI among the above coal mine blocks as shown in the following table.

Table 4-21 Development Companies for Thar Coal (as of October 2014)

Blocks	Company and Investor
Block I	Block I is developed by private financing of China Mechanical Engineering Company (CMEC). The plan is to develop power generation of 2x660 MW with investment of 1.1 billion US$.
Block II	The total investment of coal mining and power generation for the phase 1 is 2.0 billion US$. Sindh Gov. covers 51 % of the fund. The other fund is invested by the below companies. ➢ Engro,Hub-Co ➢ Habib bank ➢ China Mechanical Engineering Company Business contents are as follows; ➢ 660MW in the beginning stage, and it will eventually increase to 4,000MW. ➢ Coal production is planned with 6.5million ton / annum in the beginning stage, It will eventually increase to 20 million ton / annum. ➢ The average calorie of the coal is 2770kcal/kg. ➢ Desulfurization equipment is installed.
Block VI	Block VI is being developed by Oracle Coalfields, PLC (UK). The company has signed an EPC Framework Agreement with SEPCO for construction of initially a 600 MW mine mouth power plant and for the development of 4.0 MT per year open pit mine to supply coal lignite to power plant. Overall plan is an 8.0 MTPA mine and associated mine mouth Power Plants of 1200 MW.

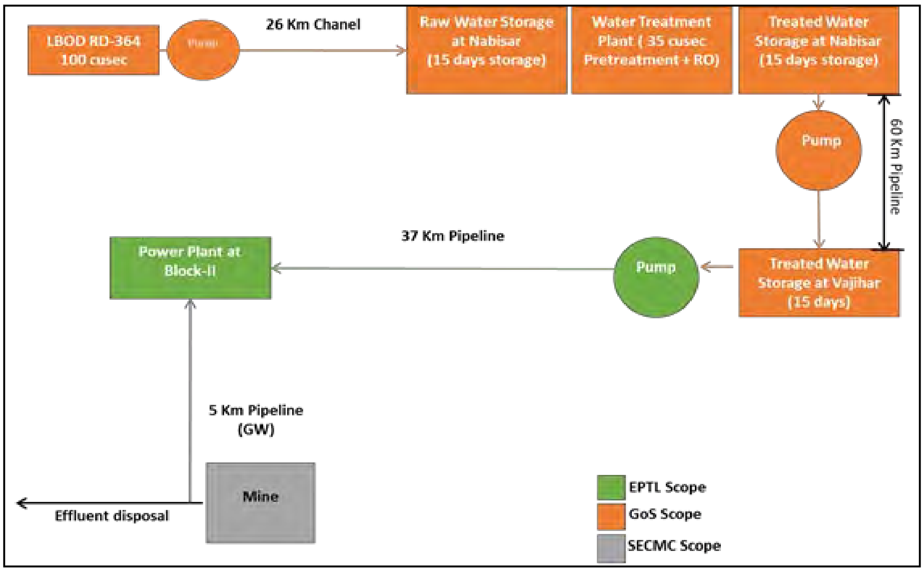
(Source : TCEB)

The following pictures are provided by SECMC (Sindh Engro Coal Mining Company) of Block II investor. It shows the development situation of Block II in Thar coal mining area at the beginning of 2015.

(Source : SECMC Block II)

Figure 4-11 Excavation of Ground Surface in Thar Coal Block II

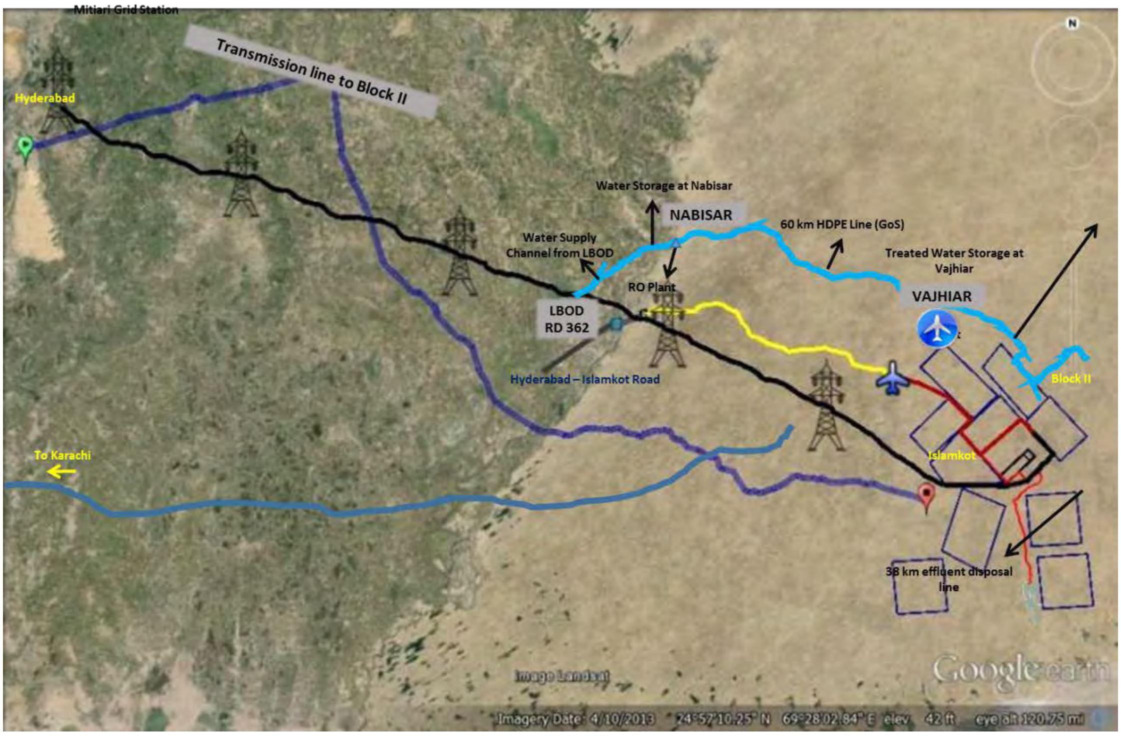
Indus River water is planned to supply to the Thar Coal Area based on LBOD (Left Bank Outfall Drainage) project. Sindh government invests and is constructing 26km open channel & 60km pipeline, RO treatment plant, etc. as Phase-1. And SECMC will construct 42km pipeline and pumping station as Phase-2. Construction works are in progress of 50% and will be completed at the end of 2016.



(Source : SECMC Block II)

Figure 4-12 Water Supply System Plan

The power line (500kV transmission) is also planned with NTDC, which route is shown in Figure 4-13.



(Source : SECMC Block II)

Figure 4-13 500kV Transmission Route

If the above mentioned power development projects could progress as planned, the total installed capacity would be 9.130MW by 2021-22 as shown in the following table.

Table 4-22 Power Development Plan in Thar Coal Area

Expected Commercial Operation Year	Block	Investment Firm	Power Development Projects (MW)		Accumulative (MW)
2016-17	Block V	UCG Project Pakistan	2 x 5	10	10
2017-18	Block II Phase1	SECMC Pakistan	2 x 330	660	670
2018	Block I	SSRL(China-Pakistan)	2 x 660	1,320	1,990
2018-19	Block VI	Oracle(China-UK)	2 x 600	1,200	3,190
2019	Block II Phase2	SECMC Pakistan	2 x 330	660	3,850
2020-21	Block IV	Harbin Electric China	2 x 660	1,320	5,170
2021	Block II Phase3	SECMC Pakistan	4 x 660	2,640	7,810
2021-22	Block III	Asia Power UK	2 x 660	1,320	9,130
—	Block VII	FFC Pakistan	2 x 660	1,320	10,450

(Source : JICA Project Team prepared based on TCEB data)

(5) Prediction of coal production

As of March 2015, the coal production in Pakistan is predicted as shown in Table 4-23. Maximum coal production will be 76 million tons per annum by 2023-24.

Table 4-23 Prediction of Coal Production

(Unit : million tons)

Project	Reserve	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Balochistan Coal	67	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Punjub Coal	79	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Thar Coal	14,811										
Block I				6.5	6.5	6.5	6.5	6.5	14.8	14.8	14.8
Block II			3.8	3.8	6.5	6.5	6.5	22.0	22.0	22.0	22.0
Block III								6.5	14.8	14.8	14.8
Block IV						6.5	6.5	6.5	14.8	14.8	14.8
Block V											
Block VI				4.0	4.0	4.0	4.0	8.0	8.0	8.0	8.0
Block VII											
Coal Total	14,957	2.0	5.8	16.3	19.0	25.5	25.5	51.5	76.4	76.4	76.4

Note: The above productions by Block are predicted based on development plan of the domestic coal thermal power plants

(Source : JICA Project Team)

4.2.4 Oil

(1) Oil reserves

Current crude oil reserve in Pakistan is 371 million bbl (barrel) as of Jun. 2013, the remaining reserve is one third of the original reserve of 1,102 million bbl.

Table 4-24 Crude Oil Reserve (As of Jun. 2013)

Type	Unit	Original Recoverable	Cumulative Production	Balance Recoverable
Country total	million bbl	1102.6	731.5	371.0
	million Toe	147.9	98.1	49.8
British Gas	1000 bbl	1,350		1,350
BHP Billiton Pakistan Pty ltd	1000 bbl	11,300	8,400	2,900
MOL Pakistan Oil & Gas Co	1000 bbl	65,000	13,700	51,300
Chevron Pakistan Limited	1000 bbl	57,701	56,403	1,298
Pakistan Oil fields Limited	1000 bbl	194,580	166,080	28,500
Pakistan Petroleum Limited	1000 bbl	68,523	31,629	36,894
United Energy Pakistan Limited	1000 bbl	222,546	189,665	32,881
Other	1000 bbl	481,600	265,623	215,877

(Source : DGPC)

(2) Crude oil supply

The production and import of crude oil has not increased in the past five years, however, the oil product import has increased by an average rate of 3 % / annum during that period, which means that domestic oil demand has not decreased. The cause of this situation is brought about by the lack of international competitiveness due to small scale domestic refineries comparing to Saudi Arabia and India, and shortage of oil refinery capacity and decline of plant factor due to high price of international crude oil.

Table 4-25 Crude Oil Production, Import and Oil Product Import

Type	Province		2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	AGR(%)
Crude Production	Balochistan	1000 bbl	26	24	22	22	20	20	–5.0
	KPK	1000 bbl	4,689	4,770	5,303	7,843	9,470	11,246	19.1
	Punjab	1000 bbl	6,518	4,909	5,121	5,164	5,400	5,263	–4.2
	Sindh	1000 bbl	14,370	14,330	13,260	11,012	9,683	11,311	–4.7
	Total	1000 bbl	25,603	24,033	23,706	24,041	24,573	27,841	1.7
	Total	1000toe	3,867	3,630	3,581	3,631	3,712	4,205	1.7
Import & Export	Crude oil import	1000ton	8,424	8,061	6,888	658	6,113	7,402	
		1000toe	8,708	8,333	7,121	6,883	6,319	7,652	–2.6
	Oil products import	1000ton	9,025	9,974	11,178	12,371	11,507	10,489	3.1
		1000toe	9,158	10,094	11,321	12,501	11,624	10,624	3.0
	Oil products export	1000ton	1,337	1,212	1,450	1,573	872	708	–11.9
		1000toe	1,416	1,278	1,523	1,655	927	756	–11.8
Domestic petro use	Total	1000toe	16,450	17,149	16,920	17,729	17,016	17,520	1.3

(Source : DGOil)

(3) Oil refinery

There are 9 oil refinery plants in Pakistan as of 2013 which total capacity is 340,000 bbl / day. The even maximum capacity of the oil refinery plant in Pakistan is less than 100,000 bbl / day, it means that the plant scale in Pakistan is extremely small scale in comparison with the current oil refinery plants in other countries. Therefore, the oil product cost in Pakistan is high and the plant factor in 2013 was around 50 %, and average oil refinery amount is 190,000 bbl / day. Therefore, the import of oil products increases

Table 4-26 Oil Refinery Capacity by Company

(Unit : million ton / year)

Companies	2008	2009	2010	2011	2012	2013	AGR (%)
Attock Refinery	1.96	1.92	1.92	1.92	1.92	1.96	0.0
Byco Petroleum Pakistan	1.50	1.50	1.74	1.70	1.74	1.74	3.0
Byco Oil Pakistan						5.45	
Dhodak Refinery	0.12	0.11	0.11	0.11	0.11	0.11	-1.7
ENAR-I Pet Refinery	0.11	0.11	0.11	0.11	0.11	0.11	0.0
ENAR-II Pet Refinery						0.22	
National Refinery	2.71	2.71	2.71	2.71	2.71	2.71	0.0
Pak Arab Refinery	4.50	4.50	4.50	4.50	4.50	4.50	0.0
Pakistan Refinery	2.10	2.10	2.10	2.10	2.10	2.10	0.0
Total	13.00	12.95	13.19	13.15	13.19	18.90	7.8

(Source : DGOil and DGPC)

Table 4-27 Crude Oil Refinery Amount by Company

(Unit : million ton / year)

Companies	2008	2009	2010	2011	2012	2013	AGR (%)
Attock Refinery	1,926	1,697	1,743	1,838	1,872	1,939	0.1
Byco Petroleum Pakistan	818	944	722	458	127	781	-0.9
Byco Oil Pakistan							
Dhodak Refinery	64	17	8	5			-100.0
ENAR-I Pet Refinery	100	103	103	95	108	185	13.2
ENAR-II Pet Refinery							
National Refinery	2,734	2,424	2,139	2,421	2,275	2,136	-4.8
Pak Arab Refinery	2,868	3,664	3,556	3,358	3,167	4,123	1.3
Pakistan Refinery	2,180	1,887	1,597	1,599	1,642	1,582	-6.2
Total	11,689	10,736	9,867	9,774	9,190	10,746	-1.7

(Source : Oil company advisory committee in Pakistan)

(4) Oil product consumption by sector

Transportation sector consumed 50 % of the total oil product and the power sector consumed 40%. The oil product consumption in the power sector has increased slightly from 2007-08 to 2012-13. It means that the oil product has complemented the shortage of natural gas in the power sector.

Table 4-28 Oil Product Consumption by Sector

	Sector		2008	2009	2010	2011	2012	2013	AGR(%)
Unit ton	Domestc	1000 ton /year	120.9	97.3	90.3	85.4	79.4	97.8	-4.2
	Industry	1000 ton /year	1,071.2	969.2	984.7	1,355.4	1,419.1	1,379.1	5.2
	Agriculture	1000 ton /year	109.4	69.8	58.1	40.6	23.3	31.8	-21.9
	Transportation	1000 ton /year	9,384.5	8,837.2	8,860.9	8,892.3	9,265.9	9,817.5	0.9
	Power	1000 ton /year	7,083.9	7,570.4	8,814.3	8,139.0	7,594.7	7,749.0	1.8
	Other Government	1000 ton /year	310.5	367.3	323.5	373.7	295.8	317.8	0.5
	Total	1000 toe /year	18,080.4	17,911.2	19,131.8	18,886.4	18,678.2	19,393.0	1.4
Unit toe	Domestc	1000 toe /year	124.5	100.2	93.0	88.0	81.8	100.7	-4.2
	Industry	1000 toe /year	1,103.3	998.3	1,014.2	1,396.1	1,461.7	1,420.5	5.2
	Agriculture	1000 toe /year	112.7	71.9	59.8	41.8	24.0	32.8	-21.9
	Transportation	1000 toe /year	9,666.0	9,102.3	9,126.7	9,159.1	9,543.9	10,112.0	0.9
	Power	1000 toe /year	7,296.4	7,797.5	9,078.7	8,383.2	7,822.5	7,981.5	1.8
	Other Government	1000 toe /year	319.8	378.3	333.2	384.9	304.7	327.3	0.5
	Total	1000 toe /year	18,622.8	18,448.5	19,705.8	19,453.0	19,238.5	19,974.8	1.4
Contribution	Domestc	%	0.7	0.5	0.5	0.5	0.4	0.5	-5.5
	Industry	%	5.9	5.4	5.1	7.2	7.6	7.1	3.7
	Agriculture	%	0.6	0.4	0.3	0.2	0.1	0.2	-23.0
	Transportation	%	51.9	49.3	46.3	47.1	49.6	50.6	-0.5
	Power	%	39.2	42.3	46.1	43.1	40.7	40.0	0.4
	Other Government	%	1.7	2.1	1.7	2.0	1.6	1.6	-0.9
	Total	%	100.0	100.0	100.0	100.0	100.0	100.0	0.0

(Source : Oil company advisory committee in Pakistan)

(5) Issues on oil product

Issues on oil product are as follows;

- Since the shortage of oil refinery capacity can be complemented by import of oil product, it would not be as serious as the natural gas situation.
- High crude oil price for the past several years raised the imported furnace oil price, the power sector that cannot help but use the imported furnace oil as an alternative fuel for domestic natural gas has faced serious financial problems. It stressed the importance of primary energy development such as crude oil, natural gas and LNG import.
- The issues on oil sector are; to develop large scale oil refineries and to integrate oil refineries for cost reduction, to consider the introduction of heavy oil cracking plants since the natural gas generation and coal fired generation gets into full swing whereas the consumption of the heavy oil for power generation decreases and heavy oil such as Furnace oil becomes redundant.

4.3 Transition of Fossil Fuel Prices

4.3.1 Natural Gas Price

Natural gas prices from 2005 to 2013 in Pakistan are shown in the below table. However, it is predicted that the future domestic natural gas prices will be affected to a large degree by the LNG price. Allotment of domestic natural gas and LNG supply for the power sector is not clear at present and future natural gas price for the power sector is still undetermined, whether to be based on the weighted average price between domestic natural gas price and LNG price. The future natural gas price for the power sector is not clear.

Table 4-29 Domestic Natural Gas Price

(Unit : Rs / MMBtu)

	1.Jun 2005	1.Jun 2006	1.Feb 2007	1.Jan 2008	1.Jan 2009	1.Jan 2010	7.Aug 2011	1 Jun 2012	1 Jan 2013
Domestic use	73.95	80.96	82.07	82.07	86.17	99.48	107.87	100.00	100.00
Commercial use	234.67	271.07	268.23	283.05	393.33	463.80	526.60	600.00	636.83
Industry	208.56	240.91	238.38	251.55	339.43	382.37	434.18	460.00	488.23
Captive power	208.56	240.91	238.38	251.55	339.43	382.37	434.18	460.00	488.23
Cement	240.28	277.55	305.15	335.67	454.95	536.42	609.10	700.00	742.97
Fertilizer as fuel	208.56	240.91	238.38	251.55	339.43	382.37	434.18	460.00	488.23
Power use from SNGPL/SSGCL	208.56	240.91	238.38	251.55	349.56	393.79	447.14	460.00	488.23
Power use for IPP					295.03	332.36	377.39	460.00	488.23
Raw Gas for WAPDA from Mari	195.95	226.34	223.96	236.64	328.42	369.97	420.10	460.00	488.23

Domestic use : category with '1.77 - 3.55 million Btu prices'
Commercial use : general use
Industry : general industry use

(Source : OGRA (Oil and Gas Regulatory Authority))

Table 4-30 International Natural Gas Price

	LNG Japan CIF (US$/mmBtu)	UK NBP price (US$/mmBtu)	German Import price (US$/mmBtu)	US Henry Hub (US$/mmBtu)	Crude oil WPI (US$/bbl)
2005	6.05	7.38	5.08	8.79	56.59
2006	7.14	7.87	7.85	6.76	66.02
2007	7.73	6.01	8.03	6.95	72.20
2008	12.55	10.79	11.56	8.85	100.06
2009	9.06	4.85	8.52	3.89	61.92
2010	10.91	6.56	8.01	4.39	79.45
2011	14.73	9.04	10.46	4.01	95.04
2012	16.75	9.46	11.03	2.76	94.13
2013	16.17	10.63	10.72	3.71	97.94
2014	(Oct.) 16.00				(Dec.) 57.00

(Source : BP Statistics 2014)

According to IEEJ (The institute of Energy Economics, Japan), it is predicted that the future natural gas price will continue to decrease until 2020 due to increase of shale gas production in USA and oil sand in Canada. Concerning the LNG price, the price is ranging between 10 US$/MMBtu and 16 US$/MMBtu during the year of 2014. There is a prospect of USA shale gas being imported at the price of 10 US$/MMBtu in 2017, therefore, the international LNG price could settle at 10 US$/MMBtu by 2020.

According to the Ministry of Planning, Development & Reform in Pakistan, Iran natural gas price is estimated as 80% of Crude oil price (13.3 % x Brent) and TAPI natural gas price is estimated as 65% of Crude oil price (10.8% x Brent). The natural gas price is calculated by the above estimation assuming crude oil prices as shown in the below table. In addition, the domestic natural gas unit cost composition is shown in Table 4-32.

Table 4-31 Imported Natural Gas Price Linked to Crude Oil Price

(Unit : US$/MMBtu)

Brent crude oil	TAPI-NG at birder price	Iran-NG at border price	Qatar-LNG Received price	Domestic gas price for power sector	Domestic gas average price for consumers
100 US$/bbl	10.8	13.3	16.7	4.8	5.6
90 US$/bbl	9.8	12.0	15.0	4.8	5.6
80 US$/bbl	8.7	10.7	13.3	4.8	5.6
70 US$/bbl	7.6	9.3	11.7	4.8	5.6
60 US$/bbl	6.5	8.0	10.0	4.8	5.6
50 US$/bbl	5.4	6.7	8.3	4.8	5.6

Note : Domestic gas prices are at Jan 2013 price

Table 4-32 Domestic Natural Gas Unit Cost Composition (as of 2012)

(Unit : US$/MMBtu)

	Elements	Unit cost
1	Production price	3.76
2	Royalty (12.5%)	0.54
3=1+2	Wellhead price	4.30
4	Excise Duty	0.09
5	T&D costs	0.37
6	Return on Assets	0.23
7	Other incomes/ Equalization	-0.19
8=3~7	Gov. purchasing price	4.80
9	Gas Development Surge	0.05
10=8+9	Notified consumer Price	4.85
11	General Sales tax	0.78
12=10+11	Consumer price	5.63

(Source : Natural gas in Pakistan and Bangladesh by Oxford Institute)

4.3.2 Coal Price

Future coal price in Pakistan will largely depend on the Thar coal price. Thar coal price is set at equivalent level to the international coal price for the time being, however, there is a possibility that Thar coal price becomes cheaper than the international coal price in the future in line with progress of exploration of Thar coal.

Table 4-33 International Coal Prices

(Unit : US$/ton)

Year	Australia FOB Price	US central Appalachian Coal Price	Japan coking Coal Import Price	Japan steam Coal Import Price	Asian market Price
2005	51.02	70.12	89.33	62.91	61,84
2006	52.60	62.96	93.46	63.04	56.47
2007	70.43	51.16	88.24	69.86	84.57
2008	136.18	118.79	179.03	122.81	148.06
2009	76.98	68.08	167.82	110.11	78.81
2010	106.04	71.63	158.95	105.19	105.43
2011	130.12	87.38	229.12	136.21	125.74
2012	130.25	72.06	191.46	133.61	105.50
2013	90.60	71.39	140.45	111.16	90.90
2014	(Nov.) 67.02				

(Source : BP Statistics 2014)

TCEB is the Coal Tariff Determination authority in Pakistan for Thar Coal Mines. The coal tariff, so determined, forms the basis of fuel cost for downstream power generation to be determined by NEPRA. Presently Cost Plus Method is being used to determine the specific coal price for each block.

4.4 Long Term Price Prediction of Gas・Coal ・Oil Products

Brent crude oil price index is used for determination of oil price and coal price in Pakistan. Therefore, the prediction of Brent crude oil price index is required to predict fossil fuel prices. Brent index and WTI index undergo a transition of almost the same level. Oil product price, LNG price, coal price which are closely correlated to the crude oil price are predicted as shown in the following table.

The oil product price of Pakistan will be linked with the international price, since the percentage of imported crude oil including furnace oil is large. Oil industry experts foresee the future international crude oil price to undergo a transition between 70 US$/bbl and 80 US$/bbl until around 2020.

Table 4-34 Long Term Price Prediction for Gas, Coal and Oil products (2010 – 2020)

	Energy	Unit	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OIl price	Brent crude oil price	$/bbl	62	80	111	109	92	60	62	64	66	68	70
	Internatl HFO price	$/bbl	85	95	98	92	60	62	64	66	68	70	71
	Aramco HFO price	$/bbl	43	48	49	46	30	31	32	33	34	35	36
	Internal Diesel price	$/bbl	87	115	123	120	101	66	68	70	73	75	77
	Brent crude oil price	$/ton	408	526	737	719	607	397	410	424	437	450	463
	Internatl HFO price	$/ton	563	629	649	609	397	410	424	437	450	463	473
	Aramco HFO price	$/ton	281	314	324	305	199	205	212	218	225	232	236
	Internal Diesel price	$/ton	644	851	910	888	746	488	505	521	537	553	570
	Brent crude oil price (9,800kcal/kg)	$/toe	417	537	752	734	619	405	419	432	446	459	473
	Internatl HFO price (10,500kcal/kg)	$/toe	574	642	662	621	405	419	432	446	459	473	482
	Aramco HFO price(10,500kcal/kg)	$/toe	287	321	331	311	203	209	216	223	230	236	241
	Internal Diesel price(10,600kcal/kg)	$/toe	657	868	929	906	762	498	515	532	548	565	581
Natural gas	Pakistan NG for Power(920Btu/cf)	$/MMBtu	4.6	5.2	4.9	4.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	TAPI -NG (900Btu/cf)	$/MMBtu	6.7	8.6	12.1	11.8	9.9	6.5	6.7	6.9	7.2	7.4	7.6
	Iran-NG(900Btu/cf)	$/MMBtu	8.2	10.6	14.8	14.5	12.2	8.0	8.3	8.5	8.8	9.1	9.3
	LNG (Japan Average: 11500Btu/cf)	$/MMBtu	10.9	14.7	16.8	16.1	13.8	9.0	9.3	9.6	9.9	10.2	10.5
	Pakistan NG for Power (920Btu/cf)	$/toe	185	207	197	195	200	200	200	200	200	200	200
	TAPI -NG	$/toe	267	345	482	471	397	260	269	277	286	295	303
	Iran-NG	$/toe	329	424	593	580	489	320	331	341	352	363	373
	LNG (Japan Average)	$/toe	436	588	670	644	550	360	372	384	396	408	420
Coal	Steam coal (Japan CIF)	$/ton (6000kcal/kg)	105	136	133	109	92	60	62	64	66	68	70
	Thar coal	$/ton (2700kcal/kg)	47	61	60	49	41	27	28	29	30	31	32
	Steam coal (Japan CIF)	$/toe	181	234	229	187	158	103	107	110	114	117	121
	Thar coal	$/toe	175	227	222	181	153	100	103	107	110	113	117

Note: Crude oil price is estimated by JICA Study team after referring study reports of The Institutes of Energy economics, Japan

Note: Oil product prices are calculated by the correlation formula with crude oil price.

Note: Natural gas prices from gas pipelines are calculated by the formula of the pipelines.

Note: International coal price is calculated by the linkage between crude oil price and steam coal price (CIF) from Australia to Japan

Note: Thar Coal Price is being determined by TCEB on Cost Plus Method as per Coal Pricing Framework and Thar Coal Tariff Determination Rules, 2014

(Source：BP Energy Statistics 2014 and Study reports of The Institutes of Energy Economics Japan)

Table 4-35 Long Term Price Prediction for Gas, Coal and Oil products (2021 – 2030)

	Energy	Unit	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
OIl price	Brent crude oil price	$/bbl	71	73	74	76	80	81	82	83	84	85
	Internatl HFO price	$/bbl	73	74	76	80	81	82	83	84	85	86
	Aramco HFO price	$/bbl	36	37	38	40	41	41	42	42	43	43
	Internal Diesel price	$/bbl	79	80	82	83	88	89	90	91	92	94
	Brent crude oil price	$/ton	473	482	492	502	530	536	543	549	556	563
	Internatl HFO price	$/ton	482	492	502	530	536	543	549	556	563	569
	Aramco HFO price	$/ton	241	246	251	265	268	271	275	278	281	285
	Internal Diesel price	$/ton	581	593	605	617	651	659	667	676	684	692
	Brent crude oil price (9,800kcal/kg)	$/toe	482	492	502	512	540	547	554	561	567	574
	Internatl HFO price (10,500kcal/kg)	$/toe	492	502	512	540	547	554	561	567	574	581
	Aramco HFO price(10,500kcal/kg)	$/toe	246	251	256	270	274	277	280	284	287	290
	Internal Diesel price(10,600kcal/kg)	$/toe	593	605	617	629	664	673	681	689	698	706
Natural gas	Pakistan NG for Power(920Btu/cf)	$/MMBtu	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	TAPI -NG (900Btu/cf)	$/MMBtu	7.7	7.9	8.0	8.2	8.7	8.8	8.9	9.0	9.1	9.2
	Iran-NG(900Btu/cf)	$/MMBtu	9.5	9.7	9.9	10.1	10.7	10.8	10.9	11.1	11.2	11.3
	LNG (Japan Average: 11500Btu/cf)	$/MMBtu	10.7	10.9	11.1	11.4	12.0	12.2	12.3	12.5	12.6	12.8
	Pakistan NG for Power (920Btu/cf)	$/toe	200	200	200	200	200	200	200	200	200	200
	TAPI -NG	$/toe	309	316	322	328	347	351	355	360	364	368
	Iran-NG	$/toe	381	388	396	404	427	432	437	443	448	453
	LNG (Japan Average)	$/toe	428	437	446	455	480	486	492	498	504	510
Coal	Steam coal (Japan CIF)	$/ton (6000kcal/kg)	71	73	74	76	80	81	82	83	84	85
	Thar coal	$/ton (2700kcal/kg)	32	33	33	34	36	36	37	37	38	38
	Steam coal (Japan CIF)	$/toe	123	126	128	131	138	140	141	143	145	147
	Thar coal	$/toe	119	121	124	126	133	135	137	138	140	142

Table 4-36 Long Term Price Prediction for Gas, Coal and Oil products (2031 – 2040)

	Energy	Unit	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
OIl price	Brent crude oil price	$/bbl	86	87	88	89	90	91	92	93	94	95
	Internatl HFO price	$/bbl	87	88	89	90	91	92	93	94	95	95
	Aramco HFO price	$/bbl	44	44	45	45	46	46	47	47	48	48
	Internal Diesel price	$/bbl	95	96	97	98	99	100	101	102	103	105
	Brent crude oil price	$/ton	569	576	583	589	596	602	609	616	622	629
	Internatl HFO price	$/ton	576	583	589	596	602	609	616	622	629	629
	Aramco HFO price	$/ton	288	291	295	298	301	305	308	311	314	314
	Internal Diesel price	$/ton	700	708	716	724	733	741	749	757	765	773
	Brent crude oil price (9,800kcal/kg)	$/toe	581	588	594	601	608	615	621	628	635	642
	Internatl HFO price (10,500kcal/kg)	$/toe	588	594	601	608	615	621	628	635	642	642
	Aramco HFO price(10,500kcal/kg)	$/toe	294	297	301	304	307	311	314	318	321	321
	Internal Diesel price(10,600kcal/kg)	$/toe	714	723	731	739	747	756	764	772	781	789
Natural gas	Pakistan NG for Power(920Btu/cf)	$/MMBtu	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	TAPI -NG (900Btu/cf)	$/MMBtu	9.3	9.4	9.5	9.6	9.8	9.9	10.0	10.1	10.2	10.3
	Iran-NG(900Btu/cf)	$/MMBtu	11.5	11.6	11.7	11.9	12.0	12.1	12.3	12.4	12.5	12.7
	LNG (Japan Average: 11500Btu/cf)	$/MMBtu	12.9	13.1	13.2	13.4	13.5	13.7	13.8	14.0	14.1	14.3
	Pakistan NG for Power (920Btu/cf)	$/toe	200	200	200	200	200	200	200	200	200	200
	TAPI -NG	$/toe	373	377	381	386	390	394	399	403	407	412
	Iran-NG	$/toe	459	464	469	475	480	485	491	496	501	507
	LNG (Japan Average)	$/toe	516	522	528	534	540	546	552	558	564	570
Coal	Steam coal (Japan CIF)	$/ton (6000kcal/kg)	86	87	88	89	90	91	92	93	94	95
	Thar coal	$/ton (2700kcal/kg)	39	39	40	40	41	41	41	42	42	43
	Steam coal (Japan CIF)	$/toe	148	150	152	153	155	157	159	160	162	164
	Thar coal	$/toe	143	145	147	148	150	152	153	155	157	158

Chapter 5 Power Development Plan

5.1 Methodology of Power Development Plan

The biggest challenge of the power generation development plan is a significant supply shortage of about 6.3GW as of 2012 due to the following causes; (i) aging of thermal power plants makes the supply shortage (installed capacity 14.9GW → net supply capacity 12.8GW) , (ii) the big variation of net supply capacity of hydropower plants between the rainy season and the dry season (summer: 6.5MW, winter:2.4MW); (iii) the fuel supply hindrance due to oil prices serge. In spite of about 23.6GW total installed capacity, there is only 13.7GW of the total net supply capacity against the peak power demand of about 20GW.

In order to resolve the above problems, it is important to develop the optimum power generation development plan, taking fully into accounts power supply reliability and economic power system operation so as to enable the economic and stable power supply.

(1) Selection of a power development planning tool

WASP IV is a standard software used for power generation development planning in developing countries, which the Pakistan government does not owns and uses for actual study.

Meanwhile, it is necessary to select a power development planning tool (simulation program) which can consider power sector conditions in detail including the following requirements.

- Daily demand curve shape is expected to change in the future (shaper peak, shift to daytime).
- Reservoir hydroelectric generation is the mainstay of the peak supply capacity during dry season (winter), and detailed simulation of the reservoir operation is required.
- The distance between the demand center and the major power plant is long, and it is necessary to consider the constraint in transmission capacity.
- Daily load curve shapes (peak hours) among seasons and in major locations are very different.
- Power import from neighboring countries such as Iran with interconnection T/L is considered.
- Since oil fuel is depended on import and the oil price hikes, procurement of fuel has become difficult (constraint of fuel supply).

In light of these points, since it is not sufficient WASP IV for the power generation development planning tool in Pakistan, the study team strongly recommend to use “PDPAT II” (Power Development Planning Assist Tool), which is the software TEPCO (Tokyo Electric Power Company Inc.) owns.

PDPAT II has been originally developed as a tool for planning power development plan strategy in the TEPCO more than 30 years ago, while used as a strategic planning tool for power development plan of TEPCO so far, it has been constantly evolving. PDPAT II has been also transferred and used for the PDP study in many countries including Turkey, Vietnam, Indonesia, Azerbaijan and China.

Major differences between PDPAT II and WASP IV are described in the below table.

Table 5-1 Major Differences between PDPAT II and WASP IV

	PDPAT II	WASP IV
Unit of operation	On a one-day basis	On a one-month basis
Demand curve shape	Input on an hourly basis	Fourier series (in order of duration)
Operating facility	Assuming stop on weekends, stop at late night	The same facility operates for one month
Operational time of pumped-storage power plant	Upper limit is set on a one-day basis (reservoir capacity time is the upper limit)	Upper limit is set on a one-month basis
Operation of thermal with fuel limit	Up to 3 groups can be considered	Impossible
Imagining time-series operation	Possible	Impossible
Objective function	Annual expense (fixed cost + fuel cost) Optimization of development plan also possible	Optimization of development plan
Interconnection with other systems	Up to 10 systems can be considered	Only one system
Reliability evaluation	Possible	Possible
Power trade	Possible	Impossible
Calculated time	Within 1 second (for one year per system) Several hours in case of optimization of development plan	Several minutes to several hours

(2) Study method in terms of supply reliability

When studying the peak supply capacity and evaluating energy security, it is very important to determine the level at which to set the supply reliability. Depending on the level, the amount of reserve power to be prepared as a risk handling ability will vary.

Power outage probability LOLP (Loss of Load Probability) is common as a supply reliability level, which is a target criterion that what a number of hours of power shortage can be allowed. The relationship between the supply reliability of LOLP and reserve margin commonly applied is calculated as illustrated in the following box. And then reserve margin of each year can be set. The supply reliability level foe the LCP will be determined in consultation with CP.

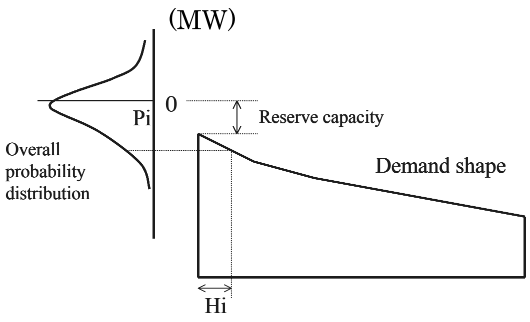
Relationship between supply reliability (LOLP) and reserve margin

LOLP is defined as probability of forced outage in a year.　LOLE is defined as expectation of forced outage.

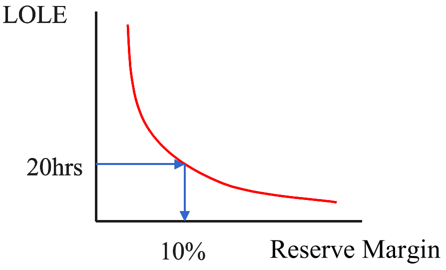
$$\mathrm{LOLE} = \Sigma\ (\mathrm{P\,i} \times \mathrm{H\,i}),\quad \mathrm{LOLP} = \mathrm{LOLE} / 8{,}760$$

Pi is a point on the overall probability distribution which synthesized supply side fluctuation and demand side fluctuation, therefore, **Pi** shows provability on some variation value. On the other hand, Hi represents the supply outage duration time that occurs on some variation value.

By calculating by successively changing the value of the reserve power, the relationship between LOLE and reserve margin of the system is obtained.



Supply reliability (LOLE)



Relationship between LOLE and reserve margin

(3) Evaluation of supply reliability

In the power demand supply operation simulation, the most important factor is the monthly supply capacity of conventional hydropower plant. In other words, the supply capacity of a conventional hydropower plant in the supply plan is statistically determined based on the size of the regulating pond and the change in the annual rainfall (rainy season, dry season and drought). In general, the supply capacity of 90% reliability (firm peak output) is regarded as the supply capacity in the supply plan.

Another important factor in the plan for conventional hydropower plants that have regulating pond or reservoir is the peak duration time which the above firm peak output can be continued per day, and the required value of this factor varies depending on the daily load curve. In general, the peak duration of reservoir-type power plants was set at 8 hours on average in the developed countries, however, it is set at 6 hours in the most developing countries.

Therefore, it is necessary to collect information as much as possible about the details of the operational status in order to figure out the real supply capacity of thermal power and hydropower plants. In addition, it is necessary to understand also the supply capacity of planned and developing hydropower plant.

< Thermal power plant >

Fuel type, Dependable capacity, Generation efficiency, Minimum output, Daily start & stop capability, Weekly start and stop capability, Forced outage rate, Scheduled outage days (days in a year when the plant is scheduled to shut down for inspection, etc.), Station own use rate, AFC operation range, Constraints in operation side (obligation for taking over fuel volume from fuel company, obligation for taking over power from IPP, etc.)

< Conventional hydropower plant with regulating pond or reservoir >

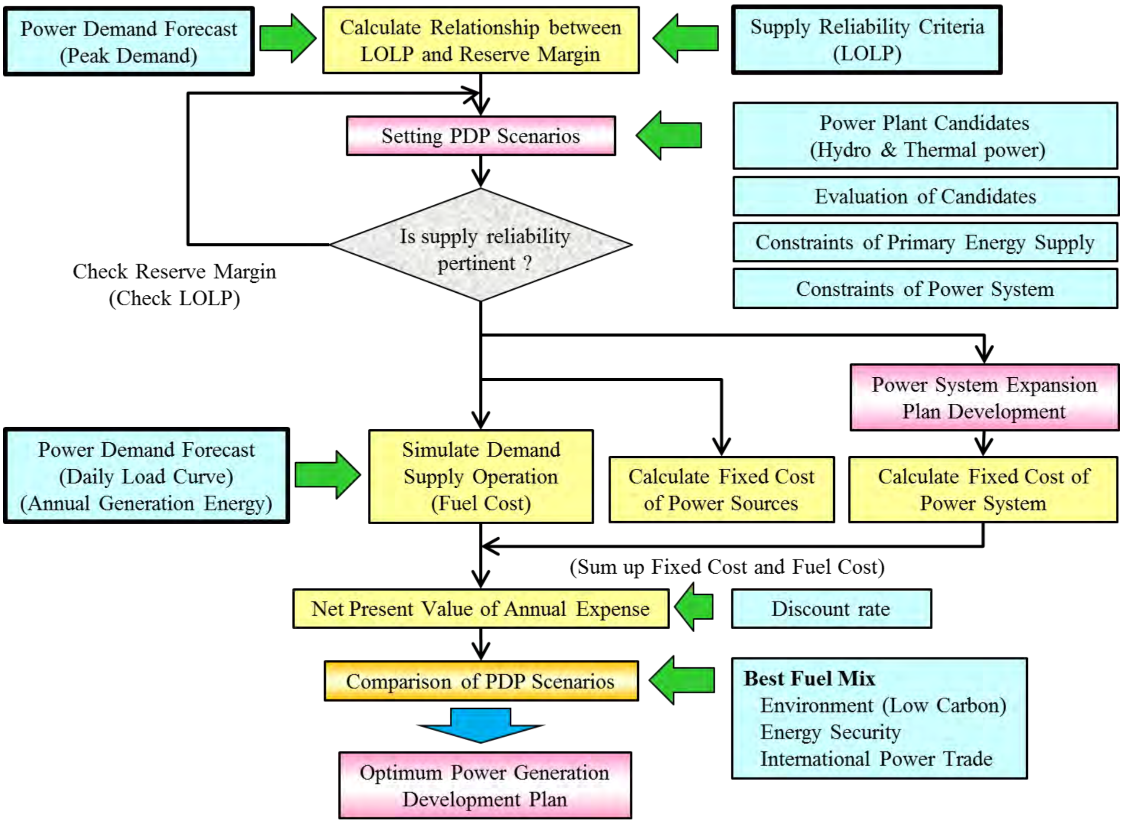
Monthly firm (peak) capacity, Monthly averaged generated energy, Minimum output, Forced outage rate, Scheduled outage days, Station own use rate, AFC operation range, Constraints in operation side (drawdown of reservoir water level for flood control, obligation of discharge for irrigation water, etc.) and difference of generated energy between day year and wet year.

(4) Power generation development planning policy / methodology

In the Study, a long-term power generation development plan up to 2035 is developed according to the study flow as shown in Figure 5-1, based on the least cost method. In addition, some development scenarios are studied and evaluated taking into consideration economic efficiency of each candidate power plant including transmission cost, constraints related to the primary energy use, operational constraints due to transmission line capacity and so on, as well as evaluated from the perspective of SEA, and then the evaluation results are reflected into the power generation development plan.

In consideration of constraints on the power system and constraints on primary energy supply considering energy security aspect in addition to the problems described above, the power development scenarios with high probability are set in consultation with the counterpart. The economic consideration is conducted for the above scenarios by the demand supply simulation and supply reliability study.

Specifically, it should be noted that Pakistani geography is long from North to South, main power demand centers are Islamabad and Lahore in the north and Karachi in the south, and primary energy sources are distributed unevenly, hydropower in the north and coal fired thermal power in the south. Accordingly, it is important for formulating the least cost power system development plan to reduce transmission cost and loss by separating NTDC system into the north system and the south system and balancing power demand and supply regionally. In addition, the two regional power system is interconnected in order to minimize the required supply reserve capacity of the whole country by accommodating the power (economically and marginally) among the systems.



(Source : JICA Project Team)

Figure 5-1 Study Flow of Power Generation Development Plan

5.2 Necessary Available Capacity based on Power Supply Reliability Criterion

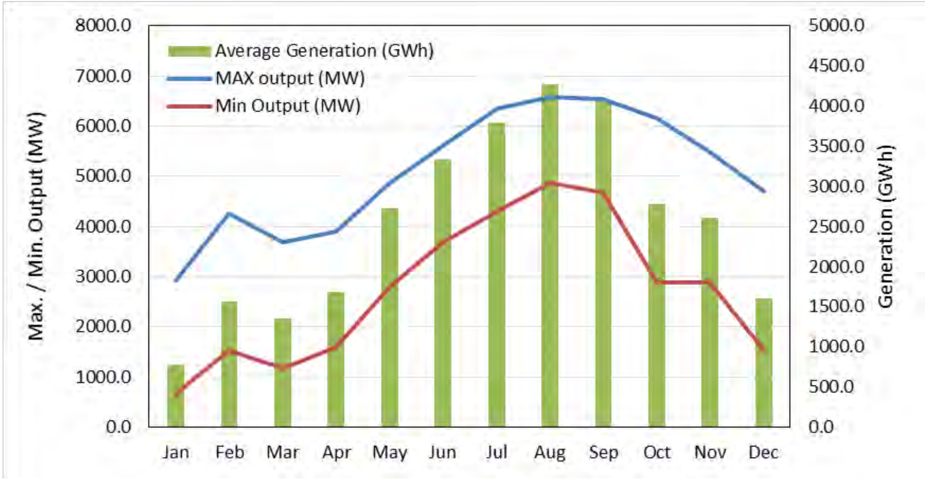
5.2.1 Review of Existing Power Development Plan

(1) Supply capacity of existing power plants

(a) Hydropower

On the basis of the existing hydroelectric power plant operation records shown in Table 2-11, the supply capacity and generated energy of hydropower plants are statistically examined as shown in Figure 5 2. Here, although there are hydropower plants, Tarbela HPP, Mangla HPP and Warsak HPP which have a large reservoir, since the primary purpose of water control of the reservoirs is for the irrigation not power in Pakistan and all those power plants are located at the upmost downstream of the river, the water discharge from the reservoir is controlled daily based upon the order from IRSA (Indus River System Authority). NPCC can order power plants to regulate generate power (peak operation) in a range between the maximum and minimum discharge ordered by IRSA in a day. That is, it is different from the operation manner of a common reservoir type hydropower plant.

Accordingly, the total minimum output (firm capacity or dependable capacity) of the existing hydropower plants from Jul. to Sep. is 4.5GW, however, that from Dec. to Apr. decreases to 1.5GW, one third of the wet season's.



(Source : JICA Project Team)

Figure 5-2 Monthly generated energy and Max. & Min. Output of Existing HPPs

Meanwhile, the future developed hydropower plants with a large reservoir such as Dasu HPP and Basha HPP will be able to yearly regulating power generation without any constraints of hourly discharge, since those reservoirs are located at the upper stream of the existing large reservoir. In addition, the run-of-river type hydropower plant developed downstream of a new reservoir type HPP can also make peaking power generation, since it uses regulated discharge from the upper stream reservoir.

(b) Thermal and Nuclear power

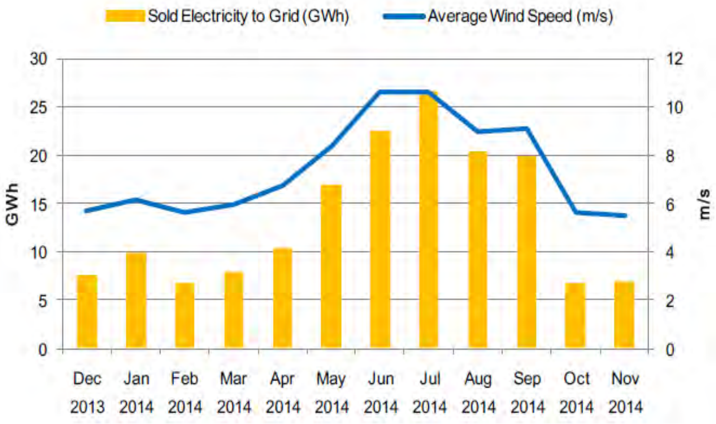
As shown in Table 2-12 (GENCOs), Table 2-13 (IPPs), Table 2-14 (KE), the total installed capacity (excluding nuclear power plants and biomass power plant) is 16,670MW, meanwhile, the total supply capacity (dependable capacity) is 14,185MW.

In addition, all nuclear power plants were developed and are owned and operated by PAEC, the total installed capacity is 787MW, meanwhile, the total supply capacity (dependable capacity) is 740MW.

(c) Wind power

The total installed capacity of wind power plants is 156MW as of the end of 2014 as shown in Table 2-15. The plant factor of the wind power plant developed by Fauji Fertilizer Company Energy Limited (FFCFL) is 31% on the contract, and the plant factor of the wind power plant developed by Zorlu Enerji Pakistan Limited (ZEPL) was recorded 32% during one year from Dec. 2013 to Nov.2014 as shown in **Figure 5-3**.

Accordingly, supply capacity of the existing and planned wind power plants is assumed as 30% of the installed capacity.



(Source : JICA Project Team (Supply Capacity Group))

Figure 5-3 Monthly Generated Energy of ZEPL Wind Power Plant

(d) Biomass power

The existing biomass power plant is the only one of JDW Sugar Mill, the installed capacity is 26.4MW and the supply capacity is 24MW. Since the generated energy was 88MWh in 2014, the available supply deration can be calculated as 153 days or 22 weeks. Accordingly, the power supply duration in a year is assumed as 5 months from Dec. to Apr. during dry season.

(e) Monthly supply capacity and reserve capacity

The monthly reserve margin in 2014 is calculated as shown in the below table and figure by sum up monthly supply capacity of each power source.

Although the supply capacity varies largely between wet and dry seasons, monthly maximum demand varies more than that, therefore, the minimum reserve capacity occurs in Jun. and Jul. Accordingly, even if the development ratio of hydropower plant becomes large, the reserve margin in winter will be larger than that in summer.

In addition, hydropower is a pure domestic energy and can supply electric power semi-permanently without fuel after commissioning. Therefore, it is desired to make the development ratio of hydropower plant as large as possible from the viewpoints of national energy security.

Table 5-2 Demand and Supply Balance in 2014

	Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Dependable Capacity	MW	15,624	16,489	16,122	16,543	17,738	18,625	19,235	19,807	19,613	17,815	17,825	16,480
Hydro		668	1,533	1,166	1,587	2,806	3,693	4,303	4,875	4,681	2,883	2,893	1,524
Thermal		14,185	14,185	14,185	14,185	14,185	14,185	14,185	14,185	14,185	14,185	14,185	14,185
Nuclear		715	715	715	715	715	715	715	715	715	715	715	715
Wind		32	32	32	32	32	32	32	32	32	32	32	32
Biomass		24	24	24	24	-	-	-	-	-	-	-	24
Maximum Demand	MW	15,466	14,466	15,262	19,515	20,894	23,919	25,317	22,813	20,465	19,214	15,202	15,858
Reserve Margin	%	1.01	12.27	5.34	(17.96)	(17.79)	(28.43)	(31.63)	(15.18)	(4.34)	(7.86)	14.72	3.77

(Source : JICA Project Team)

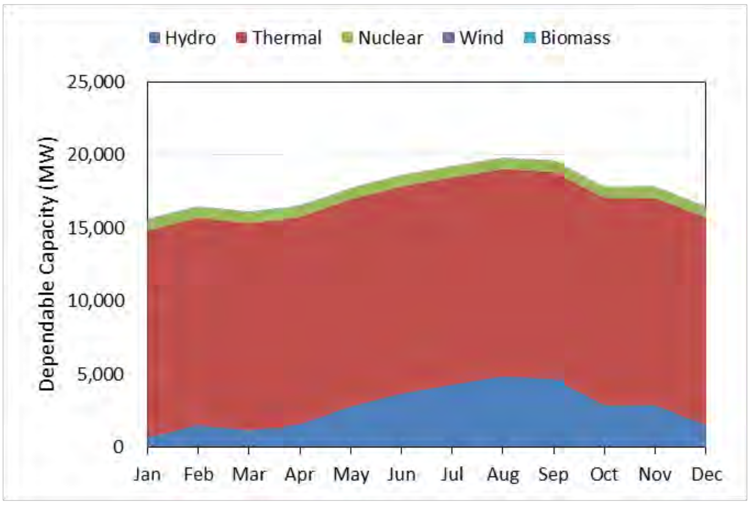


Figure 5-4 Monthly Supply Capacity in 2014

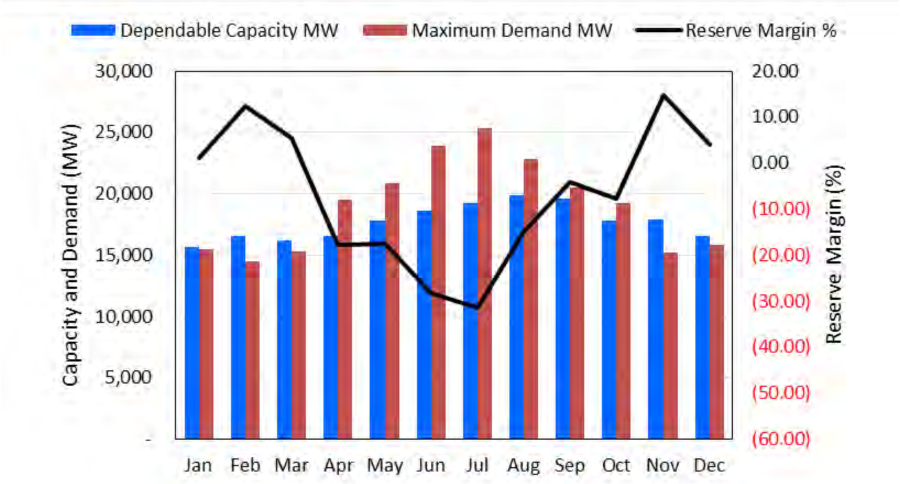


Figure 5-5 Demand and Supply Balance in 2014

(2) Current status of power development plan

(a) Hydropower

Among hydropower development plan which General Manager (Hydro), Planning WAPDA prepared in Jan. 2015, main projects under construction stage or which commercial operation date (COD) is set and ready for implementation such as detailed design and bid document preparation stage, are listed in Table 5-3.

According to this table, the total installed capacity of hydropower projects which CODs are planned to be until 2025 is 27,343MW, and that of projects which are ready for implementation is 5,246MW. The grand total installed capacity of the above projects plus existing hydropower plants of 7,097MW is around 40GW.

In this power development plan, all the above hydropower projects are incorporated into the plan. However, since monthly supply capacity and generated energy planned of each hydropower project is lacked, the JICA project team will assume them based on the operation records of the existing hydropower plants.

As above mentioned, since Akhori HPP is located at the upmost downstream of the river, it is assumed to be operated as daily regulating power generation type as well as Tarbela HPP. Meanwhile Bash HPP and Dasu HPP are assumed to be a common reservoir type hydropower, since Tarbela reservoir is located at the downstream of them.

Table 5-3 Development Plan of Hydropower Plants

No.	Project	Installed Capacity (MW)	Executive Agency	Project Status	Remarks		Rivers	Location
					Target Year	Type		
WAPDA	Neelum Jhelum	969	WAPDA	Const	2016	Pondage	Nelum	AJK
	Golen Gol	106	WAPDA	Const	2016	Run-of-river	Golen Gol	KPK
	Tarbela 4th Ext	1,410	WAPDA	Const	2017	Reservoir	Indus	KPK
	Kayal Khwar	128	WAPDA	Const	2017	Run-of-river	Kayal Khwar	KPK
	Kurram Tangi	83	WAPDA	Const	2017	Pondage		
	Tarbela 5th Ext	1,320	WAPDA	Under Stu.	2019	Reservoir	Indus	KPK
	Basho	40	WAPDA	DD	2020	Pondage		GB
	Phander	80	WAPDA	Const	2020	Run-of-river	Ghizar	AJK
	Mangla (Upgradation)	310	WAPDA	Const	2020	Reservoir	Jhelum	
	Dasu (1st stage)	2,750	WAPDA	Const	2020	Pondage *	Indus	KPK
	Diamer Basha	4,500	WAPDA	Const	2024	Reservoir	Indus	GB
	Dasu (2nd stage)	2,750	WAPDA		2027	Pondage *	Indus	KPK
	Bunji	7,100	WAPDA	Imple.	2027	Pondage	Indus	KPK
	Subtotal	21,546						
PPIB	Patrind	150	PPIB	Const	2017	Pondage	Kunhar	KPK/AJK
	Gulpur	100	PPIB	Finantial	2018	Pondage	Punch	AJK
	Sehra	130	PPIB	EPC Con.	2019	Pondage	Punch	AJK
	Karot HPP	720	PPIB	Imple.	2020	Pondage	Jhelum	Punjab
	Azad-Pattan	640	PPIB	Imple.	2020	Pondage	Jhelum	AJK
	Suki kinari	840	PPIB	Imple.	2020	Pondage	Kunhar	AJK
	Kotli	100	PPIB	Imple.	2020	Pondage	Punch	AJK
	Chakoti-Hattian	500	PPIB	Imple.	2020	Pondage	Jhelum	AJK
	Kohala	1,100	PPIB	Imple.	2020	Pondage	Jhelum	AJK
	Kaigah	545	PPIB	Imple.	2022	Pondage	Kandia	KPK
	Madian	157	PPIB	Imple.	2022	Pondage	Swat	KPK
	Asrit-kedam	215	PPIB	Imple.	2022	Pondage	Swat	KPK
	Mahl	600	PPIB	Imple.	2023	Pondage	Jhelum	KPK
	Subtotal	5,797						
Completed by 2027		27,343						
WAPDA	Palas Valley (lower)	665	WAPDA	DD		Pondage	Palas	KPK
	Palas Valley (middle)	373	WAPDA	DD		Pondage	Palas	KPK
	Palas Valley (upper)	160	WAPDA	DD		Pondage	Palas	KPK
	Spat Gah (lower)	496	WAPDA	DD		Pondage	Spatgah	KPK
	Spat Gah (middle)	424	WAPDA	DD		Pondage	Spatgah	KPK
	Spat Gah (upper)	199	WAPDA	DD		Pondage	Spatgah	KPK
	Akhori	600	WAPDA	DD		Reservoir		Punjab
	Lawi	70	WAPDA	DD		Pondage	Shishi	KPK
	Munda	740	WAPDA	DD		Reservoir	Swat	KPK
	Subtotal	3,727						
PPIB	Karrang	458	PPIB	Imple.		Pondage	Swat	KPK
	Rajdhani	132	PPIB	Imple.		Pondage	Punch	AJK
	Kalam-Asrit	197	PPIB	Imple.		Pondage	Swat	KPK
	Shashghai-Zhendoli	144	PPIB	Imple.		Pondage		KPK
	Matiltan	84	SHYDO	Imple.		Pondage	Swat	KPK
	Gabral Kalam	137	PPIB	Imple.		Pondage	Swat	KPK
	Shogo-Sin	132	PPIB	Imple.		Pondage		KPK
	Taunsa	120	PPDB	Imple.		Pondage	Indus	
	Sharmal	115	SHYDO	Imple.		Pondage		KPK
	Subtotal	1,519						
Planned Total		5,246						

(Source : JICA Project Team prepared based on General Manager (Hydro), Planning WAPDA)

(b) Thermal power

The development projects of thermal power plant prepared by GENCOs, PPIB, PPDB are listed in Table 5-4. According to this table, the total installed capacity of thermal power projects which CODs are planned to be until 2021 is 16,069MW, and in the fuel type, that of gas, oil and coal is 877MW, 332MW, 14,860MW respectively. Coal fired power plants account for about 90%.

Table 5-4 Development Plan of Thermal Power Plants

	Power Plant Name	Location	Type	No. ×Unit Cap.(MW)	Installed Capacity (MW)	Dependable Capacity (MW)	Fuel Type	Current Status	Target Commissioning Year
GENCO-I	Jamshoro (ADB)	Jamshoro, Sindh	Steam	2×660	1320	1260	Imp. Coal	L/A conclusion	Dec. 2019 Mar. 2020
GENCO-II	Guddu Ext.	Guddu, Sindh	CCGT	2×243 1×261	747	720	Gas	Commissioning test	Mar. 2015
GENCO-IV	Lakhra (JICA)	Dadu, Sindh	Steam	1×660	660	630	Imp. Coal	F/S	Jun. 2022
GENCO-V	Nandipur	Nandipur, Punjab	GT	1×96 2×96	428	400	FO/HSD	Commissioning test	2014 2015
			Steam	1×140					2015
Sub-total					3,059	2,920			
IPP	Sahiwal-1 (PPDB)	Punjab (North)	Steam	1×660	660	630	Coal		Dec. 2017
	Sahiwal-2 (PPDB)	Punjab (South)	Steam	1×660	660	630	Coal		Dec. 2017
	Nooriabad Gas Plant		GT	2×50	100	95	Gas		Dec. 2017
	Bhilli Gas Plant	Punjab	CCGT	2×400 1×400	1200	1140	LNG		Apr. 2017 2018
	Baloki Gas Plant	Punjab	CCGT	2×400 1×400	1200	1140	LNG		Apr. 2017 2018
	Haveli Bahadur Shar Gas Plant	Punjab	CCGT	2×400 1×400	1200	1140	LNG		Apr. 2017 2018
	Thar Coal Block II (SECMC Pakistan)	Thar, Sindh	Steam	2×330 2×330	1320	1260	Coal	Financial	Apr. 2018 2019
	Port Qasim (Shinohydro)	Port Qasim, Karachi	Steam	2×660	1320	1260	Imp. Coal	LOI Issue	Jun. 2018 Dec. 2018
	Thar Coal Block I SSRL (china-pakistan)	Thar, Sindh	Steam	2×660	1320	1260	Coal		Jun. 2018 Dec. 2018
	Salt Range (PPDB)	Salt Range, Punjab	Steam	1×330	330	315	Coal		Jun. 2018
	HUBCO (HUB Power)	HUB, Baluchistan	Steam	2×660	1320	1260	Coal		Jun. 2018 Dec. 2018
	Thar Coal Block VI (Oracle(China-UK))	Thar, Sindh	Steam	2×330	660	630	Coal		2019
	Thar Coal Block V (UCG project Pakistan)	Thar, Sindh	Steam	2×5	10	10	UCG		2017
	Thar Coal Block II Phase-3	Thar, Sindh	Steam	4×660	2640	2520	Coal		2021
	Thar Coal Block III (Asia Power UK)	Thar, Sindh	Steam	2×660	1320	1260	Coal		2021
	Thar Coal Block IV (Harbin Electric China)	Thar, Sindh	Steam	2×660	1320	1260	Coal		2021
	Sub-total				16,580	15,810			
Total					19,639	18,730			

(Source : JICA Project Team prepared based on NTDC data)

(c) Nuclear power

PAEC is proceeding with the construction of new power plants at Chashma Nuclear PP and KANUPP. Cahshma unit No.3 and No.4 (C-3 and C-4) and KANUPP unit No.2 and No.3 (K-2 and K-3). The domes of containment buildings of C-3 and C-4 were built in Mar. 2013 and in Jan. 2014, respectively. The ground breaking ceremony of K-2 and K-3 was held on Nov. 26, 2013.

PAEC is implementing the Nuclear Power Program 2030 set by the Energy Security Plan of GOP. In the plan, it is emphasized that generation by nuclear power plants will be increased to 8,800 MW by 2030.

Table 5-5 Development Plan of Nuclear Power Plants

Power Plant Name	Location	Project status	No. ×Unit Cap.(MW)	Installed Capacity (MW)	Dependable Capacity （MW）	Fuel Type	Commissioning Year
Chashma Unit 3-4	Chashma (PAEC)	Construction	340	340	315	NUC	2016
		Construction	340	340	315	NUC	2017
KANUPP Unit 2-3	Krachi, Sindh (PAEC)	Construction	1,100	1100	1017.5	NUC	2,020
		Construction	1,100	1100	1017.5	NUC	2,021
Total				2,880	2,665		

(Source : PAEC)

(d) K-Electric

Power development plan including the existing power plants up to 2020 in the KE system is shown in the below table. Some units of Bin Qasim power plant has been conducted with fuel conversion, and new thermal power plants of coal fired and gas fired are planned to develop. The total installed capacity of 2,548MW will be added by 2020.

Table 5-6 Power Development Plan in KE System (until 2020)

Source	Power Plant Name	Type	No. ×Unit Cap.(MW)	Installed Capacity (MW)	Dependable Capacity （MW）	Fuel Type	Current Status	Target Commissioning Year
Thermal	Korangi	CCGT	4×48 2×27	247	168	Gas	Existing	2009 2015
	SGTPS-2	Engine Steam	32×2.8 1×10	98	88	Gas	Existing Construction	2009 2016
	KGTPS-2	Engine Steam	32×2.8 1×10	98	88	Gas	Existing Construction	2009 2016
	Nooriabad (IPP)	Engine Steam	5×16 2×10	100	100	Gas	Costruction	2016
	Port Qasim	Steam	1×58	58	52	Coal	Costruction	2017
	Korangi II-1	Engine Steam	13×18.5 1×25	252	252	FO/RLNG		2018
	Korangi II-2	Engine Steam	13×16.7 1×20	245	245	FO/RLNG		2018
	North Karachi (IPP)	Engine Steam	12×20 1×18	258	250	FO/RLNG		2018
	Balidia, Karachi (IPP)	Engine Steam	10×18.5 1×15	200	194	FO/RLNG		2019
	Port Qasim II	CCGT	1×320 1×150	470	431	RLNG		2019
	Port Qasim III	Steam	2×350	700	637	Coal		2020
	Port Qasim IV	Steam	1×220	220	200	Coal		2020
	Sub-total			6,523	5,959			
Wind	Gharo Wind (IPP)			40	12		Costruction	2016
Solar	Gharo Solar I (IPP)			50	0			2018
	Gharo Solar II (IPP)			50	0			2019
Nuclear	KANUPP Unit 1	Steam	1×137	137	100	Nuclear	Existing	1971
Total				6,800	6,071			

(Source : KE)

(e) Wind power

According to information from CPPAGL, there are 30 wind firm development projects which total capacity reaches 2.202MW. Around 900MW out of them is planned to be commissioned until 2016. Besides, it should be considered that all projects are located in Sindh province and far from hydropower plants which can adjust output variation of wind power.

Table 5-7 Development Plan of Wind Power Plants

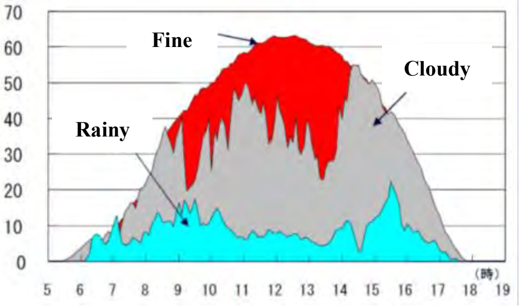
Sr. No.	Name of Company	Location	Installed Capacity (MW)	Tariff (US cent/kWh)	Present Status	Commercial Operation Date
1	Foundation Wind Energy-I Ltd.	Gharo, Thatta District, Sindh Province	50.0	14.1	Financial Close achieved on July 18, 2013	January 2015
2	Foundation Wind Energy-II Ltd.	Gharo, Thatta District, Sindh Province	50.0	14.1	Financial Close achieved on July 18, 2013	December 2014
3	Three Gorges First Wind Farm Pakistan (Pvt.) Ltd.	Jhimpir, Thatta District, Sindh Province	49.5	-	Financial Close achieved on July 17, 2013	January 2015
4	Sapphire Wind Power Co. Ltd.	Jhimpir, Thatta District, Sindh Province	50.0	13.5	Financial Close achieved on July 7, 2014	January 2016
5	Metro Power Co. Ltd.	Jhimpir, Thatta District, Sindh Province	50.0	-	EPA signed on February 26, 2014	March 2016
6	Sachal Energy Development Ltd.	Jhimpir, Thatta District, Sindh Province	50.0	14.9	EPA signed on February 27, 2014	March 2016
7	Yunus Energy Ltd.	Jhimpir, Thatta District, Sindh Province	50.0	-	EPA signed on March 26, 2014	March 2016
8	HydroChina Dawood Power Ltd.	Jhimpir, Thatta District, Sindh Province	49.5	-	EPA signed on September 25, 2014	March 2016
9	Tenaga Generasi Limited	Kuttikun, Thatta District, Sindh Province	49.6	14.3	Energy Purchase Agreement (EPA) under negotiation	October 2016
10	Master Wind Energy Limited	Jhimpir, Thatta District, Sindh Province	50.0	-	EPA under negotiation	March 2016
11	Zephyr Power Limited	Bhambore, Thatta District, Sindh Province	50.0	-	Approval of interconnection study is awaited.	-
12	Gul Ahmed Energy Limited	Jhimpir, Thatta District, Sindh Province	50.0	-	EPA under negotiation	March 2016
13	Wind Eagle Limited – I	Jhimpir, Thatta District, Sindh Province	50.0	-	Approval of interconnection study is awaited.	December 2016.
14	Wind Eagle Limited – II	Jhimpir, Thatta District, Sindh Province	50.0	-	Approval of interconnection study is awaited.	December 2016
15	HAWA Holding Limited	Jhimpir, Thatta District, Sindh Province	50.0	-	Approval of interconnection study is awaited.	-
16	United Energy Pakistan Ltd.	Jhimpir, Thatta District, Sindh Province	100.0	-	EPA under negotiation	March 2016
17	Jhimpir Wind Power Limited	Jhimpir, Thatta District, Sindh Province	49.6	13.5	EPA under negotiation	June 2016
18	Tapal Wind	Jhimpir, Thatta District, Sindh Province	30.0	-	EPA under negotiation	March 2016
19	NBT Wind Power Pakistan (Pvt) Limited	Jhimpir, Thatta District, Sindh Province	500.0	-	Power Acquisition Request submitted to NEPRA	-
20	Titan Energy Pakistan (Pvt) Limited	Jhimpir, Thatta District, Sindh Province	10.0	-	Approval of interconnection study is awaited.	-
21	China Sunec Energy (Pvt) Limited	Jhimpir, Thatta District, Sindh Province	50.0	-	Interconnection study approved	June 2016.
22	Tricon Boston Consulting Corporation	Jhimpir, Thatta District, Sindh Province	50.0	-	Approval of interconnection study is awaited.	-
23	Tricon Boston Consulting Corporation	Jhimpir, Thatta District, Sindh Province	50.0	-	Approval of interconnection study is awaited.	-
24	Tricon Boston Consulting Corporation	Jhimpir, Thatta District, Sindh Province	50.0	-	Approval of interconnection study is awaited.	-
25	Burj Wind Energy (Pvt) Limited	Jhimpir, Thatta District, Sindh Province	13.5	16.0	Approval of interconnection study is awaited.	May 2016
26	Hartford Alternate Energy	Jhimpir, Thatta District, Sindh Province	50.0	-	Approval of interconnection study is awaited.	-
27	Western Energy (Pvt) Ltd	Jhimpir, Thatta District, Sindh Province	50.0	13.2	Approval of interconnection study is awaited.	-
28	United Energy Pakistan Limited	Sindh Province	350.0	-	Letter of Intent (LOI) was obtained and Feasibility Study was done. Land is not allocated.	-
29	Zaver Petroleum Corporation Limited	Sindh Province	50.0	-	LOI was obtained and Feasibility Study was done. Land is not allocated.	-
30	Trident Energy (Pvt) Limited	Sindh Province	50.0	-	LOI was obtained and Feasibility Study was done. Land is not allocated.	-
31	Gharo Wind (IPP)	Karachi	40.0	-		June 2018
	Total		***2,241.7***			

(Source : CPPAGL and KE)

(f) Solar power

According to information from AEDB and KE, there are 8 mega solar power projects (over 10MW) and the total installed capacity reaches 1,250MW by 2020. 3 sites out of 3 sites are located in Punjab province and the other 5 sites are located in Sindh province as listed in the below table.

Since solar power can generate power only during daytime and its output fluctuates depending on the weather condition, it is assumed that the annual plant factor is around 15% (Output ratio from 8:00 to 16:00 of 45%).



Output Ratio (Output / Installed Capacity)

Meanwhile, since the peak demand occurs from 17:00 to 19:00 in a day in Pakistan, the output of solar power can not be counted as a supply capacity or dependable capacity.

Table 5-8 Development Plan of Solar Power Plants

Sr. No.	Name of Company	Location	Installed Capacity (MW)	Tariff (US cent/kWh)	Present Status (Targeted COD)
1	Quald-e-Azam Solar Ltd. (owned by the Gov. of Punjab)	Bahawalpur District, Punjab Province	100.0	Project cost : 157 mil. US$ (20 UScent/kWh)	As of Jan, 2015, 90% of construction has been completed (Feb. 2015)
2	Zonergy Company Ltd.	Bahawalpur District, Punjab Province	300.0		Construction will be commenced in Mar. 2015 at Quald-e-Azam Solar Park (June 2016)
3	Zonergy Company Ltd.	Bahawalpur District, Punjab Province	600.0		Construction will be commenced in Mar. 2015 at Quald-e-Azam Solar Park (June 2017)
4	M/s. Integrated Power Solution	Sindh Province	50.0	Awaiting announcement of upfront tariff by NEPRA	Feasibility study done, applying for generation license and upfront tariff
5	M/s. Jafri & Associates	Sindh Province	50.0	Awaiting announcement of upfront tariff by NEPRA	Feasibility study done, applying for generation license and upfront tariff
6	M/s. Solar Blue (Pvt) Ltd.	Sindh Province	50.0	Awaiting announcement of upfront tariff by NEPRA	Feasibility study done, applying for generation license and upfront tariff
7	Gharo Solar I (IPP)	Karachi	50.0		(Dec. 2017)
8	Gharo Solar II (IPP)	Karachi	50.0		(Mar. 2019)
	Total		***1,250.0***		

(Source : AEDB and KE)

(g) Biomass power

According to information from CPPAGL, there are 9 biomass power projects and the total installed capacity reaches 308MW. 7 sites out of 9 sites are located in Punjab province and the others are located in Sindh province. Meanwhile, the supply power duration is 5 months from Dec. to Apr. as above mentioned.

Table 5-9 Development Plan of Biomass Power Plants

Sr. No.	Name of Company	Location	Installed Capacity (MW)	Tariff (Rs/kWh)	Present Status
1	Chiniot Power Ltd.	Chiniot District, Punjab Province	62.4	10.4	Energy Purchase Agreement (EPA) signed on July 22, 2014, Targeted COD June 2015
2	RYK Mills Ltd.	Rahim Yar Khan District, Punjab Province	30.0	10.4	EPA signed on October 10, 2014, Targeted COD December 2014
3	Hamza Sugar Mills Ltd.	Rahim Yar Khan District, Punjab Province	15.0	10.4	Energy Purchase Agreement (EPA) negotiation is being executed.
4	SSJD Bio energy Ltd.	Mirpurkhas District, Sindh Province	12.0	10.4	Economic Coordination Committee (ECC) approval on the draft EPA is awaited.
5	Kamalia Sugar Mills Ltd.	Kamalia, Toba Tek Singh District, Punjab Province	17.0	10.4	Approval of interconnection study is awaited.
6	Alliance Sugar Mills Ltd.	Ghotki District, Sindh Province	30.0	10.4	Approval of interconnection study is awaited.
7	Almoiz Industries Ltd.	Mianwali District, Punjab Province	45.0	10.4	Approval of interconnection study is awaited.
8	Layyah Sugar Mills Ltd.	Layyah District, Punjab Province	30.0	10.4	Approval of interconnection study is awaited.
9	Etihad Power Generation Ltd.	Rahim Yar Khan District, Punjab Province	67.0	10.4	Approval of interconnection study is awaited.
	Total		308.4		

(Source : CPPAGL)

(h) Power import

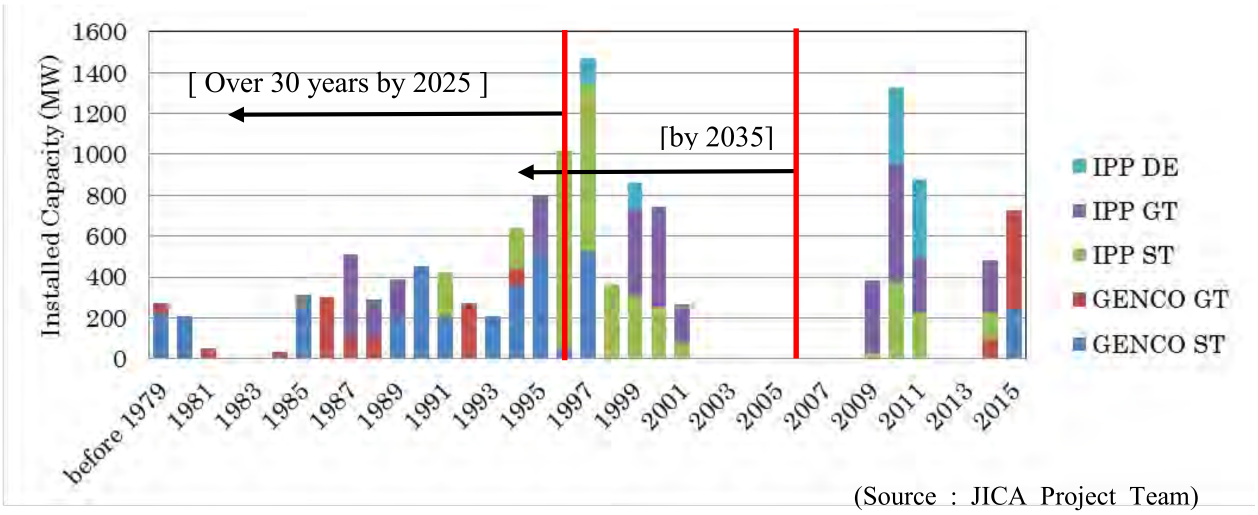
CASA-1000 project is underway, which aims to export 1000MW surplus electricity generated by hydropower plants in both Kyrgyz Republic and Tajikistan to Pakistan via Afghanistan during the summer from May to Oct. for 8 hours in a day. DC convertor station which is planned to install near Peshawar is planned to complete in 2019-20 .

Meanwhile, the power import project is also underway, which aims to export electricity generated by gas fired thermal power plants in Iran to Pakistan through DC 500kV transmission lines (Pakistan side : 585km, Iran side : 93km) between Zahedan in Iran and Qetta in Pakistan. The maximum power imported is 1000MW and it can be imported through the year.

(i) Retirement of aged power plant

Aged thermal power plants which passed over more than 30 years from COD are to be retired in principle. As for the nuclear power plants, those more than 40 years from COD are to be retired in principle.

Since COD and installed capacity of the thermal power plants in Pakistan are shown in the below figure, the total capacity of retired thermal power plant shall be 4.6GW by 2025 and 10GW by 2035, respectively. Besides, KANUPP No.1 of 137MW shall be retired as soon as possible.



(Source : JICA Project Team)

Figure 5-6 COD and Installed Capacity of Thermal Power Plant

(3) Current situation of Power Development Plan

Based on the aforementioned power development plan of each power source, the yearly power supply capacity and reserve margin of the North system, South system and KE system were arranged respectively as follows.

(a) North system

In the North system, since there is large hydropower potential, a lot of hydropower plants are planned to develop aggressively. However, since the supply capacity of most hydropower plants declines in the winter (dray season), it is necessary that the growth of supply capacity and reserve margin in both summer and winter be verified. The results are shown in the below figure.

The total supply capacity surpluses largely peak demand in the summer and the reserve margin is more than 20% after 2021. In addition, since the peak demand in the winter declines to 60% of that in the summer, the reserve margin in the winter also more than 10% in 2025.

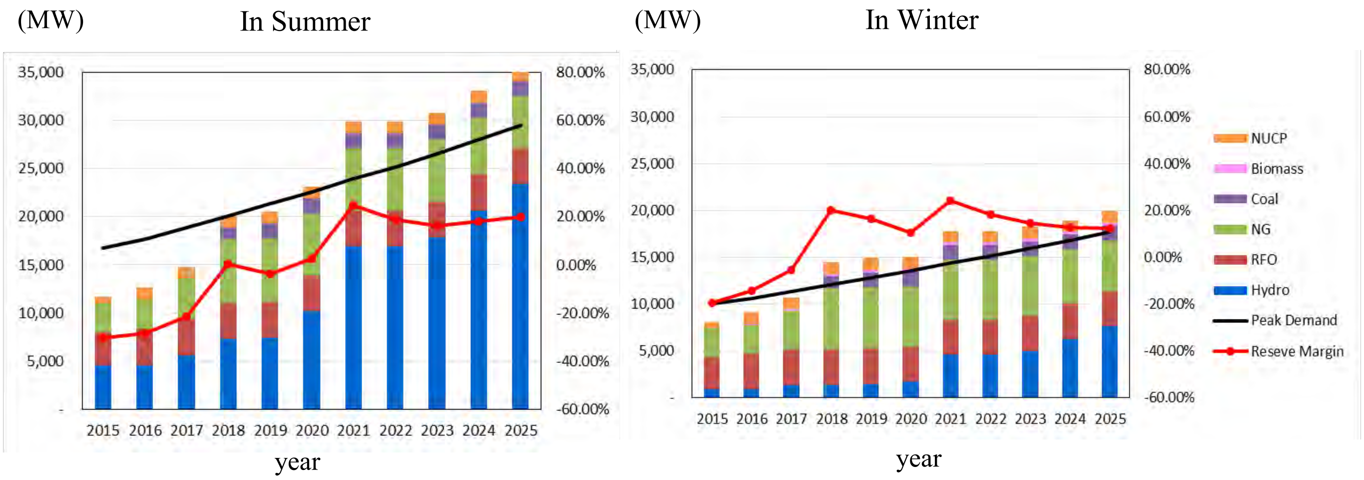


Figure 5-7 Current Power Development Plan up to 2025 in North System

(b) South system

As the north system, the yearly growth of supply capacity and reserve margin in the south system are arranged as shown in Figure 5-8. The reserve margin is more than 20% after 2020 and reaches up to 60% in 2022 and 2023. Besides, the total supply capacity of nuclear power and coal fired thermal power which are the base load supplier accounts for as much as 70%.

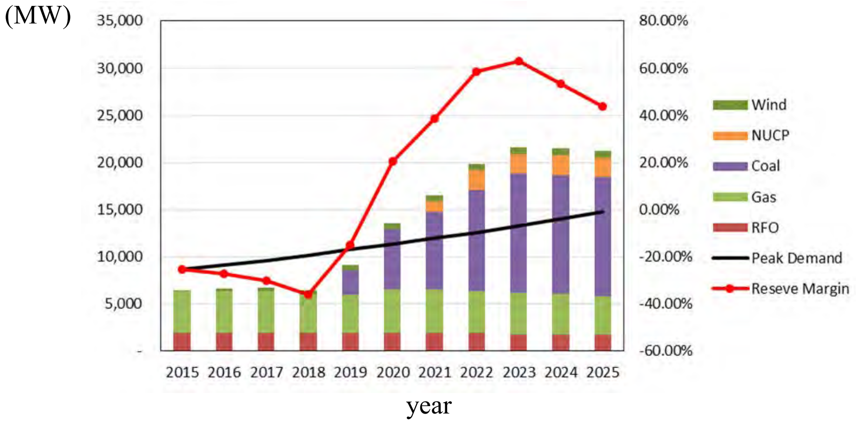


Figure 5-8 Current Power Development Plan up to 2025 in South System

(c) KE system

The yearly growth of supply capacity and reserve margin in the KE system are arranged as shown in the below figure. Here, since the power development plan after 2021 is unknown, JICA Project Team added development projects of one combined cycle gas turbine plants of 320MW (2025) and four coal fired thermal power plants of 2,800MW (2021 to 2025). Accordingly, the reserve margins after 2021 become almost 0%.

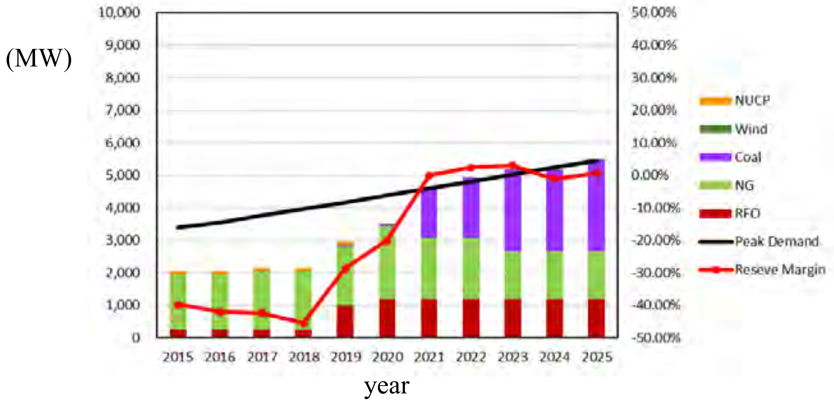


Figure 5-9 Current Power Development Plan up to 2025 in KE System

(4) Issues on supply reliability

Any criterion regarding power supply reliability was not seen in the previous power development plan. However, the target value of LOLP (Loss of Load Probability) is 1% in the grid code. Besides, the target value of LOLP is set as 1~1.5% in Bangladesh, in Southwest Asian countries (Vietnam, Indonesia, etc.), LOLP = 0.27% or LOLE = 24hr is set as annual power shortage duration. In addition, in Japan, LOLP = 0.03% or LOLE = 3hr is set.

In this study, LOLP = 1.0% or LOLE = 88hr is set as a criterion of power supply reliability as described in the grid code, after consultation with Pakistan side.

5.2.2 Economy Comparison of Various Power Sources by Screening

By calculating the power cost of each utilization rate from construction costs (fixed cost) and fuel costs (variable costs) of various powers, the optimal power supply of each of base, middle, and peak supply capacity is examined.

(1) Construction cost

By referring to Power Development Investment Cost of some projects in Pakistan, the standard construction cost of each power source was set as shown in Table 5-10.

Table 5-10 Construction Cost of Each Power Sources

Power Sources	Construction cost
Hydro (Run of river or Pondage type)	1,800 US$/kW
Hydro (Reservoir type)	2,500 US$/kW
Oil Fired Thermal (ST)	1,000 US$/kW
Gas Turbine	500 US$/kW
Combined Cycle	1,000 US$/kW
Coal Fired Thermal (ST)	1,800 US$/kW
Nuclear	3,000 US$/kW

(Source : JICA Project Team)

(2) Annual fixed cost

Annual fixed cost of each power source is calculated based on the above construction cost. Annual fixed cost generally differs, depending on the methods of depreciation, and hits maximum cost in the first year after commissioning. However, Table 5-11 shows costs equalized by the economic lifetime with the discount rate of 10% in accordance with the following formula. In addition, the common economic lifetime of each power source was used as; 25 years for thermal and nuclear power due to a large share of electrical and mechanical equipment construction cost, 40 years for hydropower due to a large share of civil engineering structures construction cost.

Annual fixed expense = Construction cost × (Capital Recovery Factor + O&M expense rate)

$$\text{Capital Recovery Factor} = \frac{i\times(1+i)^n}{(1+i)^n-1} \qquad i\text{: discount rate,} \quad n\text{: economic lifetime}$$

Table 5-11 Annual Fixed Cost of Each Power Sources

	Construction cost (US$/kW)	Expense rate (%)			Annual fixed expense (US$/kW/year)
		Capital Recovery Factor	O&M expense	Total	
Hydro (Run of river type)	1,800	10.23	1.0	11.23	202.1
Hydro (Reservoir type)	2,500	10.23	1.0	11.23	280.6
Oil Fired Thermal (ST)	1000	11.02	2.5	13.52	135.2
Gas Fired Thermal (GT)	500	11.02	5.0	16.02	80.1
Combined Cycle	800	11.02	4.5	15.52	124.1
Coal Fired Thermal (ST)	1,800	11.02	3.5	14.52	261.3
Nuclear	3,000	11.02	3.0	14.02	420.5

(Source : JICA Project Team)

(3) Fuel cost

As a fuel price forecast in the future, fuel price prediction up to 2040 which is described in the chapter 4.4 is applied as summarized in the below table.

Table 5-12 Predicted Fossil Fuel Prices

	Unit	2015	2020	2025	2030	2035
RFO	US$/bbl	62	71	81	86	91
NG	US$/MMBtu	6.5	7.6	8.7	9.2	9.8
LNG	US$/MMBtu	9.0	10.5	12.0	12.8	13.5
Imp. Coal	US$/ton	60	70	80	85	90
Dom. Coal	US$/ton	27	32	36	38	41

Based on the above prediction, the fuel costs at standard thermal power plants as of 2025 are calculated as shown in Table 5-13.

Table 5-13 Fuel Cost

	Price forecast (2025)	Calorie	Heat efficiency	Fuel cost (USC/kWh)
Oil ST	81 US$/bbl	9,600 kcal/kg	38%	12.8
GT (NG)	8.7 US$/MMBtu	11,500 kcal/kg	37%	8.4
GT (LNG)	12.0 US$/MMBtu	11,500 kcal/kg	37%	11.6
C/C (NG)	8.7 US$/MMBtu	11,500 kcal/kg	57%	5.3
C/C (LNG)	12.0 US$/MMBtu	11,500 kcal/kg	57%	7.4
Imp. Coal ST	80 US$/ton	6,000 kcal/kg	39%	3.1
Dom. Coal ST	36 US$/ton	2,750 kcal/kg	39%	3.0

(Source : JICA Project Team)

(4) Screening of generating cost

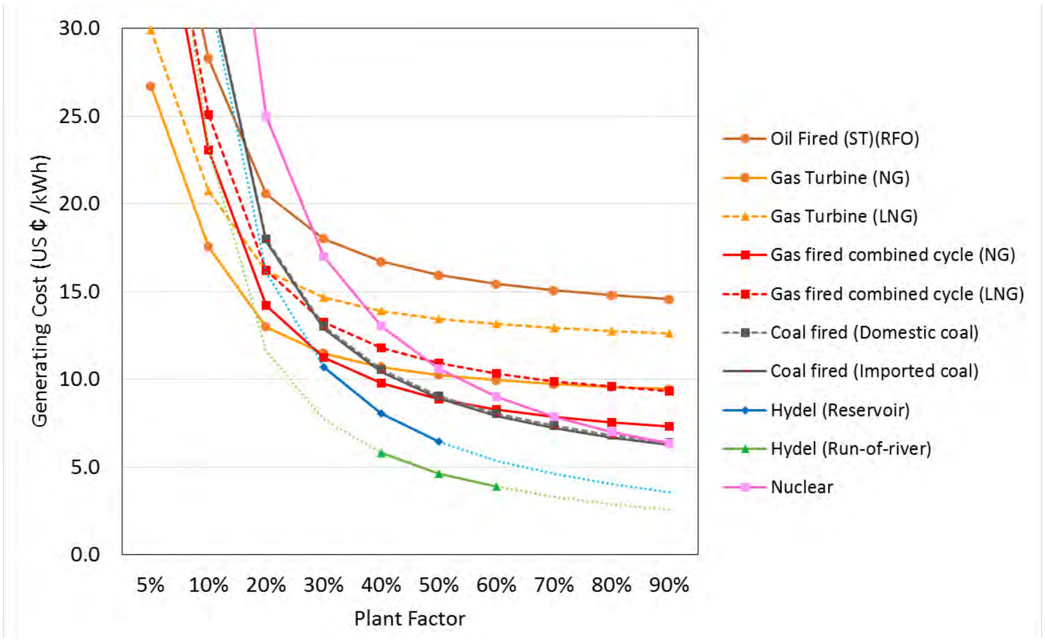
Based on the above estimation of construction costs and fuel costs, the unit generation cost of each power source in year 2025 is calculated as follows. Besides, the fuel cost of nuclear power plant is estimated as 1.0 UScent/kWh.

In a field concerning base load supplier (Capacity factor of 70% or more), nuclear power and coal fired power generation is most economical than the other power sources.

In a field of middle load supplier (Capacity factor of 30 &- 60%), hydropower (Run- of river type) is the most economical power source. This was caused by carefully finding and developing the most efficient hydropower project site (Capacity factor of 30%-50% with peak generation time of approximately 4000 hours) so as to make it more economical than other power sources and the next economical plant is gas combined cycle thermal power plant with NG.

In addition, Hydro power (Reservoir type and Pondage type) is the most economical peak and middle load supplier and the next economical one is gas turbine thermal power plant with NG.

The relation between generating costs and load factor by power source are summarized in Figure 5-10 and Table 5-14 .



(Source : JICA Project Team)

Figure 5-10 Comparison of Generating Cost of Each Power Source as of 2025

Table 5-14 Generating Cost of Each Power Source

	Construction cost (US$/kW)	Annual fixed cost (US$/kW/yr)	Fuel cost (US ¢ /kWh)	Generating cost (US ¢ /kWh)			
				L.F=10%	L.F=40%	L.F=65%	L.F=80%
Hydro (Reservoir)	2,500	280.6	0.0	30.8	7.7	---	---
Oil (RFO)	1,000	135.2	12.8	28.3	16.7	15.3	14.8
Gas CC (NG)	1,000	155.2	5.3	23.0	9.8	8.1	7.5
Gas CC (LNG)	1,000	155.2	7.4	25.1	11.8	10.1	9.6
Gas GT (NG)	500	80.1	8.4	17.6	10.7	9.8	9.6
Coal (Imp.)	1,800	261.3	3.1	32.8	10.4	7.7	6.8
Nuclear	3,000	420.5	1.0	36.0	13.0	8.4	7.0

5.2.3 Appropriate Reserve Margin base on Supply Reliability

(1) Existing power development plan

The relationship between loss of load expectation (LOLE) and the supply reserve margin is calculated, taking into consideration the generation mix forecast around 2025 (with the demand size of approx. 48GW), and the appropriate supply reserve margin is determined to achieve the targeted supply reliability criteria.

Power system in the whole county is divided into three power systems, the North, the South and KE, in consideration of interconnection among three systems.

The boundary between North and South system is specified as between Multan S/S and Guddu S/S.

(a) Input data

1) Error in Demand Forecast

Error in the demand forecast, which is 2% of the forecasted demand, is estimated as the standard deviation.

2) Configuration of power sources and forced outage rate

The generation mix and their forced outage rates are as shown in Table 5-15. The forced outage rate of hydropower plants is set based on the operation records of Tarbela, Mangla, Ghazi Barotha HPP and that of oil fired thermal power plants is set based on the operation records of Guddu, Jamshoro, Mazaffargarh TPP.

The forced outage rates of other power sources are set in reference of common value in other countries.

Especially, the forced outage rate of import power with DC is added 10% on the power source forced outage rate, since the forced outage rate of DC line is over 10% in common.

In addition, the total installed capacity in 2025 is planned to be around 68GW against the maximum demand of 48.4GW in Base demand case and 55.4GW in High demand case.

Table 5-15 Configuration of Power Sources and Forced Outage Rate

	Installed Capacity (MW)	Ratio (%)	Max. Unit Capacity	Forced Outage Rate (FOR)
Hydropower	25,395	37.3	432MW	1%
Oil fired thermal	5,670 (1,268)	8.3	386MW	8% - 10%
Gas turbine	13,911 (3,208)	20.3	156MW	4% - 6%
Combined Cycle			400MW	4% - 6%
Imp. Coal (ST)	17,165 (150)	25.0	660MW	4%
Dom. Coal (ST)			660MW	5%
Nuclear power	3,530 (137)	5.1	1100MW	5%
Biomass & Wind	2,794	4.0	67MW	5%
Power Import (CASA)	(Hydro) 1,000	-	1000MW	11%
Power Import (Iran)	(C/C) 1,000	-	1000MW	15%
Total	68,660			

Note) ・Forced outage includes events of independent stop after detecting troubles
・A number of days of outage includes repairing period
・Forced outage is defined as a number of days of outage divided by 365 days

(Source : JICA Project Team)

3) Output fluctuation probability of hydropower plants

Although the supply capacity fluctuation deviation differs a bit by seasons, approximately 12% of the available capacity of hydropower plant is estimated as the standard deviation of supply capacity fluctuation of hydropower plant based on the operation records of the existing hydropower plants.

(b) Relationship between LOLE and reserve margin (2025)

The system reliability situations in are analyzed based on the aforementioned demand forecasts (Base Case) and the aforementioned power development plan, in the north system, the south system and the KE system respectively. The analysis results are shown in Figure 5-11.

The relationship between reserve margin and LOLE in the north system does not change significantly, since the configuration rate of hydropower plant is large and then deviation of supply capacity is large, especially large reduction of supply capacity during dry season. In the case of LOLE 88-hour (LOLP = 1.0%) , the power supply reliability criterion, the required reserve margin is 10.1%.

Thermal power plant is the major power source in the south and KE systems. In the south system, the unit capacity of nuclear power plant of 1100MW is large and the forced outage rate of power import from Iran is as large as 15%. Accordingly the required reserve margin in the south system is 6.3%. Meanwhile, that of KE system is as small as 2.0%.

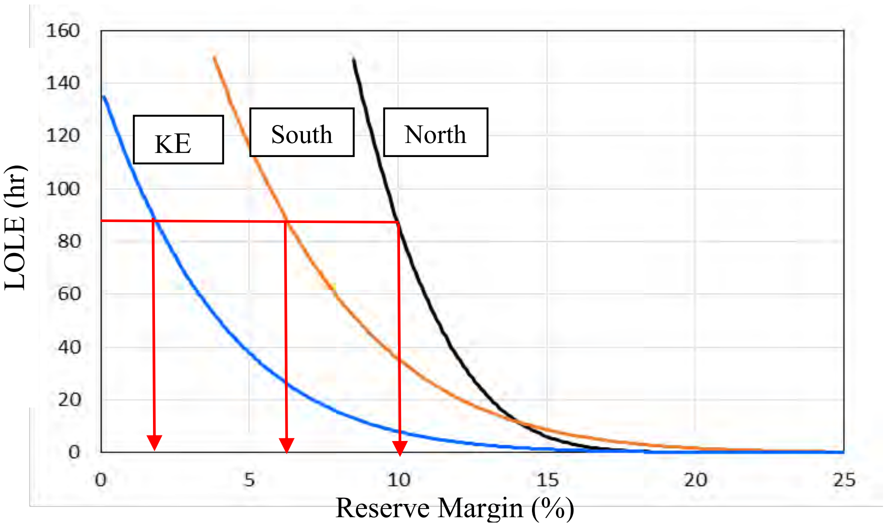
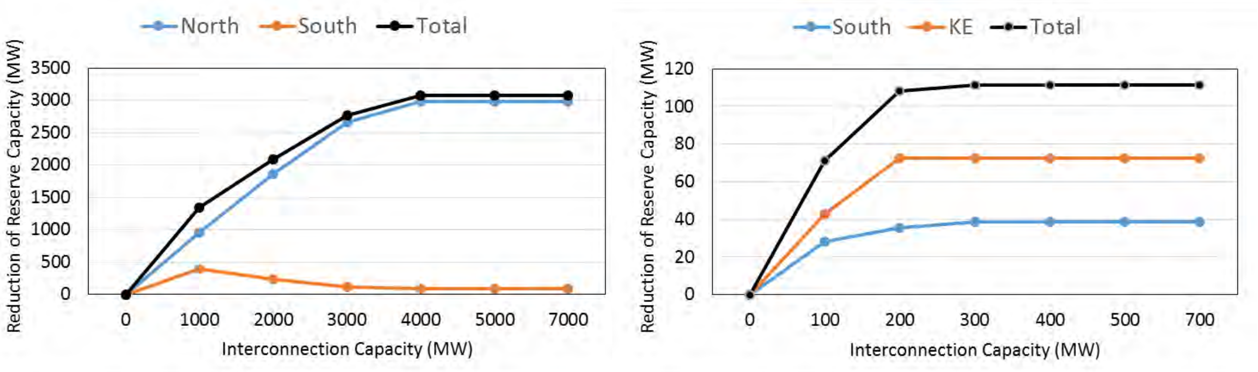


Figure 5-11 Relationship between Reserve Margin and LOLE (2025)

(c) Relationship between the reduction of reserve capacity and the interconnection capacity (2025)

The increase in the interconnection capacity brings out possibility of reduction of reserve capacity in the whole power system because demand diversity among interconnected systems enhances the mutual generation utilization. And when power supply capacity of hydropower plant is lowered during the dry season, the thermal power plant can supply power to the north system through the interconnection and the required reserve capacity can decrease significantly. The relationship between the reduction of reserve capacity and the interconnection capacity is analyzed as shown in the below figure.

Reduction of the reserve capacity between the north and he south system is saturated at approximately 3,000MW, when the interconnection capacity is 4,000MW. However, the difference of reserve capacity reduction between 3,000MW and 4,000MW is only 290MW, which means there is little advantage in investing in reinforcement of interconnection facility more than 1,000MW. Because the development cost of a coal fired thermal power plant of 300MW is around 500 million US$, on the contrary, the expansion cost of the 500kV transmission line of 1,000km is around 1,000 million US$. That is twice of the power development cost. Accordingly, the interconnection capacity between the north and the south system for the PDP simulation is set as 3,000MW from the viewpoint of efficiency of the system reliability improvement. Meanwhile, reduction of the reserve capacity between the south and KE system is saturated at 110MW, when the interconnection capacity is 200 MW. However, since there exists 220kV interconnection transmission lines (capacity of 700MW) between the south and KE systems, the interconnection capacity for the PDP simulation is set as 700MW.



(Between North and South System) (Between South and KE System)

Figure 5-12 Relationship between Reduction of Reserve Capacity and Interconnection Capacity

In the case of the above interconnection among the three systems, the required reserve capacity of each power system is 1.1% in the north, 5.3% in the south and 0.0% in the KE system, respectively.

(2) Revision of Existing PDP

The above mentioned current power development plan should be revised to maintain appropriate reserve margin. Therefore, JICA project team revised the hydropower development plan in the north and the thermal power development plan from the following viewpoints.

- In the north system, the share of hydropower plant is too big and the large scale hydropower development projects are apt to delay due to social environmental issues or financial issues. Furthermore, the reserve margin from 2021 exceeds 10% even though the required reserve margin is around 1%.
- In the south system, the reserve margin from 2021 exceeds 20% even though the required reserve margin is around 6%. And it deemed uneconomical that nuclear power and coal fired thermal power plant which are base load suppliers account for over 70% which exceeds a lot the base load of around 50%.

Meanwhile, the following points are taken into account.

- Bunji HPP (7,100MW) was substituted by Thakot HPP (4,000MW), since the supply capacity in winter is declined up to 1/5 of that in summer.
- Since Sahiwal (PPIB) coal fired TPP is located in Punjab province and the electric power generated is transmitted to Lahore S/S and Multan S/S, the both belong to the north system, the all units of Sahiwal TPP are considered as a power plant in the north system.

The yearly power supply capacity of each power source and the yearly reserve margin of the revised PDP are shown in Figure 5-13 in the north system, in Figure 5-14 in the south system, in Figure 5-15 in the KE system and in Figure 5-16 in the whole country, respectively.

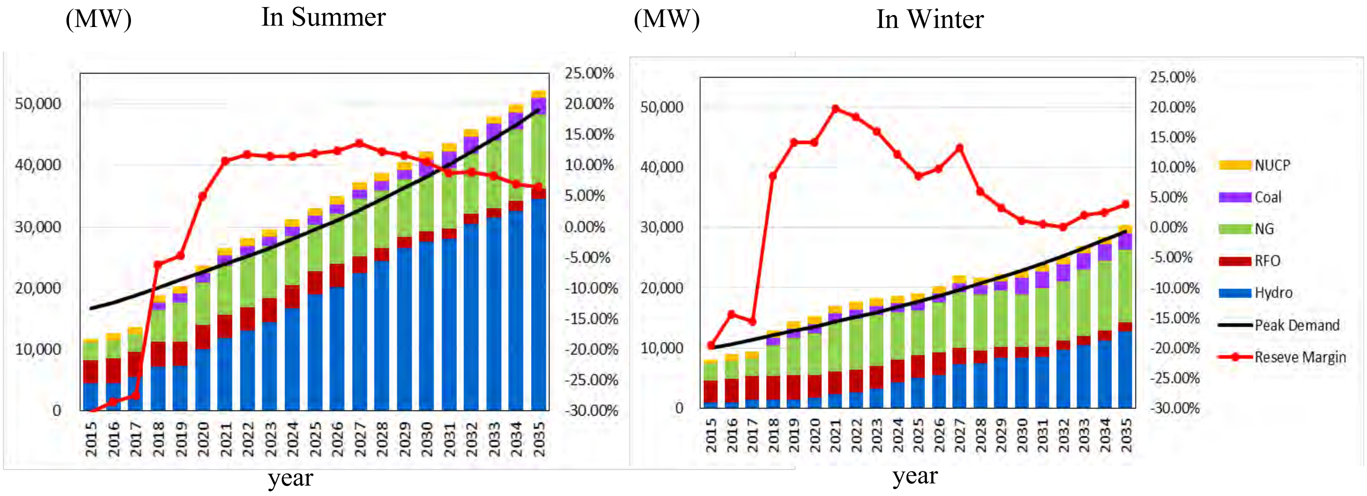


Figure 5-13 Revised PDP up to 2035 in North System

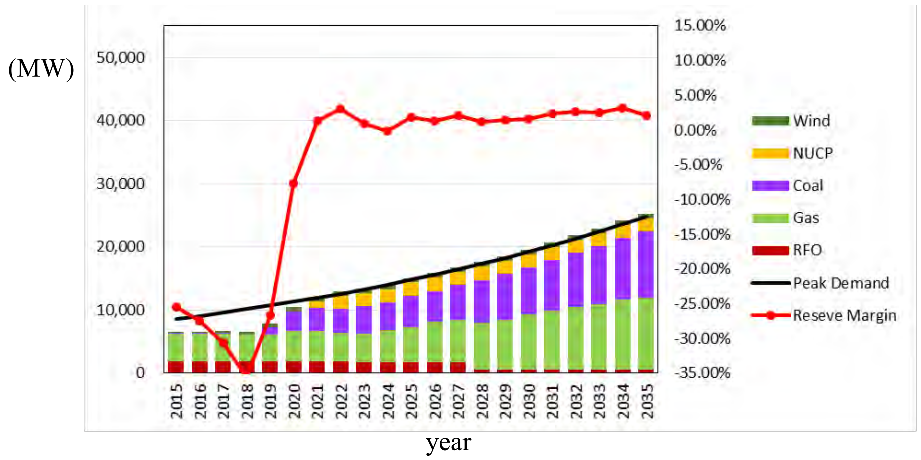


Figure 5-14 Revised PDP up to 2035 in South System

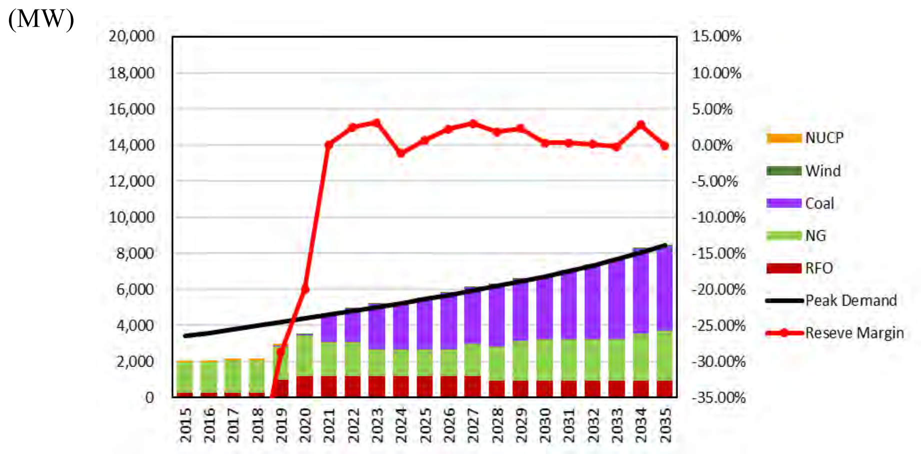


Figure 5-15 Revised PDP up to 2035 in KE System

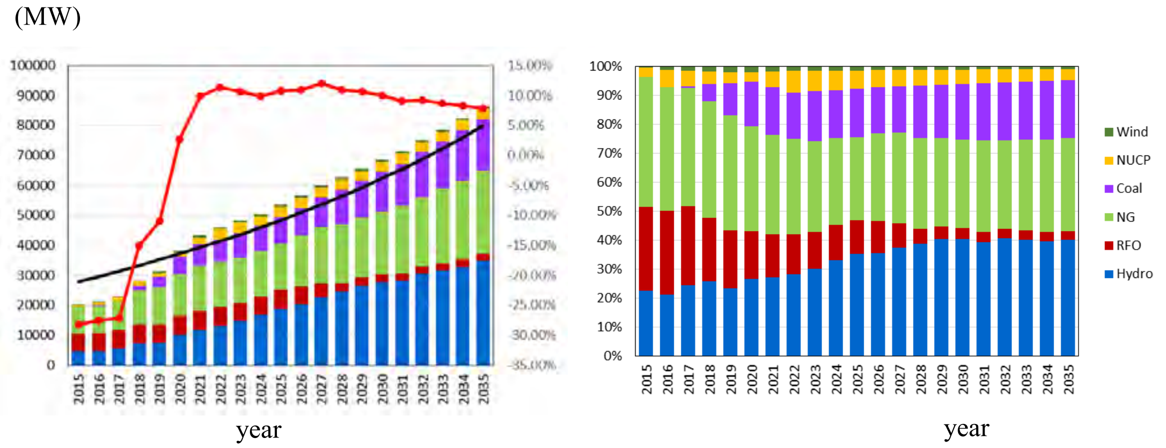


Figure 5-16 Revised PDP up to 2035 in Whole Country

As the results, the power development plan was improved as follows.

(In the North)

- HPP Supply Capacity in 2035 accounts for 66% in Summer and 42% in Winter
- Required reserve margin in Summer is positive after 2020 and is around 6% in 2035
- Reserve margin in Winter goes down from 20% in 2021 to +0% in 2032.

(In the South)

- Reserve margin become positive in 2021 and around 0% after 2021.

- Total share of Coal TPP and Nuclear PP from 2021 to 2035 is around 50%.

(In the KE)

- Reserve margin become positive in 2021 and around 0% after 2024.

(In the whole country)

- Reserve margin from 2021 to 2035 is between 7% and 11%.
- Total share of Coal TPP and Nuclear PP is around 24% after 2021.

(a) Relationship between LOLE and reserve margin (Standalone system)

Since the existing PDP was revised and the power sources configuration was changed, the relationships between LOLE and reserve margin of the revised PDP in 2025 and 2035 are re-analyzed.

The analysis results are shown in Figure 5-11. In the north system, the configuration rate of hydropower plant become 60% in 2025 which is twice of that in 2015 and the supply capacity of hydropower in 2025 is as low as 25% of that in summer due to development of Tarbela 4th & 5th extension projects and CASA-1000. Accordingly, supply capacity shortage happens in winter and the required reserve margin become larger than that of the existing PDP from 10% to 15%.

The required reserve margin of the North system, South system and KE system decrease 15.4%→10.4%, 4.7%→1.6%, 2.5%→1.3%, respectively, due to increase of the total installed capacity.

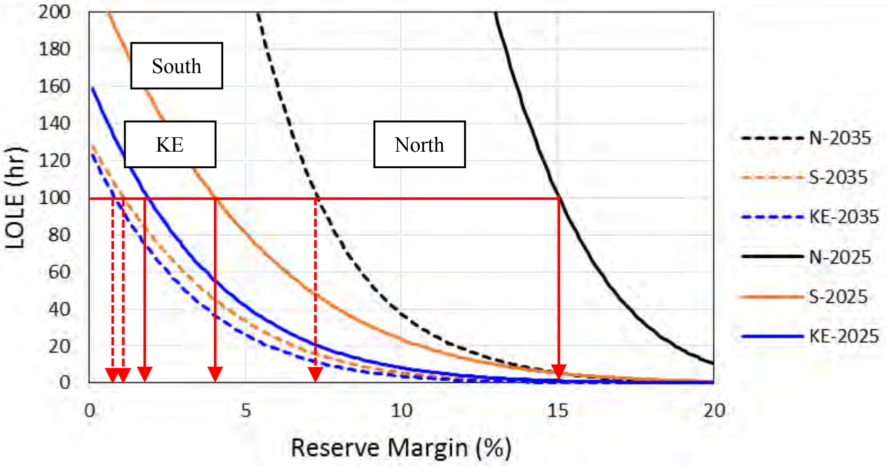


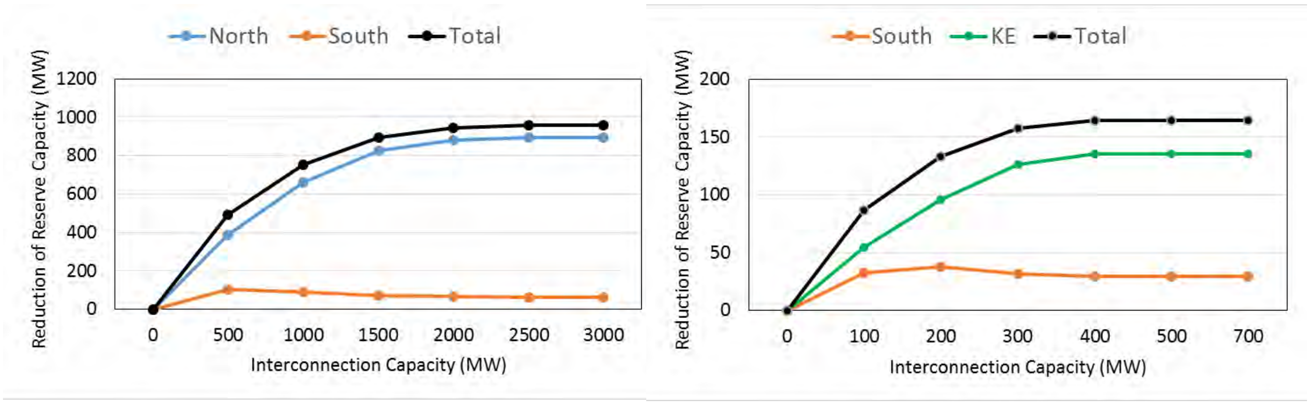
Figure 5-17 Relationship between Reserve Margin and LOLE (Revised PDP)

(b) Relationship between the reduction of reserve capacity and the interconnection capacity

The relationship between the reduction of reserve capacity and the interconnection capacity between the north and the south system and between the south and KE system was analyzed as well as the analysis on the existing PDP. The analysis results are shown in Figure 5-18 (2025) and Figure 5-19 (2035). Tendency between the north and the south system does not change, which the required reserve capacity in the north system can be largely reduced due to power supply from the TPPs in the south when the supply capacity of HPP in the north in winter.

However, since the share of HPP decreased in comparison with the existing PDP, reduction of the reserve capacity between the north and the south system is saturated when the interconnection capacity is 1,500MW. Meanwhile, reduction of the reserve capacity between the south and KE system is saturated at 160MW, when the interconnection capacity is 300 MW. However, since there exists 220kV interconnection transmission lines (capacity of 700MW) between the south and KE systems, there is no need to increase the interconnection capacity.

Reduction of the reserve capacity between the north and he south system in 2035 is saturated when the interconnection capacity is 4000MW in line with increase of HPP share. However, the difference of reserve capacity reduction between 3,000MW and 4,000MW is only 175MW, which means there is less advantage in investing in reinforcement of interconnection facility than developing power plant. Accordingly, the interconnection capacity between the north and the south system for the PDP simulation is set as 3,000MW from the viewpoint of efficiency of the system reliability improvement. Meanwhile, the interconnection capacity that reduction of reserve capacity is saturated between the south and KE system is 300MW as well as 2025.



(Between North and South System) (Between South and KE System)

Figure 5-18 Reduction of Reserve Capacity and Interconnection Capacity (2025)

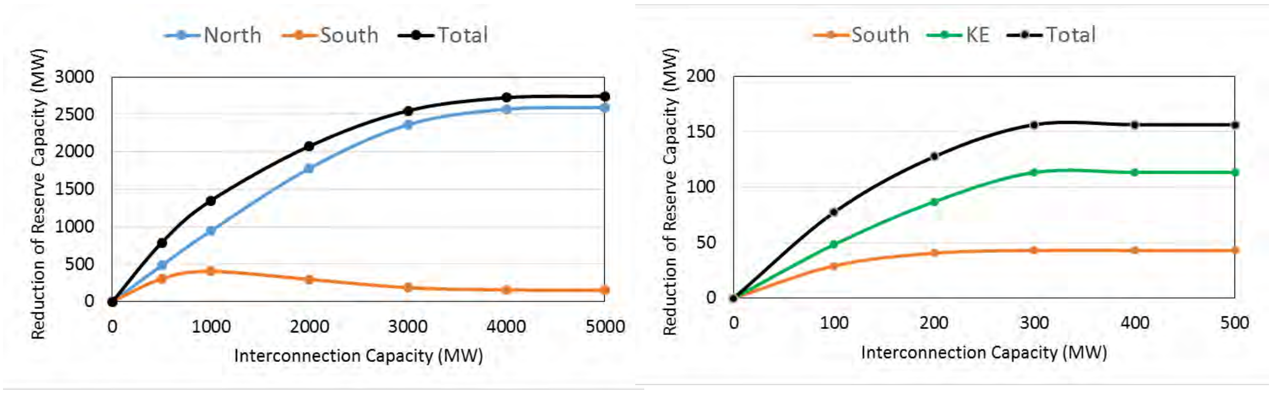


Figure 5-19 Reduction of Reserve Capacity and Interconnection Capacity (2035)

The required reserve margins of the interconnected system are summarized in the below table.

Table 5-16 Required Reserve Margin of Interconnected System

		Standalone system	Interconnected system
2025	North	15.4 %	10.4 %
	South	4.7 %	0.0 %
	KE	2.5 %	0.0 %
2035	North	7.6 %	2.5 %
	South	1.6 %	0.8 %
	KE	1.3 %	0.0 %

5.3 Optimal Generation Mix in 2025, 2035

Based on the power source configuration of the revised PDP, development ratios of coal fired TPP and IPP gas fired TPP are varied on the condition of securing the aforementioned required reserve margin (LOLE 88hr). And then, the most economical demand-supply operation of each case is simulated by PDPAT II and the annual generation cost is computed. The generation mix case of the least generation expense is determined as the optimal one in 2025 and 2035.

5.3.1 Base Scenario

(1) Assumptions

(a) Interconnection capacity

Between North and South System ; 1,500MW in 2025, 3,000MW in 2035
Between South and KE System ; 700MW in 2025 and 2035

(b) Reliability criterion

Total supply capacity (installed capacity) of each power system is adjusted so as to satisfy the required reserve margin of interconnected system in Table 5-16.

(c) Power development plan

Politically developed hydropower, nuclear power, renewable energy power, power import and LNG fired TPP are not adjusted based on the revised PDP. The development amount of the other TPPs planned to develop in the later year is adjusted so as to satisfy the reliability criterion. In other words, the development ratio of coal fired TPP and IPP gas fired TPP are adjusted.

(d) Fuel cost

Fuel cost is on the basis of the fuel price shown in Figure 5-12. All coal fired TPP in the north is assumed to use import coal except Salt Range TPP and the coal price of import coal is added transportation fee of 15.0 US$/ton.

(e) Operational constraints on IPP contract

Load factor of IPP gas fired TPP, both pipeline gas and LNG, is fixed as over 65% according to the contract condition.

(f) Environment protection cost against CO_2 emission

Environment protection cost against CO_2 emission of 10 US$/ton-$CO_2$ is considered for the deference of total CO_2 emission among cases. 10 US$/ton-$CO_2$ is the average transaction price of CDM (Kyoto Protocol) before 2012.

(2) Optimal power source configuration

(a) North system

Total generation costs (annual generation expense) are computed for the cases that coal fired TPP substitutes IPP gas fired TPP listed in the revised PDP in 2025 and in 2035. The computation results are shown in Table 5-17 and Figure 5-20, in Table 5-18 and Figure 5-21, respectively.

The case that coal fired TPP of 660MW substitutes IPP gas fired TPP is the most economical both in 2025 and in 2035. However, if the environment protection cost against CO_2 emission is not considered, the case that coal fired TPP of 1,980MW substitutes IPP gas fired TPP become the most economical.

Meanwhile, the deference of annual expense among cases is around only 10 million US$/annum, since the generation cost of import coal fired TPP at the load factor of 70% is slightly lower than that of gas fired TPP due to addition of transportation cost to the import coal.

Table 5-17 Relationship between Additional Installed Capacity of Coal TPP and Annual Generation Expense in North System (2025)

Coal Fired TPP	Unit	-1,320MW	-660MW	Base	660MW	1,320MW	1,980MW	2,450MW
Total	million US$	93.1	44.7	0.0	- 35.3	- 54.9	- 61.8	- 46.0
CDM	million US$	- 44.3	- 22.0	0.0	22.3	44.9	68.1	89.8
Total+CDM	million US$	44.8	22.7	0.0	- 13.0	- 10.0	6.3	43.4

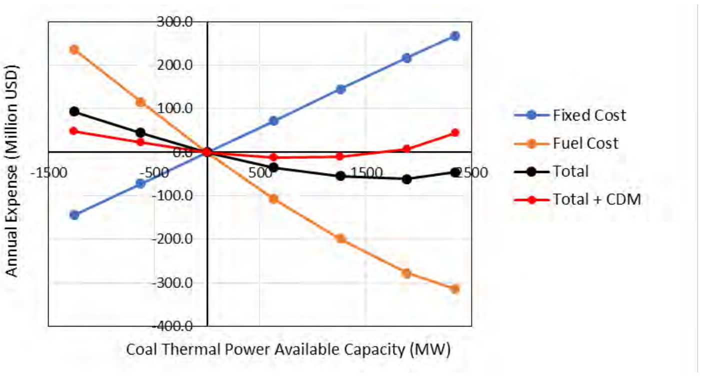


Figure 5-20 Relationship between Additional Installed Capacity of Coal TPP and Annual Generation Expense in North System (2025)

Table 5-18 Relationship between Additional Installed Capacity of Coal TPP and Annual Generation Expense in North System (2035)

Coal Fired TPP	Unit	Base	+660MW	+1,320MW	+1,980MW
Total	million US$	0.0	- 29.3	- 42.3	- 52.1
CDM	million US$	0.0	18.8	35.3	54.8
Total+CDM	million US$	0.0	- 10.5	- 7.0	2.7

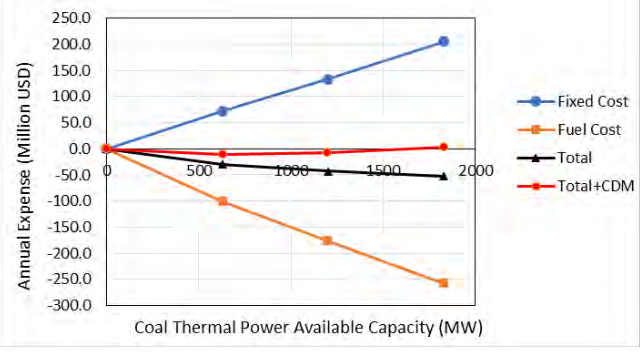
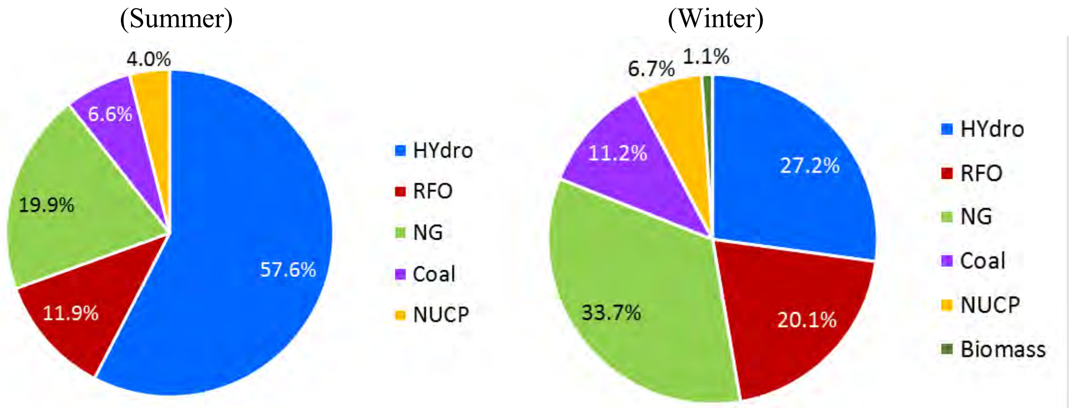


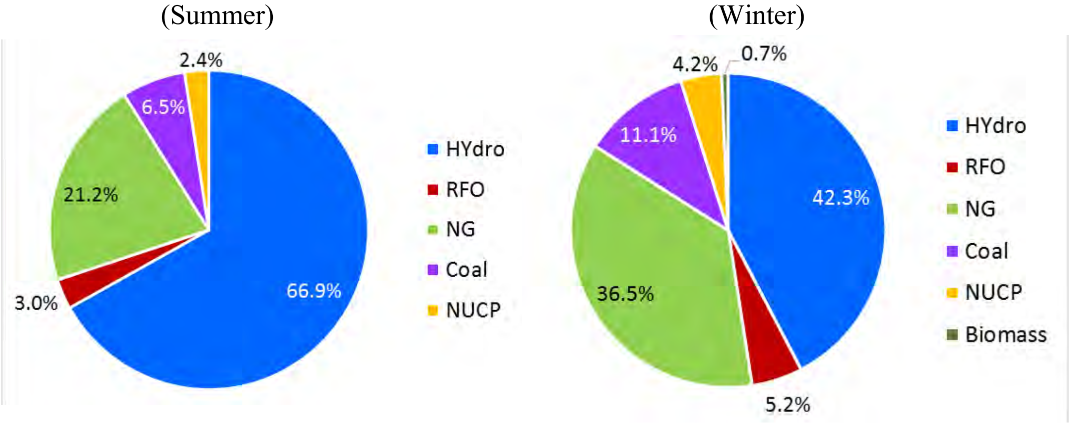
Figure 5-21 Relationship between Additional Installed Capacity of Coal TPP and Annual Generation Expense in North System (2035)

The optimal generation mixes in the north system in 2025 and in 2035 are shown in Figure 5-22 and Figure 5-23, respectively, based on the above examination results.


(Summer)

(Winter)

Figure 5-22 Optimal Power Source Configuration in North System (Base Scenario : 2025)

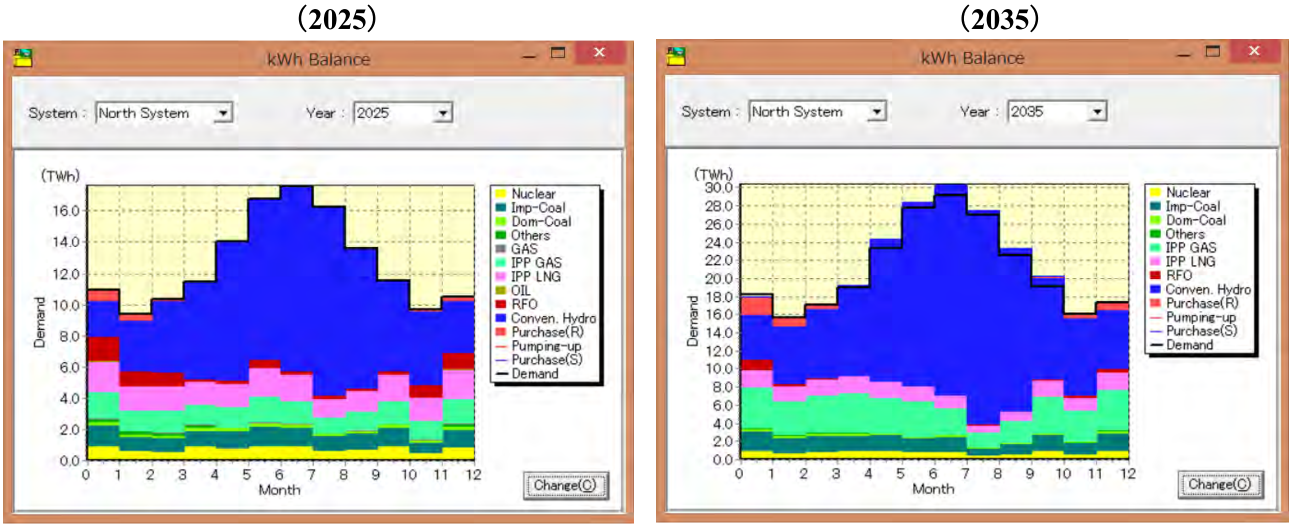

(Summer)

(Winter)

Figure 5-23 Optimal Power Source Configuration in North System (Base Scenario : 2035)

The generation mix in 2035 in the north system is optimal, which the optimal hydropower share is around 70% due to decline of supply capacity in winter. However, since there exist the oil fired TPPs which have not yet aged more than 30 years as of 2025 and those account for 12%, the share of hydropower stays at around 60%.

Annual kWh balances in 2025 and in 2035 are shown in Figure 5-24. The demand-supply balance in January is the tightest and the power supply from the south system is needed from December to February.


(2025)

System : North System

Year : 2025

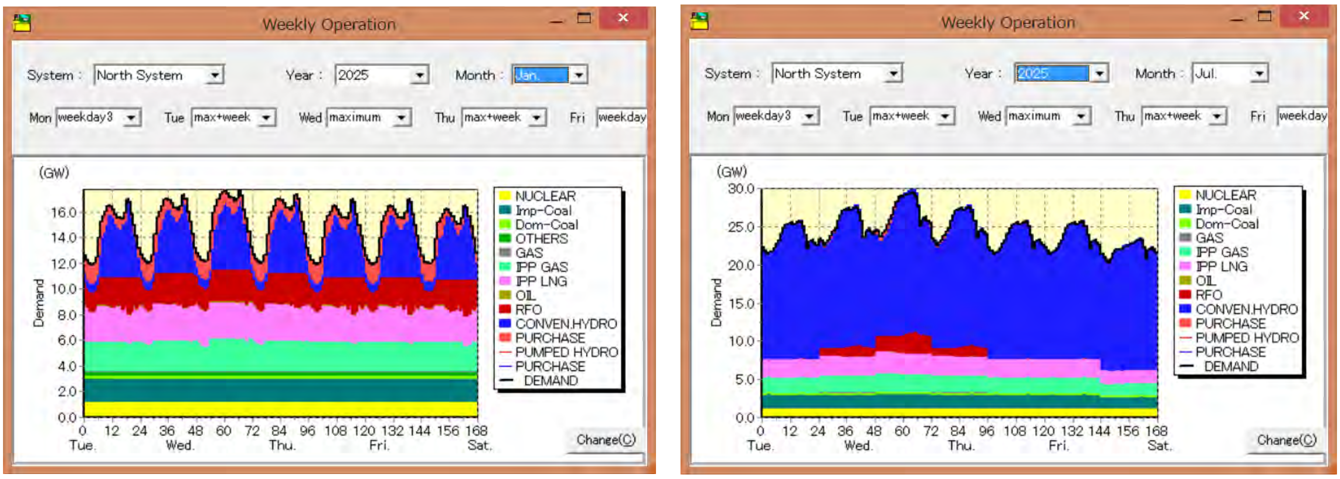
(2035)

System : North System

Year : 2035

Figure 5-24 Annual kWh Balance in North System

Weekly operation simulation results in January and July of 2025 are shown in Figure 5-25, and those in January and July of 2035 are shown in Figure 5-26. In January of 2025, although the kW demand-supply is balanced by the supply capacity in the north system, the generated energy (kWh) in the north is fallen short and is needed to accommodate generated energy from the south system. On the contrary in July of 2025, both kW and kWh demand-supply are balanced in the system. In January of 2035, both kW and kWh demand-supply are unbalanced in the system, therefore, kW and kWh are needed to accommodate from the south system.



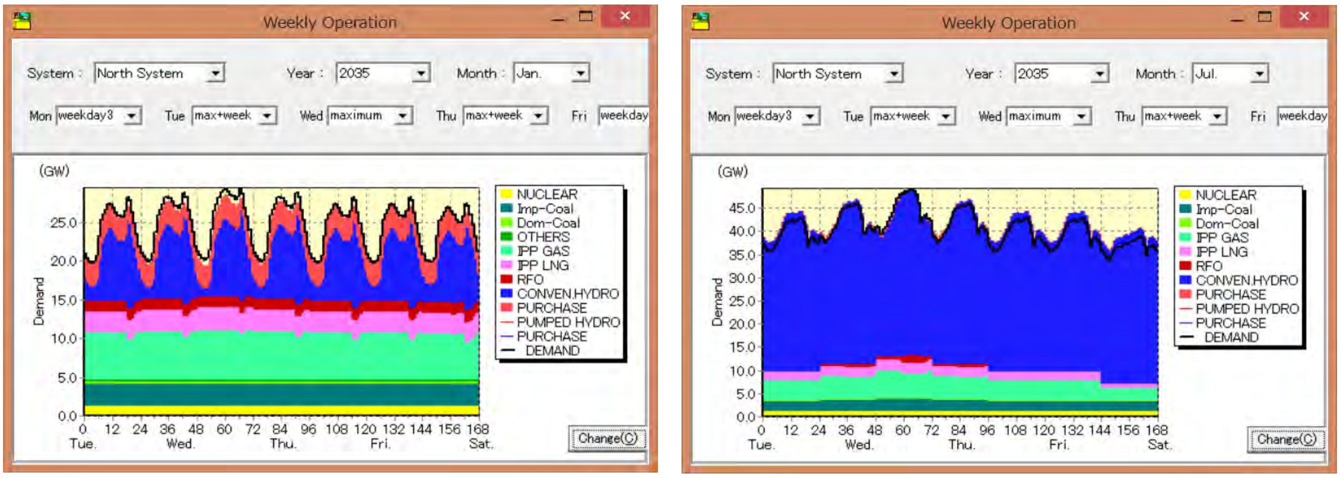
(January)

System : North System Year : 2025 Month : Jan.
Mon weekday3 Tue max+week Wed maximum Thu max+week Fri weekday

(July)

System : North System Year : 2025 Month : Jul.
Mon weekday3 Tue max+week Wed maximum Thu max+week Fri weekday

Figure 5-25 Weekly Operation in North System in 2025



(January)

System : North System Year : 2035 Month : Jan.
Mon weekday3 Tue max+week Wed maximum Thu max+week Fri weekday

(July)

System : North System Year : 2035 Month : Jul.
Mon weekday3 Tue max+week Wed maximum Thu max+week Fri weekday

Figure 5-26 Weekly Operation in North System in 2035

(b) South system

Total generation costs (annual generation expense) are computed for the cases that coal fired TPP substitutes IPP gas fired TPP listed in the revised PDP in 2025 and in 2035. The computation results are shown in Table 5-19 and Figure 5-27, in Table 5-20 and Figure 5-28, respectively.

In 2025, the case that coal fired TPP of 1,320MW substitutes IPP gas fired TPP is the most economical, however, in 2035 the installed capacity of coal thermal power in the revised PDP is the most economical. Even if the environment protection cost against CO_2 emission is not considered, the most economical case is the same as the above cases.

Table 5-19 Relationship between Additional Installed Capacity of Coal TPP and Annual Generation Expense in South System (2025)

Coal Fired TPP	Unit	-660MW	Base	+660MW	+1,320MW	+1,500MW
Total	million US$	37.1	0.0	- 108.8	- 182.6	- 187.0
CDM	million US$	- 26.3	0.0	21.1	45.4	54.9
Total+CDM	million US$	10.8	0.0	- 87.7	- 137.2	- 132.1

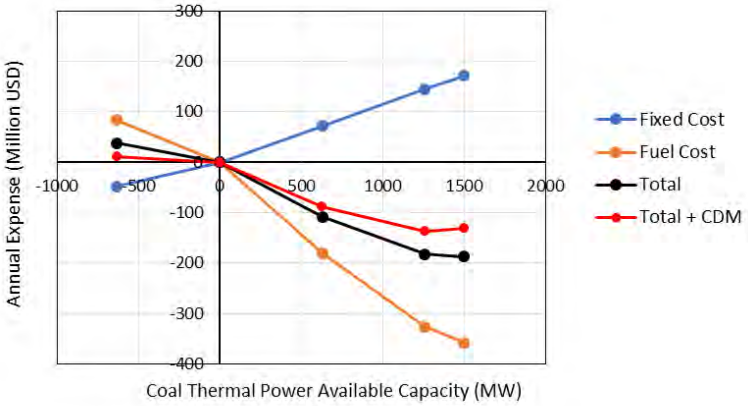


Figure 5-27 Relationship between Additional Installed Capacity of Coal TPP and Annual Generation Expense in South System (2025)

Table 5-20 Relationship between Additional Installed Capacity of Coal TPP and Annual Generation Expense in South System (2035)

Coal Fired TPP	Unit	-1,320MW	-660MW	Base	+660MW	+1,320MW
Total	million US$	37.1	44.7	0.0	- 35.3	- 54.9
CDM	million US$	- 26.3	- 22.0	0.0	22.3	44.9
Total+CDM	million US$	10.8	22.7	0.0	- 13.0	- 10.0

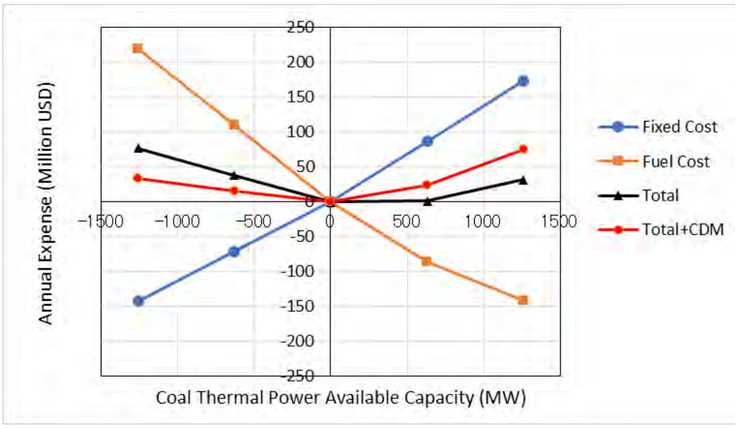


Figure 5-28 Relationship between Additional Installed Capacity of Coal TPP and Annual Generation Expense in South System (2035)

The optimal generation mixes in the south system in 2025 and in 2035 are shown in Figure 5-29, based on the above examination results.

The generation mix in 2025 is optimal in the south system, which the optimal share of base load suppliers such as coal fired, nuclear, wind power is around 60%. However, since there is contractual constraints of IPP gas fired TPPs, load factor is fixed 65%, increase of gas fired TPP is more economy than increase of coal fired TPP. Therefore, the share of base load suppliers in 2035 stays at around 52%.

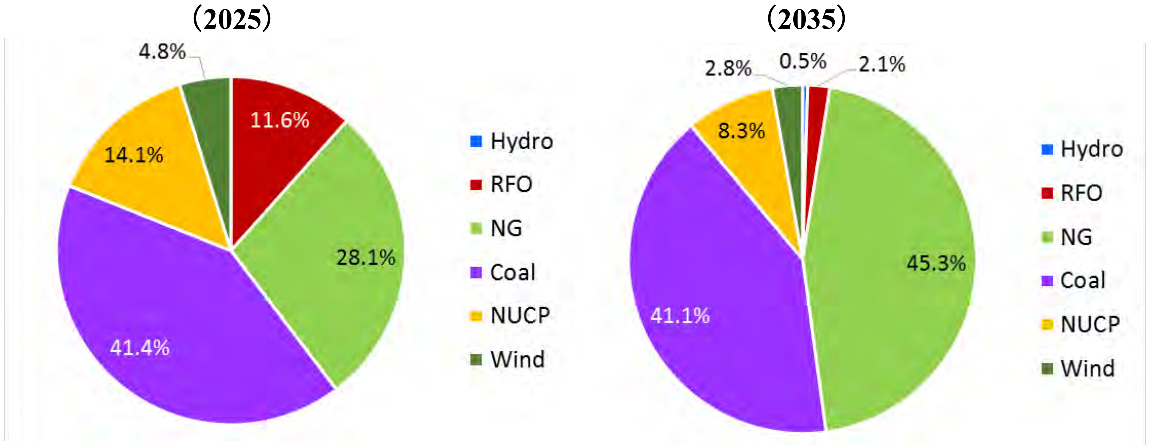
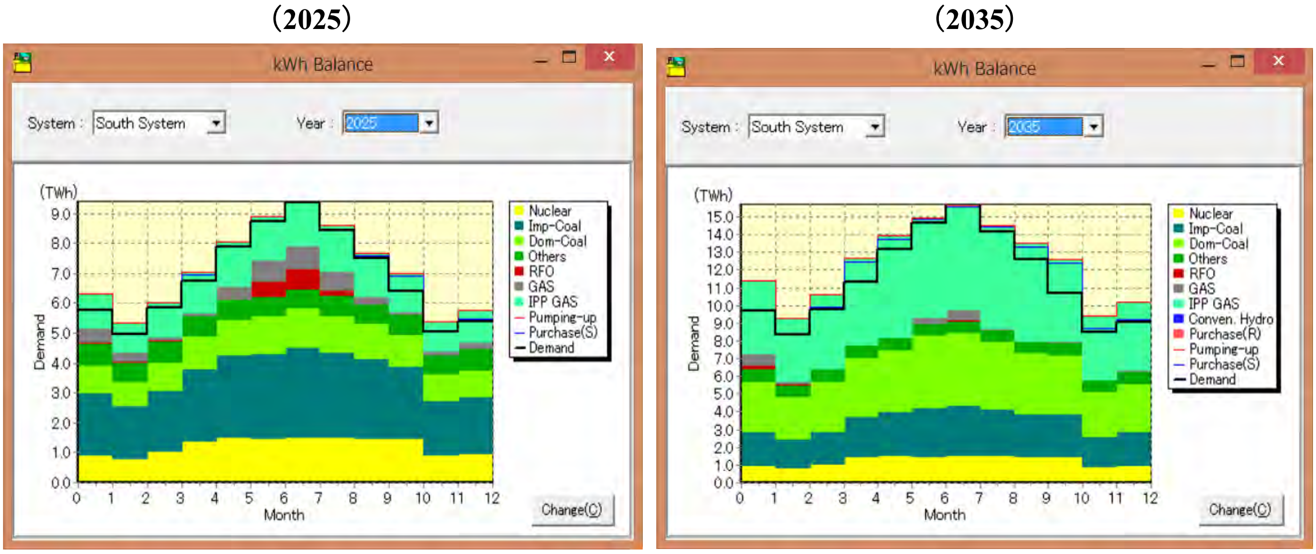

(2025) (2035)

Figure 5-29 Optimal Power Source Configuration in South System (Base Scenario)

Annual kWh balances in 2025 and in 2035 are shown in Figure 5-30. In 2025, the Oil fired and Gas fired TPP owned by GENCOs supply peak load, meanwhile, in 2035, the gas fired TPPs owned by IPP lead to supply middle and peak load in line with the decommission of the aged oil fired and gas fired TPP owned by GENCOs.

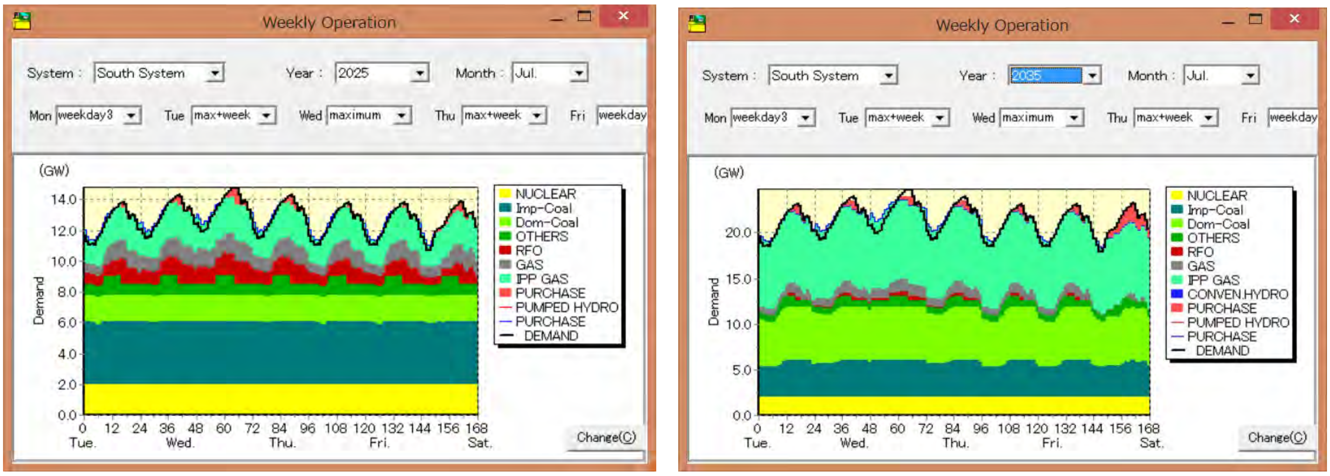
(2025) (2035)


System : South System
Year : 2025

System : South System
Year : 2035

Figure 5-30 Annual kWh Balance in South System

Weekly operation simulation results in July of 2025 and 2035 are shown in Figure 5-30. Since the supply capacity (kW) in the south system is fallen short in both 2025 and 2035, and is needed to accommodate from the south system. Meanwhile, since there is surplus generated energy by hydropower in the north, in view of economic accommodation, the energy is transmitted from the north to the south.



(2025)

Weekly Operation

System : South System
Year : 2025
Month : Jul.
Mon weekday3
Tue max+week
Wed maximum
Thu max+week
Fri weekday

(2035)

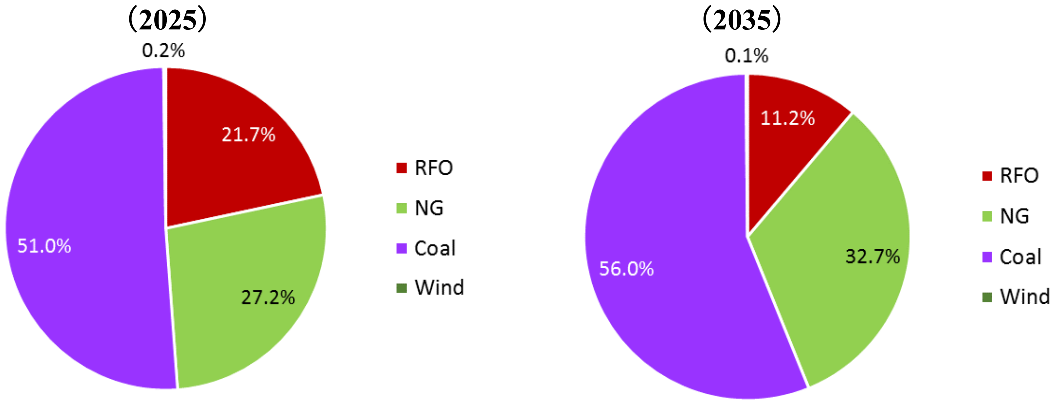
Weekly Operation

System : South System
Year : 2035
Month : Jul.
Mon weekday3
Tue max+week
Wed maximum
Thu max+week
Fri weekday

Figure 5-31 Weekly Operation in July in South System

(c) KE system

Since future power development candidate sites are unclear, the optimal share of base load supplier is assumed 60% referring to the study results in the south system. The generation mixes in KE system in 2025 and in 2035 are shown in Figure 5-32.



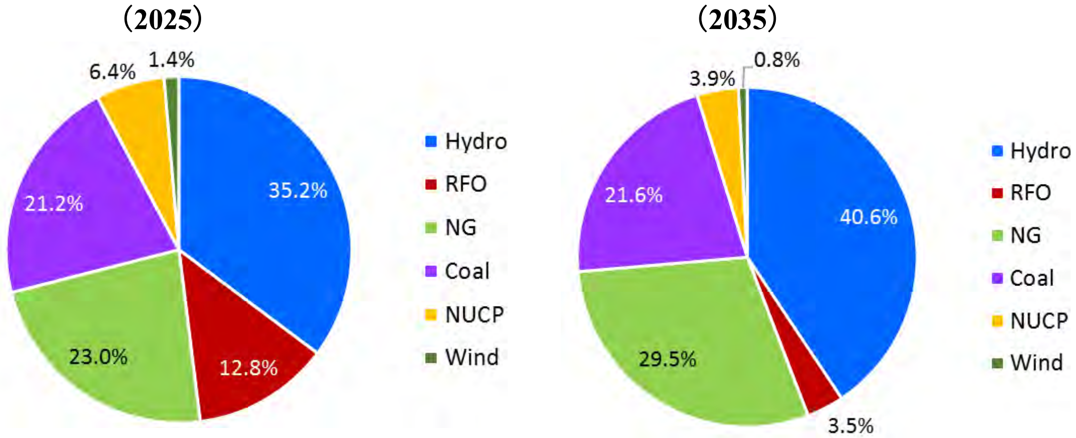
(2025)

(2035)

Figure 5-32 Optimal Power Source Configuration in KE System (Base Scenario)

(d) Whole country

The optimal generation mixes in the whole country power system in 2025 and in 2035 are shown in Figure 5-33, based on the above examination results.



(2025)

(2035)

Figure 5-33 Optimal Power Source Configuration in Whole Country (Base Scenario)

5.3.2 Alternative Scenarios

(1) Incorporation of hydropower to South system

The transmission capacity of 1route (2 poles) of DC line is 2,000MW, which connects between the north system and the south system (elongation distance of 1,000km) and its construction cost is estimated at 1,066 million US$ including two AC-DC converters.

In addition, there are hydropower potential sites in Pakistan other than the hydropower development projects listed in the current PDP as shown in the below table.

Table 5-21 Hydropower Potential Sites

Project Name	Developer	Installed Capacity (MW)	Electric Energy (GWh)	Plant Factor (%)
Tangus	WAPDA	2,200	8,791	45.6
Yulbo	WAPDA	2,800	11,376	46.4
Patan	WAPDA	2,300	12,625	62.7

Therefore, it is examined as an alternative scenario that hydropower projects are incorporated into the south system by developing the above listed hydropower plants and power line from the power plant to the demand center in the south by means of DC line.

When the construction unit cost of a hydropower is assumed as 2,500 US$/kW, the construction cost of hydropower plant of 2,000MW is 5,000 million US$ and the annual generation expense is 562 million US$/annum (annual expense rate is 11.23%). Meanwhile, the construction cost of the DC power line is 1,066 million US$ and the annual expense is 149 million US$/annum, when the life time of the power line is 25years, the annual expense rate become 14.02%. That is, the total annual expense is 711 US$/annum and the construction cost of newly developed hydropower is 6,331 million US$ (=711 / 0.1123) . Accordingly, the construction unit cost of the hydropower plants corresponds to 3,166 US$/kW. In addition of transmission loss of 1%, the construction unit cost is assumed as 3,200 US$/kW. Accordingly, the generation unit cost is around 7.0 UScent/kWh at the sending end and around 8.8 UScent/kWh at the consumer end

Table 5-22 Generation Unit Cost of Hydropower Incorporated into the South System

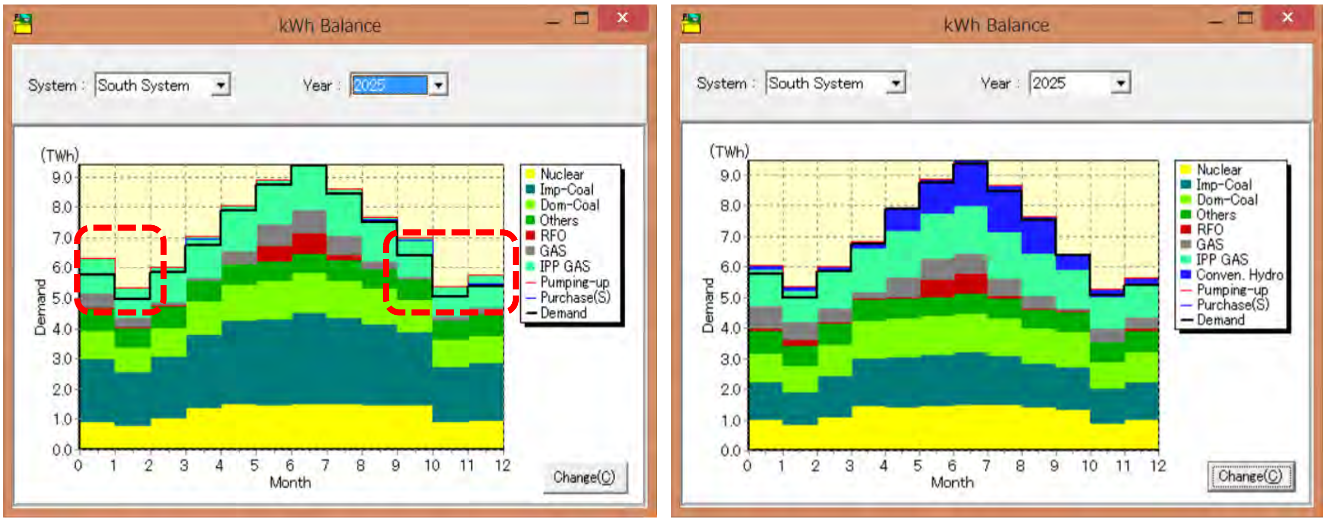
1 route of DC (2 poles)	Project Unit Cost (US$/kW)	Installed Capacity (MW)	Project Cost (mil. US$)	Annual Expense (mil. US$)	Equivalent Hydropower Project Cost (US$/kW)	Generation Unit Cost (UScent/kWh)
Hydropower	2,500	2,000	5,000	562	-	7.0
DC Power Line		2,000	1,066	149	-	1.8
Total	-	2,300	6,066	711	6,331	8.8

Based on the above assumptions, the overall generation expense in 2025 was computed by simulating demand - supply balance in the case that a new hydropower plant of 2,000MW and a route of DC power line are developed and incorporated into the south system. The overall generation expense in 2035 was computed in the case that another new hydropower plant of 2,000MW and a new route of DC power line are additionally developed. Here, the newly developed hydropower substitutes coal fired TPP of 1,980MW (supply capacity; 1,890MW) in 2025 and 3,960MW (supply capacity; 3,780MW) in 2035, respectively, in consideration of the forced outage rate of DC power line.

Comparison of the annual kWh balance in the south system with or without of hydropower incorporation into the south system is shown in Figure 5-34.

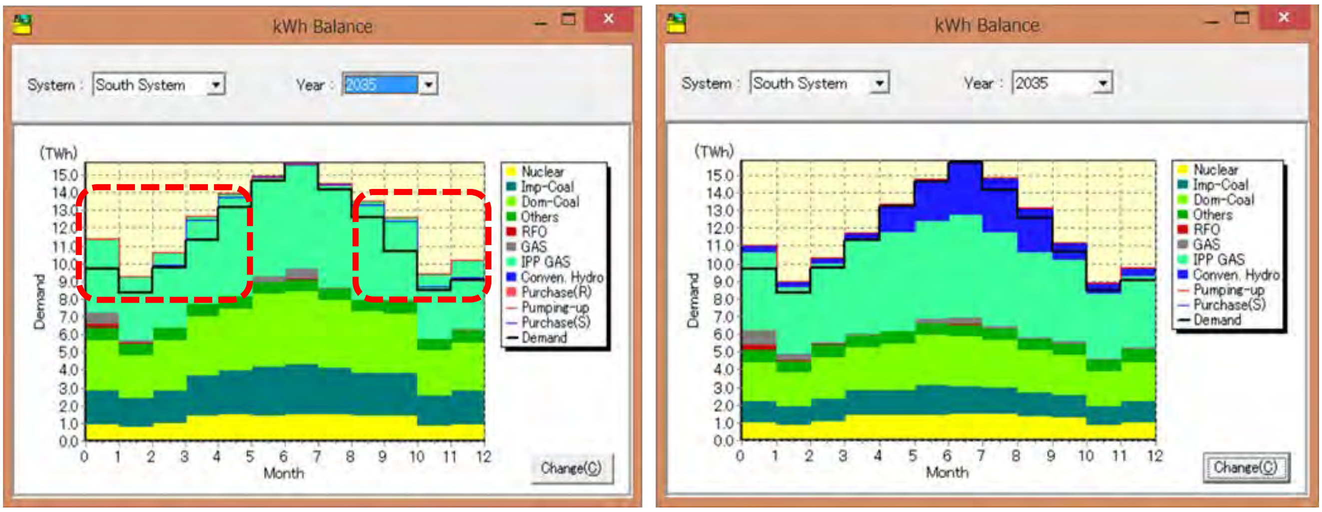
By developing and incorporating hydropower plants into the south system, the surplus generated energy due to fix of load factor of the IPP gas fired TPP can be reduced (in the drawn round areas by red dot line), and the load factor of oil fired and gas fired TPP of GENCOs, which are peak load supplier, can increase. In addition, the surplus generated energy due to fix of load factor of the IPP gas fired TPP in 2035 is a lot (in the drawn round areas by red dot line), since the aged oil and gas fired TPP are retired. However, it can be almost diminished by incorporating hydropower into the south system.

(2025) **Without Hydropower** **With Hydropower**


System : South System
Year : 2025

System : South System
Year : 2025

(2035) **Without Hydropower** **With Hydropower**


System : South System
Year : 2035

System : South System
Year : 2035

Figure 5-34 Comparison of Annual kWh Balance With or Without of Hydropower in South

The deference of annual generation expense with or without of the incorporation of hydropower plants into the south system is shown in Table 5-23. In 2025, since there still exists the oil fired and gas fired TPP as a peak load supplier, the annual generation expense decreases only 67 million US$/annum, however, in 2035, that decreases drastically 300 million US$/annum by the effect of reducing combustion of fossil fuel during the summer season and the overall generation unit cost is reduced as much as 0.07 UScent/kWh. In addition, CO2 emission amount can be reduced as per 8.9 million ton-CO_2 (8.5%) in 2025 and as per 18.6 million ton-CO_2 (11.2%) in 2035, respectively.

Table 5-23 Difference of Annual Generation Expense With or Without of Hydropower

	Unit	2025	2035
North system	million US$	24	62
South system	million US$	- 99	- 388
KE system	million US$	8	9
Total	million US$	- 67	- 317
Generation Unit Cost	UScent/kWh	- 0.03	- 0.07
CO_2 Emission	mil. ton-CO_2	- 8.9 (-8.5%)	- 18.6 (-11.2%)

(2) Influence of making load factor of LNG fired TPP free

In the base scenario, the load factor of LNG fired TPPs, which are planned to develop by Punjab government and the commercial operation date is planned to be in 2018, is fixed at 65% as well as the gas fired TPP. However, since LNG can be stored, it is deferent from pipeline gas, it is deemed that the LNG price will not vary so much even if the load factor of LNG fired TPP becomes free.

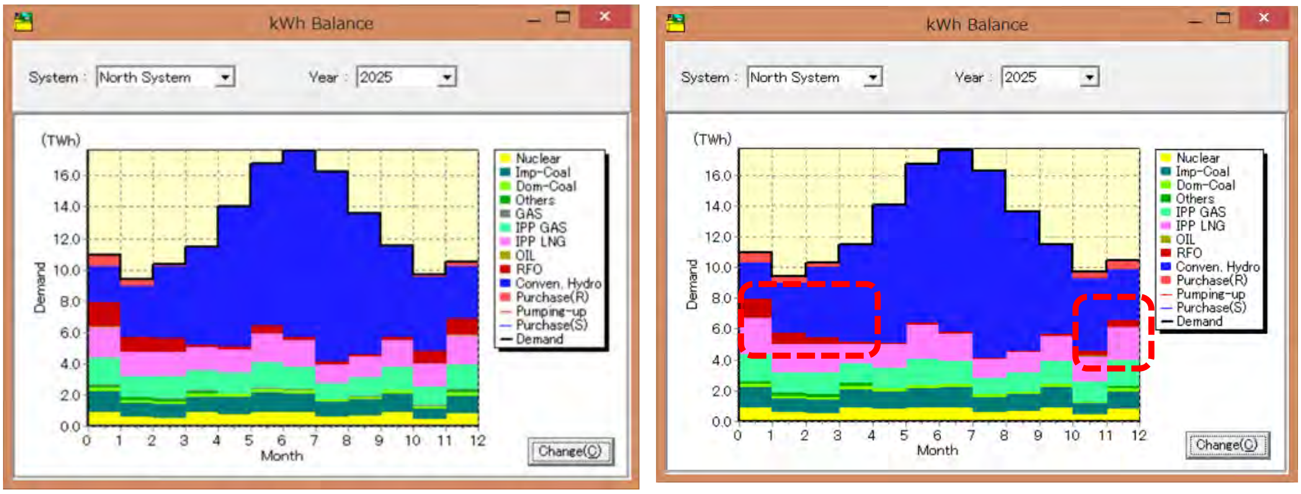
Therefore, the overall generation expenses in 2025 and 2035 were computed by simulating demand - supply balance in the case that the load factor of LNG fired TPP is free. Difference of annual generation expense between free or fixed of LNG's load factor is shown in Table 5-24, and comparison of the annual kWh balance of fixed or free of LNG's load factor is shown in Figure 5-35.

Table 5-24 Difference of Annual Generation Expense of Free or Fixed of LNG's Load Factor

	Unit	2025	2035
North system	million US$	- 258	- 682
South system	million US$	- 2	25
KE system	million US$	8	15
Total	million US$	- 252	- 642
Generation Unit Cost	UScent/kWh	- 0.10	- 0.15
LNG Volume	BCM	0.2	- 1.2

The both overall annual generation expenses in 2025 and 2035 decrease and the overall generation unit cost decreases as much as 0.1cent/kWh in 2025 and 0.15cent/kWh in 2035, respectively. Because the generated energy of the oil fired TPP, which fuel price of is the highest can be reduced in 2025 (in the drawn round areas by red dot line), and then, the load factor of LNG fired TPP increase to 70% and the annual LNG consumption amount increases 0.2BCM. Meanwhile, in 2035, since the LNG fired TPP becomes main peak load supplier during summer season in accordance with retirement of the aged oil fired TPPs, the load factor of LNG decrease to 45% and the annual LNG consumption amount decreases 1.2BCM. Since the generated energy by LNG fired TPPs is decreased (in the drawn round areas by red dot line), there is no needs to decrease the generated energy by the coal thermal power plant which fuel cost is the cheapest.

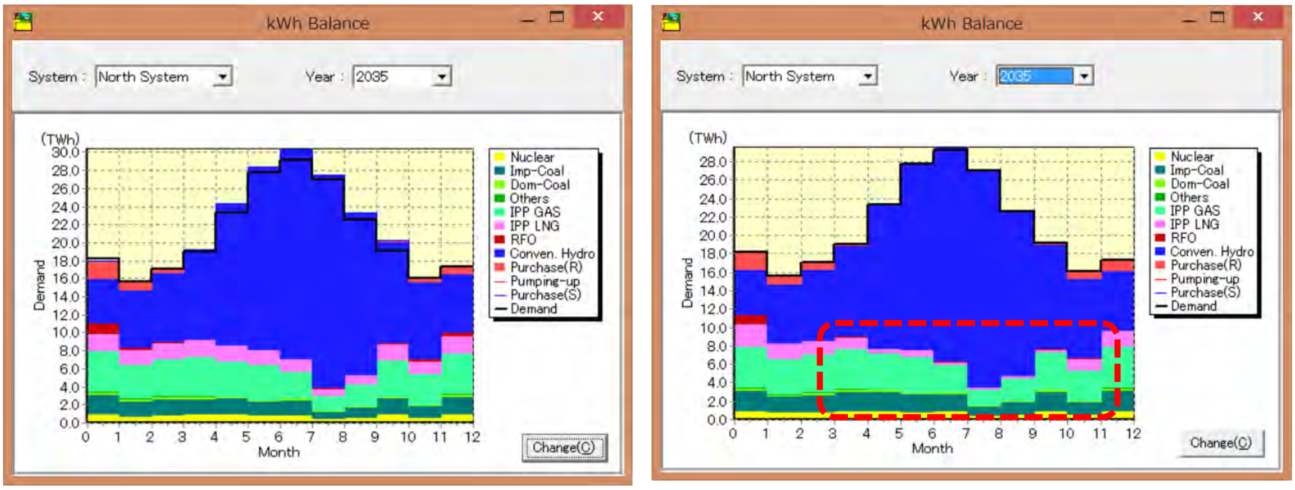
(2025) Load Factor of LNG is Fixed **Load Factor of LNG is Free**



System : North System Year : 2025

System : North System Year : 2025

(2035) Load Factor of LNG is Fixed **Load Factor of LNG is Free**



System : North System Year : 2035

System : North System Year : 2035

Figure 5-35 Comparison of Annual kWh Balance of Free or Fixed of LNG's Load Factor

(3) Without power import

(a) CASA-1000

The influence on the generation expense without power import of CASA-1000 (hydropower) project was computed by simulating demand-supply operation. Besides, the supply capacity of 1,000MW of CASA-1000 was substituted by domestic hydropower plants in order to keep the optimal generation mix.

Since CASA-1000 can supply power for only five months during the wet season, its supply capacity is zero during the dry season. In addition, since the power is transmitted by DC transmission line from Tajikistan to Pakistan and the forced outage rate of DC transmission line is more than 10%, the supply capacity substituted by domestic hydropower plants can be around 900MW to keep the same supply reliability. Furthermore, since domestic hydropower plants can supply power during the dry season in the case of substitution by them, the effect of reduction of generated energy by thermal power plants can be expected.

Accordingly, the annual generation expense decreases 174 million US$ and the overall generation unit cost of 0.07 UScent/kWh decrease in 2025 (refer to Table 5-25). And the construction cost of transmission line from the converter station in the vicinity of the border to the demand center can be also cut down.

(b) Power import from Iran

The influence on the generation expense without power import from Iran (gas CCGT) was computed by simulating demand-supply operation. Besides, the supply capacity of 1,000MW of power import from Iran was substituted by IPP CCGT (gas) plants in order to keep the optimal generation mix.

Since the power is transmitted by DC transmission line from Iran to Pakistan and the forced outage rate of DC transmission line is more than 10%, the supply capacity substituted by IPP CCGT(gas) plants can be around 900MW to keep the same supply reliability.

Accordingly, the annual generation expense of 74 million US$ decrease and the overall generation unit cost of 0.03 UScent/kWh decrease in 2025 (refer to Table 5-25). And the construction cost of transmission line from the converter station in the vicinity of the border to the demand center can be also cut down.

Table 5-25 Difference of Annual Generation Expense With or Without of Power Import

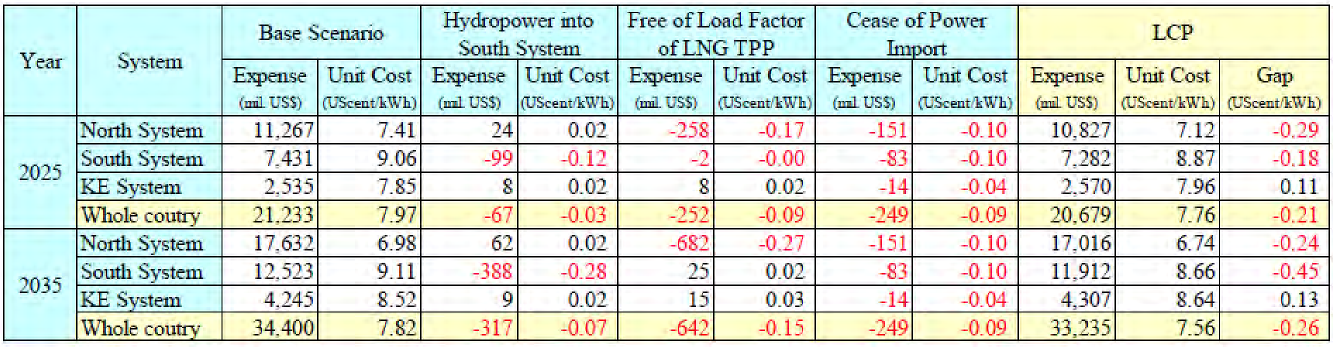
	Unit	CASA-1000	Import from Iran
North system	million US$	- 159	8
South system	million US$	5	- 88
KE system	million US$	- 20	6
Total	million US$	- 174	- 74
Generation Unit Cost	UScent/kWh	- 0.07	- 0.03

5.3.3 Least Cost Power Development Scenario

Overall generation expense and generation unit cost of the above every alternative scenario is less than those of the base scenario. Therefore, the integrated scenario of all alternative becomes the least cost power development scenario.

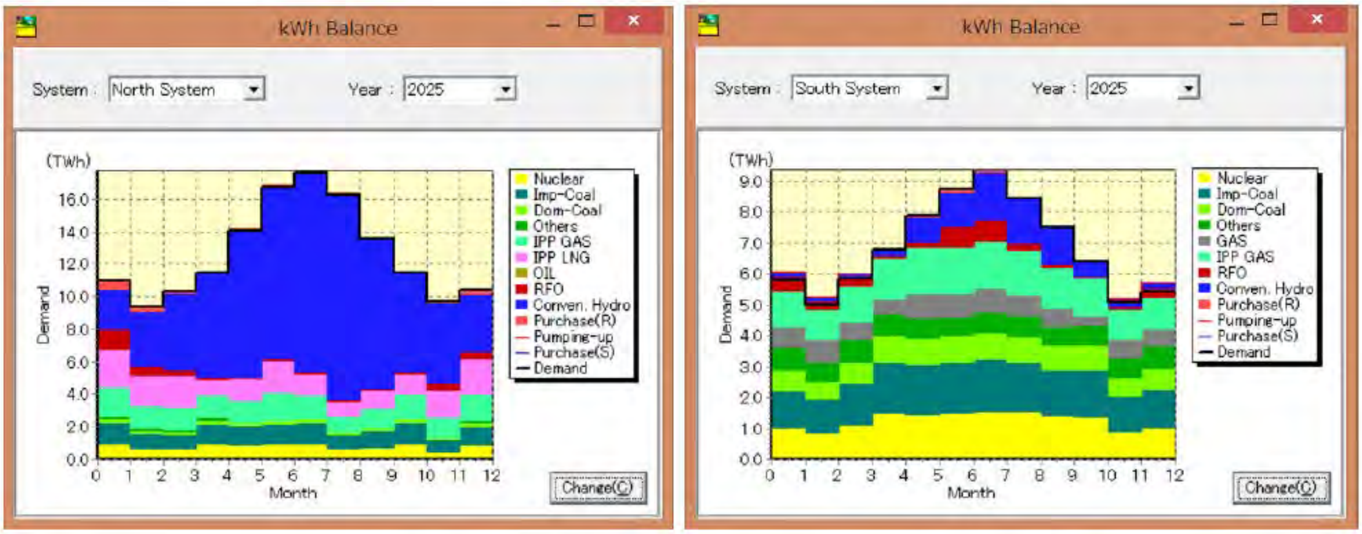
The generation expense of the integrated scenario was computed by simulating demand-supply operation. Difference of annual generation expense if the integrated scenario (LCP) and the base scenario is shown in Table 5-26. The overall generation unit cost of the LCP in 2025 and 2035 is 7,76 UScent/kWh (0.21 UScent /kWh less than the base scenario) and 7.56 UScent/kWh (0.26 UScent/kWh less than the base scenario), respectively

Table 5-26 Comparison of Generation Expense Between Base and Integrated Scenario



Year	System	Base Scenario		Hydropower into South System		Free of Load Factor of LNG TPP		Cease of Power Import		LCP		
		Expense (mil. US$)	Unit Cost (UScent/kWh)	Expense (mil. US$)	Unit Cost (UScent/kWh)	Expense (mil. US$)	Unit Cost (UScent/kWh)	Expense (mil. US$)	Unit Cost (UScent/kWh)	Expense (mil. US$)	Unit Cost (UScent/kWh)	Gap (UScent/kWh)
2025	North System	11,267	7.41	24	0.02	-258	-0.17	-151	-0.10	10,827	7.12	-0.29
	South System	7,431	9.06	-99	-0.12	-2	-0.00	-83	-0.10	7,282	8.87	-0.18
	KE System	2,535	7.85	8	0.02	8	0.02	-14	-0.04	2,570	7.96	0.11
	Whole coutry	21,233	7.97	-67	-0.03	-252	-0.09	-249	-0.09	20,679	7.76	-0.21
2035	North System	17,632	6.98	62	0.02	-682	-0.27	-151	-0.10	17,016	6.74	-0.24
	South System	12,523	9.11	-388	-0.28	25	0.02	-83	-0.10	11,912	8.66	-0.45
	KE System	4,245	8.52	9	0.02	15	0.03	-14	-0.04	4,307	8.64	0.13
	Whole coutry	34,400	7.82	-317	-0.07	-642	-0.15	-249	-0.09	33,235	7.56	-0.26

The annual kWh balances of the LCP in 2025 and in 2035 are shown in Figure 5-36 and in Figure 5-39, respectively. There is no surplus generated energy and demand and supply is fully balanced in every system and in every year.



(North System)

(South System)

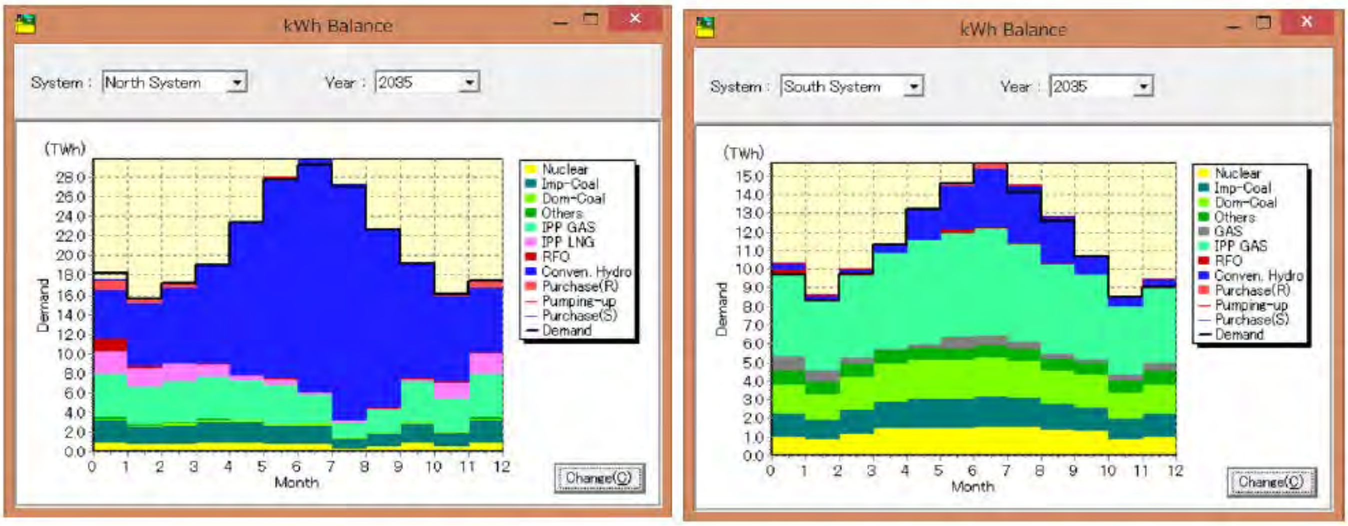
System : North System

Year : 2025

System : South System

Year : 2025

Figure 5-36 Annual kWh Balance of Integrated Scenario (LCP) in 2025



(North System)

(South System)

System : North System

Year : 2035

System : South System

Year : 2035

Figure 5-37 Annual kWh Balance of Integrated Scenario (LCP) in 2035

However, the subsequent study is carried out on the basis of the Base Scenario, since the aforementioned least cost development scenario bears the following significant issues ;

① Without power import : Pakistani government has already decided the price and the start time of the power import.

② Making load factor of LNG fired TPP free : the take or pay term of fuel should be got off in the power purchase contract by entrusting its development to any state-own companies such as GENCOs.

③ Incorporation of hydropower to South system : it is necessary to carry out concrete study like a feasibility study on which hydropower project should be developed as a power source for incorporation to the south system.

5.3.4 Risk Analysis

(1) Variation of fossil fuel price

(a) Assumptions

Risk by variation of the fossil fuel price of two cases is examined. One is the case that the domestic coal price will not change after 2015. The other is the case that the domestic coal price will not change after 2015 and the assumed escalation rate of RFO, NG, LNG and import coal in the base scenario will become twofold. Assumptions of variation of the fossil fuel price are shown in Table 5-27.

Table 5-27 Assumptions of Variation of Fossil Fuel Price

(Base Scenario)

	Unit	2015	2020	2025	2030	2035
RFO	US$/bbl	62	71	81	86	91
NG	US$/MMBtu	6.5	7.6	8.7	9.2	9.8
LNG	US$/MMBtu	9.0	10.5	12.0	12.8	13.5
Imp. Coal	US$/ton	60	70	80	85	90
Dom. Coal	US$/ton	27	32	36	38	41

(Twofold Annual Escalation Rate of Import Fuel)

	Unit	2015	2020	2025	2030	2035
RFO	US$/bbl	62	80	103	115	129
NG	US$/MMBtu	6.5	8.7	11.2	12.5	14.1
LNG	US$/MMBtu	9.0	12.0	15.4	17.5	19.4
Imp. Coal	US$/ton	60	80	103	115	129
Dom. Coal	US$/ton	27	27	27	27	27

(b) Examination results

Examination results of the case of no change of domestic coal price are shown in Table 5-28. The overall generation expense decreases 265 million US$ in 2025 and 841 million US$ in 2035, respectively. And the overall generation unit cost decreases 0.1 UScent/kWh in 2025 and 0.19 UScent/kWh in 2035, respectively.

Table 5-28 Deference of Annual Generation Expense (No change of Domestic Coal Price)

	Unit	2025	2035
North system	million US$	- 16	- 25
South system	million US$	- 89	- 434
KE system	million US$	- 160	- 382
Total	million US$	- 265	- 841
Generation Unit Cost	UScent/kWh	- 0.10	- 0.19

Examination results of the case of no change of domestic coal price and twofold escalation rate of the other Fossil fuels are shown in Table 5-29. The overall generation expense increases 1,635 million US$ in 2025 and 3,884 million US$ in 2035, respectively. And the overall generation unit cost increases largely 0.63 UScent/kWh in 2025 and 0.88 UScent/kWh in 2035, respectively.

Table 5-29 Deference of Annual Generation Expense (Twofold Annual Escalation Rate)

	Unit	2025	2035
North system	million US$	1,043	2,443
South system	million US$	545	1,323
KE system	million US$	47	118
Total	million US$	1,635	3,884
Generation Unit Cost	UScent/kWh	0.63	0.88

Comparison of the generation cost of each power source in 2025 in the case of twofold escalation rate of imported fossil fuels is shown in Figure 5-38. The generation unit cost of the domestic coal fired TPP is the cheapest in the rage over 30% of plant factor among thermal power sources.

Therefore, from the viewpoints of not only the energy security but also the risk hedge of fuel price variation, it is desirable to develop domestic coal fired TPPs instead of import coal fired TPPs.

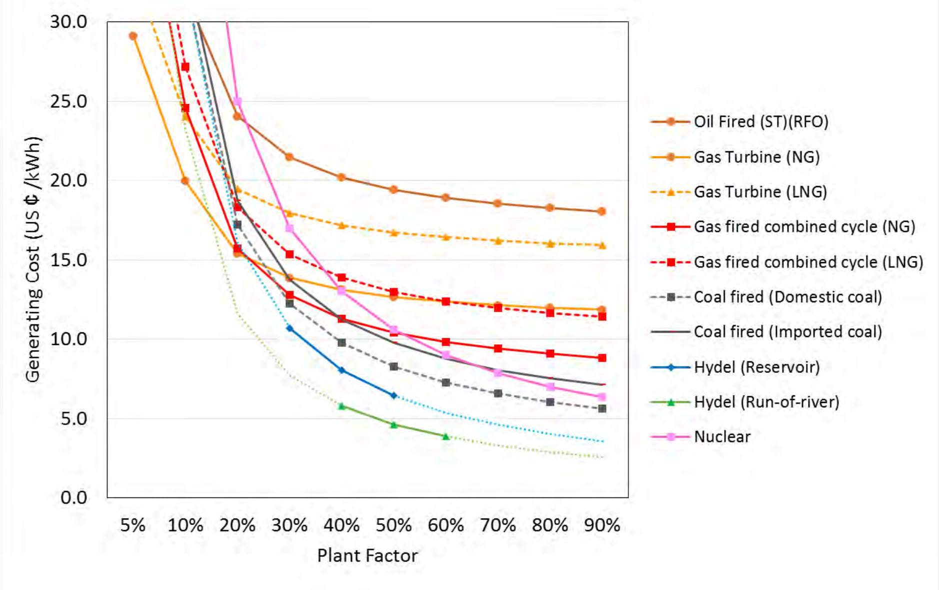


Figure 5-38 Comparison of Generation Cost of Each Power Source in 2025 (Twofold Annual Escalation Rate)

(2) Influence of delay of hydropower development

The influence of the case that all hydropower developments, including CASA-1000, in the base scenario are delayed one year is examined.

Reduction of supply capacity in the summer in the north system in line with the one year delay is shown in Figure 5-39. Since there is no substitutable power development to cope with reduction of supply capacity in 2017 and 2018, it cannot help but rely on the power supply from the south system. In addition, in order to cope with the reduction of supply capacity of 2,760MW in 2020, it is necessary that Sahiwal 4 (630MW) and New CCGT 2 & 3 (1,200MW) should be hastened from 2028 to 2020, from 2026 to 2020 and from 2029 to 2020, respectively, or new power line from thermal power plants in the south to the north should be developed.

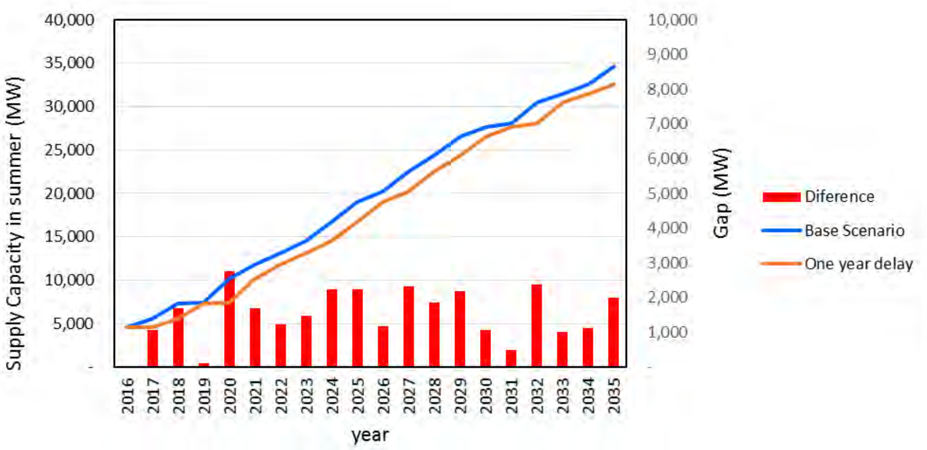


Figure 5-39 Reduction of Power Supply Capacity due to Delay of Hydropower Projects

5.4 Long-term Power Development Pattern

5.4.1 Base Demand Case

Long-term power development pattern from 2016 to 2035 was prepared by changing COD of every power development project so as to achieve the optimal generation mix in 2025 and 2035 of the base scenario as described in Section 5.3.1 in consideration of the current PDP and the required reserve margin. Here, the figures in the highlighted columns with yellow color are changed from the those in the current PDP.

(1) Long-term power development pattern

The development plan of hydropower plants based on the long-term power development pattern is shown in Table 5-30, the development plans of thermal power plants in the north system and in the south system are shown inTable 5-31 and Table 5-32, respectively.

Table 5-30 Development Plan of Hydropower Plants (Base Scenario)

No.	Project	Installed Capacity (MW)	Executive Agency	Current PDP	Installed Capacity (MW)	Revised PDP	Remarks
WAPDA	Neelum Jhelum	969	WAPDA	2016	969	2016	
	Golen Gol	106	WAPDA	2016	106	2016	
	Tarbela 4th Ext	1,410	WAPDA	2017	1,410	2017	
	Kayal Khwar	128	WAPDA	2017	128	2017	
	Kurram Tangi	83	WAPDA	2017	83	2017	
	Tarbela 5th Ext	1,320	WAPDA	2019	1,320	2019	
	Basho	40	WAPDA	2020	40	2020	
	Phander	80	WAPDA	2020	80	2020	
	Mangla (Upgradation)	310	WAPDA	2020	310	2020	
	Dasu (1st stage)	2,750	WAPDA	2020	2,160	2023-24	3, 4 year
	Dasu (2nd stage)	2,750	WAPDA	2027	3,340	2027-28	0, 1 year
	Diamer Basha	4,500	WAPDA	2024	2,250	2026	2 year
					2,250	2031	7 year
	Bunji	7,100	WAPDA	2027		-	No count
	Subtotal	21,546			14,446		
PPIB	Patrind	150	PPIB	2017	150	2017	
	Gulpur	100	PPIB	2018	100	2018	
	Sehra	130	PPIB	2019	130	2019	
	Karot HPP	720	PPIB	2020	720	2021	1 year
	Azad-Pattan	640	PPIB	2020	640	2020	
	Suki kinari	840	PPIB	2020	840	2020	
	Kotli	100	PPIB	2020	100	2020	
	Chakoti-Hattian	500	PPIB	2020	500	2021	1 year
	Kohala	1,100	PPIB	2020	1,100	2022-23	2-3 year
	Kaigah	545	PPIB	2022	545	2022	
	Madian	157	PPIB	2022	157	2022	
	Asrit-kedam	215	PPIB	2022	215	2022	
	Mahl	600	PPIB	2023	600	2023	
	Subtotal	5,797			5,797		
WAPDA	Palas Valley (lower)	665	WAPDA		665	2024	
	Palas Valley (middle)	373	WAPDA		373	2028	
	Palas Valley (upper)	160	WAPDA		160	2030	
	Spat Gah (lower)	496	WAPDA		496	2024	
	Spat Gah (middle)	424	WAPDA		424	2029	
	Spat Gah (upper)	199	WAPDA		199	2030	
	Akhori	600	WAPDA		600	2025	
	Lawi	70	WAPDA		70	2026	
	Mundah	740	WAPDA		740	2029	
	Thakot		WAPDA		4,000	2032, 33, 34	New Addition
	Subtotal	3,727			7,727		
PPIB	Karrang	458	PPIB		458	2025	
	Rajdhani	132	PPIB		132	2025	
	Kalam-Asrit	197	PPIB		197	2027	
	Shashghai-Zhendoli	144	PPIB		144	2028	
	Matiltan	84	SHYDO		84	2029	
	Gabral Kalam	137	PPIB		137	2030	
	Shogo-Sin	132	PPIB		132	2031	
	Taunsa	120	PPDB		120	2032	
	Sharmal	115	SHYDO		115	2033	
	Subtotal	1,519			1,519		
Planned Total		32,589			29,489		

Table 5-31 Development Plan of Thermal Power Plants (North: Base)

	Power Plant Name	Location	Type	Installed Capacity (MW)	Fuel Type	Current PDP COD	Revised PDP COD	Remarks
IPP (BOT, BOOT)	Sahiwal -1 (PPDB)	North	Steam	660	Imp. Coal	Dec. 2017	2017	
	Sahiwal -2 (PPDB)	South	Steam	660	Imp. Coal	Dec. 2017	2017	Change to North
	Bhikki Gas Plant	North	CCGT	1200	LNG	Apr. 2017 2018	2017 2018	
	Baloki Gas Plant	North	CCGT	1200	LNG	Apr. 2017 2018	2017 2018	
	Haveli Bahadur Shar Gas Plant	North	CCGT	1200	LNG	Apr. 2017 2018	2017 2018	
	Salt Range (PPDB)	North	Steam	330	Coal	Jun. 2018	2018	
	Sahiwal -3,4,5 (PPDB)	North	Steam	1890	Imp. Coal		2019, 27, 29	
	New Gas -1 (North)	North	CCGT	1200	Gas		2019-20	
	New Gas -2 (North)	North	CCGT	1200	Gas		2025-26	
	New Gas -3 (North)	North	CCGT	1200	Gas		2028-29	
	New Gas -4 (North)	North	CCGT	1200	Gas		2030	
	New Gas -5 (North)	North	CCGT	1200	Gas		2032	
	New Gas -6 (North)	North	CCGT	1200	Gas		2033	
Total				**14,340**				

Table 5-32 Development Plan of Thermal Power Plants (South: Base)

	Power Plant Name	Location	Type	Installed Capacity (MW)	Fuel Type	Current PDP COD	Revised PDP COD	Remarks
GENCO-I	Jamshoro (ADB)	South	Steam	1320	Imp. Coal	Dec. 2019 Mar. 2020	Dec. 2019 Mar. 2020	
GENCO-II	Guddu Ext.	South	CCGT	747	Gas	Mar. 2015	Mar. 2015	
GENCO-IV	Lakhra (JICA)	South	Steam	660	Imp. Coal	Jun. 2022	Jun. 2022	
GENCO-V	Nandipur	South	GT	428	FO/HSD	2014, 2015	2014, 2015	
			Steam			2015	2015	
Sub-total				3,059				
	Nooriabad Gas Plant	South	GT	100	Gas	Dec. 2017	2017	
	Thar Coal Block II (SECMC Pakistan)	South	Steam	1320	Coal	Apr. 2018 2019	2018 2019	
	Port Qasim (Shinohydro)	South	Steam	1320	Imp. Coal	Jun. 2018 Dec. 2018	2018 2019	1year
	Thar Coal Block I SSRL (china-pakistan)	South	Steam	1320	Coal	Jun. 2018 Dec. 2018	2024 2025	6year 7year
	HUBCO (HUB Power)	South	Steam	1320	Coal	Jun. 2018 Dec. 2018	2019 2020	1year 2year
	Thar Coal Block VI (Oracle(China-UK))	South	Steam	660	Coal	2019	Not Come	
	Thar Coal Block V (UCG project Pakistan)	South	Steam	10	UCG	2017	2017	
	Thar Coal Block II Phase-3	South	Steam	2640	Coal	2021	2030, 2032 2033, 2034	9, 11year 12,13year
	Thar Coal Block III (Asia Power UK)	South	Steam	1320	Coal	2021	2028 2031	7year 10year
	Thar Coal Block IV (Harbin Electric China)	South	Steam	1320	Coal	2021	Not Come	
	New Gas -1 (South)	South	CCGT	747	Gas		2025-26	
	New Gas -2 (South)	South	CCGT	747	Gas		2026-27	
	New Gas -3 (South)	South	CCGT	1200	Gas		2027	
	New Gas -4 (South)	South	CCGT	1200	Gas		2027-28	
	New Gas -5 (South)	South	CCGT	1200	Gas		2029	
	New Gas -6 (South)	South	CCGT	1200	Gas		2030-31	
	New Gas -7 (South)	South	CCGT	1200	Gas		2031-32	
	New Gas -8 (South)	South	CCGT	1200	Gas		2033-34	
	Sub-total			34,879				
Total				**37,938**				

The long-term power development plan in KE system is shown in Table 5-33.

Table 5-33 Power Development Plan (KE : Base)

Source	Power Plant Name	Type	No. ×Unit Cap.(MW)	Installed Capacity (MW)	Dependable Capacity (MW)	Fuel Type	Current Status	Target Commissioning Year
Thermal	Korangi	CCGT	4×48 2×27	247	168	Gas	Existing	2009 2015
	SGTPS-2	Engine Steam	32×2.8 1×10	98	88	Gas	Existing Construction	2009 2016
	KGTPS-2	Engine Steam	32×2.8 1×10	98	88	Gas	Existing Construction	2009 2016
	Nooriabad (IPP)	Engine Steam	5×16 2×10	100	100	Gas	Costruction	2016
	Port Qasim	Steam	1×58	58	52	Coal	Costruction	2017
	Korangi II-1	Engine Steam	13×18.5 1×25	252	252	FO/RLNG		2018
	Korangi II-2	Engine Steam	13×16.7 1×20	245	245	FO/RLNG		2018
	North Karachi (IPP)	Engine Steam	12×20 1×18	258	250	FO/RLNG		2018
	Balidia, Karachi (IPP)	Engine Steam	10×18.5 1×15	200	194	FO/RLNG		2019
	Port Qasim II	CCGT	1×320 1×150	470	431	RLNG		2019
	Port Qasim III	Steam	2×350	700	637	Coal		2020
	Port Qasim IV	Steam	1×220	220	200	Coal		2020
	New Coal-1	Steam	2×350	700	637	Coal		2020
	New Coal-2	Steam	2×350	700	637	Coal		2021-22
	New Coal-3	Steam	2×350	700	637	Coal		2022-24
	New Coal-4	Steam	2×351	700	637	Coal		2025-27
	New Coal-5	Steam	2×350	700	637	Coal		2030-31
	New Coal-6	Steam	2×350	700	637	Coal		2032-33
	New Gas-1	CCGT	1×320 1×150	470	431	Gas		2026-27
	New Gas-2	CCGT	1×320 1×150	470	431	Gas		2028-29
	New Gas-3	CCGT	1×320 1×150	470	431	Gas		2033-34
	Sub-total			6,523	5,959			
Wind	Gharo Wind (IPP)			40	12		Costruction	2016
Solar	Gharo Solar I (IPP)			50	0			2018
	Gharo Solar II (IPP)			50	0			2019
Nuclear	KANUPP Unit 1	Steam	1×137	137	100	Nuclear	Existing	1971
Total				6,800	6,071			

(2) Supply capacity of each power source and reserve margin of the long-term PDP

The supply capacity of each power source and reserve margin from 2015 to 2035 in the north system, in the south system and in the KE system are shown in Figure 5-40, Figure 5-41 and Figure 5-42. Besides, the supply capacity of each power source and reserve margin from 2015 to 2035 in the whole country and the power sources configurations are shown in Figure 5-43.

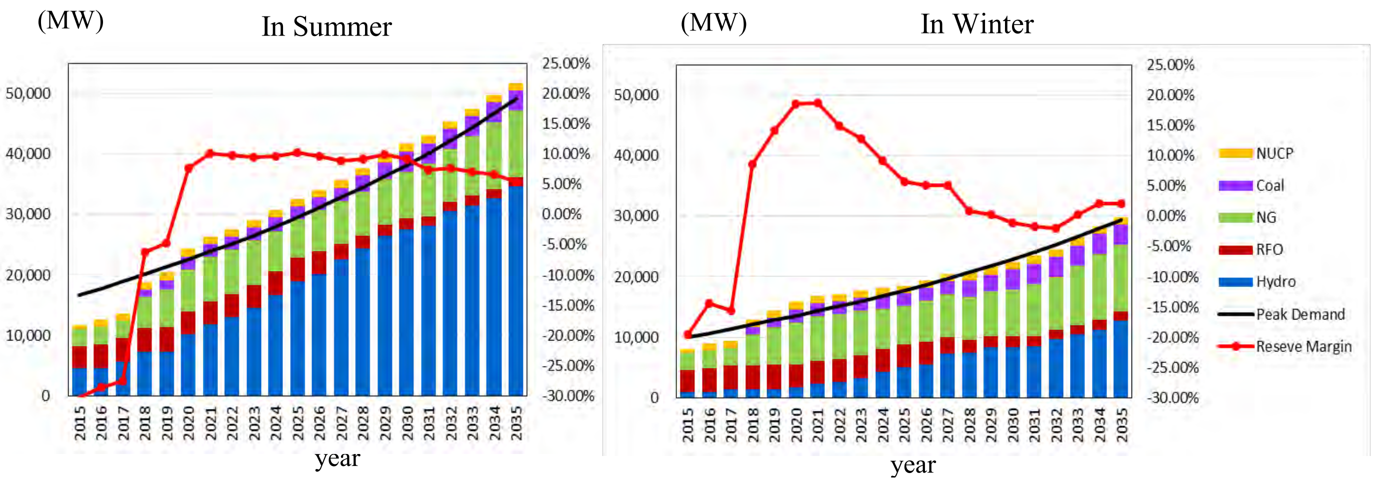


Figure 5-40 Power Development Plan up to 2035 in North System (Base Scenario)

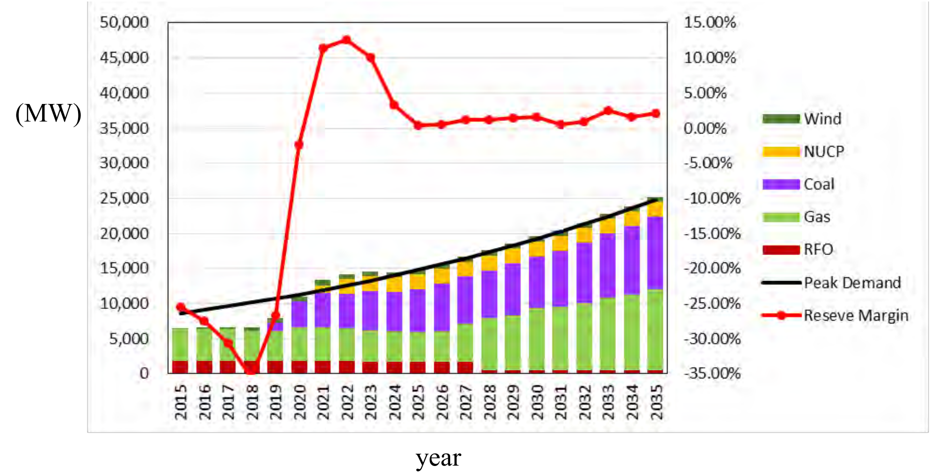


Figure 5-41 Power Development Plan up to 2035 in South System (Base Scenario)

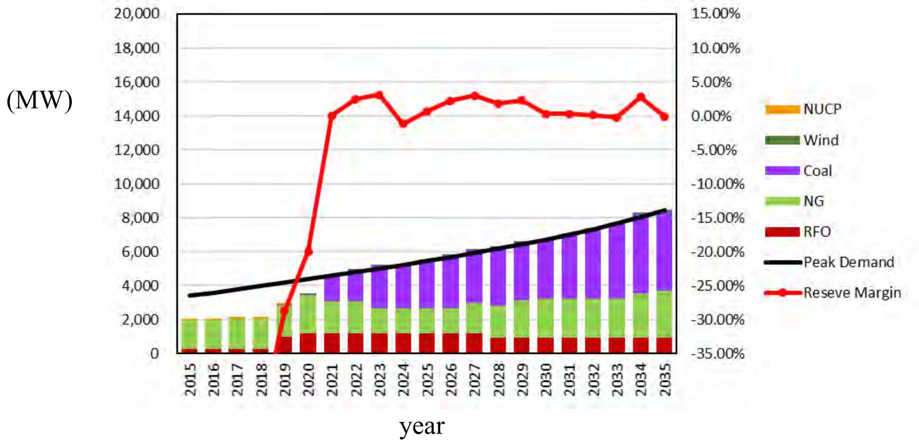


Figure 5-42 Power Development Plan up to 2035 in KE System (Base Scenario)

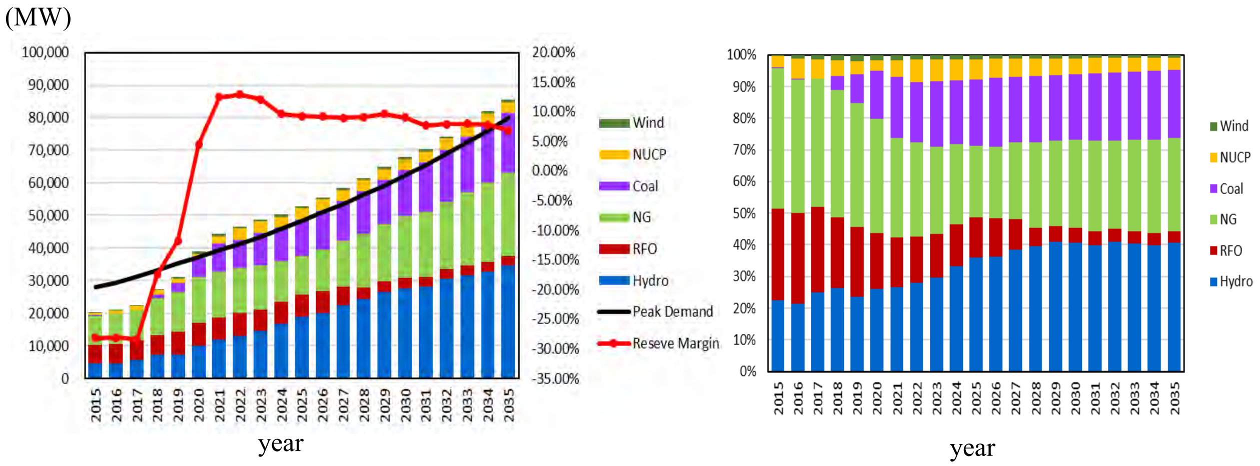


Figure 5-43 Power Development Plan up to 2035 in Whole Country (Base Scenario)

However, the supply capacity in the south system from 2021 to 2023 surplus as much as 10% regardless the required reserve margin is 0%, because the coal fired TPP of Jamshoro CFTPP No.2 (660MW) and Lakura CFTCC (660MW) by GENCO, and HUBCO CFTPP No.2 (660MW) by IPP, furthermore, Karachi Nuclear Power unit 2 and 3 (2 x 1,100MW) are planned to commence operation in this period. From the viewpoints of LCP, it is desirable that the installed capacity of 1,200MW be delayed for 2 or 3 years.

(3) Check of natural gas supply capacity

The natural gas consumption by power generation was calculated and compared with the natural gas (incl. LNG) supply plan shown in Table 4-13 and Table 4-14 to check whether gas shortage occurs or not. The comparative study results in the whole country are shown in Figure 5-44, in addition, the natural gas supply capacity for the power sector is assumed as 1/3 of the total gas supply capacity.

Although the gas will run slightly short in 2019 because the gas fired TPP will play a role of the base load supplier, the gas supply shortage will not occur up to 2035, since the coal fired TPP will substitute the gas fired TPP as the base load supplier after 2020.

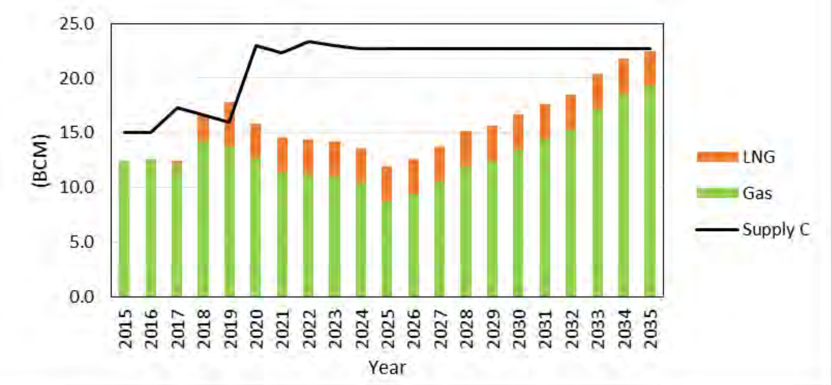


Figure 5-44 Gas Consumption versus Gas Supply Capacity for Power Sector

(4) Check of coal supply capacity

As aforementioned in Section 4.2.3, when it is assumed that the annual mining volume is 200 million tons, since the total measured and indicated reserve is 15 billion tons. The installed capacity of 35GW of coal fired thermal power plants can be developed. On the other hand, the total installed capacity of domestic coal fired thermal power plants is 16GW. Accordingly, there is no problem in coal supply capacity.

(5) Limit of integrating renewable (wind and solar) power sources

As described in Section 5.2.1, the total installed capacity of wind and solar power sources until 2020 in NTDC system is planned to integrate in 3,457MW, in which those of wind and solar power plants are 2,307MW and 1,150MW, respectively.

Meanwhile, it had been developed “Study to Determine the Limit of Integrating Intermittent Renewable (wind and solar) Resources onto Pakistan's National Grid” for USAID Energy Policy Program in November, 2015.

The study report stated that there is no need to make major reinforcement of the power grid up to the installed capacity of 4,000MW, which is around 10% of the total installed capacity as of 2016-17. Accordingly, in the case that the total installed capacity of wind and solar more than 10% of the total installed capacity of the power system is developed, the appropriate reinforcement of the power grid with system stabilizer such as battery should be considered to stabilize the power system in Pakistan, following the aforementioned study report, and then, the limit of integration of the wind / solar power is to be examined by comparing the cost with the benefit by introduction of power system stabilizers should be examined.

(6) Forecast of overall generation unit cost

The overall generation unit cost was computed by the simulation of demand-supply operation (PDPAT II) , based on the aforementioned long-term power development plan from 2015 to 2035 (20 years). The bottom lines are shown in Table 5-34. In addition, the overall generation cost includes compensation charge of power shortage of 20 UScent/kWh.

The overall generation unit cost in the whole country will go 24% down from 10.5 UScent/kWh in 2015 to 8.1 UScent/kWh in 2025, and will undergo a transition of 7.8 - 8.0 UScent/kWh until 2035, regardless that the escalation of fuel prices is considered.

The reasons why the overall generation unit cost rises up to 11.3 UScent/kWh in 2018 are that LNG fired TPPs (CCGT; 3 x 1,200MW) are planned to commence operation and that the compensation charge of power shortage increase up to 1,570 million US$ in the south system.

Table 5-34 Transition of Overall Generation Unit Cost (Base Demand Case)

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North	Energy (GWh)	86,084	91,065	97,154	103,447	109,967	116,307	123,367	129,492	136,629	144,194	152,047
	Cost (UScent)	942,871	991,587	1,026,670	1,204,433	1,203,029	886,231	933,950	978,959	1,032,894	1,079,206	1,126,721
	Unit Cost (cent/kWh)	11.0	10.9	10.6	11.6	10.9	7.6	7.6	7.6	7.6	7.5	7.4
South	Energy (GWh)	47,955	50,350	53,344	56,443	59,665	62,720	66,351	69,717	73,620	77,762	82,065
	Cost (UScent)	467,378	520,023	574,944	653,567	614,092	565,535	614,443	658,906	691,606	709,277	743,142
	Unit Cost (cent/kWh)	9.7	10.3	10.8	11.6	10.3	9.0	9.3	9.5	9.4	9.1	9.1
KE	Energy (GWh)	20,115	21,056	22,240	23,459	24,707	25,897	27,287	28,483	29,720	30,998	32,306
	Cost (UScent)	209,788	219,149	223,206	218,081	217,817	204,216	209,673	225,287	236,923	252,018	253,475
	Unit Cost (cent/kWh)	10.4	10.4	10.0	9.3	8.8	7.9	7.7	7.9	8.0	8.1	7.8
Whole Coutry	Energy (GWh)	154,154	162,471	172,738	183,349	194,339	204,924	217,005	227,692	239,969	252,954	266,418
	Cost (UScent)	1,620,037	1,730,759	1,824,820	2,076,081	2,034,938	1,655,982	1,758,066	1,863,152	1,961,423	2,040,501	2,123,338
	Unit Cost (cent/kWh)	10.5	10.7	10.6	11.3	10.5	8.1	8.1	8.2	8.2	8.1	8.0

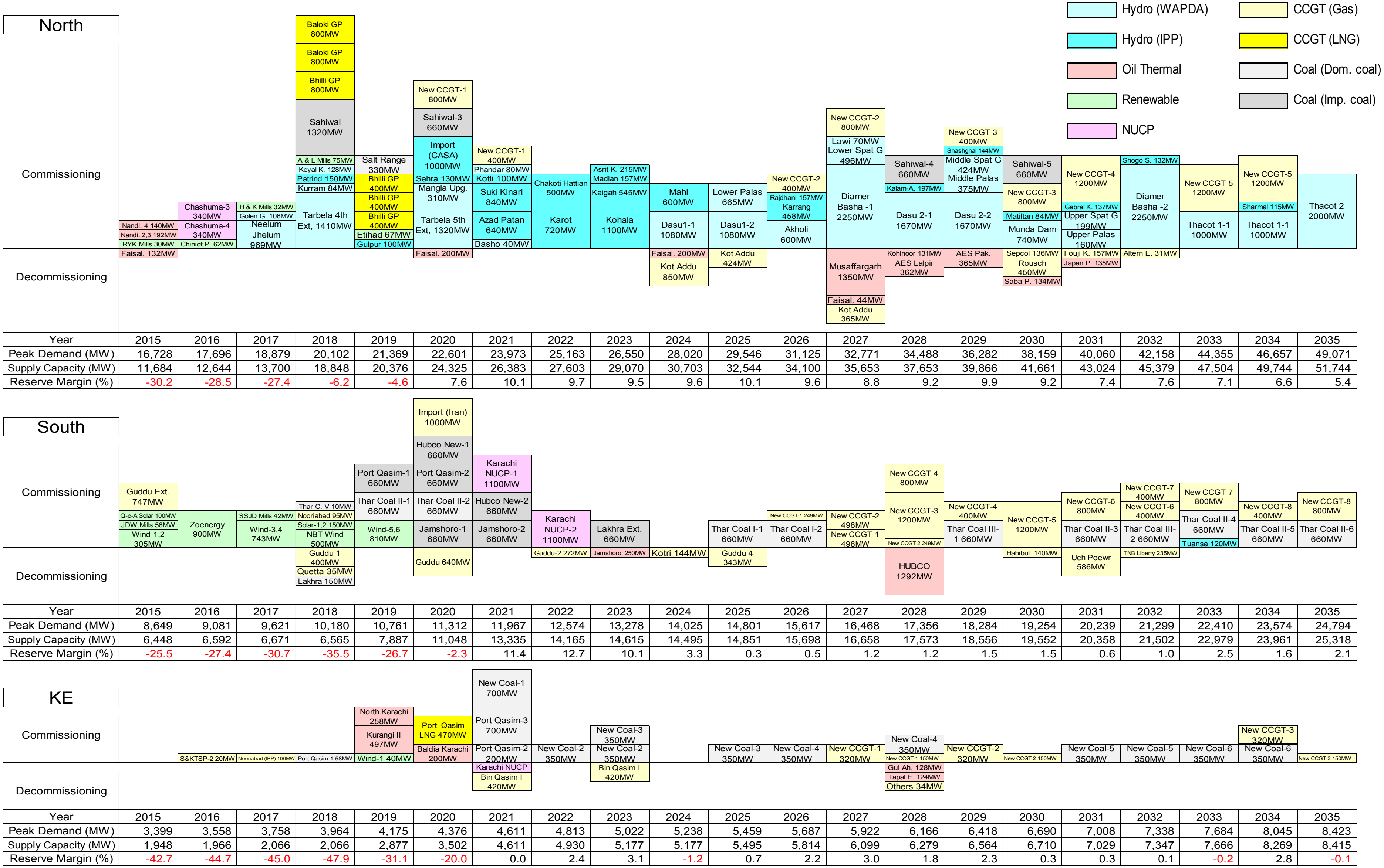
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
North	Energy (GWh)	160,172	168,643	177,479	186,711	196,370	206,153	216,950	228,256	240,102	252,525
	Cost (UScent)	1,182,460	1,239,093	1,281,096	1,330,704	1,386,204	1,451,901	1,509,054	1,602,191	1,695,018	1,763,196
	Unit Cost (cent/kWh)	7.4	7.3	7.2	7.1	7.1	7.0	7.0	7.0	7.1	7.0
South	Energy (GWh)	86,589	91,308	96,231	101,376	106,754	112,216	118,093	124,253	130,707	137,471
	Cost (UScent)	780,189	817,828	866,300	914,609	963,526	1,007,602	1,065,439	1,129,734	1,186,444	1,252,347
	Unit Cost (cent/kWh)	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.1	9.1	9.1
KE	Energy (GWh)	33,655	35,046	36,490	37,981	39,591	41,473	43,426	45,473	47,610	49,847
	Cost (UScent)	270,115	281,682	297,357	307,424	320,279	335,710	358,894	388,155	405,186	424,472
	Unit Cost (cent/kWh)	8.0	8.0	8.1	8.1	8.1	8.1	8.3	8.5	8.5	8.5
Whole Coutry	Energy (GWh)	280,416	294,997	310,200	326,068	342,715	359,842	378,469	397,982	418,419	439,843
	Cost (UScent)	2,232,764	2,338,603	2,444,753	2,552,737	2,670,009	2,795,213	2,933,387	3,120,080	3,286,648	3,440,015
	Unit Cost (cent/kWh)	8.0	7.9	7.9	7.8	7.8	7.8	7.8	7.8	7.9	7.8

(7) Yearly development of Long-term power development pattern (Base scenario)

Yearly power development (incl. decommissioning), supply capacity and reserve margin according to the long-term power development pattern (Base scenario) in the north and south system and KE system are shown in Table 5-35.

In addition, since the power plants which have commissioned until January 1st in every year are counted as a supply capacity in each year and the demand supply balance or the reserve margin is computed, the planned power plants which is planned to commission in the middle of a year is counted as a developed power plant in the next year.

Table 5-35 Yearly Development according to Long-term Power Development Pattern (Base Demand Case)



- ▨ Hydro (WAPDA)
- ▨ CCGT (Gas)
- ▨ Hydro (IPP)
- ▨ CCGT (LNG)
- ▨ Oil Thermal
- ▨ Coal (Dom. coal)
- ▨ Renewable
- ▨ Coal (Imp. coal)
- ▨ NUCP

North

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Commissioning	Nandi. 4 140MW Nandi. 2,3 192MW RYK Mills 30MW	Chashuma-3 340MW Chashuma-4 340MW Chiniot P. 62MW	H & K Mills 32MW Golen G. 106MW Neelum Jhelum 969MW	Baloki GP 800MW Baloki GP 800MW Bhilli GP 800MW Sahiwal 1320MW A & L Mills 75MW Keyal K. 128MW Patrind 150MW Kurram 84MW Tarbela 4th Ext, 1410MW	Salt Range 330MW Bhilli GP 400MW Bhilli GP 400MW Bhilli GP 400MW Etihad 67MW Gulpur 100MW	New CCGT-1 800MW Sahiwal-3 660MW Import (CASA) 1000MW Sehra 130MW Mangla Upg. 310MW Tarbela 5th Ext, 1320MW	New CCGT-1 400MW Phandar 80MW Kotli 100MW Suki Kinari 840MW Azad Patan 640MW Basho 40MW	Chakoti Hattian 500MW Karot 720MW	Asrit K. 215MW Madian 157MW Kaigah 545MW Kohala 1100MW	Mahl 600MW Dasu1-1 1080MW	Lower Palas 665MW Dasu1-2 1080MW	New CCGT-2 400MW Rajdhani 157MW Karrang 458MW Akholi 600MW	New CCGT-2 800MW Lawi 70MW Lower Spat G 496MW Diamer Basha -1 2250MW	Sahiwal-4 660MW Kalam-A. 197MW Dasu 2-1 1670MW	New CCGT-3 400MW Shashghai 144MW Middle Spat G 424MW Middle Palas 375MW Dasu 2-2 1670MW	Sahiwal-5 660MW New CCGT-3 800MW Matiltan 84MW Munda Dam 740MW	New CCGT-4 1200MW Gabral K. 137MW Upper Spat G 199MW Upper Palas 160MW	Shogo S. 132MW Diamer Basha -2 2250MW	New CCGT-5 1200MW Thacot 1-1 1000MW	New CCGT-5 1200MW Sharmal 115MW Thacot 1-1 1000MW	Thacot 2 2000MW
Decommissioning	Faisal. 132MW					Faisal. 200MW				Faisal. 200MW Kot Addu 850MW	Kot Addu 424MW		Musaffargarh 1350MW Faisal. 44MW Kot Addu 365MW	Kohinoor 131MW AES Lalpir 362MW	AES Pak. 365MW	Sepcol 136MW Rousch 450MW Saba P. 134MW	Fouji K. 157MW Japan P. 135MW	Altern E. 31MW			
Peak Demand (MW)	16,728	17,696	18,879	20,102	21,369	22,601	23,973	25,163	26,550	28,020	29,546	31,125	32,771	34,488	36,282	38,159	40,060	42,158	44,355	46,657	49,071
Supply Capacity (MW)	11,684	12,644	13,700	18,848	20,376	24,325	26,383	27,603	29,070	30,703	32,544	34,100	35,653	37,653	39,866	41,661	43,024	45,379	47,504	49,744	51,744
Reserve Margin (%)	-30.2	-28.5	-27.4	-6.2	-4.6	7.6	10.1	9.7	9.5	9.6	10.1	9.6	8.8	9.2	9.9	9.2	7.4	7.6	7.1	6.6	5.4

South

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Commissioning	Guddu Ext. 747MW Q-e-A Solar 100MW JDW Mills 56MW Wind-1,2 305MW	Zoenergy 900MW	SSJD Mills 42MW Wind-3,4 743MW	Thar C. V 10MW Nooriabad 95MW Solar-1,2 150MW NBT Wind 500MW	Port Qasim-1 660MW Thar Coal II-1 660MW Wind-5,6 810MW	Import (Iran) 1000MW Hubco New-1 660MW Port Qasim-2 660MW Thar Coal II-2 660MW Jamshoro-1 660MW	Karachi NUCP-1 1100MW Hubco New-2 660MW Jamshoro-2 660MW	Karachi NUCP-2 1100MW	Lakhra Ext. 660MW		Thar Coal I-1 660MW	New CCGT-1 249MW Thar Coal I-2 660MW	New CCGT-2 498MW New CCGT-1 498MW	New CCGT-4 800MW New CCGT-3 1200MW New CCGT-2 249MW	New CCGT-4 400MW Thar Coal III-1 660MW	New CCGT-5 1200MW	New CCGT-6 800MW Thar Coal II-3 660MW	New CCGT-7 400MW New CCGT-6 400MW Thar Coal III-2 660MW	New CCGT-7 800MW Thar Coal II-4 660MW Tuansa 120MW	New CCGT-8 400MW Thar Coal II-5 660MW	New CCGT-8 800MW Thar Coal II-6 660MW
Decommissioning				Guddu-1 400MW Quetta 35MW Lakhra 150MW		Guddu 640MW		Guddu-2 272MW	Jamshoro. 250MW	Kotri 144MW	Guddu-4 343MW			HUBCO 1292MW		Habibul. 140MW	Uch Poewr 586MW	TNB Liberty 235MW			
Peak Demand (MW)	8,649	9,081	9,621	10,180	10,761	11,312	11,967	12,574	13,278	14,025	14,801	15,617	16,468	17,356	18,284	19,254	20,239	21,299	22,410	23,574	24,794
Supply Capacity (MW)	6,448	6,592	6,671	6,565	7,887	11,048	13,335	14,165	14,615	14,495	14,851	15,698	16,658	17,573	18,556	19,552	20,358	21,502	22,979	23,961	25,318
Reserve Margin (%)	-25.5	-27.4	-30.7	-35.5	-26.7	-2.3	11.4	12.7	10.1	3.3	0.3	0.5	1.2	1.2	1.5	1.5	0.6	1.0	2.5	1.6	2.1

KE

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Commissioning		S&KTSP-2 20MW	Nooriabad (IPP) 100MW	Port Qasim-1 58MW	North Karachi 258MW Kurangi II 497MW Wind-1 40MW	Port Qasim LNG 470MW Baldia Karachi 200MW	New Coal-1 700MW Port Qasim-3 700MW Port Qasim-2 200MW	New Coal-2 350MW	New Coal-3 350MW New Coal-2 350MW		New Coal-3 350MW	New Coal-4 350MW	New CCGT-1 320MW	New Coal-4 350MW New CCGT-1 150MW	New CCGT-2 320MW	New CCGT-2 150MW	New Coal-5 350MW	New Coal-5 350MW	New Coal-6 350MW	New CCGT-3 320MW New Coal-6 350MW	New CCGT-3 150MW
Decommissioning							Karachi NUCP Bin Qasim I 420MW		Bin Qasim I 420MW					Gul Ah. 128MW Tapal E. 124MW Others 34MW							
Peak Demand (MW)	3,399	3,558	3,758	3,964	4,175	4,376	4,611	4,813	5,022	5,238	5,459	5,687	5,922	6,166	6,418	6,690	7,008	7,338	7,684	8,045	8,423
Supply Capacity (MW)	1,948	1,966	2,066	2,066	2,877	3,502	4,611	4,930	5,177	5,177	5,495	5,814	6,099	6,279	6,564	6,710	7,029	7,347	7,666	8,269	8,415
Reserve Margin (%)	-42.7	-44.7	-45.0	-47.9	-31.1	-20.0	0.0	2.4	3.1	-1.2	0.7	2.2	3.0	1.8	2.3	0.3	0.3	0.1	-0.2	2.8	-0.1

5.4.2 High Demand Case

Based on the Long-term power development pattern in the base demand case as described in Section 5.4.1, the Long-term PDP in the high demand case from 2016 to 2035 was prepared by hastening COD of every power development project and adding new power projects so as to assure the required reserve margin.

Maximum power demand forecast of the base demand case and of the high demand case are shown in Figure 5-45. The maximum demand of the base demand case in 2025 and 2035 are almost equal to the one of the high demand case in 2023 and 2031, respectively. Accordingly, the configuration of every power source excluding renewable energy and nuclear power in 2023 or 2031 is maintained to be the same as that of the base demand case in 2025 or 2035 by adjusting the development pattern.

Meanwhile, the earliest COD of power projects planned to be developed after 2020 is to be Jan. 2020 for hydropower and Jan. 2019 for thermal power in consideration of the time period of development.

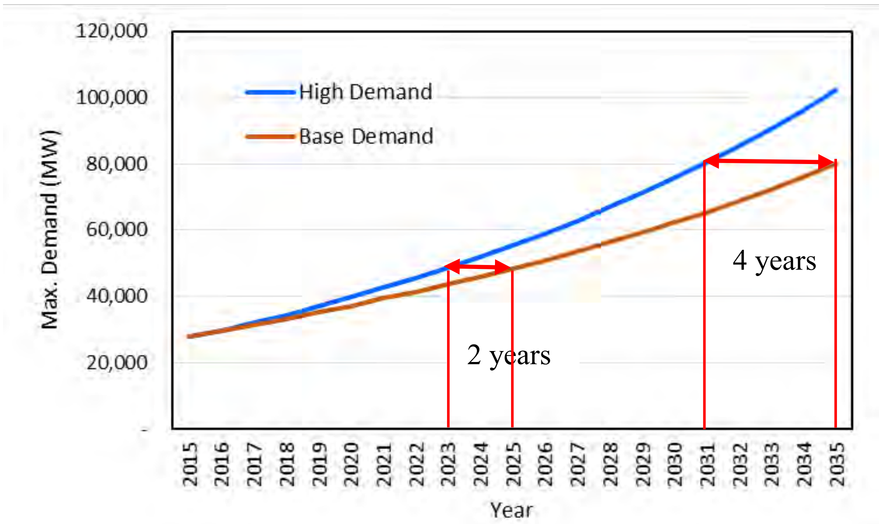


Figure 5-45 Maximum Demand Forecast (Whole Country)

(1) Long-term power development pattern

The development plan of hydropower plants based on the long-term power development pattern in the high demand case is shown in Table 5-36, the development plans of thermal power plants in the north system and in the south system are shown in Table 5-37 and Table 5-38, respectively.

The deference of COD of every project between in the base demand and in the high demand is shown in the remarks column.

Table 5-36 Development Plan of Hydropower Plants (High Demand Case)

No.	Project	Installed Capacity (MW)	Current PDP	Base Demand PDP	High Demand PDP	Remarks
WAPDA	Neelum Jhelum	969	2016	2016	2016	
	Golen Gol	106	2016	2016	2016	
	Tarbela 4th Ext	1,410	2017	2017	2017	
	Kayal Khwar	128	2017	2017	2017	
	Kurram Tangi	83	2017	2017	2017	
	Tarbela 5th Ext	1,320	2019	2019	2019	
	Basho	40	2020	2020	2019	1 year
	Phander	80	2020	2020	2019	1 year
	Mangla (Upgradation)	310	2020	2020	2020	
	Dasu (1st stage)	2,160	2020	2023-24	2021, 23	1-2 years
	Dasu (2nd stage)	3,340	2027	2027-28	2025	2-3 years
	Diamer Basha (1st)	2,250	2024	2026	2024	2 years
	Diamer Basha (2nd)	2,250	2024	2031	2031	
	Bunji		2027	-	-	No count
	Subtotal	14,446				
PPIB	Patrind	150	2017	2017	2017	
	Gulpur	100	2018	2018	2018	
	Sehra	130	2019	2019	2019	
	Karot HPP	720	2020	2021	2020	1 year
	Azad-Pattan	640	2020	2020	2019	1 year
	Suki kinari	840	2020	2020	2019	1 year
	Kotli	100	2020	2020	2019	1 year
	Chakoti-Hattian	500	2020	2021	2020	1 year
	Kohala	1,100	2020	2022-23	2021	1-2 years
	Kaigah	545	2022	2022	2021	1 year
	Madian	157	2022	2022	2021	1 year
	Asrit-kedam	215	2022	2022	2021	1 year
	Mahl	600	2023	2023	2022	1 year
	Subtotal	5,797				
WAPDA	Palas Valley (lower)	665		2024	2022	2 years
	Palas Valley (middle)	373		2028	2026	2 years
	Palas Valley (upper)	160		2030	2028	2 years
	Spat Gah (lower)	496		2024	2022	2 years
	Spat Gah (middle)	424		2029	2027	2 years
	Spat Gah (upper)	199		2030	2028	2 years
	Akhori	600		2025	2023	2 years
	Lawi	70		2026	2024	2 years
	Munda	740		2029	2027	2 years
	Thakot	4,000		2032, 33, 34	2028, 29, 30	4 years
	Patan	2,300			2032	New Addition
	Tangus	2,200			2033	New Addition
	Yulbo	2,800			2034	New Addition
	Subtotal	15,027				
PPIB	Karrang	458		2025	2023	2 years
	Rajdhani	132		2025	2023	2 years
	Kalam-Asrit	197		2027	2026	2 years
	Shashghai-Zhendoli	144		2028	2026	2 years
	Matiltan	84		2029	2027	2 years
	Gabral Kalam	137		2030	2028	2 years
	Shogo-Sin	132		2031	2028	3 years
	Taunsa	120		2032	2032	
	Sharmal	115		2033	2030	3 years
	Subtotal	1,519				
Planned Total		16,546				

Table 5-37 Development Plan of Thermal Power Plants (North: High)

	Power Plant Name	Type	Fuel Type	Installed Capacity (MW)	Current PDP COD	Base Demand	High Demand	Remarks
IPP (BOT, BOOT)	Salt Range (PPDB)	Steam	Coal	330	Jun. 2018	2018	2018	
	Sahiwal -3,4,5 (PPDB)	Steam	Imp. Coal	1890		2019, 27, 29	2019, 23, 27	0-4 years
	Sahiwal -6,7,8 (PPDB)	Steam	Imp. Coal	1890			2029, 32, 34	New addition
	New Gas -1 (North)	CCGT	Gas	1200		2019-20	2019-20	
	New Gas -2 (North)	CCGT	Gas	1200		2025-26	2025-26	
	New Gas -3 (North)	CCGT	Gas	1200		2028-29	2026	2-3 years
	New Gas -4 (North)	CCGT	Gas	1200		2030	2027	3 years
	New Gas -5 (North)	CCGT	Gas	1200		2032	2028	4 years
	New Gas -6 (North)	CCGT	Gas	1200		2033	2029	4 years
	New Gas -7 (North)	CCGT	Gas	1200			2030-31	New addition
	New Gas -8 (North)	CCGT	Gas	1200			2032-33	New addition
	New Gas -9 (North)	CCGT	Gas	1200			2033-34	New addition
Total				14,910				

Table 5-38 Development Plan of Thermal Power Plants (South: High)

	Power Plant Name	Type	Fuel Type	Installed Capacity (MW)	Current PDP COD	Base Demand	High Demand	Remarks
IPP (BOT, BOOT)	Nooriabad Gas Plant	GT	Gas	100	Dec. 2017	2017	2017	
	Thar Coal Block II	Steam	Coal	1320	2018-19	2018-19	2018-19	
	Port Qasim	Steam	Imp. Coal	1320	2018	2018-19	2018-19	
	Thar Coal Block I	Steam	Coal	1320	2018	2024-25	2023, 2025	0-1 year
	HUBCO	Steam	Coal	1320	2018	2019-20	2019-20	
	Thar Coal Block VI	Steam	Coal	660	2019	Not Come	2032	New addition
	Thar Coal Block II Phase-3	Steam	Coal	2640	2021	2030, 2032 2033, 2034	2027, 2028 2029, 2030	3-4 years
	Thar Coal Block III	Steam	Coal	1320	2021	2028, 2031	2026, 2027	2, 4 years
	Thar Coal Block IV	Steam	Coal	1320	2021	Not Come	2030-31	New addition
	New Gas -1 (South)	CCGT	Gas	747		2025-26	2022-23	3 years
	New Gas -2 (South)	CCGT	Gas	747		2026-27	2023-24	3 years
	New Gas -3 (South)	CCGT	Gas	1200		2027	2024	3 years
	New Gas -4 (South)	CCGT	Gas	1200		2027-28	2025-26	2 years
	New Gas -5 (South)	CCGT	Gas	1200		2029	2027	2 years
	New Gas -6 (South)	CCGT	Gas	1200		2030-31	2027-28	3 years
	New Gas -7 (South)	CCGT	Gas	1200		2031-32	2028-29	3 years
	New Gas -8 (South)	CCGT	Gas	1200		2033-34	2029-30	4 years
	New Gas -9 (South)	CCGT	Gas	1200			2031-32	New addition
	New Gas -10 (South)	CCGT	Gas	1200			2032-33	New addition
	New Gas -11 (South)	CCGT	Gas	1200			2033-34	New addition
	Sub-total			35,884				

The long-term power development plan in KE system is shown in Table 5-39.

Table 5-39 Power Development Plan (KE : High)

	Power Plant Name	Type	Fuel Type	Installed Capacity (MW)	Target Commissioning Year	PDP COD (Base Demand)	PDP COD (High Demand)	Difference
KE	Nooriabad (IPP)	Steam	Gas	100	2016	2016	2016	
	Port Qasim	Steam	Coal	58	2017	2017	2017	1-2 years
	Korangi II-1	Steam	FO/RLNG	252	2018	2018	2018	2 years
	Korangi II-2	Steam	FO/RLNG	245	2018	2018	2018	0-1 years
	North Karachi (IPP)	Steam	FO/RLNG	258	2018	2018	2018	2 years
	Balidia, Karachi (IPP)	Steam	FO/RLNG	200	2019	2019	2019	1-2 years
	Port Qasim II		RLNG	470	2019	2019	2019	
	Port Qasim III		Coal	700	2020	2020	2020	
	Port Qasim IV		Coal	220	2020	2020	2020	
	New Coal-1		Coal	700	2020	2020	2020	
	New Coal-2		Coal	700		2021-22	2020-21	
	New Coal-3		Coal	700		2022-23	2022	0-1 years
	New Coal-4		Coal	700		2025-27	2023-24	2 years
	New Coal-5		Coal	700		2030-31	2026-27	4 years
	New Coal-6		Coal	700		2032-33	2028-29	4 years
	New Coal-7	Steam	Coal	700			2030-31	New addition
	New Coal-8	Steam	Coal	700			2032-33	New addition
	New Coal-9	Steam	Coal	700			2034-35	New addition
	New Gas-1	CCGT	Gas	470		2026-27	2025	1-2 years
	New Gas-2	CCGT	Gas	470		2028-29	2027-28	1 year
	New Gas-3	CCGT	Gas	470		2034	2030-31	3-4 years
	New Gas-4	CCGT	Gas	470			2032-33	New addition
	New Gas-5	CCGT	Gas	470			2034-35	New addition
Total				11,153				

(2) Supply capacity of each power source and reserve margin of the long-term PDP

The supply capacity of each power source and reserve margin from 2015 to 2035 in the north system, in the south system and in the KE system are shown in Figure 5-46, Figure 5-47 and Figure 5-48. Besides, the supply capacity of each power source and reserve margin from 2015 to 2035 in the whole country and the power sources configurations are shown in Figure 5-49.

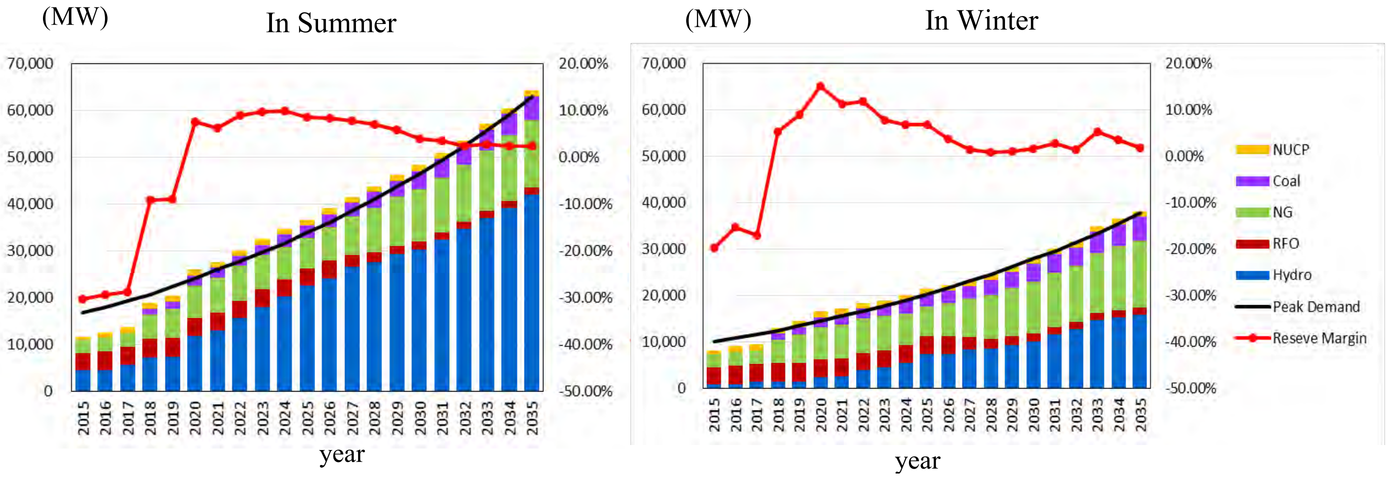


Figure 5-46 Power Development Plan up to 2035 in North System (High Demand Case)

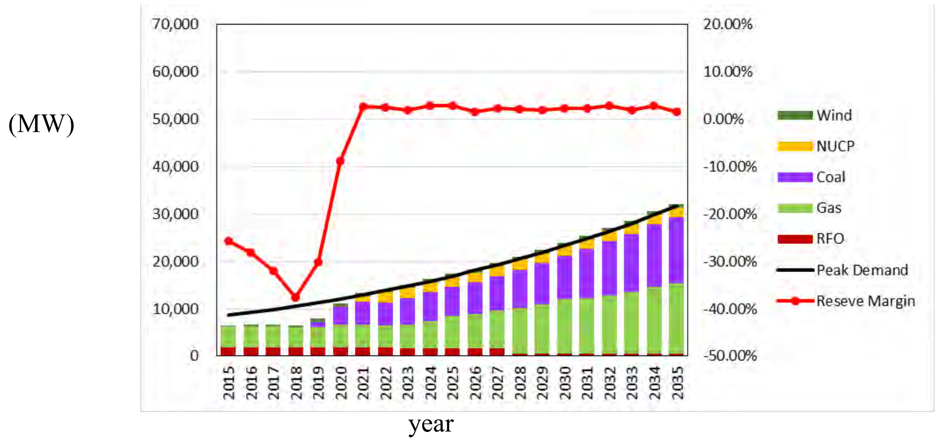


Figure 5-47 Power Development Plan up to 2035 in South System (High Demand Case)

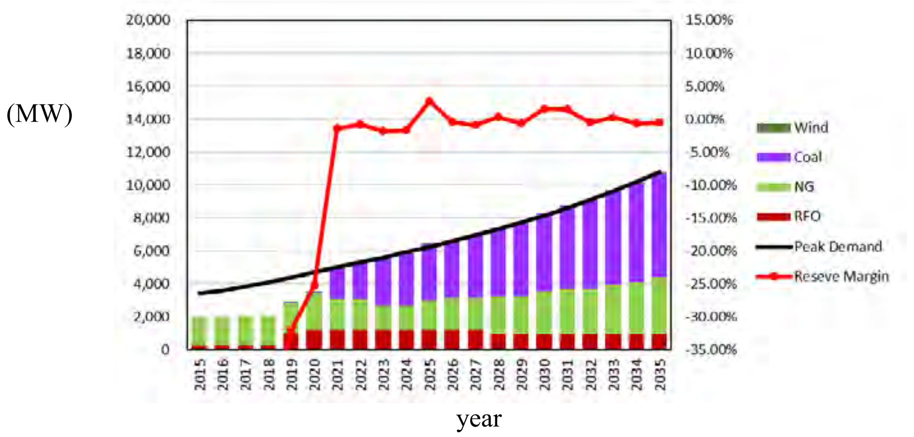


Figure 5-48 Power Development Plan up to 2035 in KE System (High Demand Case)

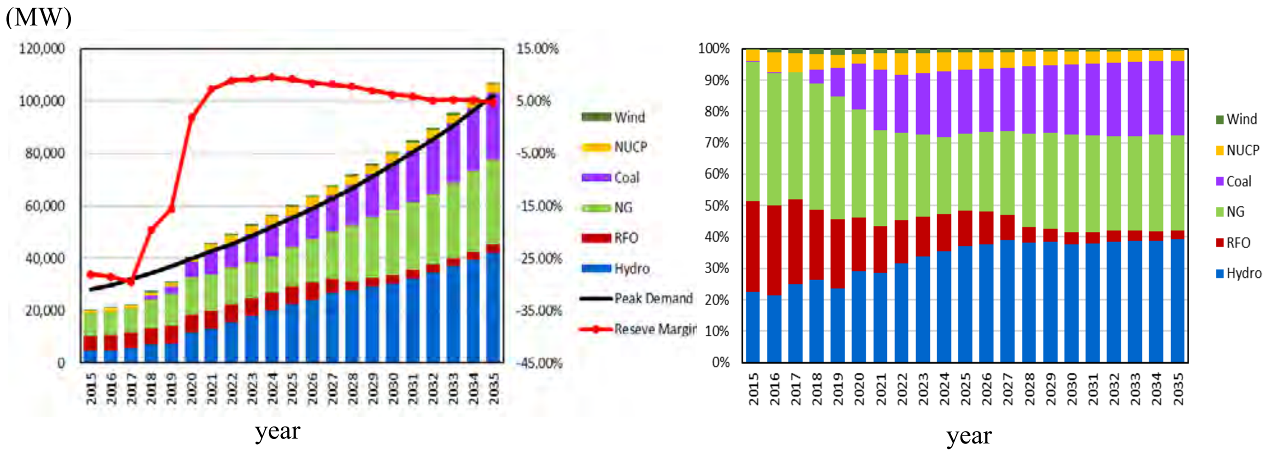


Figure 5-49 Power Development Plan up to 2035 in Whole Country (High Demand Case)

(3) Check of natural gas supply capacity

The natural gas consumption by power generation was calculated and compared with the natural gas (incl. LNG) supply plan shown in Table 4-13 and Table 4-14 to check whether gas shortage occurs or not, as well as in the base demand case.

The comparative study results in the whole country are shown in Figure 5-50. The gas supply shortage will occur after 2032.

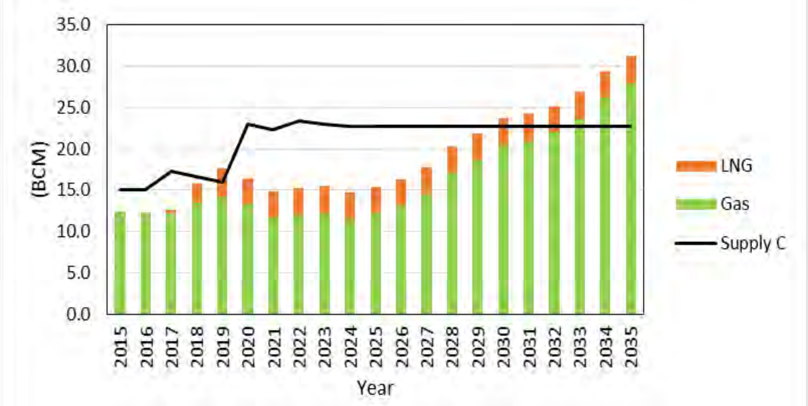


Figure 5-50 Gas Consumption versus Gas Supply Capacity for Power Sector (High)

(4) Check of coal supply capacity

As aforementioned in Section 4.2.3, when it is assumed that the annual mining volume is 200 million tons, since the total measured and indicated reserve is 15 billion tons. The installed capacity of 35GW of coal fired thermal power plants can be developed. On the other hand, the total installed capacity of domestic coal fired thermal power plants is 19GW. Accordingly, there is no problem in coal supply capacity.

(5) Forecast of overall generation unit cost

The overall generation unit cost was computed by the simulation of demand-supply operation (PDPAT II) , as well as in the base demand case. The bottom lines are shown in

Table **5-40**.

The overall generation unit cost of the high demand case in the whole country after 2020 will be the almost same as those of the base demand case, since the power sources configuration in the high demand case in 2023 or 2031 is the almost same as that in the base demand case in 2025 and 2035, respectively.

Table 5-40 Transition of Overall Generation Unit Cost (High Demand Case)

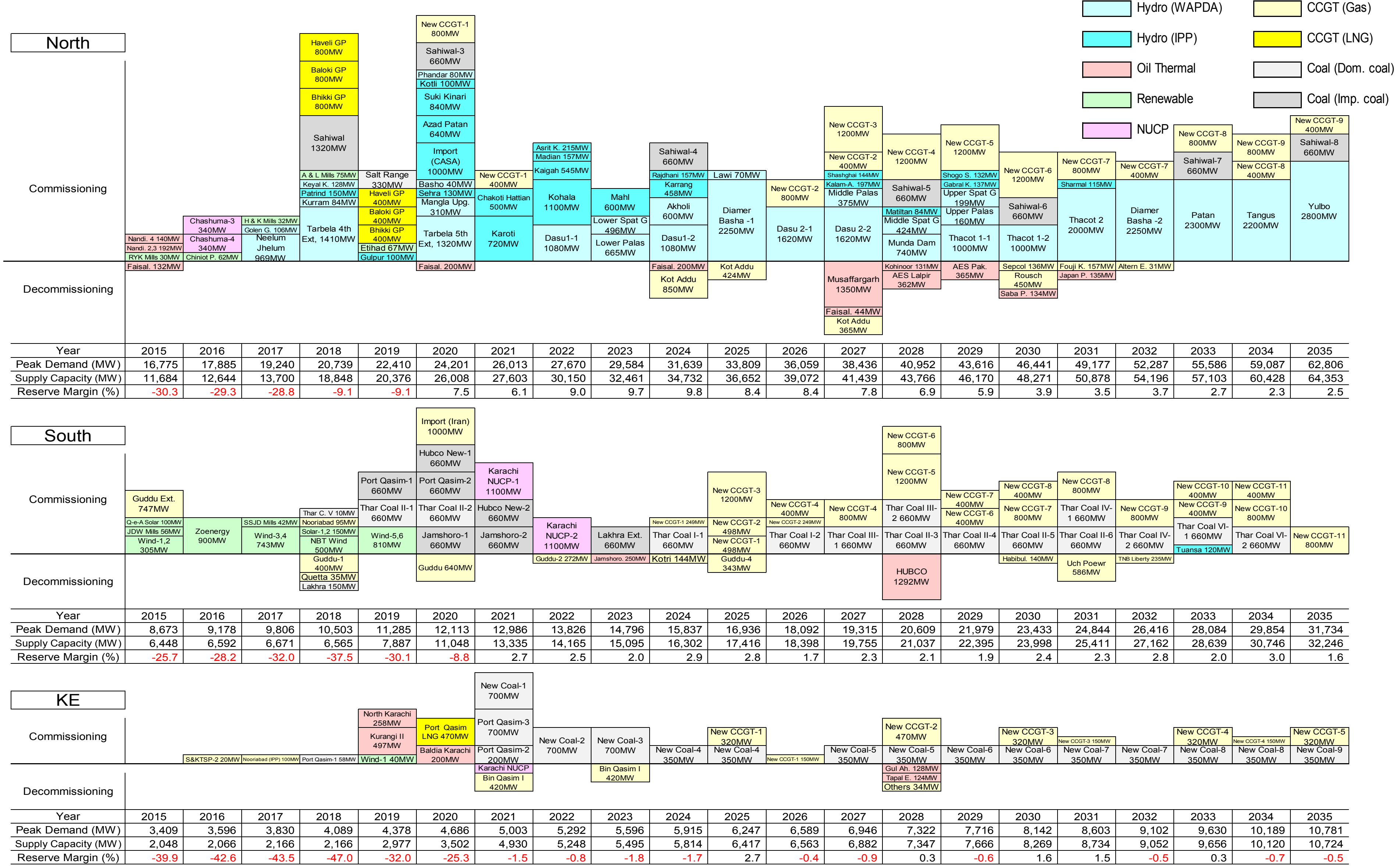
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North	Energy (GWh)	86,084	92,038	99,011	106,725	115,324	124,541	133,866	142,393	152,242	162,818	173,985
	Cost (UScent)	942,871	976,429	1,049,105	1,354,261	1,522,430	934,308	999,461	1,054,628	1,119,856	1,182,398	1,276,817
	Unit Cost (cent/kWh)	11.0	10.6	10.6	12.7	13.2	7.5	7.5	7.4	7.4	7.3	7.3
South	Energy (GWh)	47,955	50,888	54,370	58,234	62,570	67,161	72,001	76,659	82,037	87,809	93,902
	Cost (UScent)	467,378	548,070	612,019	709,496	666,299	615,322	654,687	701,791	752,771	817,772	871,936
	Unit Cost (cent/kWh)	9.7	10.8	11.3	12.2	10.6	9.2	9.1	9.2	9.2	9.3	9.3
KE	Energy (GWh)	20,115	21,281	22,666	24,198	25,909	27,731	29,607	31,318	33,117	35,005	36,969
	Cost (UScent)	209,788	226,351	232,723	232,533	191,051	222,811	233,690	245,724	262,422	279,613	301,801
	Unit Cost (cent/kWh)	10.4	10.6	10.3	9.6	7.4	8.0	7.9	7.8	7.9	8.0	8.2
Whole Coutry	Energy (GWh)	154,154	164,207	176,047	189,157	203,803	219,433	235,474	250,370	267,396	285,632	304,856
	Cost (UScent)	1,620,037	1,750,850	1,893,847	2,296,290	2,379,780	1,772,441	1,887,838	2,002,143	2,135,049	2,279,783	2,450,554
	Unit Cost (cent/kWh)	10.5	10.7	10.8	12.1	11.7	8.1	8.0	8.0	8.0	8.0	8.0

		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
North	Energy (GWh)	185,564	197,796	210,743	224,453	238,990	253,070	269,074	286,052	304,068	323,206
	Cost (UScent)	1,341,005	1,393,091	1,474,899	1,569,029	1,673,176	1,747,761	1,857,515	1,965,847	2,120,025	2,280,941
	Unit Cost (cent/kWh)	7.2	7.0	7.0	7.0	7.0	6.9	6.9	6.9	7.0	7.1
South	Energy (GWh)	100,312	107,093	114,268	121,863	129,925	137,748	146,465	155,713	165,527	175,951
	Cost (UScent)	926,303	980,791	1,071,028	1,132,160	1,202,409	1,259,374	1,304,907	1,400,652	1,480,695	1,545,557
	Unit Cost (cent/kWh)	9.2	9.2	9.4	9.3	9.3	9.1	8.9	9.0	8.9	8.8
KE	Energy (GWh)	38,993	41,106	43,332	45,663	48,184	50,912	53,865	56,989	60,298	63,801
	Cost (UScent)	317,693	333,370	361,473	379,056	404,171	439,277	465,384	502,492	540,950	580,933
	Unit Cost (cent/kWh)	8.1	8.1	8.3	8.3	8.4	8.6	8.6	8.8	9.0	9.1
Whole Coutry	Energy (GWh)	324,869	345,995	368,343	391,979	417,099	441,730	469,404	498,754	529,893	562,958
	Cost (UScent)	2,585,001	2,707,252	2,907,400	3,080,245	3,279,756	3,446,412	3,627,806	3,868,991	4,141,670	4,407,431
	Unit Cost (cent/kWh)	8.0	7.8	7.9	7.9	7.9	7.8	7.7	7.8	7.8	7.8

(6) Yearly development of Long-term power development pattern (High demand case)

Yearly power development (incl. decommissioning), supply capacity and reserve margin according to the long-term power development pattern (High demand case) in the north and south system and KE system are shown in Table 5-41. In addition, since the power plants which have commissioned until January 1st in every year are counted as a supply capacity in each year and the demand supply balance or the reserve margin is computed, the planned power plants which is planned to commission in the middle of a year is counted as a developed power plant in the next year.

Table 5-41 Yearly Development according to Long-term Power Development Pattern (High Demand Case)



▭	Hydro (WAPDA)
▭	Hydro (IPP)
▭	Oil Thermal
▭	Renewable
▭	NUCP
▭	CCGT (Gas)
▭	CCGT (LNG)
▭	Coal (Dom. coal)
▭	Coal (Imp. coal)

North

Commissioning	Nandi. 4 140MW Nandi. 2,3 192MW RYK Mills 30MW	Chashuma-3 340MW Chashuma-4 340MW Chiniot P. 62MW	H & K Mills 32MW Golen G. 106MW Neelum Jhelum 969MW	Haveli GP 800MW Baloki GP 800MW Bhikki GP 800MW Sahiwal 1320MW A & L Mills 75MW Keyal K. 128MW Patrind 150MW Kurram 84MW Tarbela 4th Ext, 1410MW	Salt Range 330MW Haveli GP 400MW Baloki GP 400MW Bhikki GP 400MW Etihad 67MW Gulpur 100MW	New CCGT-1 800MW Sahiwal-3 660MW Phandar 80MW Kotli 100MW Suki Kinari 840MW Azad Patan 640MW Import (CASA) 1000MW Basho 40MW Sehra 130MW Mangla Upg. 310MW Tarbela 5th Ext, 1320MW	New CCGT-1 400MW Chakoti Hattian 500MW Karoti 720MW	Asrit K. 215MW Madian 157MW Kaigah 545MW Kohala 1100MW Dasu1-1 1080MW	Mahl 600MW Lower Spat G 496MW Lower Palas 665MW	Sahiwal-4 660MW Rajdhani 157MW Karrang 458MW Akholi 600MW Dasu1-2 1080MW	Lawi 70MW Diamer Basha -1 2250MW	New CCGT-2 800MW Dasu 2-1 1620MW	New CCGT-3 1200MW New CCGT-2 400MW Shashghai 144MW Kalam-A. 197MW Middle Palas 375MW Dasu 2-2 1620MW	New CCGT-4 1200MW Sahiwal-5 660MW Matiltan 84MW Middle Spat G 424MW Munda Dam 740MW	New CCGT-5 1200MW Shogo S. 132MW Gabral K. 137MW Upper Spat G 199MW Upper Palas 160MW Thacot 1-1 1000MW	New CCGT-6 1200MW Sahiwal-6 660MW Thacot 1-2 1000MW	New CCGT-7 800MW Sharmal 115MW Thacot 2 2000MW	New CCGT-7 400MW Diamer Basha -2 2250MW	New CCGT-8 800MW Sahiwal-7 660MW Patan 2300MW	New CCGT-9 800MW New CCGT-8 400MW Tangus 2200MW	New CCGT-9 400MW Sahiwal-8 660MW Yulbo 2800MW
Decommissioning	Faisal. 132MW					Faisal. 200MW				Faisal. 200MW Kot Addu 850MW	Kot Addu 424MW		Musaffargarh 1350MW Faisal. 44MW Kot Addu 365MW	Kohinoor 131MW AES Lalpir 362MW	AES Pak. 365MW	Sepcol 136MW Rousch 450MW Saba P. 134MW	Fouji K. 157MW Japan P. 135MW	Altern E. 31MW			
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Peak Demand (MW)	16,775	17,885	19,240	20,739	22,410	24,201	26,013	27,670	29,584	31,639	33,809	36,059	38,436	40,952	43,616	46,441	49,177	52,287	55,586	59,087	62,806
Supply Capacity (MW)	11,684	12,644	13,700	18,848	20,376	26,008	27,603	30,150	32,461	34,732	36,652	39,072	41,439	43,766	46,170	48,271	50,878	54,196	57,103	60,428	64,353
Reserve Margin (%)	-30.3	-29.3	-28.8	-9.1	-9.1	7.5	6.1	9.0	9.7	9.8	8.4	8.4	7.8	6.9	5.9	3.9	3.5	3.7	2.7	2.3	2.5

South

Commissioning	Guddu Ext. 747MW Q-e-A Solar 100MW JDW Mills 56MW Wind-1,2 305MW	Zoenergy 900MW	SSJD Mills 42MW Wind-3,4 743MW	Thar C. V 10MW Nooriabad 95MW Solar-1,2 150MW NBT Wind 500MW	Port Qasim-1 660MW Thar Coal II-1 660MW Wind-5,6 810MW	Import (Iran) 1000MW Hubco New-1 660MW Port Qasim-2 660MW Thar Coal II-2 660MW Jamshoro-1 660MW	Karachi NUCP-1 1100MW Hubco New-2 660MW Jamshoro-2 660MW	Karachi NUCP-2 1100MW	Lakhra Ext. 660MW	New CCGT-1 249MW Thar Coal I-1 660MW	New CCGT-3 1200MW New CCGT-2 498MW New CCGT-1 498MW	New CCGT-4 400MW New CCGT-2 249MW Thar Coal I-2 660MW	New CCGT-4 800MW Thar Coal III-1 660MW	New CCGT-6 800MW New CCGT-5 1200MW Thar Coal III-2 660MW Thar Coal II-3 660MW	New CCGT-7 400MW New CCGT-6 400MW Thar Coal II-4 660MW	New CCGT-8 400MW New CCGT-7 800MW Thar Coal II-5 660MW	New CCGT-8 800MW Thar Coal IV-1 660MW Thar Coal II-6 660MW	New CCGT-9 800MW Thar Coal IV-2 660MW	New CCGT-10 400MW New CCGT-9 400MW Thar Coal VI-1 660MW Tuansa 120MW	New CCGT-11 400MW New CCGT-10 800MW Thar Coal VI-2 660MW	New CCGT-11 800MW
Decommissioning				Guddu-1 400MW Quetta 35MW Lakhra 150MW		Guddu 640MW		Guddu-2 272MW	Jamshoro. 250MW	Kotri 144MW	Guddu-4 343MW			HUBCO 1292MW		Habibul. 140MW	Uch Poewr 586MW	TNB Liberty 235MW			
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Peak Demand (MW)	8,673	9,178	9,806	10,503	11,285	12,113	12,986	13,826	14,796	15,837	16,936	18,092	19,315	20,609	21,979	23,433	24,844	26,416	28,084	29,854	31,734
Supply Capacity (MW)	6,448	6,592	6,671	6,565	7,887	11,048	13,335	14,165	15,095	16,302	17,416	18,398	19,755	21,037	22,395	23,998	25,411	27,162	28,639	30,746	32,246
Reserve Margin (%)	-25.7	-28.2	-32.0	-37.5	-30.1	-8.8	2.7	2.5	2.0	2.9	2.8	1.7	2.3	2.1	1.9	2.4	2.3	2.8	2.0	3.0	1.6

KE

Commissioning		S&KTSP-2 20MW	Nooriabad (IPP) 100MW	Port Qasim-1 58MW	North Karachi 258MW Kurangi II 497MW Wind-1 40MW	Port Qasim LNG 470MW Baldia Karachi 200MW	New Coal-1 700MW Port Qasim-3 700MW Port Qasim-2 200MW	New Coal-2 700MW	New Coal-3 700MW	New Coal-4 350MW	New CCGT-1 320MW New Coal-4 350MW	New CCGT-1 150MW	New Coal-5 350MW	New CCGT-2 470MW New Coal-5 350MW	New Coal-6 350MW	New CCGT-3 320MW New Coal-6 350MW	New CCGT-3 150MW New Coal-7 350MW	New Coal-7 350MW	New CCGT-4 320MW New Coal-8 350MW	New CCGT-4 150MW New Coal-8 350MW	New CCGT-5 320MW New Coal-9 350MW
Decommissioning							Karachi NUCP Bin Qasim I 420MW		Bin Qasim I 420MW					Gul Ah. 128MW Tapal E. 124MW Others 34MW							
Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Peak Demand (MW)	3,409	3,596	3,830	4,089	4,378	4,686	5,003	5,292	5,596	5,915	6,247	6,589	6,946	7,322	7,716	8,142	8,603	9,102	9,630	10,189	10,781
Supply Capacity (MW)	2,048	2,066	2,166	2,166	2,977	3,502	4,930	5,248	5,495	5,814	6,417	6,563	6,882	7,347	7,666	8,269	8,734	9,052	9,656	10,120	10,724
Reserve Margin (%)	-39.9	-42.6	-43.5	-47.0	-32.0	-25.3	-1.5	-0.8	-1.8	-1.7	2.7	-0.4	-0.9	0.3	-0.6	1.6	1.5	-0.5	0.3	-0.7	-0.5

5.5 Long Term Investment Plan

5.5.1 Base Demand Case

(1) Assumptions

Yearly distribution of construction cost of each power source is assumed as shown in Table 5-42.

Table 5-42 Yearly Distribution of Construction Cost

Year	7 years ago	6 years ago	5 years ago	4 years ago	3 years ago	2 years ago	1 year ago
Hydro (Reservoir)	-	10%	15%	20%	25%	20%	10%
Hydro (Run of River)	-	-	10%	20%	30%	30%	10%
Thermal (ST, CCGT)	-	-	-	10%	30%	40%	20%
Thermal (GT)	-	-	-	-	20%	40%	40%
Thermal (Coal)				10%	30%	40%	20%
Nuclear	5%	10%	15%	20%	20%	20%	10%

(2) Calculation results

Based on the long-term power development pattern (Base demand case), the calculation results of the yearly investment plan for the power development in the north and south (NTDC) systems are shown in Table 5-43 and Figure 5-51 by developers and power sources. Meanwhile, the development investment in renewable energy sources and power import are excluded.

Besides, the long-term investment plan in the power development by the public institutions such as WAPDA, GENCO and PAEC are shown in Figure 5-52.

Table 5-43 Long-term Investment Plan (Base Demand Case)

(million US$)

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North	WAPDA	1,140	1,092	728	632	961	1,051	1,992	2,766	3,418	3,584	3,245
	IPP Hydro	481	930	1,667	2,327	2,719	2,883	2,142	1,444	650	429	419
	IPP Gas	755	1,323	1,322	721	357	101	0	35	178	371	445
	IPP Coal	697	1,185	1,154	610	301	0	0	0	0	104	323
	NUCP	336	0	0	0	0	0	0	0	0	0	0
	Subtotal	3,409	4,531	4,870	4,289	4,337	4,034	4,135	4,245	4,247	4,489	4,432
South	IPP Hydro	0	0	0	0	0	0	0	0	0	0	0
	IPP CCGT (Ga	11	23	26	0	0	0	0	22	159	573	1,107
	GENCO Coal	0	104	426	783	876	659	512	334	0	0	0
	IPP Coal	213	964	1,997	2,304	1,362	301	104	426	783	761	405
	NUCP	392	685	1,010	1,242	1,372	1,263	543	0	0	0	0
	Subtotal	616	1,777	3,459	4,329	3,610	2,222	1,158	783	942	1,334	1,511
KE	Subtotal	414	683	934	992	775	456	607	883	932	693	446
Grand Total		4,439	6,990	9,263	9,610	8,723	6,713	5,900	5,911	6,120	6,516	6,389

		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
North	WAPDA	3,202	2,240	2,189	2,312	2,567	2,630	2,095	1,377	661	0
	IPP Hydro	239	249	214	179	144	98	51	38	0	0
	IPP Gas	380	476	736	771	733	789	767	303	0	0
	IPP Coal	564	623	460	301	0	0	0	0	0	0
	NUCP	0	0	0	0	0	0	0	0	0	0
	Subtotal	4,386	3,589	3,598	3,562	3,444	3,517	2,912	1,718	661	0
South	IPP Hydro	0	19	30	42	56	53	40	0	0	0
	IPP CCGT (Ga	1,344	1,119	852	899	763	690	574	410	202	0
	GENCO Coal	0	0	0	0	0	0	0	0	0	0
	IPP Coal	323	564	727	887	1,187	1,187	1,083	761	301	0
	NUCP	0	0	0	0	0	0	0	0	0	0
	Subtotal	1,667	1,702	1,609	1,828	2,007	1,930	1,697	1,171	503	0
KE	Subtotal	606	657	563	494	440	476	520	380	150	0
Grand Total		6,659	5,949	5,770	5,884	5,890	5,922	5,129	3,269	1,314	0

The yearly investments in power development in the north system are almost constant in 4,000 million US$, however, those from 2017 to 2019 in the south system are the twice of the others in order to recover the power shortage. Meanwhile, the yearly investments in power development by the public institutions increase rapidly from 2,000 million US$ in 2015 to 3,000 million US$ in 2019 and undergo a transition around 3,000 million US$ after that.

(North System) (South System)

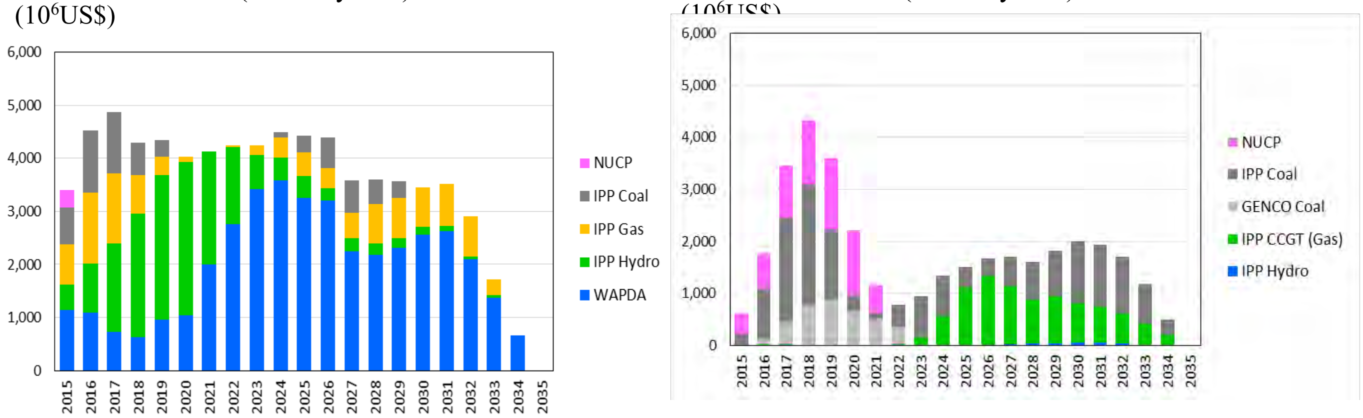


Figure 5-51 Long-term Investment Plan (Base Scenario)

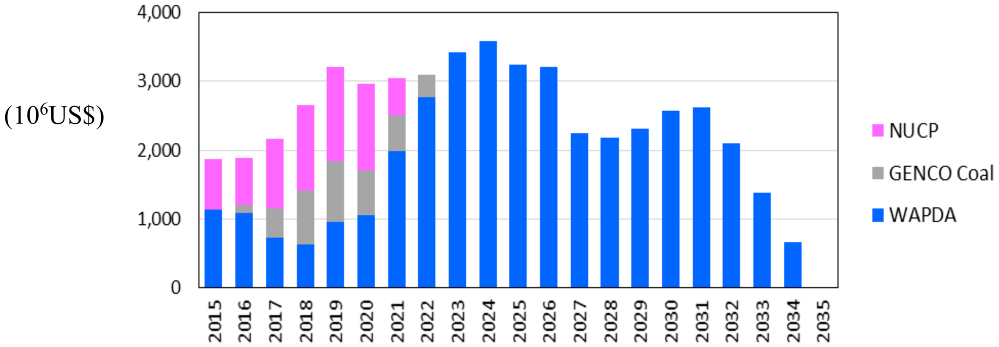


Figure 5-52 Long-term Investment Plan by Public Institutions

5.5.2 High Demand Case

(1) Assumptions

Yearly distribution of construction cost of each power source is assumed as shown in Table 5-42.

(2) Calculation results

Based on the long-term power development pattern (High demand case), the calculation results of the yearly investment plan for the power development in the north and south (NTDC) systems are shown in Table 5-44 and Figure 5-53 by developers and power sources. Meanwhile, the development investment in renewable energy sources and power import are excluded.

Besides, the long-term investment plan in the power development by the public institutions such as WAPDA, GENCO and PAEC are shown in Figure 5-54.

The yearly investments in power development in the north system increases about 1,000 - 2,000 million US$ from 3,500 - 4,000 million US$ in the base demand case. Those from 2023 to 2028 in the south system also increase around 1,000 million US$. In addition, the yearly investments in power development by the public institutions also increase around 1,000 million US$ in and after 2027 in comparison with those in the base demand case.

Table 5-44 Long-term Investment Plan (High Demand Case)

(million US$)

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North	WAPDA	1,157	1,321	1,222	1,401	2,235	2,692	3,440	3,651	3,728	3,389	2,812
	IPP Hydro	904	1,672	2,407	2,888	3,003	2,216	1,547	657	417	257	303
	IPP Gas	755	1,323	1,322	721	357	101	0	70	356	848	1,251
	IPP Coal	645	1,024	924	460	301	104	323	460	301	104	323
	NUCP	336	0	0	0	0	0	0	0	0	0	0
	Subtotal	3,798	5,341	5,875	5,470	5,895	5,113	5,310	4,838	4,802	4,597	4,687
South	IPP Hydro	0	0	0	0	0	0	0	0	0	0	0
	IPP CCGT	11	23	26	0	45	206	533	856	935	914	1,022
	GENCO Coal	0	104	426	783	876	659	512	334	0	0	0
	IPP Coal	213	964	1,997	2,304	1,362	405	323	564	727	991	1,510
	NUCP	392	685	1,010	1,242	1,372	1,263	543	0	0	0	0
	Subtotal	616	1,777	3,459	4,329	3,655	2,532	1,910	1,754	1,662	1,904	2,532
KE	Subtotal	573	1,093	1,358	1,117	650	642	769	870	833	751	830
Grand Total		4,987	8,211	10,692	10,916	10,200	8,287	7,989	7,462	7,297	7,252	8,050

		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
North	WAPDA	3,015	3,349	3,929	4,419	4,602	4,353	3,803	2,450	1,157	0
	IPP Hydro	305	187	143	51	38	0	0	0	0	0
	IPP Gas	1,298	1,092	802	481	476	770	774	458	101	0
	IPP Coal	564	623	460	405	323	564	623	460	301	0
	NUCP	0	0	0	0	0	0	0	0	0	0
	Subtotal	5,182	5,252	5,334	5,356	5,439	5,688	5,201	3,368	1,559	0
South	IPP Hydro	0	0	20	42	66	72	41	0	0	0
	IPP CCGT	1,297	1,209	953	899	833	906	883	612	202	0
	GENCO Coal	0	0	0	0	0	0	0	0	0	0
	IPP Coal	1,648	1,592	1,510	1,648	1,488	1,083	761	301	0	0
	NUCP	0	0	0	0	0	0	0	0	0	0
	Subtotal	2,944	2,801	2,482	2,588	2,386	2,062	1,684	913	202	0
KE	Subtotal	826	623	440	520	681	647	378	65	0	0
Grand Total		8,952	8,676	8,256	8,464	8,506	8,397	7,264	4,346	1,761	0

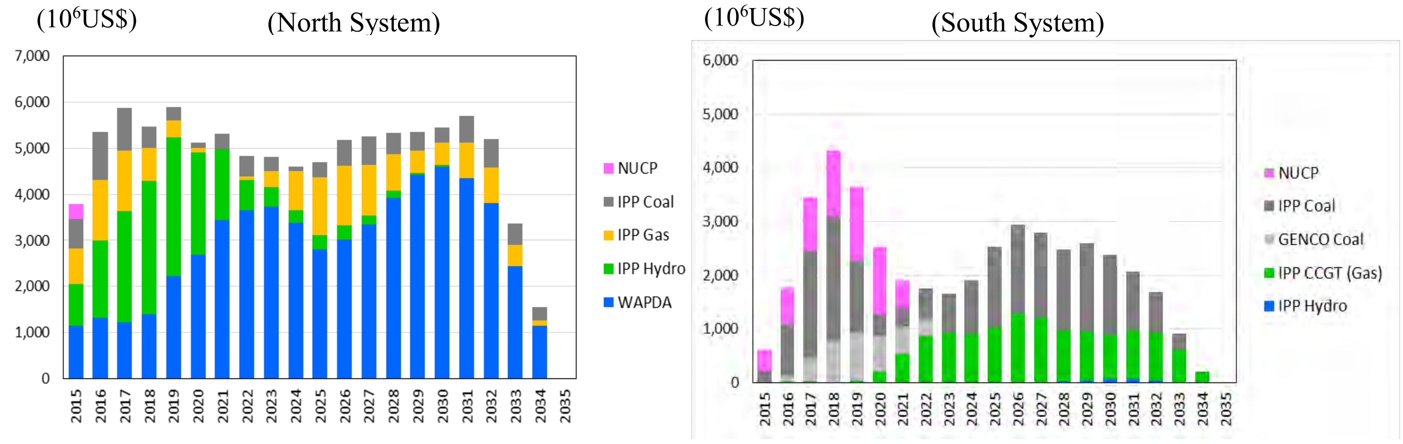


Figure 5-53 Long-term Investment Plan (High Demand Case)

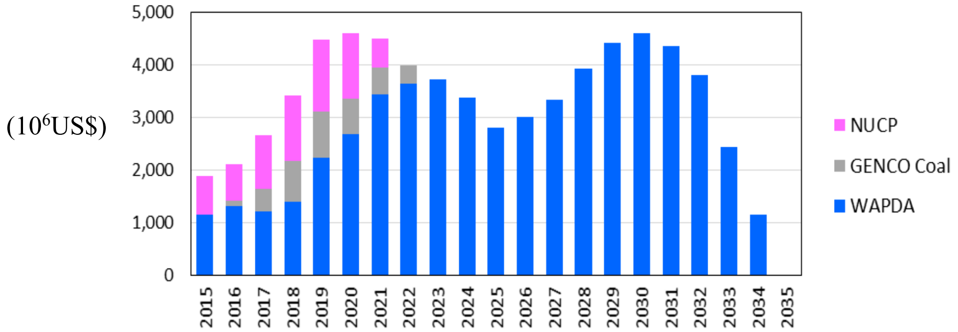


Figure 5-54 Long-term Investment Plan by Public Institutions (High Demand Case)

Chapter 6 Power System Development Plan

6.1 Basic Policy for Preparation of Development Plan

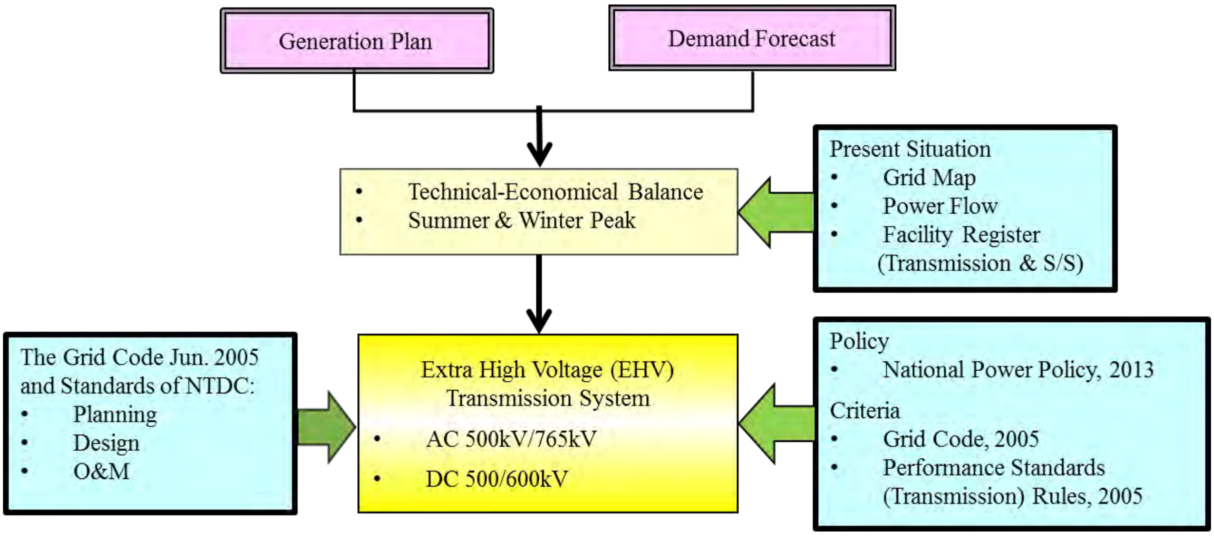
Basic policy pertaining to the power system development plan is as follows in consideration of the national targets and leading-edge technology.

(1) National policy and targets

Pakistan held up "Establishment of the leading edge power system" described in the National Power Policy. In addition, NEPRA presented the target in the regulation of power system that the current transmission losses of 3% is to be reduced to 2.5%.

(2) Principle and methods

The above policy and targets are to be achieved in consideration of the efficiency as an end of reliability, quality and effective use of resources for power supply. And "National Power System Expansion Plan (NPSEP-2030) with Revised Cost Data" (2013), NTDC prepared, is reviewed. These work flow is shown in Figure 6-1.



(Source : JICA Project Team)

Figure 6-1 Study Flow of Power System Development Plan

(a) Principle

Transmission expansion plan is prepared by connection between power demand center and power plant with the safe, economical and technically optimal manner in consideration of easy operation and maintenance, extensibility of power system and environmental & social considerations.

(b) Methods

Transmission system plan is prepared by paying attention to the existing facilities, connecting with shortest route between power demand center and power plants, selecting optimal voltage level so that power loss can decrease and variation of power flow between summer and winter season can be minimized.

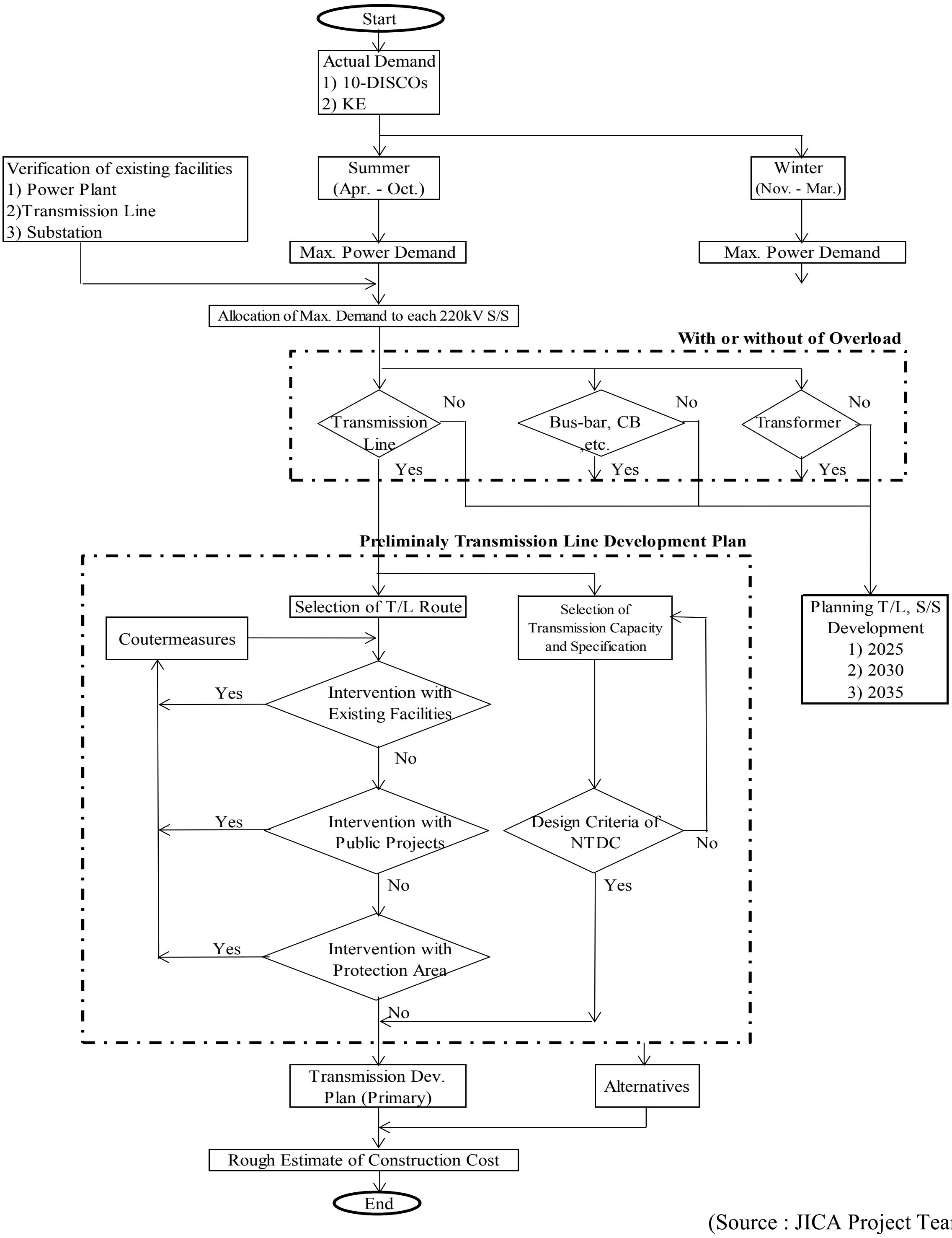
Future plan which anticipate for 20 years is considered. Besides, looped type is considered to apply for the bulk power system in order to secure power supply reliability.

Meanwhile, the specification of facilities of NTDC is basically applied.

(3) Comprehension of current conditions

Prior to preparation of the development plan, the latest power system should be verified. The power flow analysis in the close year should be carried out and it should be comprehended whether or not there is any malfunction at present. Therefore, the data of the latest power stations, transmission lines and the 220/500kV substations are to be confirmed and it should be comprehended whether or not there is any overload at the peak load in the summer and the winter season.

Common comprehension work flow of current conditions is shown in Figure 6-2.



(Source : JICA Project Team)

Figure 6-2 Comprehension Work Flow of Current Situations

6.2 Methodology of Study on Power System Reliability

It is necessary to consider comprehensively generation facilities and power transmission facilities in order to know supply reliability of the power system.

Concerning the supply reliability of the power transmission, the following three index is to be examined, D : frequency of power outage per consumer (number of times of power outage / annum), F : duration of power outage per consumer (power outage duration / annum), S : occurrence probability of power shortage of the whole power system (power shortage electric energy / annual total electric energy supplied). As for the transmission system, reliability index given by R= R (D, F, S) is used, and as for the distribution system, the reliability is expressed by using indexes of D and F. In addition, in the case of the distribution system, either number of power outage or power outage duration time is calculated by summing up that of transmission system and that of distribution system.

The optimal power system development plan needs to be examined from the both viewpoints of supply reliability and economic efficiency. In addition, it is necessary to consider the movement of inter-connection with neighboring countries.

The power supply reliability is expressed by frequency, duration time and rage of power outage, and the power system stability is the capability of settle down to the balanced status when balance between generated power and consumed power is collapsed.

Power supply reliability and power system stability are factors required to maintain “quality of electricity”. It is necessary for maintaining and improving the supply reliability to secure appropriate reserve margin, to enable to maintain the electric voltage and frequency within proper range, to take measures promptly when power outage occurs and so on. In addition, in case that the power system becomes unstable, for instance, voltage and frequency fluctuate largely, it may lead to a large scale of power outage. Therefore, quantity of power flow is to be controlled in order to keep power system stability.

NTDC prepared power system development plan until 2021-22 based on the power demand forecast by every DISCO.

(1) Preliminary prospect on the power system stability

As for the AC 500kV transmission system, the following matters are in general.

1) Reactance of transmission line is about 0.1%/km that is independent on cable type.
2) It is said that the upper limit is electric power of 5,000MW which can be stably transmitted for the distance of 100km by single circuit.
3) For instance, in the case of the distance of 200km, the above upper limit is 2,500MW.
4) Stable power flow by more than 2 circuits transmission line can be roughly estimated by the following formula.
5) Stable power flow = (number of circuits - 1) x 5,000 / transmission line length [km] / 100[km]
6) Transmission line length is calculated as follows.
7) In the case that transmission line length is 200km with 50% compensation, the length in the above formula can be estimated as 100km (200x0.5).
8) Electric cable type applied for long distance transmission line of several hundred km is 4 x ACSR 330mm^2 which has a heat capacity for around 2,500MW / circuit, meanwhile, in the case of short distance and large capacity, the other cable type is applied.

Remarks : the above preliminary prospect should be verified by detailed power system stability analysis.

6.3 Power System Analysis and Conditions

JICA study team verifies the analysis conditions through discussion with NTDC. However, the following analysis conditions are considered in view of importance of the long term development plan and the bulk power system of over 500kV.

(1) Objective Area

The whole power system of Pakistan excluding currently isolated power systems and Interconnection with Iran and Afghanistan.

(2) Analysis cases

Peak time in the summer and the winter season in 2025 and 2035

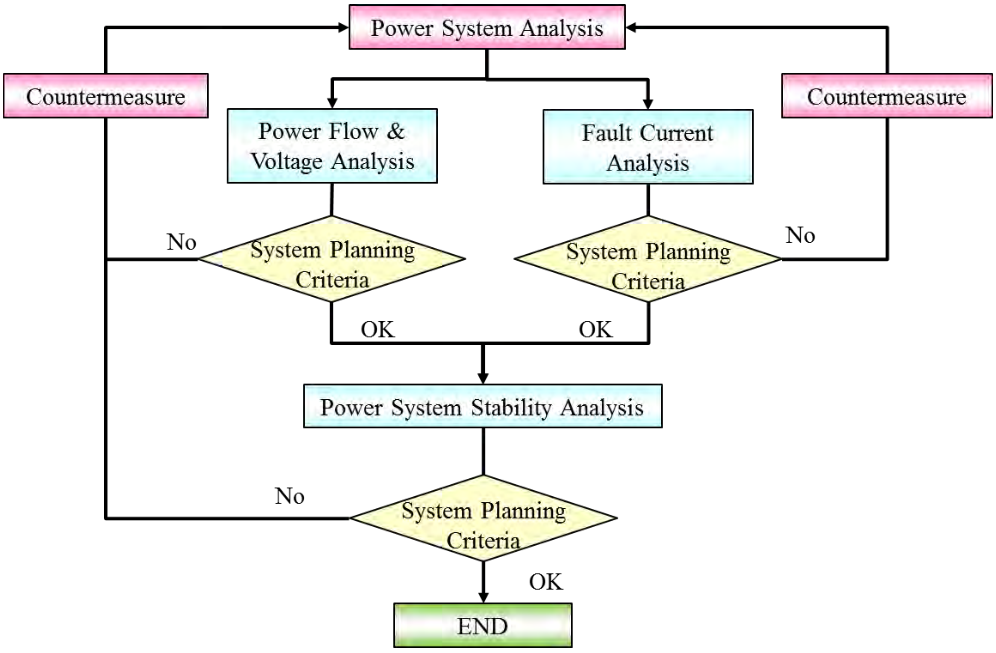
(3) Contents

The following 3 analyses are carried out by using PSS/E program.

1) Power flow analysis (overload / over voltage)
2) Fault current analysis (fault current)
3) Stability analysis (stability of generator)

According to the NEPRA grid code, five types of accident (transmission line, transformer for generator, 500kV transformer, 500kV bus and 500kV shunt reactor) are to be assumed and analyzed.

Power system analysis flow is shown in Figure 6-3.



(Source : JICA Project Team)

Figure 6-3 Power System Analysis Flow

(4) Preconditions

1) Power demand forecast by each DISCO is considered.
2) Power load of plural transmission lines is evenly allotted to each. Power load complies to the grid code.
3) Rated operation voltage of generator is used.

4) Power factor of load is 0.95. Basic configuration of power system is on the operation state that all circuit-breaker is "Close".
5) In the case that voltage control is necessary on power flow analysis, it is taken measures by change of transformer tap and connection with static capacitor and voltage control range of bus-conductor is within 1.00p.u.+/-0.05p.u. And power factor control range is within rated power factor.
6) The optimal plan target year is 2025.
7) Fault at peak load hour is assumed, and temporary over voltage and frequency variation to meet NTDC operation rule are analyzed.
8) Maximum power flows in the summer and winter are analyzed.
9) The others
   a) When single circuit fault occurs, power flow of transmission line never run over total rated capacity of remaining circuits
   b) Steady state stability of single circuit is also analyzed
   c) Transient stability analysis is carried out for more than 2 circuits. And the major fault current with 3 phases short circuit or single line to ground fault is analyzed. If necessary, failure of reclosing is also analyzed from the viewpoint of prevention of spillover to serious accident
   d) Lifetime of transmission line and substation is not considered.

(5) Analysis procedure

1) Power flow analysis of standard power system (transformer tap =1.00p.u. static capacitor uninstalled)
2) Power flow analysis after voltage control by tap change of transformer
3) Power flow analysis after voltage control by installation of static capacitor
4) Power flow analysis reflecting static capacitor installation plan
5) Calculation of short circuit capacity
6) Verification of measures for excess short circuit capacity (Alteration of power system configuration as a measure for excess short circuit capacity and 1) ~ 5) are re-verified.
7) Power flow analysis of the power system when N-1 fault is occurred (to sort out neck points of power flow on the subjects of a single circuit fault of 2 circuits transmission line and a single circuit fault of looped system)
8) System stability analysis

Besides, when the system analysis is carried out, NEPRA grid code shall be kept strictly. In the grid code, the allowable range of the voltage and frequency is shown in Table 6-1 as the main items, the basic conditions are shown in Table 6-2, and output of power station and voltage of transmission line are shown in Table 6-3.

Table 6-1 Allowable Range of Voltage / Frequency

No.	Conditions / Range	Normal	Contingency	Remarks
1	Voltage Fluctuation 1) 500kV 2) 220kV 3) 132kV	(+8%, -5%) [kV] 540>Vb>475 238>Vb>209 143>Vb>125	(±10%) [kV] 550>Vb>450 245>Vb>198 145>Vb>119	OC 4.9
2	Frequency Fluctuation 132/220/500kV	(±0.2) [Hz] 50.2>Fb>49.8	(+0.5, -0.6) [Hz] 50.5>Fb>49.4	OC 4.8.1
3	Power Factor (Lag.)	Within 95% or better	-----	OC 4.9.1

Remarks: 1) Vb is Bus-bar Voltage and Fb is Bus-bar Frequency.

(Source : NEPRA Grid Code 2005)

Table 6-2 Basic Conditions

No.	Description	Transmission	Transformer	Remarks
1	Loading Limit	Thermal limit of Conductor	Forced Cooling Capacity	PC 2.2.1
2	Temperature	Maximum Anbient Temeprature		
3	Allowable Over Load	For 15 min. and Transient and voltage stubility limit	For 2 hours	
4	Minimum Clearance	To ground at mid-span under maximum load	N.A.	
5	Others	Maximum allowable conductor temperature and Wind Velocity	Summer (April - October) loading and Winter (November - March) loading	

(Source : NEPRA Grid Code 2005)

Table 6-3 Output of Power Station and Voltage of Transmission Line

Output of Power Station	[MW]	1～4	4～40	40～150	150～400	400≦	Remarks
Voltage of Transmission Line	[kV]	11& Below	66	132	220	500	CC6.1

(Source : NEPRA Grid Code 2005)

(6) Basic conditions on bulk power network facilities

Bulk power network facilities are planned based on the following conditions.

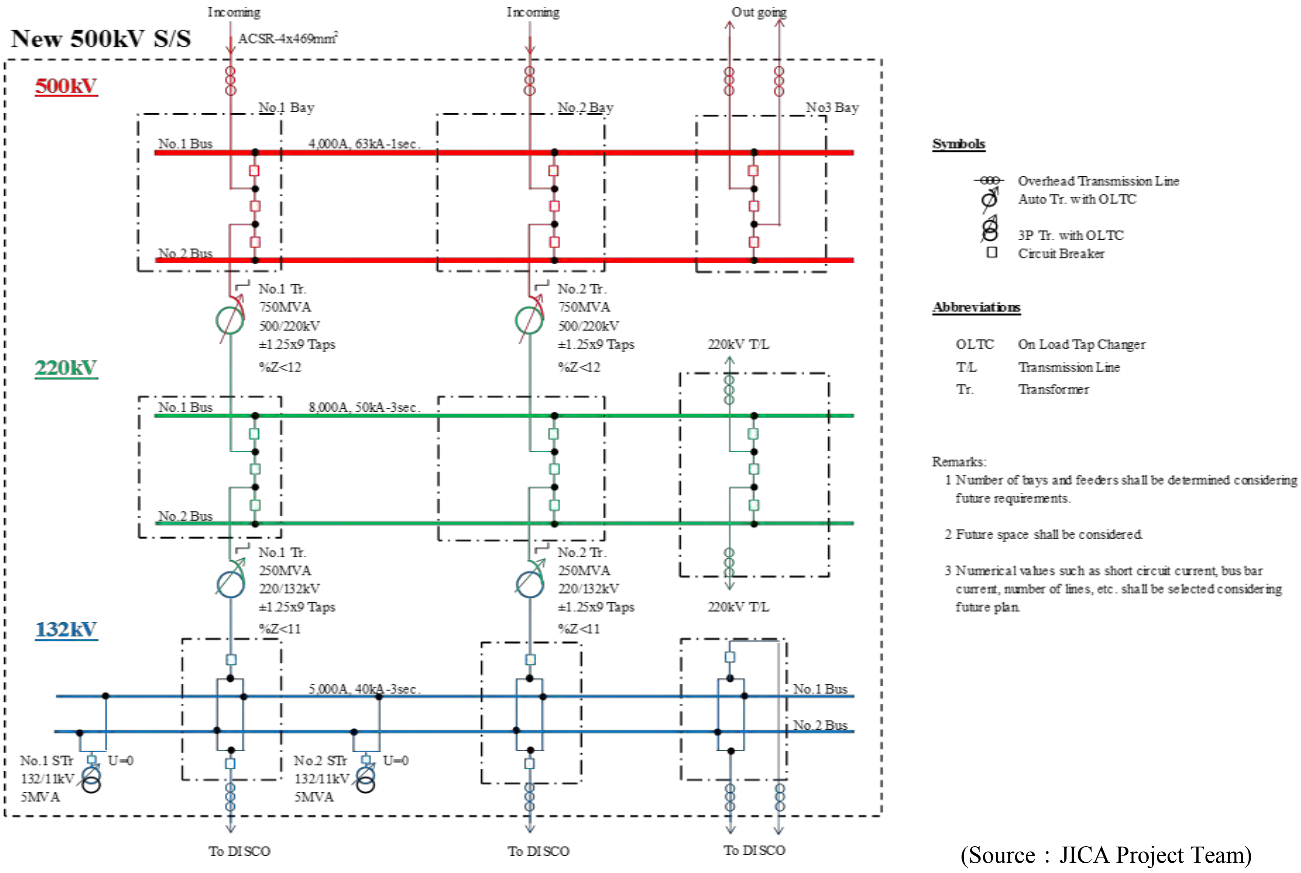
(a) Transmission line :

1) Double circuits are planned
2) Conductor is 4xACSR 469mm^2
3) OPGW-24Cx2 or 48Cx1 is adopted
4) Consideration of the latest damage classification, earthquake map and natural conditions
5) Avoiding environmental conservation area
6) Avoiding intersection of bulk transmission line as much as possible

(b) Substation :

1) Dualizing in-station power facility and installation of emergency power supply device
2) Adopting 100% protect against lightening
3) Selecting specification and site of equipment and bus conductor in consideration of 20 years later plan
4) Introducing common facilities in station

Conceptual design diagram of 500kV is shown in Figure 6-4



(Source：JICA Project Team)

Figure 6-4　Conceptual Diagram of 500kV S/S

6.4 Study on Bulk Power Network in 2025 and 2035

6.4.1 Current Bulk Power System Development Plan

(1) In 2021-22

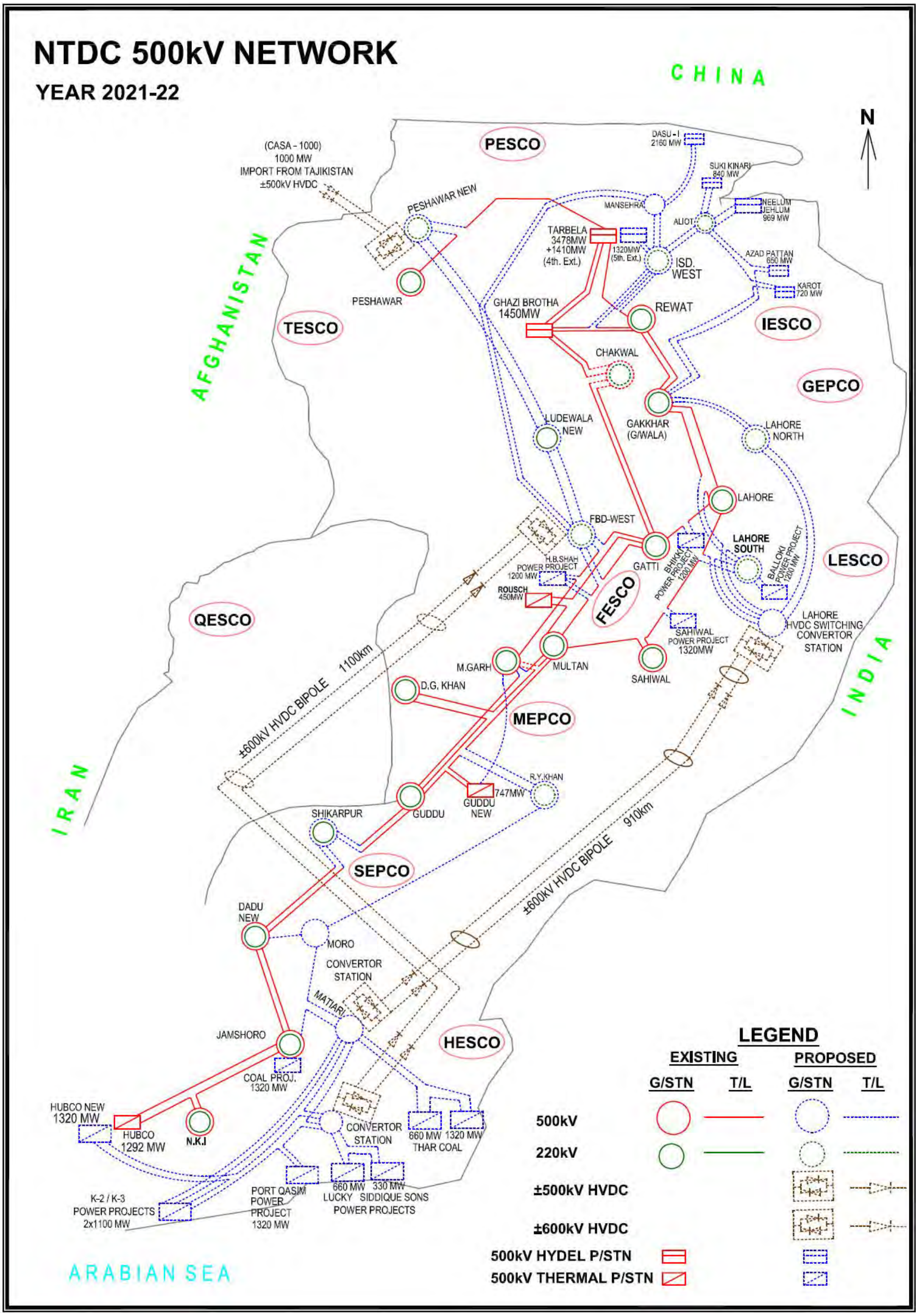
The list of the power system expansion plan by 2021-22 that was obtained from NTDC to date is shown in Table 6-4. And the NTDC 500kV grid map in 2021-22 is shown in Figure 6-5.

Table 6-4 Power System Expansion Plan by 2021-22

(As of End of Aug. 2015)

No.	New Substation	500kV Transmission Line/ 500/220kV Transformer Description	Transmission Line [km]			Transformer Capacity [MVA]			Donor	Cost (m-US$)	Expected Year of Commissioning
			No.	Unit	Total	No.	Unit	Total			
Ongoing Projects											
1	R.Y. Khan	Guddu-Multan 3rd CCT In/Out at R.Y. Khan	2	30	60	2	600	1,200	JICA	81	Dec. 2015
		(220kV)				2	250	500			
2	Shikarpur New	Guddu-Dadu 1st CCT In/Out at Shikarpur New	2	20	40	2	600	1,200	JICA	94	Dec. 2015
		Guddu-Dadu 2nd CCT In/Out at Shikarpur New	2	22	44						
3	Lahore South	Sahiwal-Lahore S/C In/Out at Lahore New	2	15	30	2	750	1,500	JICA	147	Dec. 2015
		Gujranwala-Lahore S/C In/Out at Lahore New	2	50	100						
4		Augmentation of 1x450MVA T/F with 1x750MVA capacity at Rawat New 500kV S/S				1	750	750	ADB	46	Dec. 2015 (Including 220kV)
5		Neelum Jhelum HPP-Gakkhar (Gujranwala), Ph-I	1	145	145				NTDC	218	Dec. 2015
		Ph-II	1	130	130						Dec. 2016
		Total	**12**		**549**	**[km]**		**5,150**	**[MVA]**		Including 220/132kV Tr.
Ready For Implementation Projects											
1	(Jamshoro S/S)	Jamshoro - Moro Switching Station (SS)	1	200	200				ADB	284	Dec. 2016
2	⇳	Dadu - Moro SS	1	55	55				ADB		Dec. 2016
3	(R. Y. Khan S/S)	Moro SS - R.Y. Khan	1	335	335				ADB		Dec. 2016
4		Ext. at Jamshoro, 3rd 500/220kV T/F				1	450	450	ADB	55	Dec. 2016
5		Guddu New Power Plant-M. Garh	1	276	276				ADB	91	Dec. 2016
6		D. G. Khan-Multan S/C In/Out at M. Garh	2	10	20				ADB		Dec. 2016
7		Lahore South-Sahiwal S/C In/Out at Sahiwal	2	0.5	1						2016-17
8		Ext. at Sahiwal, 3rd 500/220kV T/F				1	600	600			2016-17
		Total	**8**		**887**	**[km]**		**1,050**	**[MVA]**		
Future Development Projects											
1		Lahore - Gatti S/C In/Out at 1200MW Bhikki	2	5	10						2016-17
2		Lahore South-1200MW Balloki	2	40	80						2016-17
3		Ext. at Lahore South, 3rd 500/220kV T/F				1	750	750			2016-17
4		Faisalabad West-M. Garh S/C In/Out at 1200MW Haveli Bahadur Shah (HBA)	2	5	10					16	2016-17
5		Faisalabad West-Multan S/C In/Out at 1200MW HBA	2	15	30						2016-17
6		Augmentation of 3x237MVA T/Fs with 3x450MVA capacity at Tarbela 500kV G/S				3	450	1,350	WB		2016-17
7	Matiari	Engro Thar Coal-Matiari Switching Station (SS)	2	250	500	2	750	1,500	NTDC	237	2016-17
8	Faisalabad West	M. Garh-Gatti circuit In/Out at Faisalabad West, Ph-I	2	2	4	2	750	1,500	JICA	30	2017-18
		(220kV)				3	250	750			
9		Multan-Gatti circuit In/Out at Faisalabad West	2	30	60						2017-18
10		Port Qasim Coal Power Plant-Matiari	2	180	360					129	2017-18
11	Islamabad West	Ghazi Barotha-Rewat S/C In/Out at Islamabad West	2	15	30	2	750	1,500			2017-18
12		Tarbela-Rawat In/Out S/C at Islamabad West	2	12	24						2017-18
13		Tarbela 5th Ext. switchyrd- Islamabad West	1	77	77						2017-18
14		±600kV HVDC Bipole from Matiari - Lahore South	1	910	910						2018-19
15	Chakwal New	In/Out of Ghazi Barotha-Gatti D/C at Chakwal New	4	5	20						2018-19
		(220kV)				3	250	750			
16		Hubco Coal Power Plant -Matiari	2	220	440					162	2018-19
17		±600kV HVDC Bipole from 500kV South New Switching station-FSD WEST	1	1,000	1,000						2018-19
18		Siddiqson-Port Qasim	2	35	70						2018-19
19		Siddiqson-Port Qasim S/C In/Out at Lucky PP	2	3	6						2018-19
20		Port Qasim Coal Power Plant-Matiari S/C In/Out at Qasim	5								
21		Hubco Coal Power Plant -Matiari S/C In/Out at Qasim	20								
22	Peshawar New	In/Out of existing 500kV Tarbela-Peshawar S/C at Peshawar New	2	15	30	2	750	1,500			2018-19
23	Ludewala	Ludewala-Faisalabad West	2	100	200	2	600	1,200			2018-19
24		Ludewala-Peshawar New	2	325	650						2018-19
25	Lahore HVDC Convertor Station (CS)	In/Out of Lahore South-Lahore D/C at Lahore CS	4	20	80						
26	±500kV HVDC Convertor Station at Peshawar New	±500kV HVDC Bipole to Peshawar New(CASA-1000)	1	15	15	2	750	1,500	WB	120	2019-20(*1)
27	[(*1) means need to completion of other portion]	HVDC Transmission Line	1	71	71				WB		2019-20
28	Mansehra Switching Station	Dasu HPP to Mansehra	2	140	280				WB	350	2019-20
29		Mansehra to Islamabad West	2	100	200				WB		2019-20
30		Mansehra to Faisalabad West with 40% series compensation	2	375	750				WB		2019-20
31	Switching Station at Alliot	Suki Kinari HPP-Alliot	2	100	200						2019-20
32		Neelum Jhelum HPP-Gujranwala D/C In/Out at Alliot	4	2	8						2019-20
33		Alliot-Islamabad West	2	96	192						2019-20
34	Lahore North	Lahore North - Lahore South	2	60	120	2	750	1,500			2019-20
35		Lahore Nporth - Gujranwala (Gakkhar)	2	50	100						2019-20
36		Alliot-Gujranwala S/C In/Out at Azad Pattan	2	5	10						2019-20
37		Port Qasim TPP-Matiari SS S/C In/Out at K-2/K-3	2	70	140						2020-21
38		Ubco TPP-Matiari SS S/C In/Out at K-2/K3	2	5	10						2020-21
39		Alliot-Gujranwala S/C In/Out at Karot	2	5	10						2021-22
		Total	**96**		**6,697**	**[km]**		**13,800**	**[MVA]**		
		Grand Total	**116**		**8,133**	**[km]**		**20,000**	**[MVA]**		

(Source : JICA Project Team prepared based on NTDC data)



(Source : NTDC)

Figure 6-5 NTDC 500kV Grid Map in 2021-22

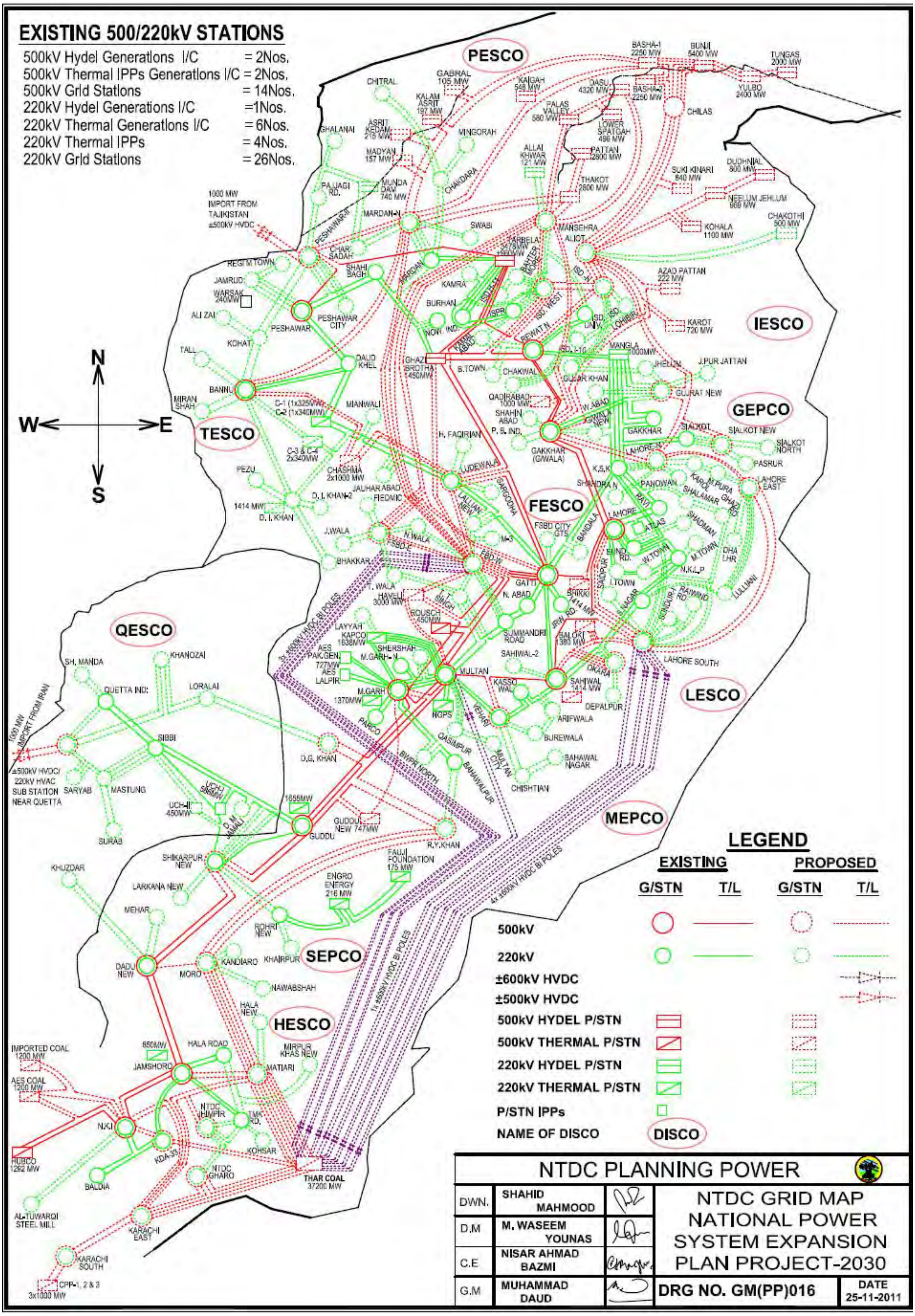
(2) In 2029-30

The list of the transmission system expansion projects by 2029-30 is shown in Table 6-5. And the NTDC 500kV/220kV grid map in 2029-30 is shown in Figure 6-6.

Table 6-5 Power System Expansion Plan by 2029-30

No.	New Substation	500kV Transmission Line/ 500/220kV Transformer Description	Transmission Line		Transformer Capacity [MVA]			Remarks
			No.	[km]	No.	Unit	Total	
New Grid Stations								
1	Asrit-Kedam	In/Out Basha-Mardan 500kV S/C	2	5	2			
2	Madyan	In/Out Basha-Mardan 500kV S/C	2	5	2			
5	Gabral Kalam	In/Out Basha-Mardan 500kV S/C	2	5	2			
6	Kalam Asrit	In/Out Basha-Mardan 500kV S/C	2	5	2			
7	Chashma Nuclear	Chashma-Ludewala 500kV	2	130	1			
8	Basha	Basha-Chilas 500kV	2	42				
		Basha-Mardan 500kV (via Swat Valley)	2	337				
9	Bunji	Bunji-Chilas 500kV	2	70	7			
10	Qadirabad Nuclear	±500kV D/C from Qadirabad Nuclear to Gujranwala	2	30	1			
11	Import from Iran	HVDC ±500kV from Pak-Iran Border to Quetta	2	678				
12	Matiari (initially Switching Station)	500kV Jamshoro-Moro S/C (3rd cct) already constructed via Matiari			2	750	1,500	
13	Mardan	Mardan-Peshawar	2	50	3	750	2,250	
14	Karachi (KDA)	Thar-Karachi (KDA)	2	375	3	1,000	3,000	
15	Vehari	In/Out Multan-Sahiwal	2	30	2	750	1,500	
16	Chilas (Switching Station)	Chilas-Aliot	2	212				
17	Aliot	Aliot-ISBD-W	2	96	2	600	1,200	
		Aliot-Lahore-N	2	245	2	600	1,200	
18	Moro				2	750	1,500	
19	Lahore-N	Gujranwala-Lahore-N	2	50	2	1,000	2,000	
		Lahore-S to Lahore-N	2	40	2	1,000	2,000	
20	Gujrat	In/Out Aliot (S/S) to Lahore-N 500kV S/C	2	30	2	750	1,500	
21	Ludewala	In/Out G-Barotha-Gatti 500kV D/C	4	30	2	750	1,500	
New Transformers								
1	Lahore-S				1	750	750	
2	ISBD-W				1	750	750	
3	Gujranwala (Gakhar)				1	750	750	
4	Rewat				2	750	1,500	
5	Peshawar-New				1	750	750	
6	FSBD-W				1	750	750	
7	NKI				2	600	1,200	
8	Sahiwal				2	750	1,500	
New Transmission Line								
1		In/Out Rousch-Gatti at FBD-W	2	20				
2		In/Out Multan-Gatti at FBD-W	2	20				
3		Lahore-S-Lahore	2	40				
4		Lahore-S-Sahiwal	2	115				
5		In/Out Karachi-Coal PPs to Matiar at NKI	4	10				
6		Ghazi-Barotha to FBD-W	2	330				
Power Dispersal Projects								
1	Bunji-2	Bunji-Chilas 500kV 2nd D/C	2	70				
		Chilas-Aliot	2	235				
2	Bhikki	In/Out Lahore-Gatti 500kV S/C	2	30				
3	Kohala	In/Out Neelum-Jehlum to Aliot 500kV D/C	2	10				
4	Thar	HVDC ±600kV from Thar to Lahore	2	1,020				
5	Basha-2	In/Out Basha-1 to Chilas 500kV D/C	2	10				
6	Bunji-3				6			
7	Kaigah	In/Out Basha-1 to Mardan S/C at Kaigah	2	10	2			
8	Palas Valley	Palas Valley to Mansehra 500kV	2	103	3			
9	PAEC-Nuclear (Karachi)	Nuclear PP to Karachi-S 500kV	2	25	1			
10	Dasu	Dasu-Mansehra 500kV	2	136				
		Dasu-Palas Valley 500kV	2	40				
11	Lower Spatgah	In/Out Dasu-Palas 500kV one circuit	2	10	6			
12	Wind Power Cluster Jhimpir	In/Out Matiari-Karachi-E 500kV one circuit	2	30	2			
13	PAEC-Nuclear (Karachi)				1			
14	Thakot	Thakot-Mansehra 500kV	2	89	8			
15	Pattan	Pattan-Thakot 500kV	2	113				
		Thakot-Mardan New	2	113				
16	Wind Power Cluster Gharo	Gharo-Karachi-E 500kV	2	30				
17	Thar	Thar-Karachi-E 500kV	2	320				
18	Dhudnial	Dhudnial-Neelum Jehlum 500kV	2	115				
19	ISBD-N	In/Out Aliot to ISBD-W 500kV	4	20	3	750	2,250	
		Aliot-ISBD-N 500kV direct line	2	110	3	750	2,250	
		ISBD-N to Rewat 500kV	2	40	3	750	2,250	
20	Karachi-E	In/Out NKI-Matiari at Karachi-E	2	320	3	1,000	3,000	

(Source : NTDC, National Power System Expansion Plan 2011-2030)



(Source : NTDC)

Figure 6-6 NTDC 500kV/220kV Grid Map in 2029-30

6.4.2 Review of the Bulk Power Network System Plan for 2021-22

The Study Team reviewed the plan of the bulk power network system made by NTDC for 2021-22 including the system over 500 kV. Its suitability was examined from the viewpoints of system reliability and its cost with using the power system analysis data obtained from NTDC.

In this study, the system performance was checked by confirming its suitability to the following criteria for their normal operation and contingencies. The contingencies were assumed as the faults of the single circuit of the transmission lines above 500 kV.

The used criteria were set out as follows according to the grid code of NTDC (THE GRID CODE June, 2005).

- The operating voltage limits were set out as follows.

Table 6-6 Operating Voltage Limits (Normal / Contingency Condition) [kV]

	Normal Condition		(N-1) Condition	
	Max	Min	Max	Min
500 kV	540	475	550	450
220 kV	238	209	245	198
132 kV	143	125	145	119

- Loading levels of the transmission lines were set out as follows.
  System operator must report the limits of the capacities of the transmission lines for the cases of the normal operation in summer and winter and the cases of emergency to NEPRA every year. The capacities described in the power system analysis data (Rate A) obtained by NTDC were used for this study.
- The criteria for the stability were set out as follows.
  The system were considered stable when the angle oscillation became converged after fault clearance 5 cycle after three phase short circuit.

(1) Evaluation of the current transmission system plan of NTDC 2021-22

(a) Power system configuration

NTDC's transmission system plan connects north to south of the country by two pole direct current transmission lines with 1,000 km to transmit the power from the thermal power stations in the south area to the north in direction to Lahore. Figure 6-7 shows the power system configuration of new transmission lines planned from north to south.

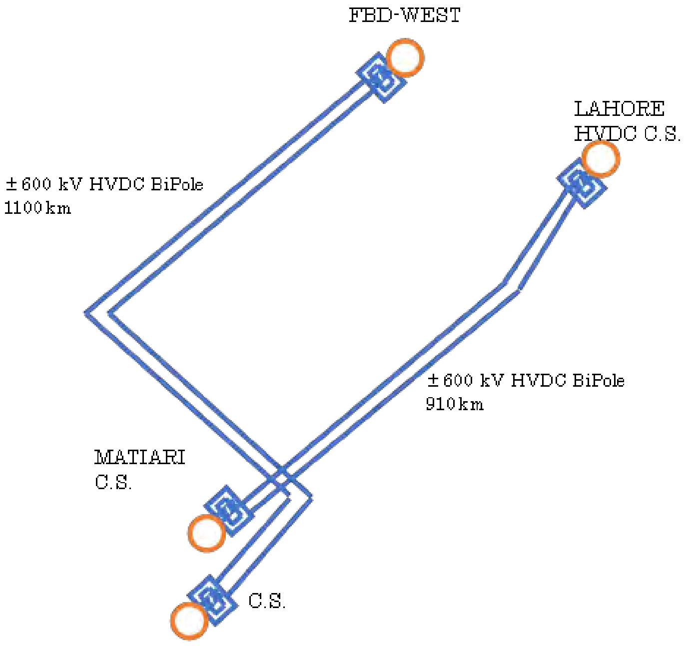


Figure 6-7 NTDC 500kV HVDC Network: 2021-22

(b) Power flow in summer 2021

Power flows and voltages in normal operation and those at contingencies being out of their criteria were not observed.

(c) Power flow in winter 2022

Power flows and voltages in normal operation and voltages at contingencies being out of their criteria were not observed.

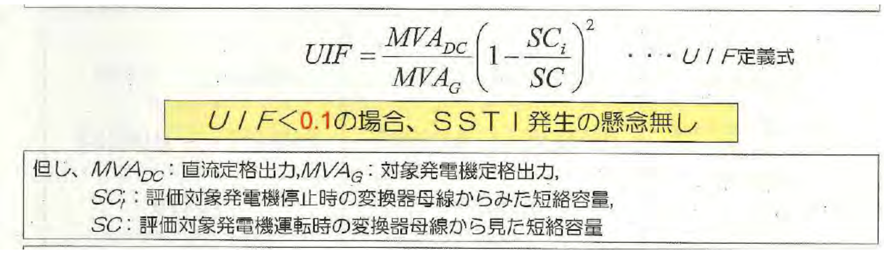
Only one of the transmission lines was overloaded for a case of contingency.

- Fault locations: PORT QASIM 500.00 (87)- SOUTH 500 KV500.00 (93)
- Overloading points: HUBCO-CFPP 500.00 (92)- SOUTH 500 KV500.00 (93)
- Overloading ratio: 137.9% 2317.3MVA capacity 1600.0MVA

This overloaded situation may be avoided during the short period of time by adjusting power outputs of the generators because it occurs only near a power station. There is a possibility of enlargement of the capacity of the transmission lines by adapting individual weather considerations.

(d) Sub-synchronous resonance

Whether or not the effects of sub-synchronous resonance occurred around direct current facilities was confirmed by using the following formula.



$$UIF = \frac{MVA_{DC}}{MVA_G}\left(1 - \frac{SC_i}{SC}\right)^2 \quad \cdots UIF定義式$$

ＵＩＦ<0.1の場合、ＳＳＴＩ発生の懸念無し

但し、MVA_{DC}：直流定格出力,MVA_G：対象発電機定格出力,
SC_i：評価対象発電機停止時の変換器母線からみた短絡容量,
SC：評価対象発電機運転時の変換器母線から見た短絡容量

Here, Port Qasim was examined as the generators installed near direct current facilities.

- Rated capacity of direct current facility MVAdc = 1,800 MVA
- Rated capacity of generator MVAg = 1,200 MVA
- Short circuit capacity observed from the bus bar at a converter station when a generator is stopped Sci = 2,8723.3 A
- Short circuit capacity observed from the bus bar at a converter station when a generator is operated SC = 3,1450.1 A

From the abovementioned values UIF = 0.011276
It means UIF < 0.1

From the above criterion formula, it was confirmed that there is no problem on the sub-synchronous resonance occurrence.

(e) System stability in summer 2021

Table 6-7 outlines the results of the system stability calculation assuming a single circuit fault (N-1) of the transmission lines above 500 kV. Table 6-8 shows their details. Figure 6-8 illustrates the unstable cases in addition to Figure 6-9 that shows the typical results of the calculation.

Table 6-7 Outline of Results of System Stability Calculation in case of A Single Circuit Fault adopting NTDC's Current Plan

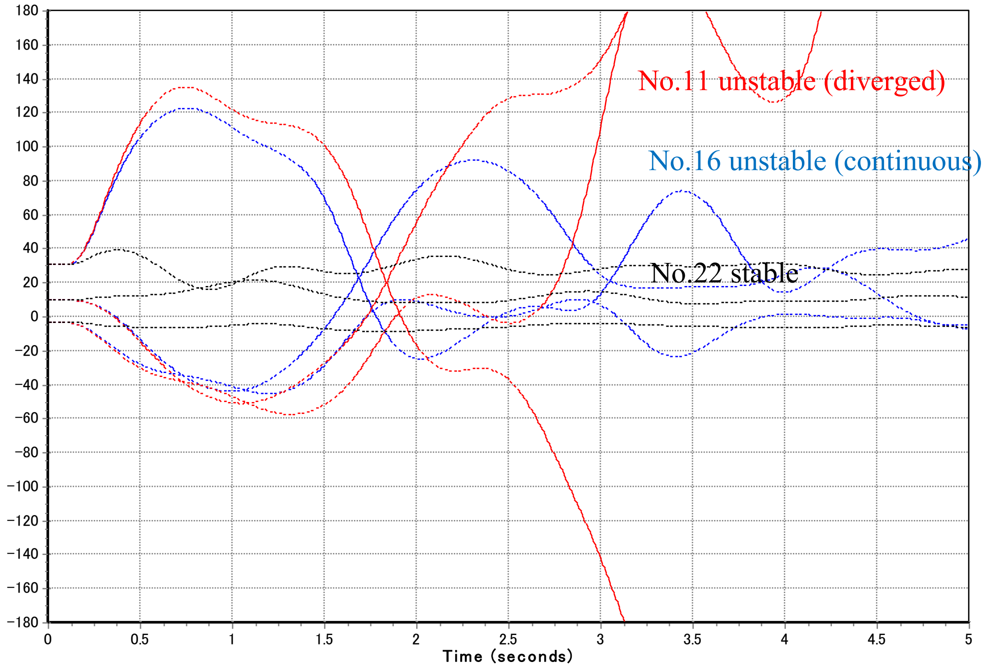
Number of the cases of the single circuit fault of 500kV alternative current transmission lines	184
Number of stable cases	163
Number of unstable cases	21

Number of cases of divergent oscillation among those	14
Number of cases of continuous oscillation among those	7

Number of cases of the single pole fault of ±600kV direct current transmission lines	8
Number of stable cases	8
Number of cases of continuous oscillation among those	0

Table 6-8 Details of Unstable Cases of Single Circuit Faults adopting NTDC's Current Plan

No.	Fault bus no.	To bus name	From bus no.	From bus name	To bus no.	To bus name	Id	Results (stable/unstable)
1	80	JAMSHORO	70	DADU	80	JAMSHORO	1	unstable (diverged)
2	80	JAMSHORO	70	DADU	80	JAMSHORO	2	unstable (diverged)
3	80	JAMSHORO	80	JAMSHORO	90	HUB	1	unstable (diverged)
4	80	JAMSHORO	80	JAMSHORO	91	NKI	1	unstable (diverged)
5	80	JAMSHORO	80	JAMSHORO	95	MATIARI	1	unstable (diverged)
6	89	K-2/K-4	89	K-2/K-4	95	MATIARI	1	unstable (diverged)
7	89	K-2/K-4	89	K-2/K-5	95	MATIARI	2	unstable (diverged)
8	95	MATIARI	75	MORO	95	MATIARI	1	unstable (diverged)
9	95	MATIARI	85	ENGRO THAR	95	MATIARI	1	unstable (diverged)
10	95	MATIARI	86	SSRL	95	MATIARI	1	unstable (diverged)
11	95	MATIARI	89	K-2/K-4	95	MATIARI	1	unstable (diverged)
12	95	MATIARI	89	K-2/K-5	95	MATIARI	2	unstable (diverged)
13	95	MATIARI	93	PRT QSM (SS)	95	MATIARI	1	unstable (diverged)
14	95	MATIARI	93	PRT QSM (SS)	95	MATIARI	2	unstable (diverged)
15	92	HUBCO-CFPP	92	HUBCO-CFPP	93	PRT QSM (SS)	1	unstable (continuous)
16	93	PRT QSM (SS)	87	PORT QASIM	93	PRT QSM (SS)	1	unstable (continuous)
17	93	PRT QSM (SS)	92	HUBCO-CFPP	93	PRT QSM (SS)	1	unstable (continuous)
18	93	PRT QSM (SS)	93	PRT QSM (SS)	95	MATIARI	1	unstable (continuous)
19	93	PRT QSM (SS)	93	PRT QSM (SS)	95	MATIARI	2	unstable (continuous)
20	93	PRT QSM (SS)	93	PRT QSM (SS)	930	LUCKY-CFPP	1	unstable (continuous)
21	93	PRT QSM (SS)	93	PRT QSM (SS)	931	SIDQSNS-CFPP	1	unstable (continuous)



No.	Fault bus no.	To bus name	From bus no.	From bus name	To bus no.	To bus name	Id	Results (stable/unstable)
22	32	LAHORE-S	32	LAHORE-S	36	SAHIWAL-PP	1	stable

Figure 6-8 Typical Generator Angle Oscillation in Three of Examples of Power System Stability Analysis

Figure 6-9 Transmission Lines and Faulting Points Causing Instability after Occurrence of Single Circuit Faults

(f) Issues

It can be found out that the locations of the faulting points causing instability were concentrated near the converter/inverter stations installed at north and south. If a fault occurs at those transmission lines, the direct current transmission lines are temporarily stopped at the converter/inverter stations. The operation of the direct current transmission lines are restarted immediately 100ms after the fault occurrence, however, it takes around 150 ms for the power flow to recover from the insufficient value. Thus, the system cannot be maintained its stability.

The following graph shows those kinds of situations.

This example has a fault point at JAMSHORO 500.0 (80) and tripped transmission line DADU 500.0 (70)－JAMSHORO 500.0 (80).

Figure 6-10 illustrates the active power flow passing through the direct current transmission lines and the change in the active power flow when this direct current transmission line is replaced by 765 kV alternative current transmission line.

A fault continues during 0.1sec and 0.2sec. 0.2sec after the fault clearance, the power flow at alternative current transmission line is recovered in the stepping manner, however, the direct current transmission line is slowly recovered taking around 0.15 sec.

Consequently, when the direct current transmission lines are applied, the difference of the recovering speed causes the unstable cases of divergent generator angle oscillation as shown in the Figure 6-11.

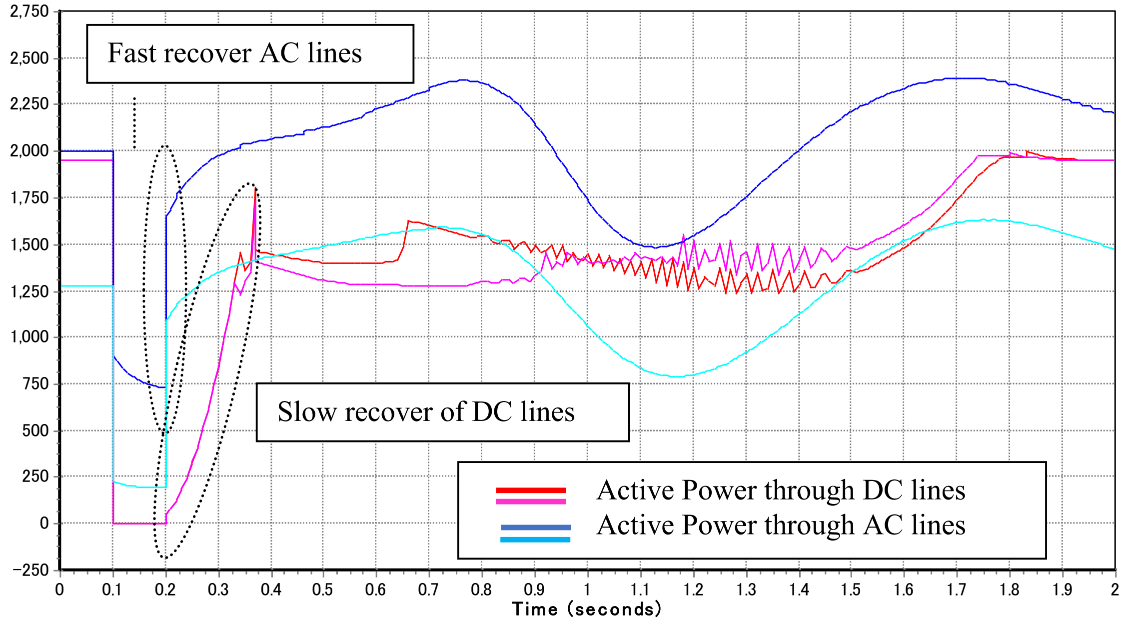


Figure 6-10 Change in Active Powers Flow of DC and AC Transmission Lines before and after Occurrence of Faults

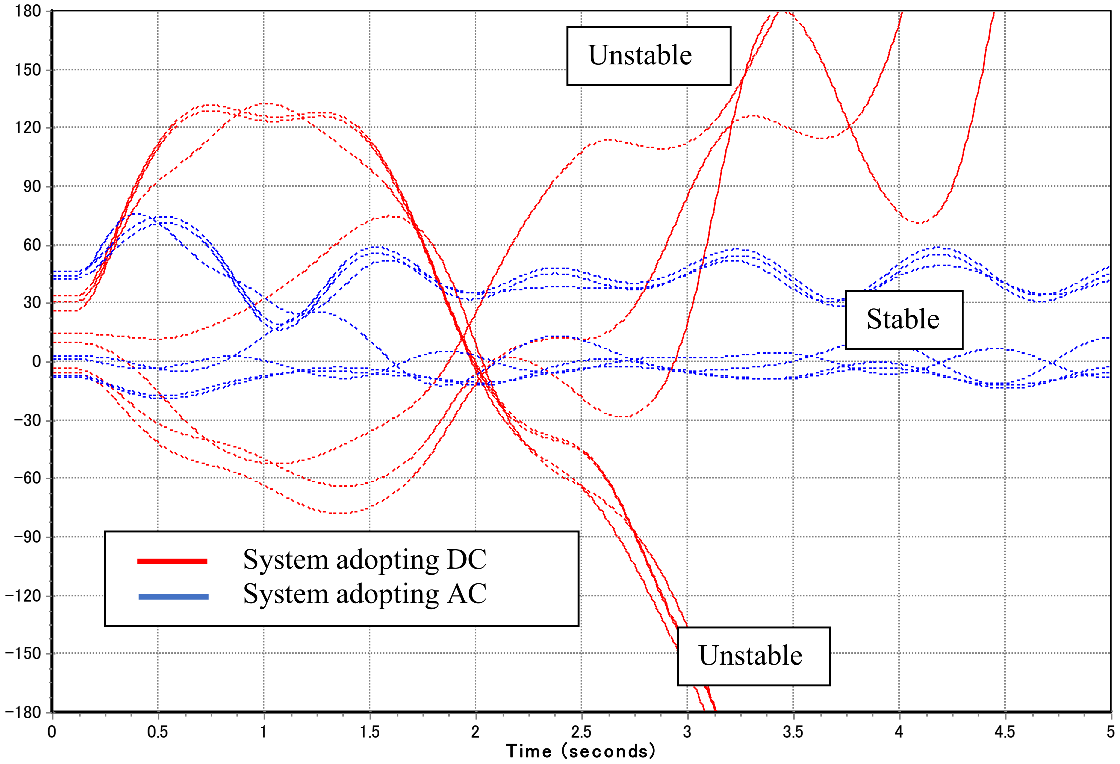


Figure 6-11 Generator Angles of Seven Representative Generators in Case of Application of Direct Current and Alternative Current Transmission Lines

(2) Study of the options of the countermeasures for the current plan by NTDC for 2021-22

(a) Option of double route of alternative current (Alternative 1)

1) System Configuration

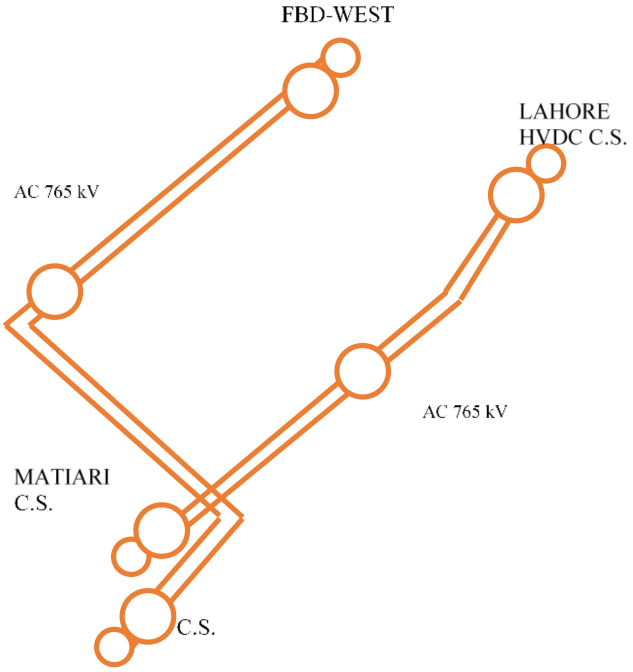


Figure 6-12 System Configuration by Replacement of Double Routes of DC Transmission Lines by AC Transmission Lines (765 kV)

2) System stability in summer 2021

Table 6-9 outlines the results of the system stability calculation assuming a single circuit fault (N-1) of the transmission lines above 500kV. Table 6-10 shows their details. Figure 6-13 illustrates the unstable cases on system configuration map.

Table 6-9 Outline of Results of System Stability Calculation in case of A Single Circuit Fault adopting Double Routes of AC Transmission Lines

Number of the cases of the single circuit fault of 500kV alternative current transmission lines	184
Number of stable cases	182
Number of unstable cases	2
Number of cases of divergent oscillation among those	0
Number of cases of continuous oscillation among those	2

Number of the cases of the single circuit fault of 765 kV alternative current transmission lines	48
Number of stable cases	36
Number of unstable cases	12
Number of cases of divergent oscillation among those	12
Number of cases of continuous oscillation among those	0

Table 6-10 Details of Unstable Cases of Single Circuit Faults adopting Double Routes of AC Transmission Lines

No.	Fault bus no.	From bus name	From bus no.	From bus name	To bus no.	To bus name	Id	Results (stable/unstable)
1	80	JAMSHORO	80	JAMSHORO	95	MATIARI	1	unstable (continuous)
2	95	MATIARI	80	JAMSHORO	95	MATIARI	1	unstable (continuous)
3	713	765	712	765	713	765	1	unstable (diverged)
4	713	765	713	765	715	765	1	unstable (diverged)
5	714	765	712	765	714	765	1	unstable (diverged)
6	714	765	714	765	716	765	1	unstable (diverged)
7	720	765	718	765	720	765	1	unstable (diverged)
8	720	765	720	765	722	765	1	unstable (diverged)
9	721	765	719	765	721	765	1	unstable (diverged)
10	721	765	721	765	722	765	1	unstable (diverged)
11	731	765	729	765	731	765	1	unstable (diverged)
12	731	765	731	765	733	765	1	unstable (diverged)
13	732	765	730	765	732	765	1	unstable (diverged)
14	732	765	732	765	733	765	1	unstable (diverged)

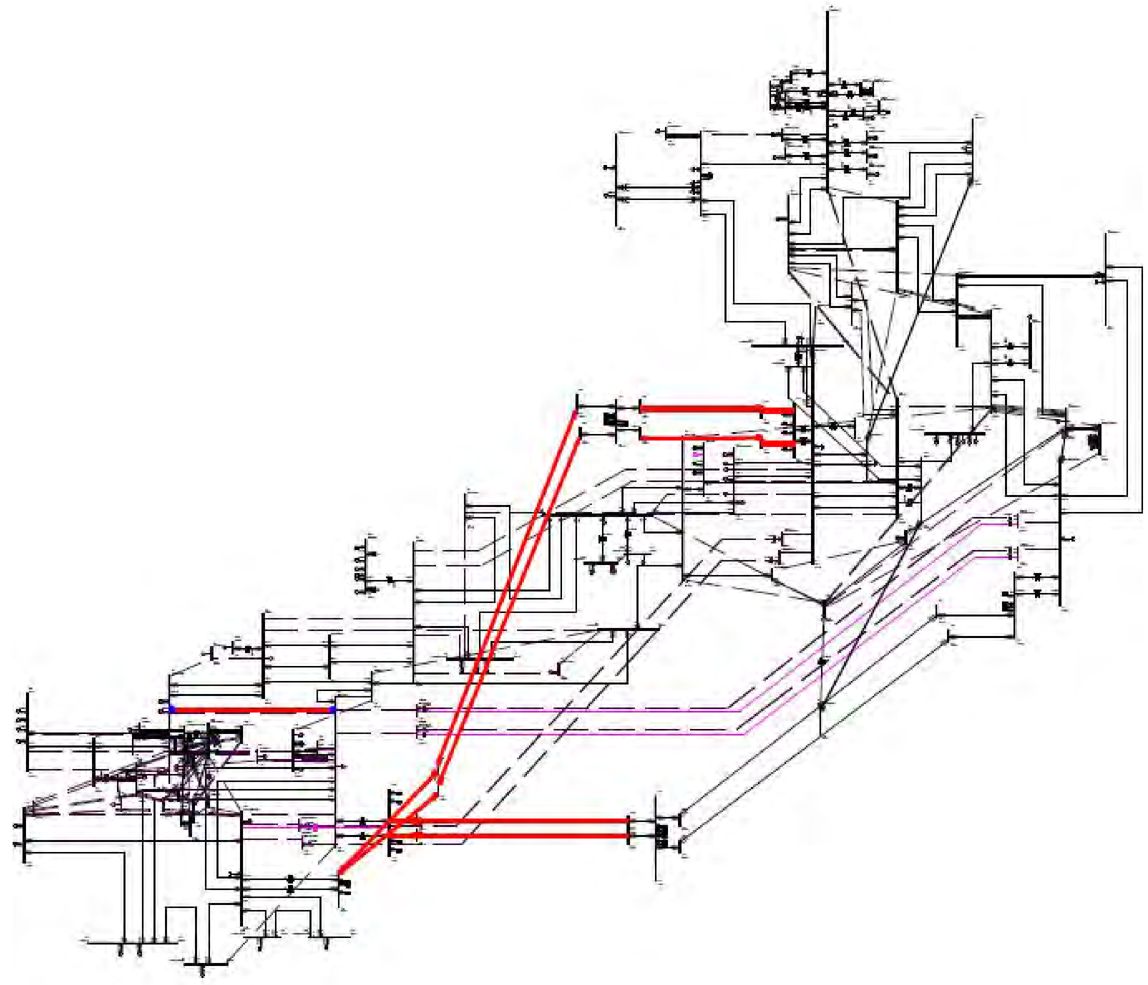


Figure 6-13 Transmission Lines and Faulting Points Causing Instability in case of A Single Circuit Fault

3) Issues

The positions of the fault points causing instability were at the 765kV system and the system could not be maintained stable.

For faults at 500kV system, all the cases were stable except for a fault at a transmission line that caused continuous oscillation.

(b) Triple routes of direct current transmission lines (Alternative 2)

1) System configuration

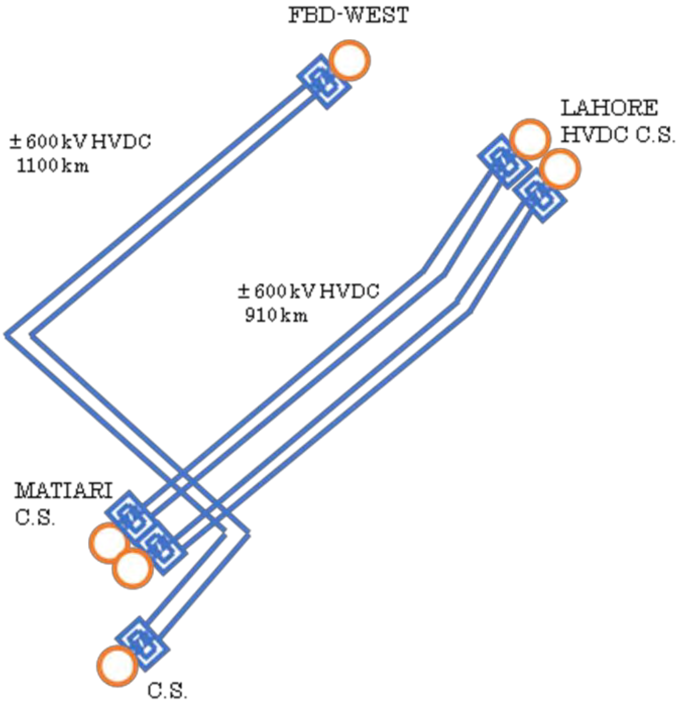


Figure 6-14 System Configuration of Triple Routes of DC Transmission Lines

2) System stability in the summer 2021

Table 6-11 outlines the results of the system stability calculation assuming a single circuit fault (N-1) of the transmission lines above 500kV.

Owing to increase in the number of circuits, the triple routes of the direct current transmission lines could avoid the instability caused by the contingencies of south converter stations that could not be avoided in case of the double routes although the recovering time of power flow was still slow after fault clearance.

Table 6-11 Outline of Results of System Stability Calculation in case of A Single Circuit Fault adopting Triple Routes of DC Transmission Lines

Number of the cases of the single circuit fault of 500kV alternative current transmission lines	184
Number of stable cases	184
Number of unstable cases	0

Number of cases of the single pole fault of ±600kV direct current transmission lines	12
Number of stable cases	12
Number of cases of continuous oscillation among those	0

3) Issues

There no issues because all the cases could be stable.

(c) Triple routes of alternative current transmission lines (Alternative 3)

1) System configuration

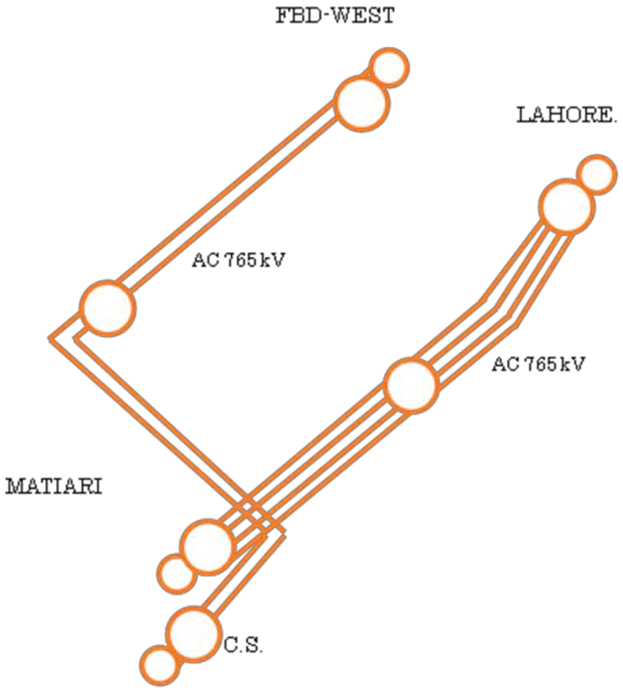


Figure 6-15 System Configuration of Triple Routes of Alternative Current Transmission Lines

2) System stability in the summer 2021

Table 6-12 outlines the results of the system stability calculation assuming a single circuit fault (N-1) of the transmission lines above 500 kV.

Table 6-12 Outline of Results of System Stability Calculation in case of A Single Circuit Fault adopting Triple Routes of AC Transmission Lines

Number of the cases of the single circuit fault of 500kV alternative current transmission lines	184
Number of stable cases	182
Number of unstable cases	2
Number of cases of divergent oscillation among those	0
Number of cases of continuous oscillation among those	2

Number of the cases of the single circuit fault of 765 kV alternative current transmission lines	72
Number of stable cases	36
Number of unstable cases	16
Number of cases of divergent oscillation among those	16
Number of cases of continuous oscillation among those	0

Table 6-13 Details of Unstable Cases of Single Circuit Faults adopting Triple Routes of AC Transmission Lines

No.	Fault bus no.	From bus name	From bus no.	From bus name	To bus no.	To bus name	Id	Results (stable/unstable)
1	80	JAMSHORO	80	JAMSHORO	95	MATIARI	1	unstable (continuous)
2	95	MATIARI	80	JAMSHORO	95	MATIARI	1	unstable (continuous)
3	713	765	712	765	713	765	1	unstable (diverged)
4	713	765	713	765	715	765	1	unstable (diverged)
5	714	765	712	765	714	765	1	unstable (diverged)
6	714	765	714	765	716	765	1	unstable (diverged)
7	720	765	718	765	720	765	1	unstable (diverged)
8	720	765	720	765	722	765	1	unstable (diverged)
9	721	765	719	765	721	765	1	unstable (diverged)
10	721	765	721	765	722	765	1	unstable (diverged)
11	731	765	729	765	731	765	1	unstable (diverged)
12	731	765	731	765	733	765	1	unstable (diverged)
13	731	765	729	765	731	765	2	unstable (diverged)
14	731	765	731	765	733	765	2	unstable (diverged)
15	732	765	730	765	732	765	1	unstable (diverged)
16	732	765	732	765	733	765	1	unstable (diverged)
17	732	765	730	765	732	765	2	unstable (diverged)
18	732	765	732	765	733	765	2	unstable (diverged)

3) Issues

The positions of the fault points causing instability were at the 765kV system same as the case of double routes and the system could not be maintained stable.

For faults at 500kV system, all the cases were stable except for a fault at a transmission line that caused continuous oscillation.

(3) Summary of the results of the present study and its future study items

(a) Results of the present study

1) Summary of the results of power stability analysis

① NTDC current plan in 2021-22
Double routes of DC transmission lines: There were some unstable cases
② Double routes of AC transmission lines: There were some unstable cases
③ Triple routes of DC transmission lines: There were no unstable cases
④ Triple routes of AC transmission lines: There were some unstable cases

2) Findings from the results of the analysis

⑤ It was found out that the option of the double circuit direct current transmission lines had issues about system stability. The reason is that the recovering time is slow from the contingencies of converter/inverter stations after the fault occurrence in their neighboring 500 kV system due to their characteristics that causes the temporarily stop of converter/inverters. It was also found out that there are no issues about voltage, overloading and sub-synchronous resonance.

⑥ From the results of the study of the alternatives, it was found out that double routes of direct current transmission lines and double routes of alternative current transmission lines both could not maintain system stability, however, triple routes of direct current transmission lines had no stability problems.

(b) Future examination matters

Based on the results of abovementioned study, the following matters will be examined.

① As further studies regarding triple routes of direct current transmission lines or mixing of alternative and direct current transmission lines, their merit and demerit will be compared and further studied from the viewpoints of power system operation.
② Based on the abovementioned results, the costs of the cases without any problems will be estimated.
③ The suitable power system configuration will be recommended based on the results of the merit-demerit analysis of system operation and their cost estimation.

6.5 500kV Power System Development Plan until 2035

A bulk power network system plans (grid maps) are made for year 2025 and 2030 respectively based on the power generation plan. The amounts of the required costs for expanding the bulk power grid are estimated based on the resultant grid maps as explained later. The bulk power network system plans are made for 500kV transmission lines and substations. Total amounts of their costs are estimated including the expansion of the grid above 220kV levels.

The detailed study of the individual elements of the plan is not carried out here because a main purpose of the grid study in this report is just to carry out the rough estimate of the total cost for the power grids expansion.

6.5.1 Number of Required 500kV Substations

The number of required future 500kV substations is roughly estimated base on the demand forecast that is already prepared. Firstly, the amount of the power demand supplied from a 500kV substation is estimated.

Table 6-14 shows the capacities of 500/220 kV transformers confirmed through the bulk power network system plan for 2021-2022 obtained from NTDC. Their averaged capacity is 1,324 MVA.

In consideration with this figure and the scale economy, the amount of the power demand covered by a 500 kV substation can be assumed 1,500 MW.

Table 6-14 500/275kV Transformer Capacity [MVA]

From Bus Number	From Bus Name	To Bus Number	To Bus Name	Capacity
10	PESHAWAR 500.00	100	PESHAWAR 220.00	1350
11	PESHAWAR-2 500.00	151	PESHWR-2 220.00	1500
20	TARBELA 500.00	200	TARBELA 220.00	1350
21	ISBD-W 500.00	212	ISBD-W 220.00	1500
22	REWAT-N 500.00	220	REWAT-N 220.00	900
22	REWAT-N 500.00	223	REWAT-2 220.00	750
23	CHAKWAL-N 500.00	2336	CHAKWAL-NEW 132.00	750
24	GUJRNWLA 500.00	245	GUJRNWLA 220.00	1800
25	G.BROTHA 500.00	205	G.BROTHA 220.00	1200
28	LAHORE-N 500.00	260	LAHORE-N 220.00	2250
30	LAHORE 500.00	300	LAHORE 220.00	1500
30	LAHORE 500.00	300	LAHORE 220.00	1500
32	LAHORE-S 500.00	303	LAHORE-S 220.00	2250
35	SAHIWAL 500.00	350	YOSAFWAL 220.00	1800
36	SAHIWAL-PP 500.00	361	SAHIWAL U-2 22.000	810
36	SAHIWAL-PP 500.00	362	SAHIWAL U-1 22.000	810
37	LUDEWALA 500.00	360	LUDEWALA 220.00	1200
38	VEHARI500 500.00	460	VEHARI 220.00	1500
40	GATTI 500.00	400	GATTI 220.00	1800
41	FBD-WEST 500.00	444	FBD-W 220.00	2250
50	MULTAN 500.00	500	MULTAN 220.00	1350
53	M.GARH 500.00	528	M.GARH-2 220.00	600
53	M.GARH 500.00	530	M.GARH-1 220.00	600
54	D.G.KHAN 500.00	746	D.G.KHAN 220.00	1200
58	R.Y.KHAN 500.00	552	R-Y-KHAN 220.00	1200
60	GUDDU 500.00	600	GUDDU 220.00	1350
62	SHKPR500 500.00	620	SHKPR220 220.00	1200
70	DADU 500.00	700	DADU 220.00	900
80	JAMSHORO 500.00	800	JAMSHORO 220.00	1350
91	NKI 500.00	910	NKI-220 220.00	1200

Table 6-15 shows the total number of the required substations in 2025 and 2035 estimated from the aforementioned figure of 1,500 MVA and the power demand forecast.

33 and 54 of 500kV substations are required including the existing 500kV substations in 2025 and 2035 respectively.

Table 6-15 Number of Required Future 500kV Substations

	2025			2035		
	Peak Demand [MW]	Peak Demand / 1500	Rounded Up	Peak Demand [MW]	Peak Demand / 1500	Rounded Up
PESCO	5660	3.77	4	8942	5.96	6
TESCO	857	0.57	1	1439	0.96	1
IESCO	3934	2.62	3	6587	4.39	5
GEPCO	4276	2.85	3	7168	4.78	5
LESCO	9361	6.24	7	15718	10.48	11
FESCO	5554	3.70	4	9311	6.21	7
MEPCO	7350	4.90	5	12312	8.21	9
SEPCO	2378	1.59	2	3983	2.66	3
HESCO	2114	1.41	2	3542	2.36	3
QESCO	2748	1.83	2	4605	3.07	4
North	29642	19.76	22	49165	32.78	35
South	14590	9.73	11	24442	16.29	19
TOTAL	44232		33	73607		54

6.5.2 Making Grid Map 1

The 500kV grid map is made according to the following procedure.

(1) The existing transmission lines and substations are drawn up on the map

(2) The future substations are placed according to the required number of substations in consideration of the following points.

- (a) Using the number of the substations installed in each distribution company as shown in the above mentioned table.
- (b) Considering the plan of the transmission lines as shown in the below item (3).

(3) The required routes of the transmission lines in their plan are selected in consideration of the followings.

- (a) To transmit the power from the hydropower stations located in the north to the load centers.
- (b) To transmit the power from the thermal power stations located in the south to the load centers
- (c) To place the double circuit lines from the north to the south for further reinforcement of the existing grids
- (d) To expand the existing transmission lines to the north

(4) The number of the circuits of the transmission lines are set out in order to maintain their Surge Impedance Load (SIL) for each routes (refer to **Box-1**). The number of the circuits is assumed to be even numbers.

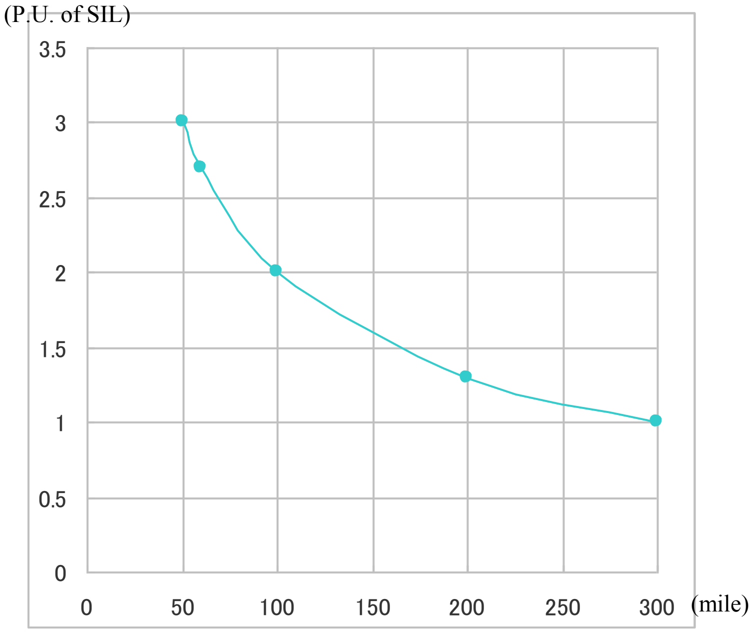
The following specifications are assumed as the main specifications of the future 500 kV transmission lines.

Table 6-16 Specification of 500kV Transmission lines

Type	Size [mm^2]	No. of Conductor	Current [A]	Line Capacity [MVA]
ACSR	469	4	800	2,700

<Box – 1> Relationship between Length of Transmission Line and its Allowable Power Flow

One of the indications of the allowable power flow of a transmission line is Surge Impedance Load (SIL), which indicates the level of power flow to balance the voltage drop caused by reactance of the transmission line and the voltage boost caused by its capacitance. SIL is varied by some factors such as voltage classes. The relationship between the length of a transmission line and its allowable power flow has been empirically obtained as a multiple of the SIL values and it is used as a guide for estimation of the allowable power flow. The following figure shows the relationship between the length of the transmission line and its allowable power flow.



(Source: Analytical Development of Load ability Characteristics for EHV and UHV Transmission Lines," R.D. Dunlop, R. Gutman and P.P. Marchenko, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979.)

The following specifications are assumed as the standard of 500kV substation.

Table 6-17 Specifications of 500kV Substation

500 / 220kV Trf.			No. of 500kV Line
Capacity of Bank [MVA]			
No.	Unit	Total	
4	450	1,800	8

The resultant grid maps based on the above mentioned procedures in 2025 and 2035 are as shown in Figure 6-16 and Figure 6-17, respectively.

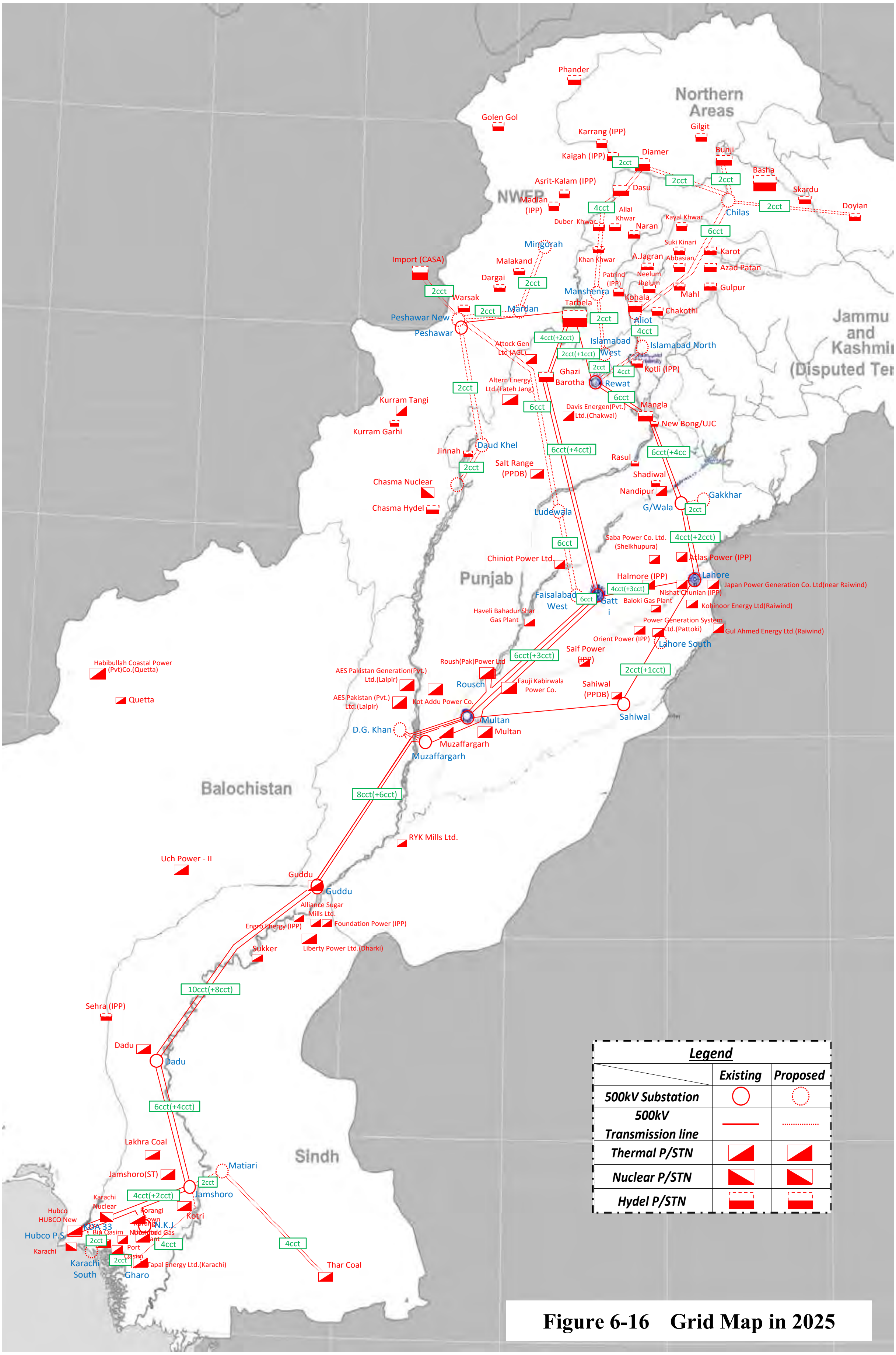


Figure 6-16 Grid Map in 2025

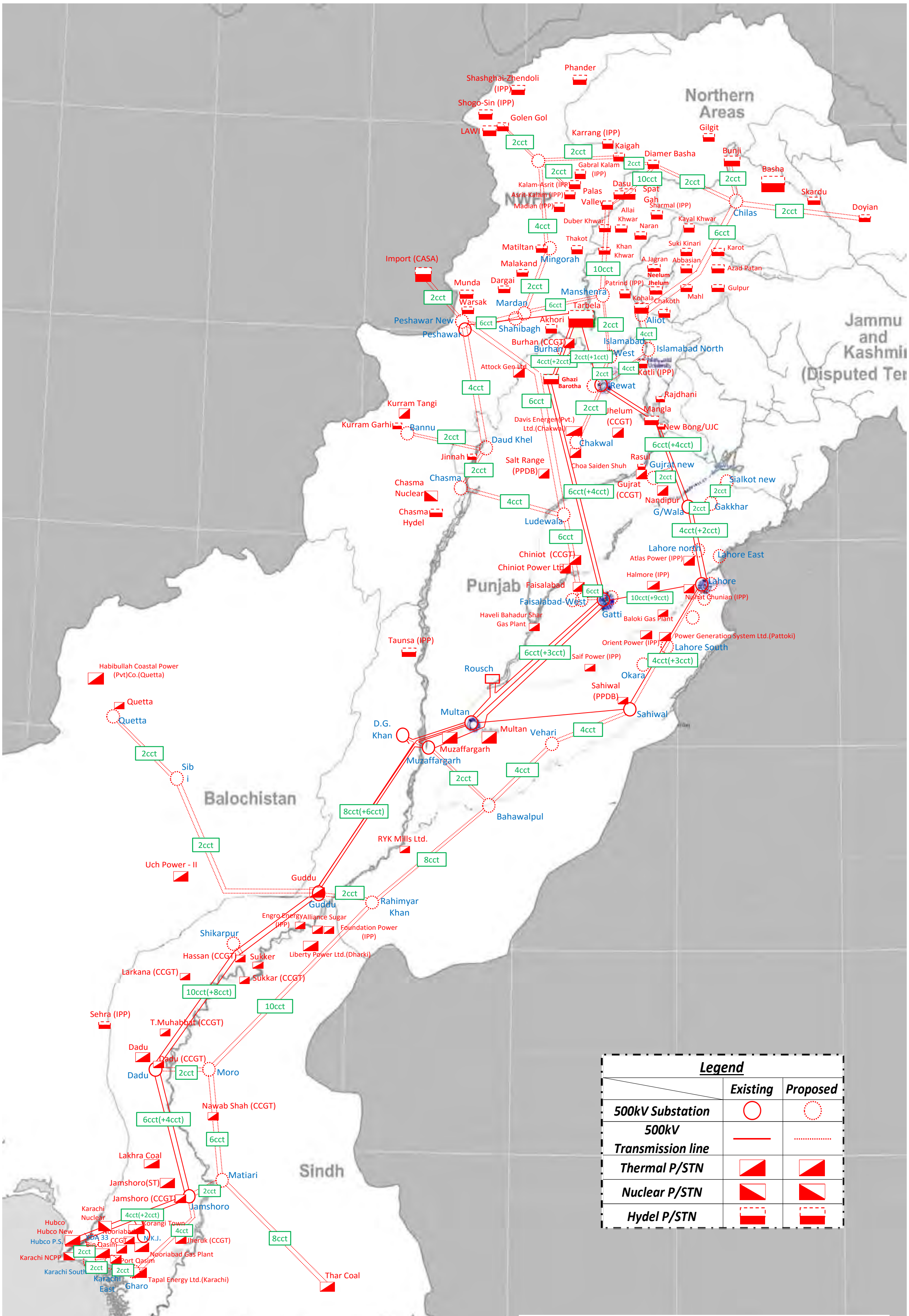


Figure 6-17 Grid Map in 2035

6.5.3 Alternative Grid Map 2 – Consideration of HVDC

The case of application of high voltage direct current transmission lines is considered as the alternatives of 500 kV grid maps in 2035.

The following points are taken into consideration for selection of the locations of High Voltage Direct Current transmission lines.

(1) To select their routes saving the number of the 500kV AC transmission lines
(2) To apply HVDC lines to the intervals requiring the constant large power flow through a year

In conclusion, their application is considered from the south area where the thermal power stations are located to the large power consumption area around Lahore.

The double routes of HVDC lines for the eastern side and a single route for the western side are assumed to be applied because the application of just double routes may cause the demerits of HVDC lines due to their delayed responses to the faults on the grid.

The locations of their three routes are determined at first and the remaining portions are studied following the same procedures of the grid mapping as above mentioned.

The grid map in 2035 considering the HVDC lines is as shown in Figure 6-18.

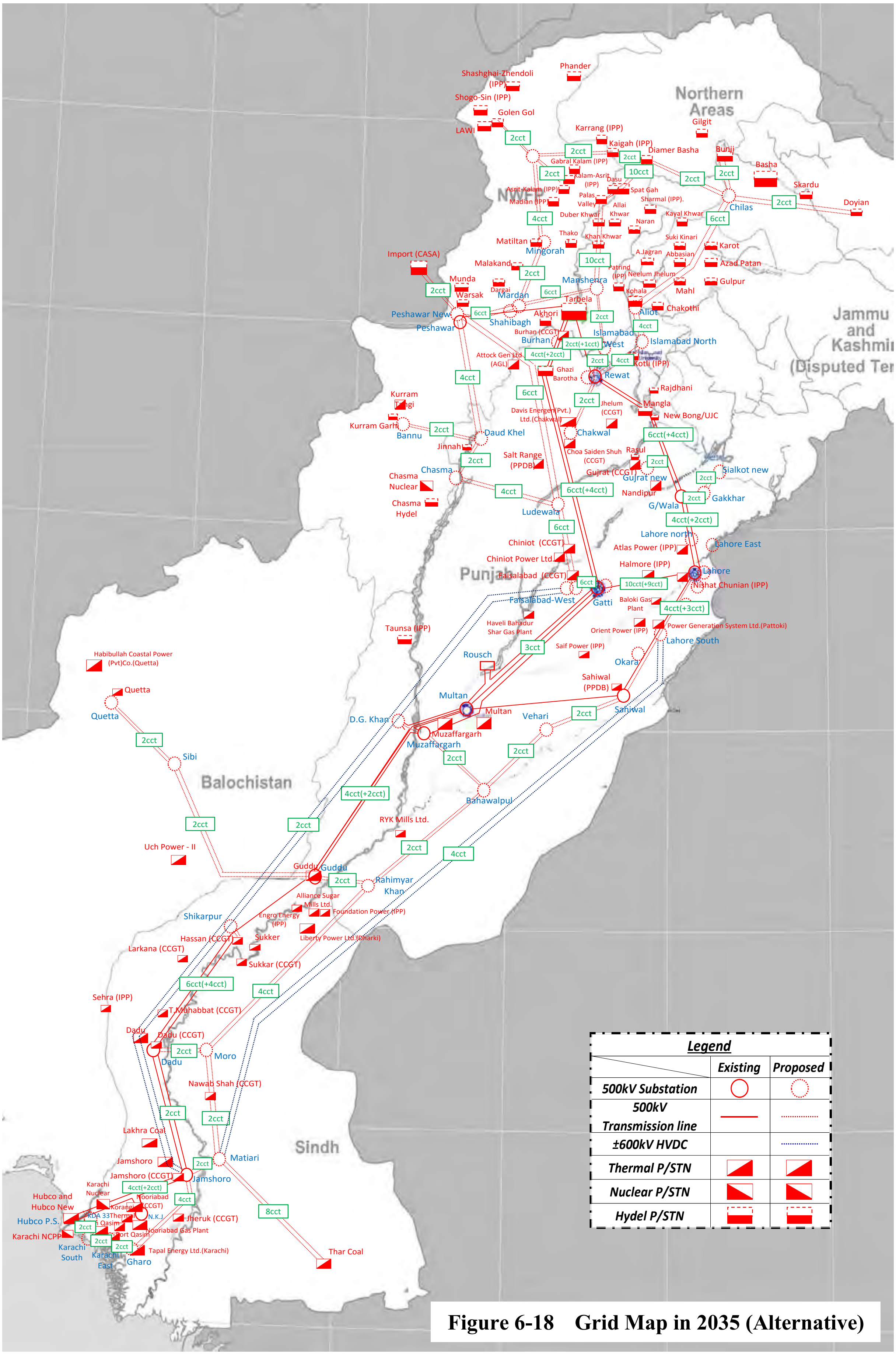


Figure 6-18 Grid Map in 2035 (Alternative)

6.6 Least Cost Plan of Power Network System

6.6.1 Amount of Costs for Installation of Required 500kV Power Network Facilities

The required amount of costs is estimated for the installation of 500kV power network facilities to achieve the abovementioned plan.

The total costs required for new 500kV system after 2015 are summarized as follows.

(1) By the year 2025

(a) 500kV substations
(33 – 18) x 40 mil. US$ = 600 mil. US$

(b) 500kV AC transmission lines
9,755 km - 2cct x 0.6 mil. US$/km / 2cct = 5,853 mil. US$

(c) Total
6,453 mil. US$

(2) By the year 2035

(a) 500kV substations
(54 – 18) x 40 mil. US$ = 1,440 mil. US$

(b) 500kV AC transmission lines
17,695 km - 2cct x 0.6 mil. US$/km / 2cct = 10,617 mil. US$

(c) Total
12,057 mil. US$

(3) By the year 2035 for alternative of application of DC lines

(a) 500kV substations
(54 – 18) x 40 mil. US$ = 1,440 mil. US$

(b) 500kV AC transmission lines
13,500 km - 2cct x 0.6 mil. US$/km / 2cct = 8,100 mil. US$

(c) 600kV High voltage direct current
3,470 km - 2cct x 0.42 mil. US$/km / 2cct = 1,457 mil. US$

(d) 600kV Converter Station, Grounding / Electrode Station (4,000MW)
3 route x 2 x (285+38) mil. US$ = 1,938 mil. US$

(e) Total
12,935 mil. US$ (its difference from the original plan is 878 mil. US$)

6.6.2 Rough Estimate of Amount of 230 kV Power Network Facilities by 2035

According to the data regarding the volumes of the existing system facilities, the length of 230 kV lines is approximately 1.6 times of 500 kV and the total capacity of 220 kV substations is approximately 3.4 times of 500 kV.

By applying those ratios, the amount of the total volume of 220 kV facilities by 2035 is calculated and the total cost for 220kV power grid by 2035 is estimated as follows.

(1) By the year 2025

(a) 220kV substations
201,960 MVA / 500MVA x 12 mil. US$ = 4,847 mil. US$

(b) 220kV AC transmission lines
15,608km - 2cct × 0.24 mil. US$/km / 2cct = 3,746 mil. US$

(c) Total
8,593 mil. US$

(2) By the year 2035

(d) 220kV substations
330,480 MVA / 500MVA x 12 mil. US$ = 7,932 mil. US$

(e) 220kV AC transmission lines
28,312km - 2cct x 0.24 mil US$/km / 2cct = 6,795 mil. US$

(f) Total
14,726 mil. US$

6.7 Required Future Tasks

The abovementioned results discusses only the rough estimation of the required volumes of the transmission lines and substations. The detailed specific plans of transmission lines and substations should be studied based on the detailed power flow and power system stability analysis through the precise identifications of the locations of the power stations and substations.

Chapter 7 Financial Analysis

7.1 Electricity Tariff Reform

7.1.1 Background for Electricity Tariff Reform

Circular debt issue can be pointed out as an important background behind Pakistan Government's efforts for Electricity tariff reform. Circular debt means the situation that power distribution companies financially owe to a power transmission company due to insufficient cash income, the power transmission company financially owe to power generation companies, and the power generation companies financially owe to fuel supply companies. It was reported that the total amount of the circular debt in the energy sector was approximately 600 billion PKR as of May 2015[5]. The reasons for the circular debt are 1) Subsidies to fill the gap between retail tariff and a fair price are not paid timely, 2) Non-payment is increasing in both the private sector and the public sector, and 3) Distribution loss is very high.

(1) Retail Tariff below Appropriate Price

As aforementioned in "2.5 Electricity Tariff System", NEPRA sets tariffs for generation, transmission, and distribution (NEPRA Determined Tariff). Although details of tariff setting differ among the subsectors, tariff setting mechanism is based on the fully-distributed cost (FDC) method in principal[6]. NEPRA Determined Tariff differs among DISCOs because each company has unidentical operational conditions. NEPRA Determined Tariff does not allow the recovery of some cost items required for operation (such as uncollected fuel adjustment, interest for late payments, and uncollected general sales tax) [7] and has some rooms for further improvement. Nevertheless, the FDC method itself is a standard procedure for tariff setting in the power sector.

It is considered a major issue of retail tariff that NEPRA Determined Tariff is not applied to an actual retail tariff. Apart from NEPRA Determined Tariff, the Pakistan government approves retail tariff for each DISCO and the lowest tariff among the NEPRA Determined Tariffs for DISCOs is used as a proxy for the whole country. As this single tariff is lower than NEPRA Determined Tariff, it does not allow DISCOs to operate stably. Accordingly, the Pakistan government provides DISCOs with a Tariff Differential Subsidy (TDS), a price difference between NEPRA Determined Tariff and GOP Notified Tariff for the most efficient DISCO. Available GOP notified tariff and NEPRA determined tariff of 3 DISCOs (Residential under 5kW) in 2014-15 is shown Table 7-1. The Ministry of Finance reimburses TDS to DISCOs via the government agency Central Power Purchase Agency Guarantee Limited (CPPAGL).

Table 7-1 GOP Notified Tariff and NEPRA Determined Tariff (Residential under 5kW)

(Unit:PKR/kWh)

	GOP Nortified Tariff	GEPCO NEPRA Determinded Tariff	PESCO NEPRA Determinded Tariff	QUESCO NEPRA Determinded Tariff
Up to 50kWh	2.00	4.00	4.00	4.00
51 to 150kWh	5.79	11.82	12.50	12.50
151 to 250kWh	8.11	14.00	16.50	15.00
251 to 350kWh	10.20	14.00	16.50	15.00
351 to 700kWh	16.00	17.00	17.90	17.00
700kWh-	18.00	19.00	19.00	19.00

(Source : NEPRA)

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[5] An article dated in May 13,2015, Dawn, "Govt, IMF agree plan to end Rs600bn circular debt"

[6] Planning Commission (2013),"The Causes and Impacts of Power Sector Circular Debt"

[7] Planning Commission (2013), "Energy Sector Crisis & Reforms Way Forward by Shahid Shattar"

TDS was rarely reimbursed on time within the fiscal year in which payment requests are made and, as a result, CPPAGL owed debts to DISCOs. At the end of June 2014, TDS for the power sector was estimated to be 512.9 billion PKR[8]. TDS deceased in the certain year due to a one-time payment made by the central government. Nevertheless, the accumulated amount of unpaid TDS increased in general as a newly-claimed amount usually surpassed a paid amount (refer to Table 7-2). As of April 2014, the Ministry of Finance demanded auditing for the claims of TDS in 2008, 2009, 2010, and 2011, and planned to settle the reimbursement of TDS in 2012 and 2013 with non-cash payment[9].

Table 7-2 Net Increase / Decrease of Tariff Differential Subsidy

(Unit: billion PKR)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14
TDS for DISCOs	76.0	94.1	-92.5	56.7	88.4	23.1
TDS for KESC	8.0	1.6	-2.0	21.7	-6.7	20.7
Total	83.9	95.7	-94.4	78.4	81.7	43.8

Note: The amount for each fiscal year shows the net amount (newly claimed minus payment) for the corresponding year. The negative amount means a net reduction of TDS. The last fiscal year covers only six months until December 2013.

Source: ADB (2014) "Proposed Programmatic Approach and Policy-Based Loan for Subprogram 1, Islamic Republic of Pakistan: Sustainable Energy Reform Program "

(2) Non-payment of the Private Sector and the Public Sector

Non-payment of electricity tariff occurred in both the private sector and the public sector, and the accumulated amount of receivables was on the rise. While the accumulated amount of the public sector decreased temporarily, that of the private sector increased constantly. At the end of 2013, DISCOs' receivables from the private sector were 288.4 billion PKR, and that from the public sector was 192.3 billion PKR (refer to Table 7-3).

Table 7-3 DISCOs' Receivables

(Unit: billion PKR)

	6/2008	6/2009	6/2010	6/2011	6/2012	6/2013	12/2013
Private sector	58.0	77.8	103.4	142.7	197.3	260.1	288.4
Public Sector	140.8	150.7	100.7	143.1	188.3	150.9	192.3
Total	198.8	228.6	204.2	285.8	385.6	411.0	480.7

Note: The amount for each physical year shows an accumulated amount at the year-end of the corresponding year and at the end of the first half for the last fiscal year.

Source ADB (2014) "Proposed Programmatic Approach and Policy-Based Loan for Subprogram 1, Islamic Republic of Pakistan: Sustainable Energy Reform Program "

Note: DISCOs' receivables from the public sector include that from KESC which is partially owned by the Pakistan government.

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[8] An article dated April 5,2015, Business Recorder, "Tariff Differential Subsidy: Ministry seeks Rs 20 billion to clear PSO's, IPPs' dues"

[9] ADB (2014) "Proposed Programmatic Approach and Policy-Based Loan for Subprogram 1, Islamic Republic of Pakistan: Sustainable Energy Reform Program "

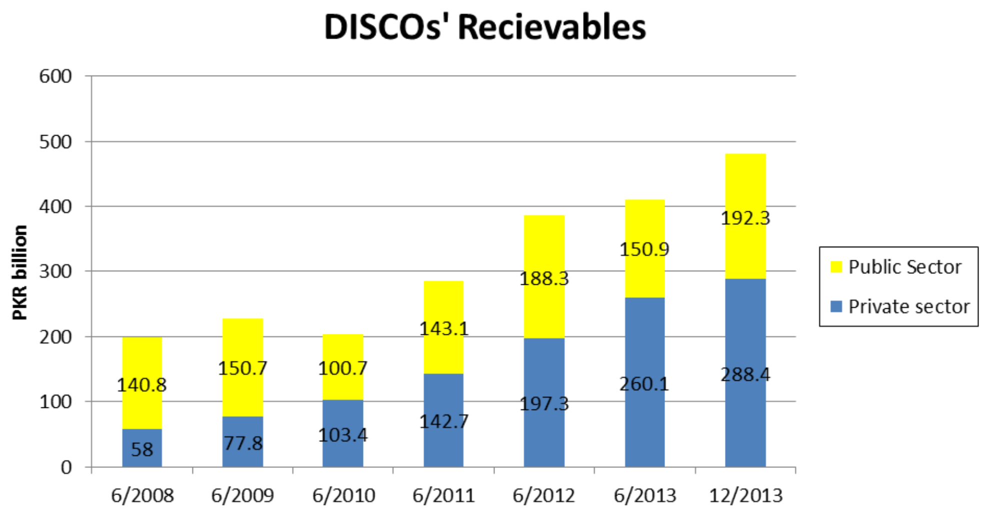

Figure 7-1 DISCOs' Receivables

The collection rate (collected amount / billed amount) is approximately 90% for the whole DISCOs. As a notable point, the rate differs significantly among DISCOs. In 2013-14, DOSCOs can be categorized for three groups: those with collection rate at above 90% (LESCO, GEPCO, FESCO, IESCO, and MEPCO), those at 70-80% (PESCO and HESCO) and those below 60% (TESCO, SEPCO, and QESCO) (refer to Table 7-4). The collection rate is low in Balochistan province (an area covered by QESCO), Hyderabad (an area covered by SEPCO), and Federally Administered Tribal Areas (an area covered by TESCO).

Table 7-4 Billed Amount and Collected Amount of Electricity by DISCOs

(Unit: million PKR)

DISCO	2012-13			2013-14		
	(A) Billed	(B) Collected	(B)/(A)	(A) Billed	(B) Collected	(B)/(A)
LESCO	163,868	160,340	98%	226,044	221,239	98%
GEPCO	63,705	62,588	98%	86,026	82,708	96%
FESCO	95,606	94,711	99%	124,665	124,729	100%
IESCO	84,123	79,445	94%	110,070	99,519	90%
MEPCO	107,932	99,035	92%	138,621	133,127	96%
PESCO	71,749	60,700	85%	82,921	71,537	86%
TESCO	15,025	17,498	116%	15,740	1,264	8%
HESCO	33,944	27,560	81%	40,199	31,829	79%
SEPCO	33,024	17,708	54%	33,933	19,875	59%
QESCO	36,007	11,461	32%	44,962	18,968	42%
Total	704,983	631,046	90%	903,181	804,795	89%

Source: NTDC "Power System Statistics 2013-2014"

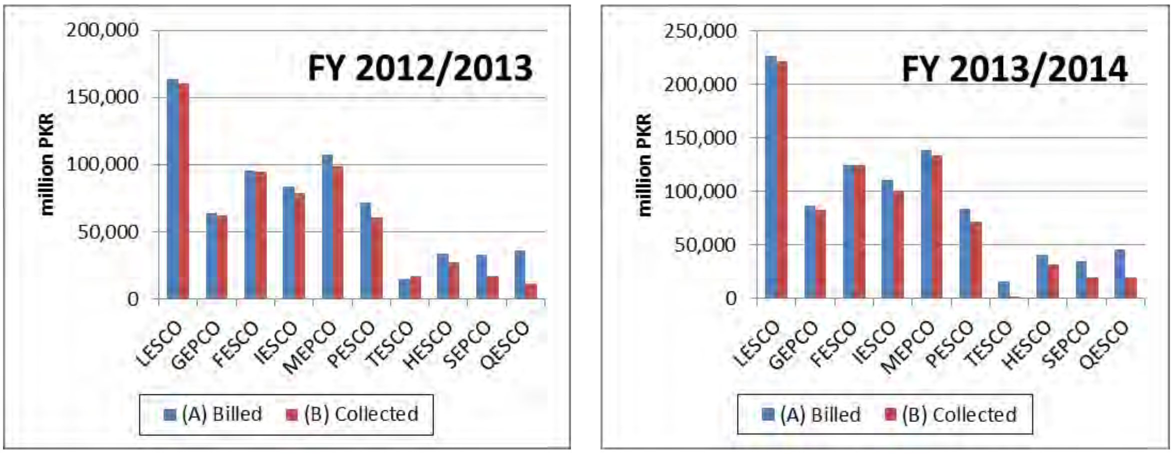

Figure 7-2 Billed Amount and Collected Amount (2012/13 and 2013/14)

(3) High level of Distribution Loss

As a factor negatively affecting DISCOs' abilities to serve debts, it can be pointed out that distribution loss has stayed at a high level. Out of the total electricity supplied to the distribution subsector, a fifth was lost due to distribution loss. The loss became a financial burden for DISCOs. The aging of facilities, theft, and malfunction/tampering of power meters caused the distribution loss.

Table 7-5 Distribution Loss

	2005	2010	2011	2012	2013	2014
Distribution Loss	16.5%	18.4%	18.4%	18.2%	17.6%	17.5%

(Source: NTDC "Power System Statistics 2013-2014")

7.1.2 Tariff Setting Mechanism

(1) Budgeting and Financial Results

As basic data for tariff setting, NTDC and DISCOs submit the investment plans, the power purchasing plans, data on transmission and distribution loss to NEPRA until September 1st every year. NEPRA assesses the plans and set the targets for transmission and distribution loss by the end of November. By using the approved plans and targets, DISCOs submit a petition for tariff revision by the end of January in the next year (refer to the next section for revision process). NTDC and GENCO submit petitions for tariff revisions every few years and often apply for tariff adjustments on certain items in consideration of changes in inflation rate and fuel costs. State-own companies in the public sector make budgets every year based on the approved various plans and the next year tariff predicted.

Fiscal year of electric utility companies is from July 1 to June 30 same as that of the Pakistan government. External audit is carried out after end of fiscal year. Since it takes a long period to complete external audit, financial statements are often confirmed two fiscal years later. Audit firms conduct external audits on financial statements and assess whether financial information complies with the accounting standards and requirements set by the Corporate Ordinance in 1984. Unlike those in the United State and Japan, auditor opinion does not explicitly referrers effectiveness of internal control and audit result does not assure effectiveness of internal control.

(2) NEPRA Determined Tariff

An electric utility company files a tariff petition at NEPRA and NEPRA assesses the petition. After a public hearing, NEPRA Determined Tariff is decided. The electric utility company can request for recalculation of tariff, and the government is also allowed to request NEPRA to reassess its decision. To promote efficient promotion and keep electricity tariff at appropriate level, NEPRA assesses O&M

Cost, fuel costs, and transmission and distribution loss. After this assessment, the costs that NEPRA allowed the utility company to charge customers were below actual costs in many cases. NEPRA Determined Tariff is based on the FDC method and allows the utility company to recover investment cost, O&M cost, and fuel costs. Tariff setting methods by subsector are shown in Table 7-6.

In the generation and transmission subsectors, the cost contains interest payment and deprecation. In the actual tariff setting, principal payment of debt was covered instead of depreciation or deprecation is balanced with principal payment. In the distribution subsector, distribution cost includes depreciation and the return on regulated assets (approximately 80-90% of the net asset of balance sheet) is set at 17%. The tariff setting mechanism allows utility companies to pay interest and principal of their debts.

As aforementioned, the FDC does not cover a full amount of O&M cost and, thus, fuel costs and distribution loss beyond the standards set by NEPRA cannot be recovered. The investment return is included in the costs for all subsectors. Nevertheless, some factors such as an unrecovered portion of O&M cost, circular debt, and payment of existing debt disenabled allocating capital to reinvestment in fixed assets. These factors resulted in the aging of generation facilities, which plants mentioned in “2.4.4 Existing Generation Facilities”, and high distribution loss aforementioned in the previous section.

Table 7-6 Tariff Setting Methods by Subsector

Subsector	Tariff Setting Methods
Generation	・Capacity Charge Capacity Charge = (Interest Expenses＋Return on Equity＋Depreciation＋Fixed Operating Expenses) ÷ Dependable Generating Capacity ・Energy Charge Energy Charge =(Fuel Cost＋Variable Operating Expenses) ÷ Total Units Generated
Transmission	・Use of System Charges Fixed Charge = (Interest Expenses＋Return on Equity＋Depreciation＋Fixed Operating Expenses)÷ Maximum Demand Variable Charge ＝Variable Operating Expenses ÷ Total Units Transmitted ・Transfer Prices to DISCOs Capacity Transfer Charge = Sum of Net Capacity Charge of all GENCOs× (Maximum Demand of relevant DISCO ÷ Maximum Demand of all DISCOs Energy Transfer Price= Sum of Energy Charge of all GENCOs×Transmitted Units to relevant DISCO ÷ Total Units Transmitted to all DISCOs
Distribution	・Revenue Requirement Revenue Requirement = Power Purchase Price＋Tax＋Distribution Margin* *Distribution Margin includes Net Operating Costs, Depreciation, and Return on Rate Base ・Electricity tariff Electricity tariff per kWh = Revenue Requirement ÷ Units Sold (Distribution loss is adjusted)

(Source: Planning Commission (2013),”The Causes and Impacts of Power Sector Circular Debt”)

(3) Progress of the Electricity Tariff Reform

As mentioned above, NEPRA Determined Tariff is based on the FDC method and the framework of tariff setting is considered appropriate in general. Thus, the immediate goals of the electricity tariff reform are to reduce TDS borne by the government and to make actual tariff converged to NEPRA

Determined Tariff. In accordance with the agreement with IMF, the Pakistan government has the policy to reduce subsidies in the energy sector by following steps[10]:

Phase I: Almost full elimination of subsidies for indusial, commercial and bulk users and those in Azad, Jammu, and Kashmir.

Phase II: Elimination of subsidies for consumption over 200 kWh/month, Salinity Control and Reclamation Program, and others (public lighting, housing schemes, railways, and high voltage transmission line). Reduction of subsidies for agriculture by 13 percent

Phase III&IV: Reduction of subsidies for agriculture and consumption below 200 kWh/month. Elimination of subsidies for consumption over 200 kWh / month. The fiscal burden to be reduced to 0.3-0.4% of GDP in 2014-15 and 2015-16

In line with the above reform schedule, National Power Tariff and Subsidy Policy Guideline 2014, which was set by MWP, shows a policy to limit the provision of subsidies only to consumption below 200 kWh/month and the Guideline also directed NEPRA to develop a procedure to control subsidies in the case that the subsidies to DISCOs goes beyond its budget allocation. As of August 2015, four DISCOs (FESCO, GEPCO, IESCO, and LESCO) were planned to be privatized. In tandem with the privatization, a multiyear tariff will be introduced to these utility companies.

7.1.3 Sensitivity Analysis on Elimination of Circular Debt

The circular debt issue is due to a problem in the recovery of cash at the distribution subsector, an initial step of tariff revenue in the power sector. NEPRA Determined Tariff is based on appropriate costs for generation, transmission, and distribution. Proper collection of receivables would enable sufficient payment from the distribution subsector to other subsectors, and a large amount of circular debt would not occur.

In short, Full recovery of appropriately determined retail tariff and payment to the transmission and distribution sectors would prevent circular debt. The tariff reform, which the Pakistan government and IMF agreed upon, intends to eliminate the difference between actual retail tariff and NEPRA Determined Tariff and make TDS small enough to be paid timely.

Nevertheless, the tariff reform has not tackled better collection of receivables. In the case that the collection of receivables would not be improved sufficiently, it is an option to put surcharge on retail tariff and keep retail tariff above full cost recovery. Thus, an approach to eliminate circular debt can be a combination of (a) raising collection of receivables, and (b) imposing surcharge on retail price while keeping the tariff reform on truck.

With two variables, the non-payment rate of tariff (approximately 10% for 2012-13 and 2013-14) and a surcharge on electricity tariff, the sensitivity analysis estimates years that circular debt would be fully paid under various conditions. The assumptions for this analysis are following:

Size of Circular Debt: 600 billion PKR at the end of 2015

Demand Forecast: Based on the base case in “3.4 Power Demand Forecast”

Transmission and Distribution Loss: Based on the base case in “3.4 Power Demand Forecast”

TDS： The tariff reform progresses in accordance with the agreement with IMF. This makes TDS small enough to be paid timely.

If the non-payment rate stays at the current level (10%), a tariff hike by 0.5-1.0 Rs/kWh will not eliminate the circular debt until 2035. In the case that the non-payment rate was decreased to 5%, a tariff hike by 1.0 Rs/kWh will wipe out the circular debt fully by 2024. The circular debut will be paid completely by 2023 with a small increase of tariff by 0.5 Rs/kWh under the assumption of 100% payment of tariff. The Pakistan government made efforts to reduce the circular debt by an additional

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[10] IMF (2013) “IMF Country Report No.13/287 Pakistan”

allocation of budget. If the government takes a similar effort again, it will bring forward the timing of full payment of the circular debt.

Table 7-7 Results of Sensitivity Analysis

		Non-Payment Rate		
		10%	5%	0%
Surcharge*	PKR 2.0/kWh (+17.5%)	2020	2019	2018
	PKR 1.5/kWh (+13.1%)	2025	2020	2018
	PKR 1.0/kWh (+8.7%)	Not solved	2024	2020
	PKR 0.5/kWh (+4.4%)	Not solved	Not solved	2023

*Numbers in parenthesis are percentages over the average billing rates in FY2014/15.

Numbers in parenthesis are percentage over the average billing rates in 2014-15.

7.2 Funding Gap in the Power Sector

7.2.1 Base Demand Case

(1) Investment Requirement

For the computation of investment requirement, estimation of investment requirement for each of generation, transmission, and distribution is required. The following assumptions are made for the estimation of investment requirement by subsector.

Generation: Investment requirement is based on the investment amount from 2015 to 2035 for the Base Demand Case, which is shown in "5.5 Long-term Investment Plan".

Transmission: Investment requirement for 2015 - 2035 is based on "6.6 Least Cost Plan of Power Network System". During the period of 2015 - 2025, the ratio of annual investment requirement over the total amount of the plan period is in line with the same ratio in the generation subsector. Investment requirement is the same amount for each year in and after 2026.

Distribution: Investment requirement is estimated at 10% of the total investment during the whole plan period (2015 - 2035) but some modifications are made on investment timing for each region. In the North System, the investment amount in generation stays at a higher level during the period from 2015 to 2030. The equal amount is required to be invested in transmission during the same period, and 20% of the total investment requirement is needed annually for transmission after 2030. In the South System, 20% of the total investment requirement is needed annually from 2015 to 2020. The equal amount is to be invested every year during the period of 2020-2030 and after 2030 the investment requirement is 20% of the total again. The investment requirement for the KE system is based on the same assumptions for the South System.

Investment requirements for generation, transmission, and distribution are shown in the following table. The amount of investment requirement is 101.5 billion US$ from 2015 to 2025 and 165.7 billion US$ from 2015 to 2035.

Table 7-8 Investment Requirement (Base Demand Case)

(Unit : million US$)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Generation-North	3,409	4,531	4,870	4,289	4,337	4,034	4,135	4,245	4,247	4,489	4,432
Generation-South	616	1,777	3,459	4,329	3,610	2,222	1,158	783	942	1,334	1,511
Generation-KE	414	683	934	992	775	456	607	883	932	693	446
Generation-Subtotal	4,439	6,990	9,263	9,610	8,723	6,713	5,900	5,911	6,120	6,516	6,389
Transmission-Subtotal	872	1,374	1,820	1,888	1,714	1,319	1,159	1,161	1,203	1,280	1,255
Distribution-North	542	542	542	542	542	542	542	542	542	542	542
Distribution-South	173	272	361	374	340	261	240	240	240	240	240
Distribution-KE	58	92	122	126	115	88	81	81	81	81	81
Distribution-Subtotal	773	906	1,024	1,042	996	891	862	862	862	862	862
Total	6,084	9,270	12,108	12,541	11,433	8,923	7,921	7,934	8,185	8,659	8,506

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Generation-North	4,386	3,589	3,598	3,562	3,444	3,517	2,912	1,718	661	0
Generation-South	1,667	1,702	1,609	1,828	2,007	1,930	1,697	1,171	503	0
Generation-KE	606	657	563	494	440	476	520	380	150	0
Generation-Subtotal	6,659	5,949	5,770	5,884	5,890	5,922	5,129	3,269	1,314	0
Transmission-Subtotal	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	0
Distribution-North	542	542	542	542	542	488	435	309	177	0
Distribution-South	240	240	240	240	240	235	209	149	85	0
Distribution-KE	81	81	81	81	81	79	71	50	29	0
Distribution-Subtotal	862	862	862	862	862	803	715	508	291	0
Total	8,825	8,115	7,936	8,050	8,057	8,029	7,148	5,081	2,909	0

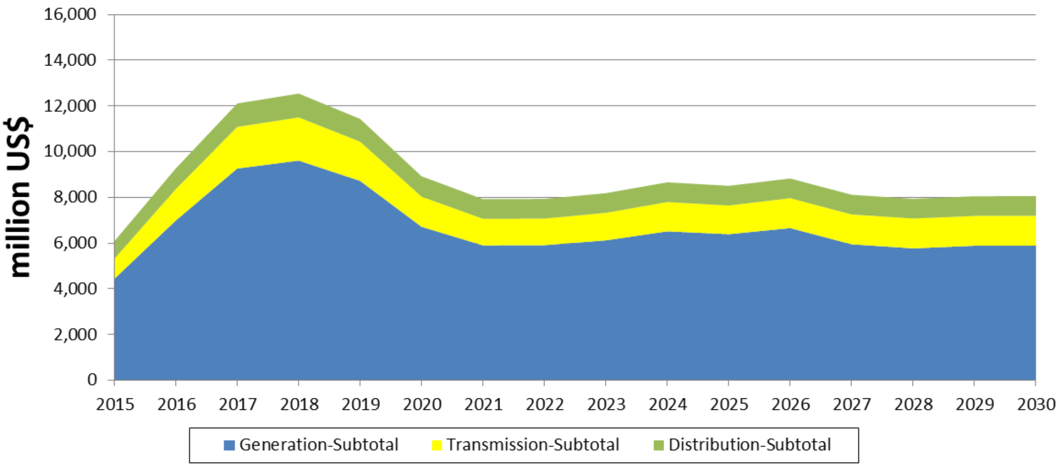


Figure 7-3 Investment Requirement by Category

(2) Available Fund

Funding gap can be estimated by subtracting available fund from the investment requirement calculated in the above section. The estimation of available fund by funding source is based in the following assumptions:

Internal Fund from DISCOs and GENCOs: NEPRA **Determined** Tariff allows utility GENCOs and DISCOs to pay principle and interest of their debt and to make profits from capital investment. The current tariff scheme enables reinvestment of cash flow from existing capital investment. In fact, however, a little fund is allocated for capital investment due to (a) circular debt and (b) costs unapproved by NEPRA. To be on the conservative side, electricity tariff is assumed to cover operational costs, principal and interest payments of debts but not to allow fund allocation for capital investment.

Internal Fund from WAPDA: In 2013-14, WAPDA had positive operating cash flow and the amount of capital expenditure was below that of operating cash flow. WAPDA spent 31,218 million PKR for capital expenditure in 2013-14. Capital expenditure is expected to grow at 5.8% annually in line with the electricity demand for Pakistan.

Internal Fund from NTDC: NTDC is also allowed to pay principle and interest of its debt and ensure profits under the current tariff scheme. NTDC spent 9,757 million PKR for capital expenditure in 2012-13. Capital expenditure is expected to grow at 5.8% annually in line with the electricity demand for Pakistan.

Internal Fund from KE: KE posted positive operating cash flow for 2014-15. The amount of capital investment was almost financed by operating cash flow. For the first nine months of 2014-15, capital expenditure was 15,093 million PKR. Capital expenditure is expected to grow at 5.8% annually in line with the electricity demand for Pakistan. The allocation of capital expenditure by subsector is assumed to be 70% for generation, 20% for transmission, and 10% for distribution.

Public Sector Development Program: Available fund for the first year of the plan period is estimated by subtracting donor assistance from the Public Sector Development Program (PSDP) for 2014-15 and 2015-16 and, as shown in the following table, the fund is expected to grow along with GDP growth (Base Demand Case: 5%). Since the long-term investment plan for generation assumes that investment will not be made in a nuclear power plant after 2021-22 and in a thermal power plant owned by GENCO after 2022-23, it is assumed that no budget is allocated for those areas after the aforementioned fiscal years. This unused amount is to be allocated for the power sector with the share of 70% for generation, 20% for transmission, and 10% for distribution.

Table 7-9 Public Sector Development Program (Base Demand Case)

(Unit : million PKR)

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Atomic Energy Commission	24,621	15,321	16,087	16,892	17,736	18,623	9,539	0	0	0	0
WAPDA	72,791	88,267	92,680	97,314	102,180	107,289	112,653	118,286	124,200	130,410	136,931
GENCOs	46,152	74,010	77,710	81,596	85,675	89,959	94,457	48,380	0	0	0
NTDC	51,719	49,247	51,710	54,295	57,010	59,860	62,853	65,996	69,296	72,760	76,398
DISCOs	28,327	25,330	26,597	27,927	29,323	30,789	32,328	33,945	35,642	37,424	39,295
Power Sector								71,331	125,697	131,982	138,581
Generation								49,932	87,988	92,388	97,007
Transmission								14,266	25,139	26,396	27,716
Distribution								7,133	12,570	13,198	13,858
Total	223,610	252,175	264,784	278,023	291,924	306,520	321,846	337,939	354,836	372,577	391,206

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Atomic Energy Commission	0	0	0	0	0	0	0	0	0	0
WAPDA	143,777	150,966	158,515	166,440	174,762	183,500	192,675	202,309	212,425	223,046
GENCOs	0	0	0	0	0	0	0	0	0	0
NTDC	80,218	84,229	88,441	92,863	97,506	102,381	107,500	112,875	118,519	124,445
DISCOs	41,260	43,323	45,489	47,764	50,152	52,660	55,293	58,057	60,960	64,008
Power Sector	145,510	152,786	160,425	168,447	176,869	185,712	194,998	204,748	214,985	225,734
Generation	101,857	106,950	112,298	117,913	123,808	129,999	136,499	143,323	150,490	158,014
Transmission	29,102	30,557	32,085	33,689	35,374	37,142	39,000	40,950	42,997	45,147
Distribution	14,551	15,279	16,043	16,845	17,687	18,571	19,500	20,475	21,499	22,573
Total	410,766	431,305	452,870	475,514	499,289	524,254	550,466	577,990	606,889	637,234

IPPs: IPPs' investment amount depends on investment opportunities (availability of projects to be invested). For this reason, it is assumed that out of the IPP projects included in "5.5 Long-term Investment Plan", the projects with sponsors secure enough funds for investment. Available fund from IPPs is shown in the following table:

Table 7-10 Available Fund from IPPs (Base Demand Case)

(Unit:USD million)

Location	Items	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North	Total-North	1,933	3,438	4,142	3,658	3,376	2,984	2,142	1,479	828	904	1,186
	Unsponsored-North	0	17	57	88	66	10	0	3	18	48	77
	IPP finance-North	1,933	3,421	4,085	3,570	3,311	2,973	2,142	1,475	811	857	1,110
South	Total-South	224	988	2,023	2,304	1,362	301	104	449	942	1,334	1,511
	Unsponsored-South	0	0	0	0	0	0	0	0	10	46	104
	IPP finance-South	224	988	2,023	2,304	1,362	301	104	449	931	1,288	1,408
Total		2,157	4,409	6,107	5,874	4,673	3,274	2,246	1,924	1,742	2,145	2,517

Location	Items	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
North	Total-North	1,183	1,349	1,409	1,250	877	887	818	341	0	0
	Unsponsored-North	94	110	120	107	73	79	77	30	0	0
	IPP finance-North	1,089	1,239	1,290	1,143	804	808	741	311	0	0
South	Total-South	1,667	1,702	1,609	1,828	2,007	1,930	1,697	1,171	503	0
	Unsponsored-South	153	170	175	166	145	126	98	61	20	0
	IPP finance-South	1,514	1,532	1,434	1,662	1,861	1,803	1,598	1,110	482	0
Total		2,602	2,771	2,723	2,805	2,665	2,611	2,339	1,421	482	0

Donor Agencies: The following table shows infrastructure development projects which major donors in the power sector (ADB, WB, JICA, and USAID) agreed upon with the Pakistan government. Available fund from the aid agencies is assumed to be the equal amount from the next year of project commencement to the completion year.

Table 7-11 Infrastructure Development Project by Aid Agencies

No	Donor	Project Name	Type	Budget*	Start	End	Infrastructure	Fuel
1	ADB	Power Transmission Enhancement Investment Program T.3	Loan	243	2011	2016	Transmission	N/A
2	ADB	Power Transmission Enhancement Investment Program T.4	Loan	248	2014	2016	Transmission	N/A
3	ADB	Power Distribution Enhancement Investment Program T.2	Loan	172	2010	2015	Distribution	N/A
4	ADB	Power Distribution Enhancement Investment Program T.3	Loan	245	2012	2016	Distribution	N/A
5	ADB	Power Distribution Enhancement Investment Program T.4	Loan	167	2013	2017	Distribution	N/A
7	ADB	Jamshoro Power Generation Project	Loan	840	2013	2019	Generation	Coal
8	JICA	Punjab Transmission Lines and Grid Station Project**	Loan	99	2008	2015	Transmission	N/A
9	JICA	National Transmission Lines and Grid Stations Strengthening Project**	Loan	192	2010	2017	Transmission	N/A
10	USAID	Tarbela Dam Rehabilitation Project (Phase-I)	Grant	17	2010	2015	Generation	Hydro
11	USAID	Mangla Dam Rehabilitation Project	Grant	150	2013	2017	Generation	Hydro
12	USAID	Guddu Power Station Project	Grant	19	2010	2015	Generation	Oil/Gas
13	USAID	Jamshoro Power Station Project	Grant	19	2010	2016	Generation	Oil/Gas
14	USAID	Muzaffargarh Power Station Project	Grant	16	2010	2016	Generation	Oil/Gas
15	USAID	Power Distribution Program	Grant	230	2010	2015	Distribution	N/A
16	USAID	Tarbela Dam Rehabilitation Project (Phase-II)	Grant	25	2014	2016	Generation	Hydro
18	WB	Tarvela 4th Extension Hydropower Project	Loan	840	2012	2017	Generation	Hydro
19	WB	Pakistan Natural Gas Efficiency Project	Loan	100	2012	2017	Transmission	N/A
20	WB	Dasu Hydropower Stage I Project***		1,048	2014	2022	Generation	Hydro

*Unit: million US$

**JICA's project budget is denominated in the Japanese Yen (US$1=JPY121.18 as of August 31,2015)

***Project budget is 588 million US$ plus guarantee of 460 million US$. Transmission is 15 million US$

(3) Funding Gap

Investment requirement, available fund, and funding gap for the power sector are shown in the following table. Funding gaps continues in all subsectors (generation, transmission, and distribution) for a long period. The funding gap for the power sector is expected to reach almost 3 billion US$ annually in 2018, and 2019. The amount of funding gap is 17.7 billion US$ from 2015 to 2025 and 19.2 billion US$ from 2015 to 2035.

Funding gap for generation does not occur at the beginning of the plan but the gap is expected to stay at approximately 1 billion US$ annually for the period of 2018 - 2024. For transmission, funding gap is expected to peak out in 2018 but the annual gap will surpass 1 billion US$ at the peak point. For distribution, the funding gap is expected to peak out in 2018 but the gap will exist up to 2031 longer than in other subsectors.

In tandem with privatization in the power sector, private enterprises will own power utilities and may make capital expenditure with their funds. In terms of funding, however, financial support from PSDP and aid agencies will be required for foreseeable future.

Table 7-12 Funding Gap (Base Demand Case)

(Unit : million US$)

Subsector	Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Generation	Investment Requirement	4,439	6,990	9,263	9,610	8,723	6,713	5,900	5,911	6,120	6,516	6,389	6,659	5,949	5,770	5,884	5,890	5,922	5,129	3,269	1,314	0
	Public Sector Development Program	1,436	1,776	1,865	1,958	2,056	2,159	2,166	2,380	2,499	2,624	2,755	2,893	3,038	3,189	3,349	3,516	3,692	3,877	4,071	4,274	4,488
	WAPDA	321	340	360	380	402	426	451	477	504	534	565	597	632	669	707	748	792	838	886	938	992
	K-Electric	109	115	122	129	136	144	152	161	171	181	191	202	214	226	239	253	268	283	300	317	0
	IPPs	2,157	4,409	6,107	5,874	4,673	3,274	2,246	1,924	1,742	2,145	2,517	2,602	2,771	2,723	2,805	2,665	2,611	2,339	1,421	482	0
	Donors	502	495	477	271	271	131	131	131													0
	Available Fund	4,524	7,134	8,930	8,613	7,538	6,134	5,147	5,073	4,916	5,483	6,028	6,295	6,654	6,808	7,101	7,183	7,363	7,337	6,678	6,012	5,480
	Funding Gap	0	0	333	998	1,184	579	753	838	1,204	1,034	361	364	0	0	0	0	0	0	0	0	0
Transmission	Investment Requirement	872	1,374	1,820	1,888	1,714	1,319	1,159	1,161	1,203	1,280	1,255	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	0
	Public Sector Development Program	517	492	517	543	570	599	629	803	944	992	1,041	1,093	1,148	1,205	1,266	1,329	1,395	1,465	1,538	1,615	1,696
	NTDC	100	106	112	119	126	133	141	149	158	167	176	187	197	209	221	234	247	262	277	293	310
	K-Electric	31	33	35	37	39	41	44	46	49	52	55	58	61	65	68	72	77	81	86	91	0
	Donors	234	220	48	0	0	0	0	0													0
	Available Fund	883	852	712	699	735	773	813	998	1,151	1,210	1,272	1,338	1,406	1,479	1,555	1,635	1,719	1,808	1,901	1,999	2,006
	Funding Gap	0	522	1,108	1,190	979	546	346	164	52	70	0	0	0	0	0	0	0	0	0	0	0
Distribution	Investment Requirement	773	906	1,024	1,042	996	891	862	862	862	862	862	862	862	862	862	862	803	715	508	291	0
	Public Sector Development Program	283	253	266	279	293	308	323	411	482	506	532	558	586	615	646	678	712	748	785	825	866
	K-Electric	16	16	17	18	19	21	22	23	24	26	27	29	31	32	34	36	38	40	43	45	0
	Donors	183	103	42	0	0	0	0	0													0
	Available Fund	482	373	325	298	313	328	345	434	507	532	559	587	617	648	680	715	751	788	828	870	866
	Funding Gap	291	533	699	745	684	563	517	428	356	330	303	275	246	214	182	148	52	0	0	0	0
Total	Investment Requirement	6,084	9,270	12,108	12,541	11,433	8,923	7,921	7,934	8,185	8,659	8,506	8,825	8,115	7,936	8,050	8,057	8,029	7,148	5,081	2,909	0
	Available Fund	5,890	8,359	9,967	9,609	8,586	7,235	6,305	6,505	6,573	7,225	7,859	8,219	8,677	8,934	9,336	9,533	9,833	9,933	9,407	8,880	8,352
	Funding Gap	291	1,055	2,141	2,932	2,847	1,688	1,616	1,430	1,612	1,434	664	639	246	214	182	148	52	0	0	0	0

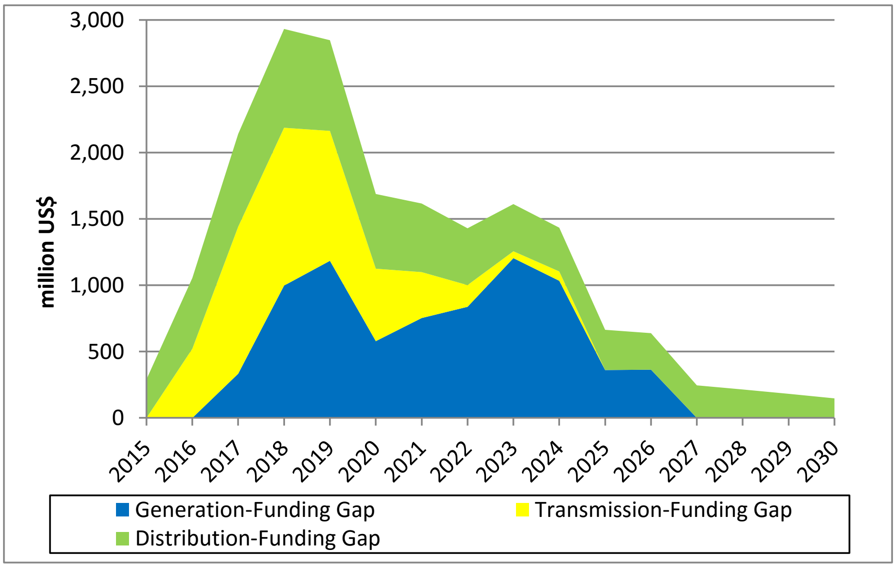


Figure 7-4 Funding Gap by Category

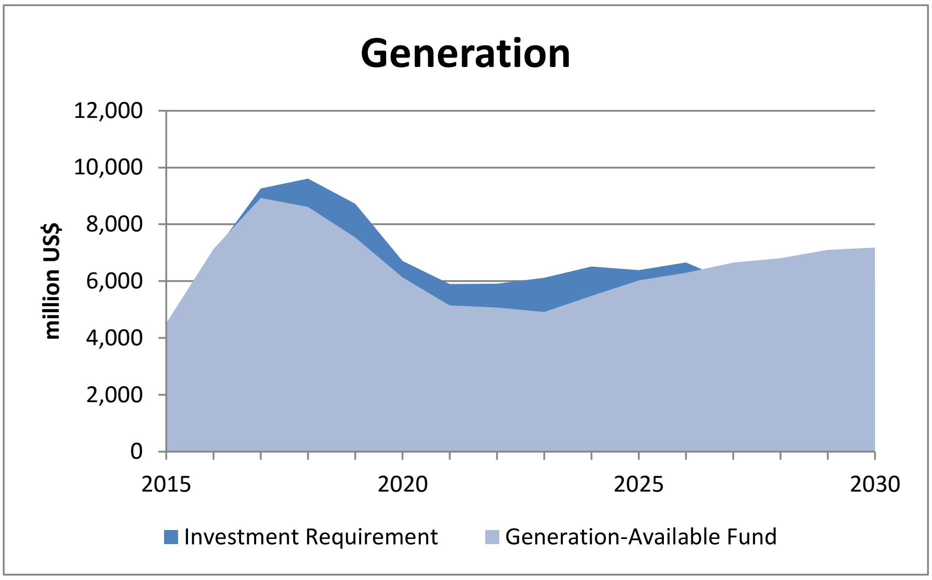


Figure 7-5 Investment Requirement and Funding (Generation)

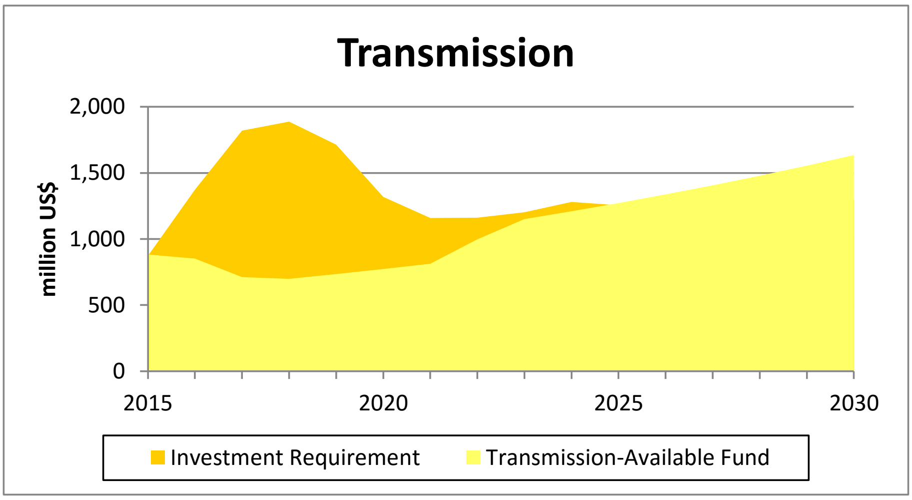


Figure 7-6 Investment Requirement and Funding (Transmission)

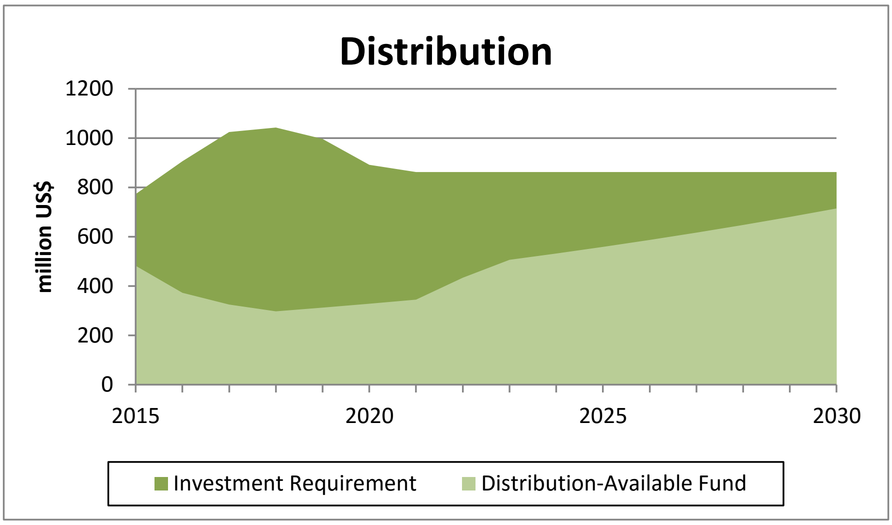


Figure 7-7 Investment Requirement and Funding (Distribution)

7.2.2 High Demand Case

(1) Investment Requirement

Investment requirement for each of generation, transmission, and distribution is estimated for the computation of investment requirement as done in Base Demand Case. The following assumptions are made for the estimation of investment requirement by subsector.

Generation: Investment requirement is based on the investment amount from 2015 to 2035 for the High Demand Case, which is shown in "5.5 Long-term Investment Plan".

Transmission: The investment plan for 2015-2035 in "6.6 Least Cost Plan of Power Network System" could accommodate larger demand growth to some extents. Thus, the investment requirement is assumed to be the same amount of Base Demand Case. Similarly, annual requirement of Base Demand Case is used.

Distribution: Investment requirement for distribution is estimated at 10% of the total investment during the whole plan period (2015 - 2035) and some modifications are made on investment timing for each region. Investment requirement for the North System, the South System, and the KE system is based on the same assumptions for Base Demand Case.

Investment requirement for generation, transmission, and distribution is shown in the following table. The amount of investment requirement is 118.3 billion US$ from 2015 to 2025 and 203.1 billion US$ from 2015 to 2035.

Table 7-13 Investment Requirement (Base Demand Case)

(Unit : million US$)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Generation-North	3,798	5,341	5,875	5,470	5,895	5,113	5,310	4,838	4,802	4,597	4,687
Generation-South	616	1,777	3,459	4,329	3,655	2,532	1,910	1,754	1,662	1,904	2,532
Generation-KE	573	1,093	1,358	1,117	650	642	769	870	833	751	830
Generation-Subtotal	4,987	8,211	10,692	10,916	10,200	8,287	7,989	7,462	7,297	7,252	8,050
Transmission-Subtotal	822	1,353	1,761	1,798	1,680	1,365	1,316	1,229	1,202	1,195	1,326
Distribution-North	680	680	680	680	680	680	680	680	680	680	680
Distribution-South	183	301	392	400	374	304	295	295	295	295	295
Distribution-KE	57	93	121	124	116	94	91	91	91	91	91
Distribution-Subtotal	920	1,075	1,194	1,204	1,170	1,078	1,067	1,067	1,067	1,067	1,067
Total	6,729	10,638	13,647	13,919	13,050	10,730	10,372	9,758	9,566	9,513	10,442

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Generation-North	5,182	5,252	5,334	5,356	5,439	5,688	5,201	3,368	1,559	0
Generation-South	2,944	2,801	2,482	2,588	2,386	2,062	1,684	913	202	0
Generation-KE	826	623	440	520	681	647	378	65	0	0
Generation-Subtotal	8,952	8,676	8,256	8,464	8,506	8,397	7,264	4,346	1,761	0
Transmission-Subtotal	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	0
Distribution-North	680	680	680	680	680	678	599	395	214	0
Distribution-South	295	295	295	295	295	305	270	178	97	0
Distribution-KE	91	91	91	91	91	94	83	55	30	0
Distribution-Subtotal	1,067	1,067	1,067	1,067	1,067	1,078	952	628	341	0
Total	11,323	11,047	10,626	10,835	10,877	10,779	9,520	6,278	3,406	0

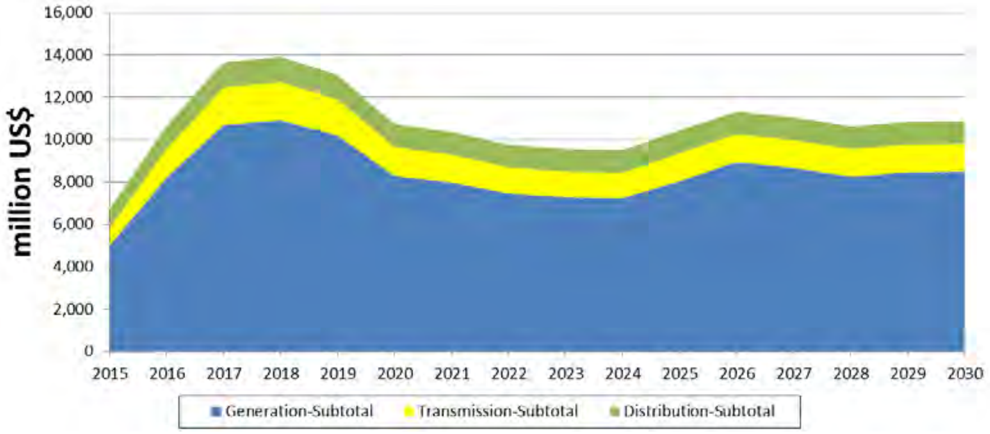


Figure 7-8 Investment Requirement by Category

(2) Available Fund

The estimation of available fund by funding source is based in the following assumptions:

Internal Fund from DISCOs and GENCOs: As shown in Base Demand Case, electricity tariff is assumed to cover operational costs, principal and interest payments of debts but not to allow fund allocation for capital investment.

Internal Fund from WAPDA: As shown in Base Demand Case, capital expenditure is expected to grow in line with the electricity demand for Pakistan. The demand growth is assumed to be 7%, a higher growth than in Base Demand Case.

Internal Fund from NTDC: As shown in Base Demand Case, capital expenditure is expected to grow in line with the electricity demand for Pakistan. The demand growth is assumed to be 7%, a higher growth than in Base Demand Case.

Internal Fund from KE: As shown in Base Demand Case, capital expenditure is expected to grow in line with the electricity demand for Pakistan. The demand growth is assumed to be 7%, a higher growth than one in Base Demand Case. The allocation of capital expenditure by subsector is assumed to be 70% for generation, 20% for transmission, and 10% for distribution.

Public Sector Development Program: As shown in Base Demand Case, available fund for the first year of the plan period is estimated by subtracting donor assistance from the Public Sector Development Program (PSDP) for 2014-15 and 2015-16. The fund is expected to grow along with GDP growth (Base Demand Case: 6.5% p.a.).

Table 7-14 Public Sector Development Program (High Demand Case)

(Unit : million PKR)

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Atomic Energy Commission	24,621	15,433	16,436	17,505	18,643	19,854	10,240	0	0	0	0
WAPDA	72,791	88,913	94,692	100,847	107,402	114,383	121,818	129,736	138,169	147,150	156,715
GENCOs	46,152	74,551	79,397	84,558	90,054	95,907	102,141	52,678	0	0	0
NTDC	51,719	49,607	52,832	56,266	59,923	63,818	67,967	72,384	77,089	82,100	87,437
DISCOs	28,327	25,516	27,174	28,940	30,821	32,825	34,959	37,231	39,651	42,228	44,973
Power Sector								78,622	139,835	148,924	158,604
Generation								55,035	97,884	104,247	111,023
Transmission								15,724	27,967	29,785	31,721
Distribution								7,862	13,983	14,892	15,860
Total	223,610	254,020	270,531	288,116	306,844	326,788	348,030	370,652	394,744	420,402	447,728

Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Atomic Energy Commission	0	0	0	0	0	0	0	0	0	0
WAPDA	166,901	177,750	189,304	201,608	214,713	228,669	243,533	259,362	276,221	294,175
GENCOs	0	0	0	0	0	0	0	0	0	0
NTDC	93,120	99,173	105,619	112,484	119,796	127,583	135,875	144,707	154,113	164,131
DISCOs	47,896	51,009	54,325	57,856	61,617	65,622	69,887	74,430	79,268	84,420
Power Sector	168,913	179,892	191,585	204,039	217,301	231,426	246,468	262,489	279,550	297,721
Generation	118,239	125,925	134,110	142,827	152,111	161,998	172,528	183,742	195,685	208,405
Transmission	33,783	35,978	38,317	40,808	43,460	46,285	49,294	52,498	55,910	59,544
Distribution	16,891	17,989	19,159	20,404	21,730	23,143	24,647	26,249	27,955	29,772
Total	476,831	507,825	540,833	575,988	613,427	653,299	695,764	740,989	789,153	840,448

IPPs: It is assumed that out of the IPP projects included in "5.5 Long-term Investment Plan", the projects with sponsors secure enough funds for investment. Available fund from IPPs is shown in the following table:

Table 7-15 Available Fund from IPPs (High Demand Case)

(Unit : million US$)

Location	Items	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
North	Total-North	2,304	4,020	4,653	4,069	3,660	2,421	1,870	1,187	1,074	1,209	1,876
	Unsponsored-North	0	17	57	88	66	20	32	53	66	95	157
	IPP finance-North	2,304	4,002	4,595	3,981	3,594	2,400	1,838	1,134	1,008	1,113	1,719
South	Total-South	224	988	2,023	2,304	1,407	610	856	1,420	1,662	1,904	2,532
	Unsponsored-South	0	0	0	0	0	0	0	0	0	7	39
	IPP finance-South	224	988	2,023	2,304	1,407	610	856	1,420	1,662	1,897	2,493
Total		2,529	4,990	6,618	6,286	5,001	3,010	2,693	2,553	2,670	3,011	4,211

Location	Items	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
North	Total-North	2,167	1,902	1,405	936	837	1,335	1,398	918	402	0
	Unsponsored-North	186	172	126	89	80	133	140	92	40	0
	IPP finance-North	1,981	1,731	1,279	848	757	1,201	1,258	826	361	0
South	Total-South	2,944	2,801	2,482	2,588	2,386	2,062	1,684	913	202	0
	Unsponsored-South	103	166	185	173	174	179	150	81	20	0
	IPP finance-South	2,842	2,636	2,297	2,415	2,213	1,883	1,535	832	182	0
Total		4,822	4,366	3,576	3,263	2,969	3,084	2,793	1,658	543	0

Donor Agencies: Available fund from the aid agencies is assumed to be the equal amount from the next year of project commencement to the completion year. In the investment plan in "5.5 Long-term Investment Plan", there is a power plant that its completion year in High Demand Case differs from that in Base Demand Case. Available fund is adjusted for the project which finances the power plant.

(3) Funding Gap

Investment requirement, available fund, and funding gap for the power sector in High Demand Case are shown in the following table. Since investment requirements for generation and distribution are larger than those in High Demand Case, investment gap will reach almost 4 billion US$ in 2018 and 2019. The amount of funding gap is 25.0 billion US$ from 2015 to 2025 and 26.7 billion US$ from 2015 to 2035.

Funding gap for generation occurs even at the beginning of the plan and will stay at approximately 2 billion US$ annually from 2019 to 2021. For transmission, the funding gap is expected to surpass 1 billion US$ in 2017 and 2018 but the annual gap will disappear faster than in Base Demand Case due to an increase of available fund. For destitution, the funding gap is expected to peak out in 2018 but the annual gap is bigger than one in Base Demand Case by 100-200 million US$.

Table 7-16 Funding Gap (High Demand Case)

(Unit: million US$)

Subsector	Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Generation	Investment Requirement	4,987	8,211	10,692	10,916	10,200	8,287	7,989	7,462	7,297	7,252	8,050
	Public Sector Development Program	1,436	1,789	1,905	2,029	2,161	2,301	2,342	2,610	2,780	2,961	3,153
	WAPDA	323	346	370	396	424	453	485	519	555	594	636
	K-Electric	109	117	125	134	143	153	164	176	188	201	215
	IPPs	2,529	4,990	6,618	6,286	5,001	3,010	2,693	2,553	2,670	3,011	4,211
	Donors	521	514	495	290	290	150	150	0			
	Available Fund	4,917	7,755	9,513	9,134	8,019	6,068	5,834	5,858	6,193	6,766	8,215
	Funding Gap	70	456	1,178	1,782	2,181	2,219	2,155	1,604	1,104	486	0
Transmission	Investment Requirement	822	1,353	1,761	1,798	1,680	1,365	1,316	1,229	1,202	1,195	1,326
	Public Sector Development Program	517	496	528	563	599	638	680	881	1,051	1,119	1,192
	NTDC	101	108	116	124	132	142	152	162	174	186	199
	K-Electric	31	33	36	38	41	44	47	50	54	57	61
	Donors	234	220	48	0	0	0	0	0			
	Available Fund	884	858	727	725	773	824	878	1,093	1,278	1,362	1,452
	Funding Gap	0	495	1,034	1,073	908	541	438	136	0	0	0
Distribution	Investment Requirement	920	1,075	1,194	1,204	1,170	1,078	1,067	1,067	1,067	1,067	1,067
	Public Sector Development Program	283	255	272	289	308	328	350	451	536	571	608
	K-Electric	16	17	18	19	20	22	23	25	27	29	31
	Donors	183	103	42	0	0	0	0	0			
	Available Fund	482	375	331	309	329	350	373	476	563	600	639
	Funding Gap	437	700	862	896	841	728	694	591	503	467	428
Total	Investment Requirement	6,729	10,638	13,647	13,919	13,050	10,730	10,372	9,758	9,566	9,513	10,442
	Available Fund	6,283	8,988	10,572	10,167	9,120	7,242	7,085	7,428	8,034	8,728	10,306
	Funding Gap	507	1,651	3,074	3,751	3,930	3,488	3,286	2,330	1,607	952	428

Subsector	Year	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Generation	Investment Requirement	8,952	8,676	8,256	8,464	8,506	8,397	7,264	4,346	1,761	0
	Public Sector Development Program	3,358	3,576	3,809	4,056	4,320	4,601	4,900	5,219	5,558	5,919
	WAPDA	680	728	779	833	891	954	1,021	1,092	1,169	1,250
	K-Electric	230	246	264	282	302	323	345	370	395	0
	IPPs	4,822	4,366	3,576	3,263	2,969	3,084	2,793	1,658	543	0
	Donors										
	Available Fund	9,091	8,917	8,427	8,434	8,483	8,962	9,059	8,338	7,665	7,169
	Funding Gap	0	0	0	30	24	0	0	0	0	0
Transmission	Investment Requirement	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	1,304	0
	Public Sector Development Program	1,269	1,352	1,439	1,533	1,633	1,739	1,852	1,972	2,100	2,237
	NTDC	213	227	243	260	279	298	319	341	365	391
	K-Electric	66	70	75	81	86	92	99	106	113	0
	Donors										
	Available Fund	1,547	1,649	1,758	1,874	1,997	2,129	2,269	2,419	2,578	2,628
	Funding Gap	0	0	0	0	0	0	0	0	0	0
Distribution	Investment Requirement	1,067	1,067	1,067	1,067	1,067	1,078	952	628	341	0
	Public Sector Development Program	648	690	735	783	833	888	945	1,007	1,072	1,142
	K-Electric	33	35	38	40	43	46	49	53	56	0
	Donors										
	Available Fund	681	725	772	823	877	934	995	1,060	1,129	1,142
	Funding Gap	386	341	294	244	190	144	0	0	0	0
Total	Investment Requirement	11,323	11,047	10,626	10,835	10,877	10,779	9,520	6,278	3,406	0
	Available Fund	11,319	11,291	10,957	11,131	11,357	12,025	12,323	11,817	11,372	10,939
	Funding Gap	386	341	294	273	214	144	0	0	0	0

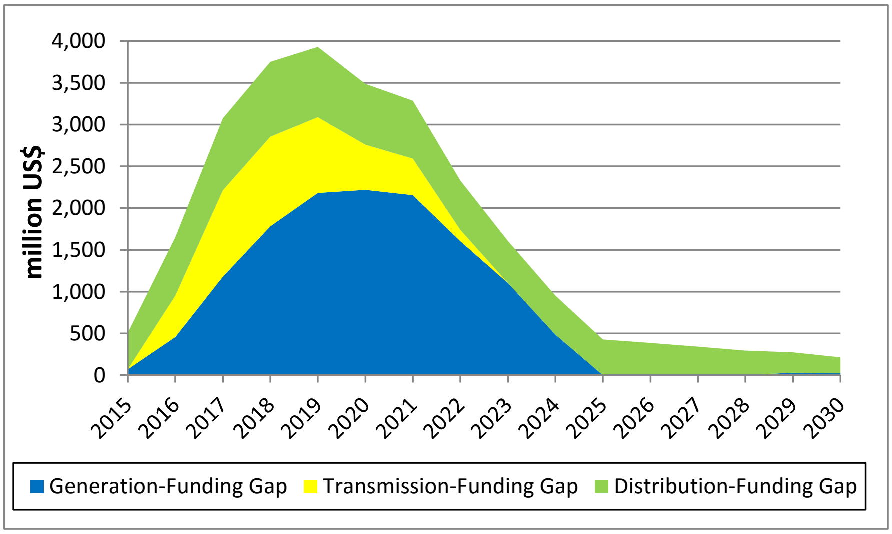


Figure 7-9 Funding Gap by Category

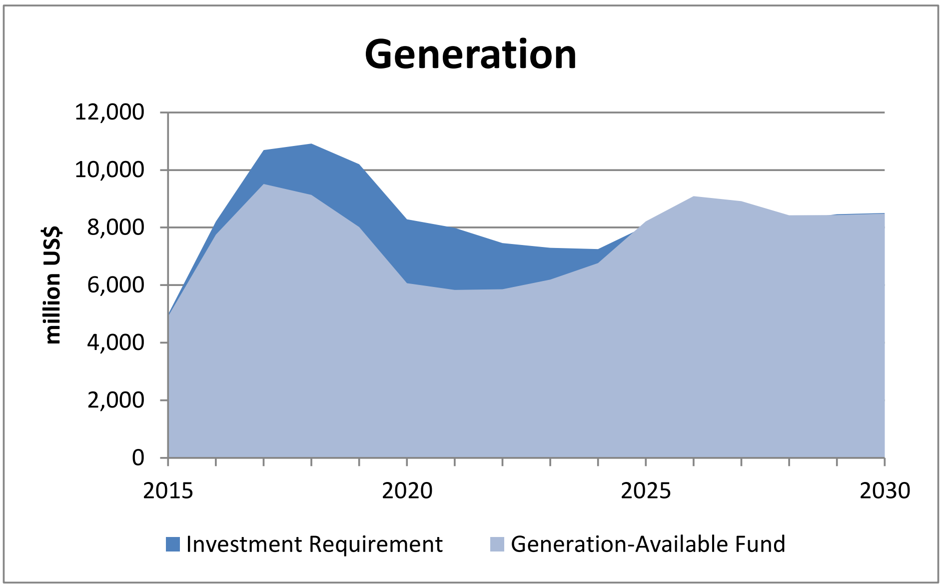


Figure 7-10 Investment Requirement and Funding (Generation)

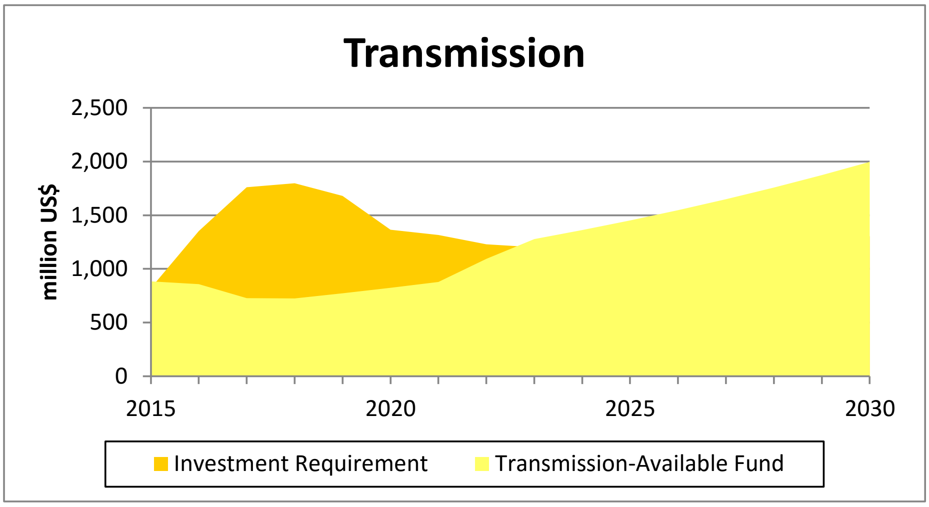


Figure 7-11 Investment Requirement and Funding (Transmission)

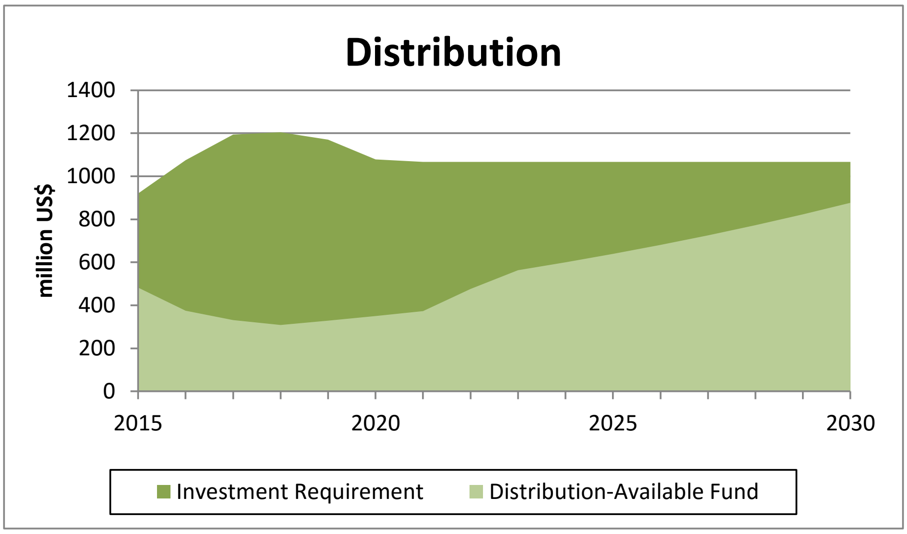


Figure 7-12 Investment Requirement and Funding (Generation)

7.3 Comparison of Fully Distributed Cost and Electricity Tariff

7.3.1 Assumptions for Computation of Fully-Distributed Cost (Base Demand Case)

Estimation of a fully-distributed cost (FDC) is based on those of subcomponents (generation cost, transmission cost, and distribution cost). For computation of these costs, the following assumptions are made:

Generation Cost: Based on the generation cost from 2015 to 2035 in Base Demand Case in "5.4 Long Term Power Development Pattern".

Transmission Cost: The cost on new investment during the plan period is estimated by multiplying the accumulated investment requirement with the sum of capital recovery factor (11.02%) and annual O&M cost (1.67%). Under the assumption that the existing investment in transmission is 20% of the power sector, the cost of existing facilities is estimated at approximately 30% of fixed cost of generation in the first year of the plan period (transmission 20%/transmission 70%=29%). The rationale of this estimation method is that transmission cost is mostly a fixed cost of capital investment.

Distribution Cost: The cost on new investment during the plan period is estimated by multiplying the accumulated investment requirement with the sum of capital recovery factor (11.02%) and annual O&M cost (1.67%). On the cost of existing facilities, it is assumed that distribution margin for 2014-15 (total cost of distribution) remains the same during the plan period. The distribution margin for DISCOs is based on the data to calculate NEPRA Determined Tariff. Given 12 % of the distribution margin for DISCOs, the distribution margin for KE is estimated by multiplying KE's sales with the above percentage for the distribution margin.

Power Supply: power supply after distribution and transmission loss (T&D loss) is employed for the calculation. Power supply and T&D loss are based on Base Demand Case in "3.4 Power Demand Forecast".

7.3.2 Fully Distributed Cost (Base Demand Case)

The average billing rate for 2014/15 was 11.45 Rs/kWh (excluding tax and duties such as VAT). With the assumptions mentioned in the previous section, generation cost, transmission cost, generation cost, and FDC (total of all costs) are calculated and shown in the following table. A large amount of capital investment continues from 2015 to 2020 but new facilities will not supply electricity for the same period. For this reason, FDC will stay at a higher level for the early years of the plan. In tandem with an increase in power supply, FDC will start to decline and reach 11.2 UScent/kWh in 2035. Assuming the full cost recovery, electricity tariff cannot be lowered in the short- and medium-term but tariff reduction can be an option in the long-run.

Table 7-17 Fully Distributed Cost over the Plan Period (Base Demand Case)

Items	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy (GWh)	117,525	124,760	133,606	142,821	152,451	161,882	172,610	182,353	193,510	205,368	217,760
Generation (million US$)	16,200	17,308	18,248	20,761	20,349	16,560	17,581	18,632	19,614	20,405	21,233
Transmission (million US$)	2,314	2,222	2,303	2,442	2,589	2,714	2,789	2,843	2,898	2,958	3,028
Distribution (USD million)	1,231	1,231	1,350	1,504	1,675	1,829	1,952	2,064	2,176	2,288	2,400
Total (million US$)	19,746	20,761	21,902	24,707	24,613	21,103	22,321	23,539	24,688	25,651	26,662
Generation Cost (UScent/kWh)	13.8	13.9	13.7	14.5	13.3	10.2	10.2	10.2	10.1	9.9	9.8
Transmission Cost (UScent/kWh)	2.0	1.8	1.7	1.7	1.7	1.7	1.6	1.6	1.5	1.4	1.4
Distribution Cost (Uscent/kWh)	1.0	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Total Cost (UScent/kWh)	16.8	16.6	16.4	17.3	16.1	13.0	12.9	12.9	12.8	12.5	12.2

Items	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy (GWh)	230,738	244,340	258,616	273,617	289,400	304,492	320,267	336,784	354,089	372,234
Generation (million US$)	22,328	23,386	24,448	25,527	26,700	27,952	29,334	31,201	32,866	34,400
Transmission (million US$)	3,095	3,168	3,241	3,313	3,386	3,459	3,532	3,605	3,678	3,751
Distribution (USD million)	2,513	2,625	2,737	2,849	2,961	3,073	3,181	3,274	3,333	3,357
Total (million US$)	27,935	29,178	30,425	31,690	33,048	34,485	36,047	38,080	39,877	41,508
Generation Cost (UScent/kWh)	9.7	9.6	9.5	9.3	9.2	9.2	9.2	9.3	9.3	9.2
Transmission Cost (UScent/kWh)	1.3	1.3	1.3	1.2	1.2	1.1	1.1	1.1	1.0	1.0
Distribution Cost (Uscent/kWh)	1.1	1.1	1.1	1.0	1.0	1.0	1.0	1.0	0.9	0.9
Total Cost (UScent/kWh)	12.1	11.9	11.8	11.6	11.4	11.3	11.3	11.3	11.3	11.2

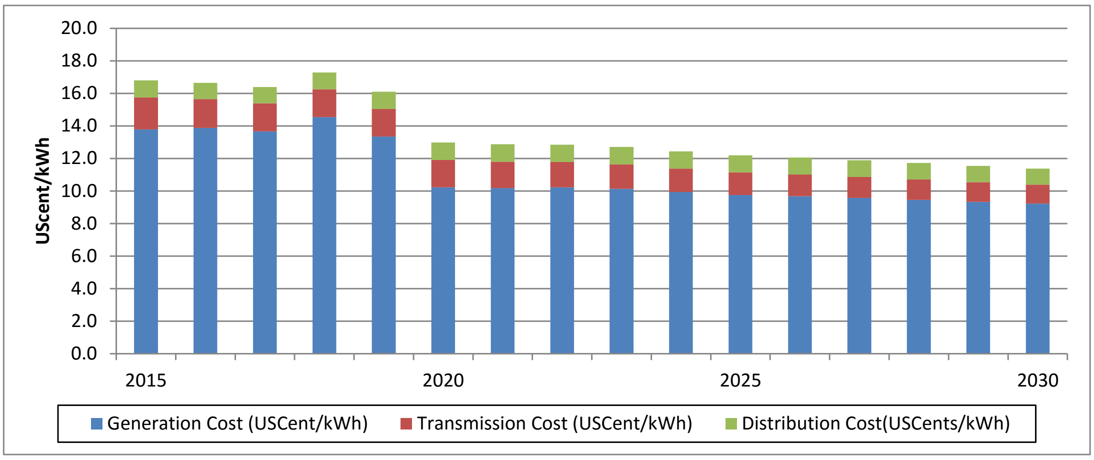


Figure 7-13 Fully Distributed Cost by Category

7.3.3 Assumptions for Computation of Fully-Distributed Cost (High Demand Case)

For computation of generation cost, transmission cost, and distribution cost in High Demand Case, the following assumptions are made:

Generation Cost: Based on the generation cost from 2015 to 2035 in High Demand Case in “5.4 Long Term Power Development Pattern”.

Transmission Cost: The assumptions for Base Demand Case are utilized. Specifically, the cost on new investment during the plan period is estimated by multiplying the accumulated investment requirement with the sum of capital recovery factor (11.02%) and annual O&M cost (1.67%). The cost of existing facilities is estimated at approximately 30% of fixed cost of generation in the first year of the plan period (transmission 20%/transmission 70%=29%).

Distribution Cost: The assumptions for Base Demand Case are utilized. The cost on new investment during the plan period is estimated by multiplying the accumulated investment requirement with the sum of capital recovery factor (11.02%) and annual O&M cost (1.67%). On the cost of existing facilities, it is assumed that distribution margin for 2014-15 (total cost of distribution) remains the same during the plan period likewise in Base Demand Case.

Power Supply: power supply after distribution and transmission loss (T&D loss) is employed for the calculation. Power supply and T&D loss are based on High Demand Case in "3.4 Power Demand Forecast".

7.3.4 Fully Distributed Cost (High Demand Case)

With the assumptions mentioned in the previous section, generation cost, transmission cost, generation cost, and FDC (total of all costs) are calculated and shown in the following table. Since the amount of capital expenditure is larger than in Base Demand Case at an earlier phase of the plan, FDC shows a steeper increase. On the other hand, FDC will decrease at a later phase of the plan due to larger electricity demand. FDC will decline to 10.8 UScent/kWh in 2035 and this can make tariff reduction larger than in Base Demand Case.

Table 7-18 Fully Distributed Cost over the Plan Period (High Demand Case)

Items	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Energy (GWh)	117,850	126,096	136,162	147,346	159,876	173,344	187,300	200,514	215,624	231,895	249,177
Generation (million US$)	16,200	17,509	18,938	22,963	23,798	17,724	18,878	20,021	21,350	22,798	24,506
Transmission (million US$)	2,314	2,222	2,301	2,432	2,567	2,688	2,769	2,843	2,906	2,966	3,025
Distribution (USD million)	1,231	1,231	1,368	1,519	1,672	1,821	1,957	2,093	2,228	2,364	2,499
Total (million US$)	19,746	20,962	22,607	26,914	28,037	22,233	23,604	24,957	26,485	28,128	30,030
Generation Cost (UScent/kWh)	13.7	13.9	13.9	15.6	14.9	10.2	10.1	10.0	9.9	9.8	9.8
Transmission Cost (UScent/kWh)	2.0	1.8	1.7	1.7	1.6	1.6	1.5	1.4	1.3	1.3	1.2
Distribution Cost (Uscent/kWh)	1.0	1.0	1.0	1.0	1.0	1.1	1.0	1.0	1.0	1.0	1.0
Total Cost (UScent/kWh)	16.8	16.6	16.6	18.3	17.5	12.8	12.6	12.4	12.3	12.1	12.1

Items	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy (GWh)	267,309	286,581	307,088	328,927	352,207	373,784	397,215	422,060	448,424	476,422
Generation (million US$)	25,850	27,073	29,074	30,802	32,798	34,464	36,278	38,690	41,417	44,074
Transmission (million US$)	3,101	3,174	3,247	3,320	3,393	3,466	3,539	3,612	3,685	3,758
Distribution (USD million)	2,634	2,770	2,905	3,040	3,176	3,311	3,448	3,569	3,648	3,691
Total (million US$)	31,585	33,016	35,226	37,163	39,366	41,241	43,265	45,870	48,750	51,523
Generation Cost (UScent/kWh)	9.7	9.4	9.5	9.4	9.3	9.2	9.1	9.2	9.2	9.3
Transmission Cost (UScent/kWh)	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.9	0.8	0.8
Distribution Cost (Uscent/kWh)	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8
Total Cost (UScent/kWh)	11.8	11.5	11.5	11.3	11.2	11.0	10.9	10.9	10.9	10.8

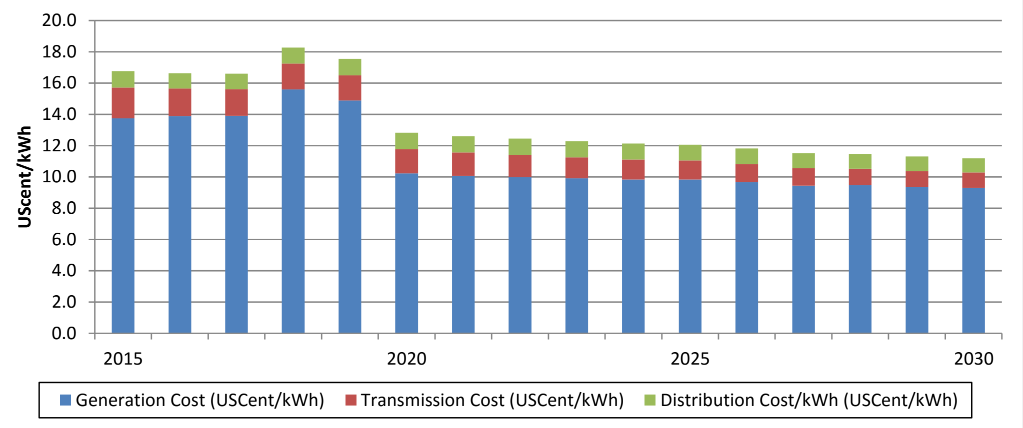


Figure 7-14 Fully Distributed Cost by Category

Chapter 8 Environmental and Social Considerations

8.1 General Outline of Strategic Environmental Assessment (SEA)

SEA (Strategic Environmental Assessment) is widely accepted as a tool to integrate environmental and social considerations into a decision-making process. It is generally understood as a process for assessing the environmental impacts caused by a proposed policy, plan and program. And then, it is also accepted as a supportive method to conduct appropriate decision-making from the viewpoint of environment and sustainable development.

UNEP (2000) summarizes the advantage of conducting SEA into following three points, namely supporting informed and integrated decision making, contributing to environmentally sustainable development and reinforcing project EIA. Supporting informed and integrated decision-making would be achieved by identifying environmental effects of proposed actions, considering alternatives and specifying appropriate mitigation measures. Contributing to environmentally sustainable development would be achieved by anticipating and preventing environmental impacts at source of the outbreaks, by early stage warning of cumulative impact and global risks, and by establishing safeguards based on principles of sustainable development.

8.1.1 SEA under JICA's Guideline for Environmental and Social Considerations

Japan International Cooperation Agency (JICA) has conducted its environmental and social considerations at the Master Plan and Feasibility Study levels. In particular, after the introduction of JICA's Guidelines for Environmental and Social Considerations in 2004 (hereinafter "2004 Guidelines"), JICA officially started to integrate the concept of SEA into its operations.

The 2004 Guidelines define SEA as "an assessment being implemented at the policy, plan and program level rather than a project-level EIA", and then stipulate that "JICA introduces the concept of SEA when conducting Master Plan studies and works with the recipient governments to address a wide range of environmental and social factors from the early stage. JICA makes an effort to include an analysis of alternatives on such occasions".

In 2010, new JICA Guidelines for Environmental and Social Considerations (hereinafter New Guidelines") was formulated following the establishment of new JICA in 2008. The New Guidelines clearly states that "JICA applies a Strategic Environmental Assessment when conducting Master Plan Studies", and thus introduction of SEA has been further promoted.

JICA's definition of SEA is clear and concise and its actual implementation is quite flexible depending on the country and the plan concerned.

The following procedure shall be included as a standard procedure under the New Guidelines.

a) Survey of basic conditions (policies, regulations, geography)
b) Creating the development scenarios / alternatives
c) Establishing the scoping and setting indicator for evaluation
d) Stakeholder meetings
e) Survey, prediction, analysis and evaluation of impacts
f) Mitigation measures
g) Selection of programs / projects
h) Reporting (including stakeholder meetings if necessary)

8.1.2 Regulatory Framework and Strategic Environmental Assessment in Pakistan

(1) Federal government level

(a) Legal framework

Environmental Assessment was introduced for the first time in Pakistan as a legal requirement in 1983 through Environment Protection Ordinance which enacted as a Federal law applicable to the whole of Pakistan. In 1997, the Pakistan Environmental Protection Act (hereinafter the Act) replaced the Ordinance.

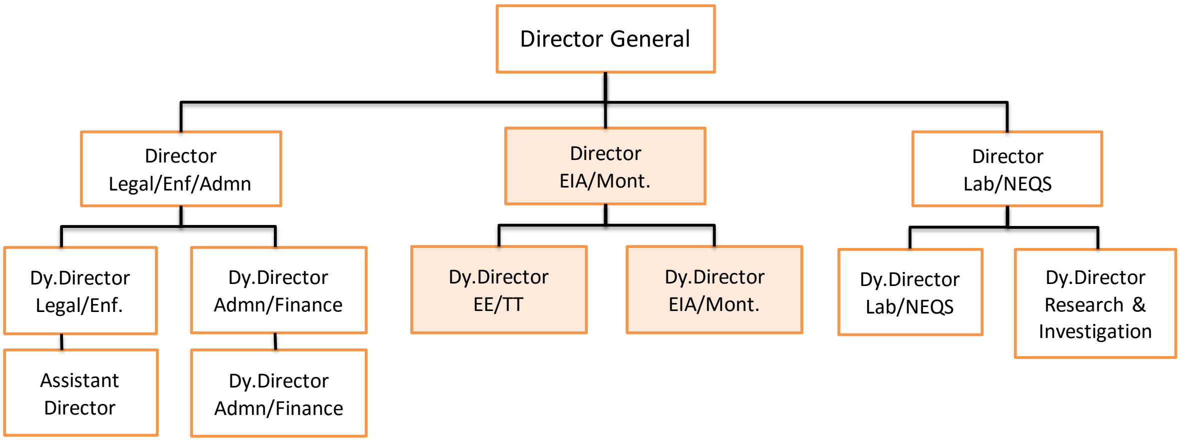
The Act defines EIA and IEE, requires submission of IEE / EIA and also requires an approval before commencement of projects. However, the provision of SEA was never included at any previous law amendment occasion. Therefore, SEA is still in the formative stage in Pakistan.

On the other hand, The National Environmental Policy 2005, which provides an overarching framework for addressing the environmental issues which Pakistan is facing, particularly pollution of fresh water bodies and coastal waters, air pollution, lack of proper waste management, deforestation, loss of biodiversity, desertification, natural disasters and climate change, states in article 5.1 d) that SEA should be promoted as a tool for incorporating environment into decision-making process.

But the adoption of SEA at the level of policy such as National environmental Policy, which evaluates the environmental impacts of a policy, plan or program and its alternatives, is no less mandatory than the Act level in Pakistan.

(b) Organizations responsible for Environmental and Social Considerations in Pakistan

Pakistan Environmental Protection Agency is a subordinate organization of the Ministry of Climate Change and is responsible to implement the Environmental and Social Considerations based on the Pakistan Environmental Protection Act, 1977.



(Source : JICA Project Team)

Figure 8-1 Organizational Structure of Environmental Protection Agency

(2) Provincial level

(a) Legal framework

In 2010, through the 18th Amendment of the Constitution of the Islamic Republic of Pakistan (1973), environmental measures became purely a provincial control matter, empowering each province to legislate and issue its own law. Moreover, implementation of environmental and social considerations associated with IEE / EIA was handed over to Environment Protection Agency (EPA) of each province respectively. However, there are some provinces of which the federal government executes the environmental measures instead.

(b) SEA compliance status by province

(Punjab Province)

In 2012, Punjab promulgated the Punjab Environmental Protection Act, 2012. Punjab Act adopted the IEE / EIA provisions of the Act verbatim, the only relevant amendment being the enhancement of penalties in the provincial law. This Act does not include SEA provision.

(Balochistan Province)

In 2013, Balochistan promulgated the Balochistan Environmental Protection Act, 2012. The Balochistan Act has incorporated all IEE / EIA requirements of the Act and specifically requires environmental approvals for mining activities and setting up of cellular towers.

It also defines Strategic Environmental Assessment (SEA) and requires the government at all levels of administration to incorporate environmental considerations into policies, plans, programs and strategies.

(Sindh Province)

In 2014, Sindh promulgated Sindh Environmental Protection Act, 2014. The Sindh Environmental Protection Act has kept all of the IEE / EIA provisions of the Act, however, some definitions and additional process / requirement have been added.

Penalties for non-compliance of IEE / EIA obligations have been enhanced. Furthermore, for the first time, the Sindh Environmental Protection Act has incorporated mandatory requirement of post-approval environmental monitoring to review the compliance with the conditions of approval and to review whether the actual environmental impact exceeds the predicted levels or not.

It also defines Strategic environmental Assessment (SEA) and requires government authorities to submit SEA to the Sindh Environment Agency (EPA) before formulating any policies, legislation, plans and programs that might cause an environmental impact.

(Khyber Pakhtunkhwa Province)

As of 2014, the Environment Protection Act in Khyber Pakhtunkhwa Province (KPK) does not exist and the Regulations are currently drafting. (according to IUCN Report on National Impact Assessment Program)

8.2 Approach and Methods for SEA and Results of Initial Environmental Survey

8.2.1 Approach and Methods for SEA

Currently, SEA is widely introduced in many developed countries as a tool to integrate Environmental and Social Considerations into a decision-making process but there is no single approach to SEA that can be applied to all cases and no internationally recognized definition of SEA, since there are differences in the scope, comprehensiveness, duration and degree of association to policies, plans and programs.

Under the above mentioned background, the Study Team applies “The SEA approach method” as shown in (Source : JICA Project Team)

Figure 8-2 to the study, which is considered as one of effective methods of SEA and focuses on identification, prospect and evaluation of likely significant environmental impacts caused by implementation of Policy, Plan and Program (PPPs), and then, “Best Practicable Environmental Option” is selected through comparison among scenario alternatives on the Power Development Plan.

The detailed methodology is described below.

(1) Selection of Issues and Indicators concerning Environmental and Social Considerations (Scoping Stage)

At this scoping stage, following issues are to be clarified.

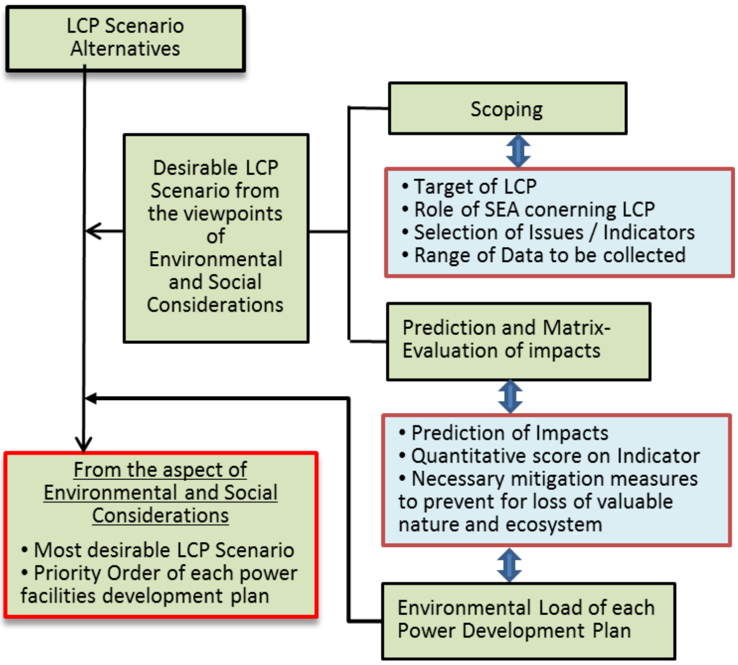
(a) Target of the LCP

The objective of LCP is to support the implementation toward goals of the Government of Pakistan National Power Policy to develop an efficient and consumer oriented electric power system that meets the needs of its people, economic sustainability and affordability.

(b) Role of the SEA concerning LCP

SEA concerning LCP means to provide the environmental and part of the social information to decide "Best practicable Option" (In parallel to the SEA, a broad cost-benefit-analysis is to be carried out).

(c) Selection of Impact Items / Indicators



(Source : JICA Project Team)

Figure 8-2 SEA Approach Method for LCP

As for Environmental impact items and indicators, "Natural Environment", "Social Environment", and "Global Environment" are appropriately selected to evaluate the LCP Scenario, based on JICA Guidelines for Environmental and Social Considerations.

Indicators to evaluate each impact items are shown in the below table.

Table 8-1 Items and Indicators for Evaluation of LCP Scenario

	Evaluation Item	Detailed Indicator
Natural Environment	Geology	Landscape (Subsidence)
	Soil	Erosion
		Disposal (Incl. Coal ash, etc.)
		Leak (Hazardous materials)
		Abruption of top soil / Submersion
	Water Quality	Modification (Drainage patterns)
		Sedimentation / Contamination (River / Ocean)
		Spoil / Leak (Hazardous materials)
	Air Quality	Equipment emission / dust
	Noise/Vibration	Heavy equipment
		Disruption/blast by traffic
	Aesthetic resources	Disruption (Views)
		Degradation (Landscape)
	Flora/Ecosystem	Deforestation/destruction (vegetation)
	"Terrestrial Fauna/Ecosystem"	Loss/fragmentation (Habitat-breeding, nesting)
		Disturbance (migratory Bird/Spawning Fish)
	Protected Areas	(National Parks/ Ramsar Sites)
Social Environment	"Involuntary Resettlement"	Loss of a means of Livelihood
		Creation / Contribution of Local Economy
	Life Environment	Deterioration of Habitat by Pollution / Loss of Historical Culture or Heritage
Global Environment	Greenhouse Gases	Emission Volume of CO_2

8.2.2 Analysis Methods on Survey Results

Matrix-Evaluation on Environmental and Social Considerations for each scenario alternative is carried out through the following three chronological steps.

(a) Anticipated Environmental Impacts caused by implementation of each scenario are to be confirmed by GIS analysis of the areas in which power development projects are planned in each scenario alternative.

(b) Evaluation items are three categories of a) Natural environment, b) Social Environment and c) Global Environment and evaluation methods are as follows.

(c) The magnitude of impacts on environment caused by each development project is digitalized on the above mentioned three evaluation items (average score is adopted when there are plural development projects) as shown in Table 8-2. The scores are summarized in the matrix and quantitatively evaluated. And then, the scores of each power development plan indicated in the development scenarios are summed up and the comparative evaluation is carried out from the viewpoints of Environmental and Social Considerations.

Besides, JICA Project Team also proposes an environmentally preferable scenario from the following 3 aspects.

i) Human-living environment preference: The most important item is that the human directly or easily can notice its adverse impact to its health
ii) Natural environment conservation preference: The most important item needs to have a great effect on natural resources such as habitats of flora/fauna and natural ecosystem
iii) Global environment conservation preference: The most important item needs to have a great effect on global adverse impacts such as air emissions of CO_2.

Quantitative evaluation is to be carried out based on the impact evaluation criteria, which score varies 5 levels from 0 to 4, as illustrated in the below table.

Table 8-2 Impact Evaluation Criteria for Environmental and Social Considerations

Score	Evaluation Standard
0	- Significant negative is expected and mitigation is difficult.
1	- Significant negative is expected and mitigation is viable.
2	- Minor negative impact is expected and mitigation is viable
3	- Minor negative impact is expected and mitigation is not needed.
4	- Positive impact is expected

(Source : JICA Project Team)

8.3 Analysis of Survey Results and SEA

8.3.1 Matrix Evaluation and Analysis on PDP (Base Scenario)

Matrix evaluation of anticipated items of environmental & social considerations was executed about each project listed in PDP (Base Scenario) which site location is fixed.

(1) Hydropower development project (Reservoir type)

(a) Matrix evaluation

Evaluation results of Environmental & Social Considerations on 45 hydropower projects which are listed in PDP (Base Scenario) are shown in Table 8-3.

Table 8-3 Matrix of Environmental Impact Assessment (Reservoir Type Hydropower)

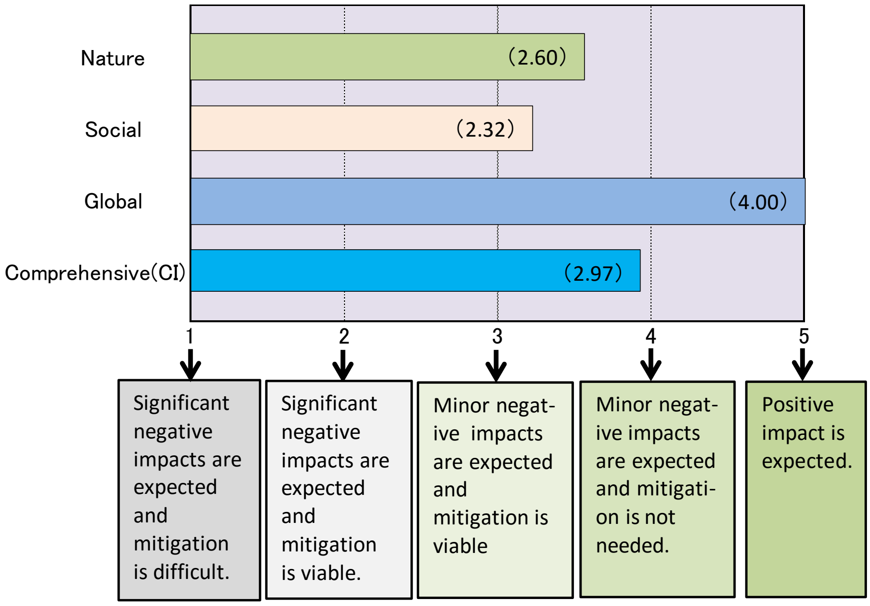
Name of Project	Natural Environment																	Sub	Social Environment			Sub	Global	Total
	Geology	Soil				Water Quality			Air Quality	Noise/Vibration		Aesthetic resources		Flora/Ecosystem	Terrestrial Fauna?Ecosystem		Protected Areas		Involuntary Resettlement		Socio-economic		Greenhouse Gases	
	Land-subsidence	Erosion	Compaction(Soil/Ash)	Spoil/Leak (Hazardous materials)	Disposal (Cleared debris)	Modification (Drainage patterns)	Sedimentation/River,Sea (Contamination)	Spile/leak (Hazardous materials)	Equipment emission/dust	Heavy equipment	Disruption/blast by trafic	Disruption (Views)	Degradation (Landscape)	Deforestation/destruction (vegetation)	Loss/fragmentation (Habitat-breeding,nesting)	Disturbance (migratory Bird/Spawning Fish)	Protected Areas		Displacement/Relocation	Sedimentation/River,Sea (Contamination)	Deterioration (Environmental standards, heitage)		Voluml of CO2	
Basho	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Akhori	3	2	2	3	2	3	3	3	3	3	3	3	3	3	1	1	0	41	0	3	3	6	4	4
Sub Total	6	4	4	6	4	6	6	6	6	6	6	6	6	6	4	4	3		2	6	6		8	
Total																		89.00				14		8
Natural Evaluation 89x 1/136 : 0.64x4 2.60(A)																		2.60						
Social Evaluation/14x 1/24 : 0.58x4 2.32(B)																						2.32		
Global Evaluationv8x 1/8 : 1.00x4 4.00(C)																							4.00	
Comprehensive Evaluation (A+B+C)/3																								2.97

Note1) : Expansion projects of the existing reservoirs are counted as a pondage type, since the reservoirs are not newly developed. The Diamer Basha (4,500MW), Akhori (600MW) HPP are counted as a Reservoir type hydropower.

(Source : JICA Project Team)

(b) Analysis on matrix evaluation

Impact indicator to Natural Environment by hydropower is "2.60", to Social Environment is "-2.32", and to Global Environment is "4.00", and the comprehensive indicator to Environmental and Social Considerations is "2.97".



(Source : JICA Project Team)

Figure 8-3 Indicator of Environmental & Social Considerations (Reservoir)

(c) Evaluation of hydropower development projects from the viewpoints of SEA

1) Natural environment evaluation

1 project out of 2 projects which are listed in LCP by 2035 are located inside of Nature Protected area. This sites is classified into "Significant negative is expected and mitigation is difficult".

2) Social environment evaluation

Since Diamer Basha Project, 4500MW, is planned to develop a large reservoir in line with 29,000 resettlements, this will cause significant impacts on the social environment such as a large scale of involuntary resettlement.

3) Global environment evaluation

Except for construction stage which emits Green House Gas (15g-CO_2/kWh : IPCC, 2009), hydro power projects contribute to reduce CO_2 during operation. It is estimated based on CDM of Azad-Pattan (640MW, 3064GWh, CDM ; 1.46 million ton/year) that 2 hydropower projects can reduce around 7.45 million ton-CO_2 /year. Therefore, hydropower projects are classified into "Positive impacts is expected and contribute to Environmental and Social Considerations".

4) Comprehensive evaluation

Total indicator is 2.97 and it is classified into the project of "Minor negative impact is expected and mitigation is not needed.".

(2) Hydropower development project (Pondage type)

(a) Matrix evaluation

Evaluation results of Environmental & Social Considerations on 45 hydropower projects which are listed in PDP (Base Scenario) are shown in Table 8-4.

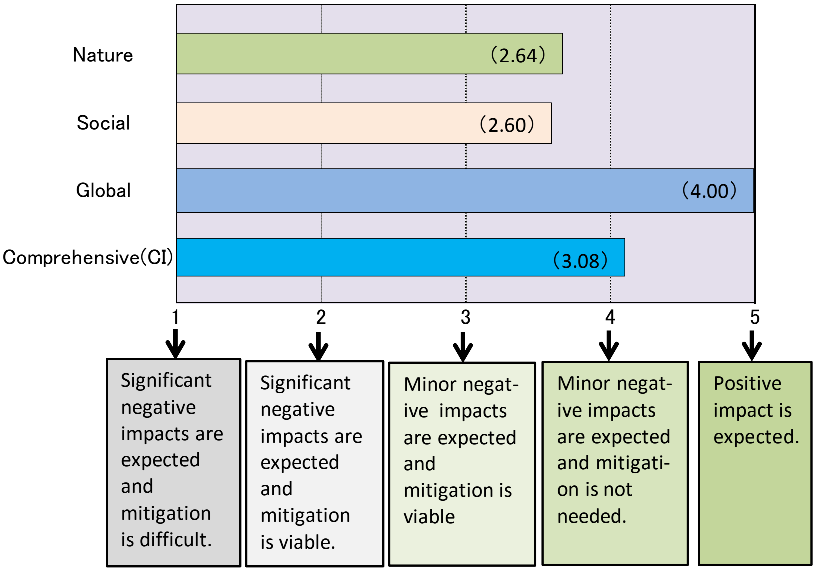
Table 8-4 Matrix of Environmental Impact Assessment (Pondage Type Hydropower)

Name of Project	Natural Environment																	Sub	Social Environment			Sub	Global	Total
	Geology	Soil				Water Quality			Air Quality	Noise/Vibration		Aesthetic resources		Flora/Ecosystem	Terrestrial Fauna?Ecosystem		Protected Areas		Involuntary Resettlement		Socio-economic		Greenhouse Gases	
	Land-subsidence	Erosion	Compaction(Soil/Ash)	Spoil/Leak (Hazardous materials)	Disposal (Cleared debris)	Modification (Drainage patterns)	Sedimentation/River,Sea (Contamination)	Spile/leak (Hazardous materials)	Equipment emission/dust	Heavy equipment	Disruption/blast by trafic	Disruption (Views)	Degradation (Landscape)	Deforestation/destruction (vegetation)	Loss/fragmentation (Habitat-breeding,nesting)	Disturbance (migratory Bird/Spawning Fish)	Protected Areas		Displacement/Relocation	Sedimentation/River,Sea (Contamination)	Deterioration (Environmental standards, heitage)		Voluml of CO2	
Neelum Jhelum	3	2	2	3	2	2	2	3	3	3	3	3	3	3	3	3	3	46	2	3	3	8	4	4
Golen Gol	3	2	2	3	2	3	2	3	3	3	3	3	3	3	3	2	3	46	2	3	3	8	4	4
Tarbela 4th Ext.	3	2	2	3	2	2	2	3	3	3	3	3	3	3	3	3	3	46	2	3	3	8	4	4
Kayal Khwar	3	2	2	3	2	3	2	3	3	3	3	3	3	3	3	3	3	47	2	3	3	8	4	4
Kurram Tangi	3	2	2	3	2	3	2	3	3	3	3	2	3	3	3	3	3	46	2	3	3	8	4	4
Tarbela 5th Ext.	3	2	2	3	2	3	2	3	3	3	3	3	3	3	3	3	3	47	2	3	3	8	4	4
Phander	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	2	3	47	2	3	3	8	4	4
Mangla	3	2	2	3	2	2	2	3	3	3	3	3	3	2	2	2	3	43	2	3	3	8	4	4
Dasu 1st stage	3	2	2	3	2	3	3	3	3	3	3	0	3	2	1	2	0	38	0	3	0	3	4	4
Diamer Basha	3	2	2	3	2	2	2	3	3	3	3	0	3	2	1	2	3	39	0	3	0	3	4	4
Dasu 2nd stage	3	2	2	3	2	3	3	3	3	3	3	0	3	2	1	2	0	38	0	3	0	3	4	4
Bunji	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	2	3	47	2	3	3	8	4	4
Patrind	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Gulpur	3	2	2	3	2	3	3	3	3	3	3	2	3	1	1	0	0	37	2	3	3	8	4	4
Sehra	3	2	2	3	2	3	3	3	3	3	3	3	3	0	1	0	0	37	2	3	3	8	4	4
Karot HPP	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Azad-Pattan	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Sukikinari	3	2	2	3	2	3	3	3	3	3	3	3	3	2	2	1	0	41	2	3	3	8	4	4
Kotli	3	2	2	3	2	3	3	3	3	3	3	3	3	0	1	1	0	38	2	3	3	8	4	4
Chakoti-Hattian	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Kohala	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Kaigah	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	2	3	47	2	3	3	8	4	4
Madian	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	2	3	47	2	3	3	8	4	4
Asrit-Kedam	3	2	2	3	2	3	3	3	3	3	3	3	3	3	2	2	3	46	2	3	3	8	4	4
Mahl	3	2	2	3	2	3	3	3	3	3	3	3	3	3	2	2	3	46	2	3	3	8	4	4
Palas Valley (L)	3	2	2	3	2	3	3	3	3	3	3	0	3	3	3	2	0	41	3	3	3	9	4	4
Palas Valley (M)	3	2	2	3	2	3	3	3	3	3	3	0	3	3	3	2	0	41	3	3	3	9	4	4
Palas Valley(U)	3	2	2	3	2	3	3	3	3	3	3	0	3	3	3	2	0	41	3	3	3	9	4	4
Spat Gah (L)	3	2	2	3	2	3	3	3	3	3	3	0	3	3	3	2	3	44	2	3	3	8	4	4
Spat Gah (M)	3	2	2	3	2	3	3	3	3	3	3	0	3	3	3	2	3	44	2	3	3	8	4	4
Spat Gah (UL)	3	2	2	3	2	3	3	3	3	3	3	0	3	3	3	2	3	44	2	3	3	8	4	4
Lawi	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Mundah	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Thakot	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Karrang	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	2	3	3	8	4	4
Rajdhami	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	3	3	3	9	4	4
Kalam-Astit	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	3	3	3	9	4	4
Shashghai-Zhe.	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	3	3	3	9	4	4
Matiltan	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	3	3	3	9	4	4
Gabral Kalam	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	3	3	3	9	4	4
Shogo-Sin	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	3	3	3	9	4	4
Taunsa	3	2	2	3	2	3	3	3	3	3	3	3	3	1	1	1	0	39	3	3	3	9	4	4
Sharmal	3	2	2	3	2	3	3	3	3	3	3	3	3	3	3	3	3	48	3	3	3	9	4	4
Sub-Total	129	86	86	129	86	125	121	129	129	129	129	100	129	114	111	100	99		91	129	120		172	
Total																		1931				340		172
Natural Evaluationc1931x 1・2924 : 0.66x4 2.64(A)																		2.64						
Social Evaluation 340x 1/516 : 0.65x4(B)																						2.60		
Global Evaluation 164x1/164 : 1.00x4(C)																							4.00	
Comprehensive Evaluation (A+B+C)/3																								3.08

(Source : JICA Project Team)

(b) Analysis on matrix evaluation

Impact indicator to Natural Environment by hydropower is “2.64”, to Social Environment is “-2.60”, and to Global Environment is “4.00”, and the comprehensive indicator to Environmental and Social Considerations is “3.08”.



(Source : JICA Project Team)

Figure 8-4 Indicator of Environmental & Social Considerations (Pondage)

(c) Evaluation of hydropower development projects from the viewpoints of SEA

1) Natural environment evaluation

10 projects out of 41 projects which are listed in LCP by 2035 are located inside of Nature Protected area. These sites are classified into "Significant negative is expected and mitigation is difficult". Run-of river with pondage type projects which construction activities cannot help but affect tentatively negative impact on inhabitation and growth of fauna and flora, however, the projects are judged not to yield permanent negative impacts on the natural environment in the whole project area.

2) Social environment evaluation

Since run-of river with pondage type hydropower projects do not need large reservoirs, those will not cause significant impacts on the social environment such as a large scale of involuntary resettlement.

3) Global environment evaluation

Except for construction stage which emits Green House Gas (15g-CO_2/kWh : IPCC, 2009), hydro power projects contribute to reduce CO_2 during operation. It is estimated based on CDM of Azad-Pattan (640MW, 3064GWh, CDM ; 1.46 million ton/year) that 41 hydropower projects can reduce around 69.6 million ton-CO_2/year. Therefore, hydropower projects are judged to promote to develop positively from the viewpoints of reduction of GHG emission.

4) Comprehensive evaluation

Total indicator is 3.08 and it is classified into "Minor negative impact is expected and mitigation is not needed.".

(3) Coal fired thermal power development plan

(a) Matrix evaluation

Evaluation results of Environmental & Social Considerations on 14 coal fired thermal power projects which are listed in PDP (Base Scenario) are shown in Table 8-5.

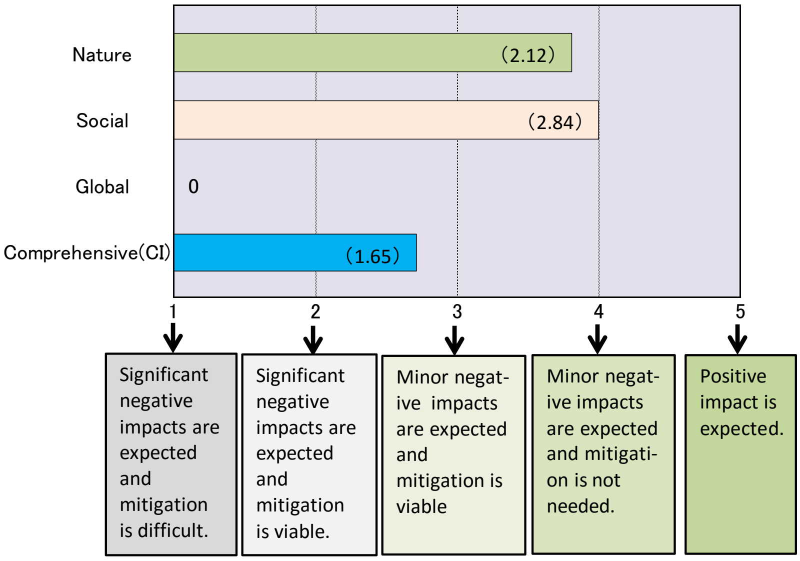
Table 8-5 Matrix of Environmental Impact Assessment (Coal Fired TPP)

Name of Project	Natural Environment																	Sub	Social Environment			Sub	Global	Total
	Geology	Soil				Water Quality			Air Quality	Noise/Vibration		Aesthetic resources		Flora/Ecosystem	Terrestrial Fauna?Ecosystem		Protected Areas		Involuntary Resettlement	Socio-economic			Greenhouse Gases	
	Land-subsidence	Erosion	Compaction(Soil/Ash)	Spoil/Leak (Hazardous materials)	Disposal (Cleared debris)	Modification (Drainage patterns)	Sedimentation/River,Sea (Contamination)	Spile/leak (Hazardous materials)	Equipment emission/dust	Heavy equipment	Disruption/blast by trafic	Disruption (Views)	Degradation (Landscape)	Deforestation/destruction (vegetation)	Loss/fragmentation (Habitat-breeding,nesting)	Disturbance (migratory Bird/Spawning Fish)	Protected Areas		Displacement/Relocation	Contribution to local economy	Deterioration (Environmental standards, heitage)		Voluml of CO2	
Jamshoro	3	3	0	2	3	3	3	2	2	2	2	3	3	3	3	3	3	−8	2	4	3	9	0	0
Lakhra	3	3	0	2	3	3	3	2	2	2	2	3	3	3	3	3	3	43	3	4	3	10	0	0
Sahiwal PPDB−1	3	3	0	2	3	3	3	2	2	2	2	3	3	3	3	3	3	−8	3	4	3	10	0	0
Sahiwal PPDB−2	3	3	0	2	3	3	3	2	2	2	2	3	3	3	3	3	3	−8	3	4	3	10	0	0
Sahiwal PPDB−3.4,5	3	3	0	2	3	3	3	2	2	2	2	3	3	3	3	3	3	43	3	4	3	10	0	0
Thar Coal Block II	2	0	0	2	0	2	2	2	2	2	2	1	3	2	1	3	3	29	1	4	2	7	0	0
Port Qasim Sinohydro	3	3	0	2	3	2	3	2	2	2	2	3	3	2	3	3	3	41	3	4	3	10	0	0
Thar Coal Block I	2	0	0	2	0	2	2	2	2	2	2	1	3	2	3	0	0	25	1	4	2	7	0	0
Salt Range PPDB	2	0	0	2	0	2	2	2	2	2	2	3	3	2	3	3	3	33	2	4	3	9	0	0
HUBCO	3	3	0	2	3	2	2	2	2	2	2	3	3	2	3	3	3	40	3	4	3	10	0	0
Thar Coal Block VI	2	0	0	2	0	2	2	2	2	2	2	1	3	2	1	3	3	29	1	4	2	7	0	0
Thar Coal Block II (Ph−3)	2	0	0	2	0	2	2	2	2	2	2	1	3	2	1	3	3	29	1	4	2	7	0	0
Thar Coal Block III	2	0	0	2	0	2	2	2	2	2	2	1	3	2	1	3	3	29	1	4	2	7	0	0
Thar Coal Block IV	2	0	0	2	0	2	2	2	2	2	2	1	3	2	1	3	3	29	1	4	2	7	0	0
Sub−Total	35	21	0	28	21	33	34	28	28	28	28	30	42	33	32	39	39		28	56	36	120	0	
Total																		499				120		0
Natural Evaluation 509x1/952 : 0.53x4(A)																		2.12						
Social Evaluation 120x1/168 : 0.71x4(B)																						2.84		
Global Evaluation 0 0(C)																							0.00	
Comprehensive Evaluation (A+B+C)/3																								1.65

(Source : JICA Project Team)

(b) Analysis on matrix evaluation

Impact indicator to Natural Environment by coal fired thermal power is “2.12”, to Social Environment is “2.84”, and to Global Environment is “0.0”, and the comprehensive indicator to Environmental and Social Considerations is “1.65”.



(Source : JICA Project Team)

Figure 8-5 Indicator of Environmental & Social Consideration (Coal Fired TPP)

(c) Evaluation of coal fired thermal power development projects from the viewpoints of SEA

1) Natural environment evaluation

Except for 4 coal fired thermal projects (Jamshoro, Lakhra, Port Qasim, Sahiwal) which use import coal, the projects have strong concerns of adverse impact on natural environment (ecosystem) by removal of its top soil. The other negative impacts are concerned on underground water, surrounding living environment caused by coal ash or treated water. Furthermore, negative impact on the living environment caused by unlimited expansion of coal ash yard are strongly concerned.

2) Social environment evaluation

Except for concern of impact on surrounding local society with resettlement in Thar Coal projects caused by a large scale of coal mining, most of the projects are not likely to have significant impacts on the surrounding people' health and safety by dust or polluted air, since these projects are planned to locate far from local communities. In point of direct and indirect economic benefits, opportunity of new employment for local people will increase in line with construction and operation & maintenance.

Therefore, the projects are classified into "Positive impacts is expected and contribute to Environmental and Social Considerations required in JICA Guideline."

3) Global environment evaluation

Even if high efficiency coal combustion technologies such as Super Critical Technology or Ultra Super Critical Technology, and Integrated Gasification Combined Cycle (IGCC) are introduced into the projects, large amount of emission of Green House Gas (GHG) is inevitable. Therefore, the projects are classified into "Significant negative impacts is expected and mitigation is difficult and then Environmental and Social Considerations is far from those of JICA Guideline."

4) Comprehensive evaluation

Total indicator is 1.65 and it is classified into "Significant negative impacts is expected and mitigation is viable". However, the indicator for global environment is 0.00 and it is classified into " Significant negative is expected and mitigation is difficult".

(4) Other fired thermal power development plan

(a) Matrix evaluation

Evaluation results of Environmental & Social Considerations on 14 projects, which location is specified, out of 35 other fired thermal power projects listed in PDP (Base Scenario) are shown in the below table.

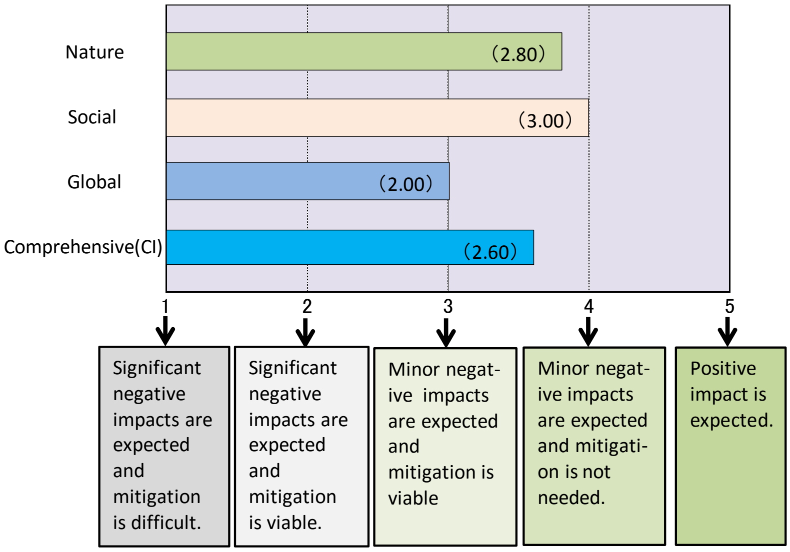
Table 8-6 Matrix of Environmental Impact Assessment (Other Fired TPP)

Name of Project	Natural Environment																	Sub	Social Environment			Sub	Global	Total
	Geology	Soil				Water Quality			Air Quality	Noise/Vibration		Aesthetic resources		Flora/Ecosystem	Terrestrial Fauna?Ecosystem		Protected Areas		Involuntary Resettlement		Socio-economic		Greenhouse Gases	
	Land-subsidence	Erosion	Compaction(Soil/Ash)	Spoil/Leak (Hazardous materials)	Disposal (Cleared debris)	Modification (Drainage patterns)	Sedimentation/River,Sea (Contamination)	Spile/leak (Hazardous materials)	Equipment emission/dust	Heavy equipment	Disruption/blast by trafic	Disruption (Views)	Degradation (Landscape)	Deforestation/destruction (vegetation)	Loss/fragmentation (Habitat-breeding,nesting)	Disturbance (migratory Bird/Spawning Fish)	Protected Areas		Displacement/Relocation	Sedimentation/River,Sea (Contamination)	Deterioration (Environmental standards, heitage)		Voluml of CO2	
Guddu Ext.	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	
Nandipur,	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	
Nooriabad Gas	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	
Bhilli Gas	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
Baloki Gas	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
Haveli Bahadur	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
Thar Coal B-V	3	3	3	3	2	3	2	2	2	2	2	3	3	3	3	3	3	45	3	4	2	9	2	2
BQPS-2	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
Korangi	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
SGTPS-2	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
KGTPS-2	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
Bin-Qasim	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
Gul Ahmed	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
Tapal Energy	3	3	3	3	3	3	3	3	2	2	2	3	3	3	3	3	3	48	3	4	2	9	2	2
Sub-Total	42	42	42	42	41	42	41	41	28	28	28	42	42	42	42	42	42		42	56	28		28	
Total																		669				126		28
Natural Evaluation 669x1/952 : 0.70x4(A)																		2.80						
Social Evaluation 126x1/168 : 0.75x4(B)																						3.00		
Global Evaluation 28x1/56 : 0.50x4(C)																							2.00	
Comprehensive Evaluation (A+B+C)/3																								2.60

(Source : JICA Project Team)

(b) Analysis on matrix evaluation

Impact indicator to Natural Environment by the other thermal power is “2.80”, to Social Environment is “3.00”, and to Global Environment is “2.00”, and the comprehensive indicator to Environmental and Social Considerations is “2.60”.



(Source : JICA Project Team)

Figure 8-6 Indicator of Environmental & Social Consideration (Other Fired TPP)

(c) Evaluation of other thermal power development projects from the viewpoints of SEA

1) Natural environment evaluation

Since 12 other thermal projects except for 2 projects (Nooriabaad, Thar Coal Block V) are expansion projects located in the existing plant site area, adverse impact on natural environment (ecosystem) is deemed minor. As for Nooriabaad, Thar Coal Block V, since both projects are small scale, adverse impact on natural environment (ecosystem) is deemed minor.

2) Social environment evaluation

Most of the projects are not likely to have significant impacts on the surrounding people' health and safety by dust or polluted air, since the projects are located far from social communities. In point of direct and indirect economic benefits, opportunity of new employment for local people will increase in line with construction and operation & maintenance. Therefore, the projects are classified into "Positive impacts is expected".

3) Global environment evaluation

Since high efficiency generation technology of the advanced combined cycle is planned to introduce, amount of emission of Green House Gas (GHG) is not so large. Therefore, the projects are classified into " Significant negative impacts is expected and mitigation is viable ".

4) Comprehensive evaluation

Total indicator is 2.60 and it is classified into " Minor negative impact is expected and mitigation is viable".

(5) Wind power development plan

(a) Matrix evaluation

Evaluation results of Environmental & Social Considerations on 27 projects, which location is specified, out of 30 other thermal power projects listed in PDP (Base Scenario) are shown in Table 8-7.

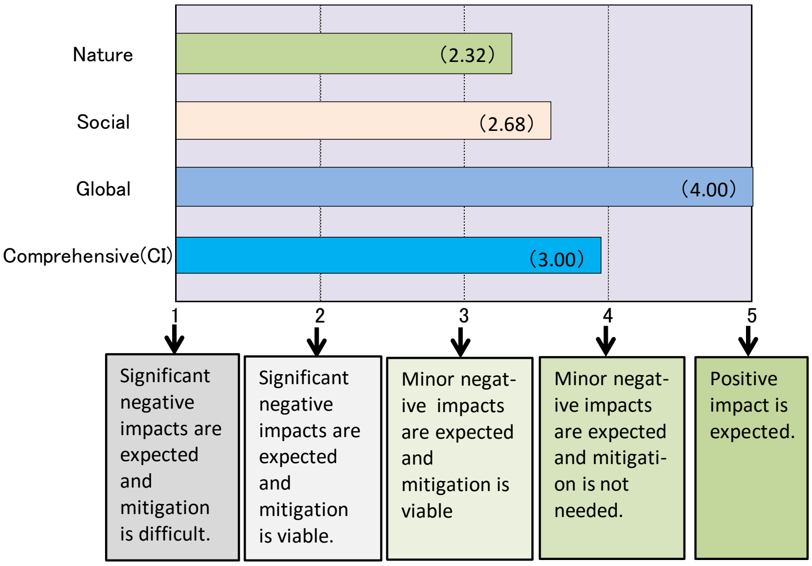
Table 8-7 Matrix of Environmental Impact Assessment (Wind Power)

Name of Project	Natural Environment																	Sub	Social Environment			Sub	Global	Total
	Geology	Soil				Water Quality			Air Quality	Noise/Vibration		Aesthetic resources		Flora/Ecosystem	Terrestrial Fauna?Ecosystem		Protected Areas		Involuntary Resettlement		Socio-economic		Greenhouse Gases	
	Land-subsidence	Erosion	Compaction(Soil/Ash)	Spoil/Leak (Hazardous materials)	Disposal (Cleared debris)	Modification (Drainage patterns)	Sedimentation/River,Sea (Contamination)	Spile/leak (Hazardous materials)	Equipment emission/dust	Heavy equipment	Disruption/blast by trafic	Disruption (Views)	Degradation (Landscape)	Deforestation/destruction (vegetation)	Loss/fragmentation (Habitat-breeding,nesting)	Disturbance (migratory Bird/Spawning Fish)	Protected Areas		Displacement/Relocation	Contribution to local economy	Deterioration (Environmental standards, heitage)		Volumi of CO2	
Foundation Energy-I	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Foundation Energy-II	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Three Gorges	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Sapphire Wind Pow.	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Metro Power	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Sachal Energy	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Yunus Energy	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Hydro China	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Tenaga G/L	3	2	2	3	2	2	2	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Master Wind	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Zephyr Power	3	2	2	3	2	2	2	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Gul Ahmed	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Wind Eagle L-I	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Wind Eagle L-II	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
HAWA Holding	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	3		4	
United Energy	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Jhimpir Wind	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	3		4	
Tapal Wind	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
NBT Wind	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Titan Energy	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
China Sunec	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Tricon Boston -I	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Tricon Boston-II	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Tricon Boston-III	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Burj Wind	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
Hartford Alternate	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
WesternEnergy	3	2	3	3	2	3	3	3	3	1	3	2	0	3	2	1	3		3	3	2		4	
United Energy	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*		*	*	*			
Zaver Petroleum	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*		*	*	*			
Trident Energy	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*	*		*	*	*			
Sub-Total	81	54	79	81	54	79	79	81	81	27	81	54	0	81	54	27	81		81	81	56		108	
Total																		1074				218		108
Natural Evaluation 1074x1/1836 : 0.58x4(A)																		2.32						
Social Evaluation 218x1/324 : 0.67x4(B)																						2.68		
Global Evaluation 108x1/108 : 1 x4(C)																							4.00	
Comprehensive Evaluation (A+B+C)/3																								3.00

(Source : JICA Project Team)

(b) Analysis on matrix evaluation

Impact indicator to Natural Environment by wind power is “2.32”, to Social Environment is “2.68”, and to Global Environment is “4.00”, and the comprehensive indicator to Environmental and Social Considerations is “3.00”.



(Source : JICA Project Team)

Figure 8-7 Indicator of Environmental & Social Consideration (Wind Power)

(c) Evaluation of wind power development projects from the viewpoints of SEA

1) Natural environment evaluation

All wind projects are located in Sindh province and 80% of them are planned to construct in Jhimpir district (others are Gkaro-2, Bhambore-1 and Kuttikum-1). Since all project areas are located under "Indus Flyway", which is well-known internationally as the migratory bird flying route, it is concerned that accidental death of birds occurs due to bird strike to the wind power facilities.

2) Social environment evaluation

Most projects are not likely to have negative impacts on surrounding people' health and safety by noise, vibration, low frequency waves, shadow and flicker, since the projects sites are planned to locate far from local communities. In view of direct and indirect economic benefits, opportunity of new employment for local people will not be expected to increase.

3) Global environment evaluation

Wind power project contributes to CO_2 reduction, since it has zero emission of GHG during operation except construction. Therefore, these facilities are thought to put the high development priority.

4) Comprehensive evaluation

Total indicator is 3.00 and it is classified into "Minor negative impact is expected and mitigation is viable".

(6) Solar power development plan

(a) Matrix evaluation

Evaluation results of Environmental & Social Considerations on 6 solar power projects listed in PDP (Base Scenario) are shown in Table 8-8.

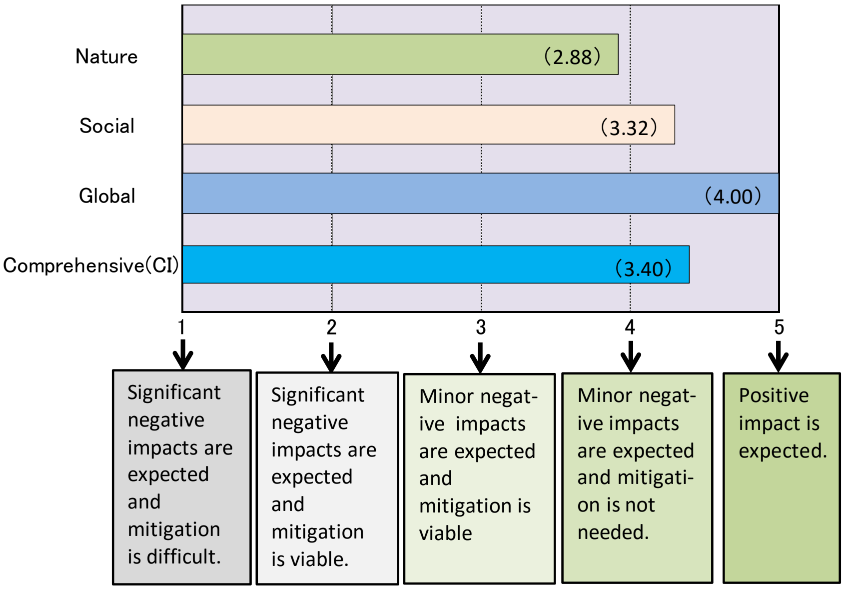
Table 8-8 Matrix of Environmental Impact Assessment (Solar Power)

	Natural Environment																	Sub	Social Environment			Sub	Global	Total
	Geology	Soil				Water Quality			Air Quality	Noise/Vibration		Aesthetic resources		Flora/Ecosystem	Terrestrial Fauna/Ecosystem		Protected Areas		Involuntary Resettlement		Socio-economic		Greenhouse Gases	
Name of Project	Land-subsidence	Erosion	Compaction(Soil/Ash)	Spoil/Leak (Hazardous materials)	Disposal (Cleared debris)	Modification (Drainage patterns)	Sedimentation/River,Sea (Contamination)	Spile/leak (Hazardous materials)	Equipment emission/dust	Heavy equipment	Disruption/blast by trafic	Disruption (Views)	Degradation (Landscape)	Deforestation/destruction (vegetation)	Loss/fragmentation (Habitat-breeding,nesting)	Disturbance (migratory Bird/Spawning Fish)	(National Parks/ Ramsar Sites)		Displacement/Relocation	Sedimentation/River,Sea (Contamination)	Deterioration (Environmental standards, heitage)		Voluml of CO2	
Quaid-e-Azam (Phase-I) 100MW	3	3	3	3	3	3	3	3	3	3	3	2	3	3	2	3	3	49	3	4	3	10	4	4
Quaid-e-Azam (Phase-II) 300MW	3	3	3	3	3	3	3	3	3	3	3	2	3	3	2	3	3	49	3	4	3	10	4	4
Quaid-e-Azam (Phase-III) 600MW	3	3	3	3	3	3	3	3	3	3	3	2	3	3	2	3	3	49	3	4	3	10	4	4
M/s. Integrated Power Solution 50MW	3	3	3	3	3	3	3	3	3	3	3	2	3	3	2	3	3	49	3	4	3	10	4	4
M/s.Jafri & Associates 50MW	3	3	3	3	3	3	3	3	3	3	3	2	3	3	2	3	3	49	3	4	3	10	4	4
M/s. Solar Blue 50MW	3	3	3	3	3	3	3	3	3	3	3	2	3	3	2	3	3	49	3	4	3	10	4	4
Sub-Total	18	18	18	18	18	18	18	18	18	18	18	12	18	18	12	18	18		18	24	18		24	
Total																		294				60		24
Natural Evaluation 294x 1/408 : 0.72x4(A)																		2.88						
Social Evaluation 60x1/72 : 0.83x4(B)																						3.32		
Global Evaluation 24x1/24 : 1x4©																							4.00	
Comprehensive Evaluation (A+B+C)/3																								3.40

(Source : JICA Project Team)

(b) Analysis on matrix evaluation

Impact indicator to Natural Environment by solar power is “2.88”, to Social Environment is “3.32”, and to Global Environment is “4.00”, and the comprehensive indicator to Environmental and Social Considerations is “3.40”.



(Source : JICA Project Team)

Figure 8-8 Indicator of Environmental & Social Consideration (Solar Power)

(c) Evaluation of solar power development projects from the viewpoints of SEA

1) Natural environment evaluation

There are some concerns of adverse impacts on natural terrestrial habit of Fauna and Flora due to broad shut out of sola light by solar panel.

2) Social environment evaluation

Most projects are not likely to have negative impacts on local society by reflected light, since the projects sites are planned to locate far from local communities. In view of direct and indirect economic benefits, opportunity of new employment for local people will be expected to increase in line with construction and operation & maintenance.

3) Global environment evaluation

Solar power project contributes to CO_2 reduction, since it has zero emission of GHG during operation except construction. Therefore, these facilities are thought to put the high development priority.

4) Comprehensive evaluation

Total indicator is 3.40 and it is classified into “Minor negative impact is expected and mitigation is viable”.

(7) Biomass power development Plan

(a) Matrix evaluation

Evaluation results of Environmental & Social Considerations on 9 biomass power projects listed in PDP (Base Scenario) are shown in Table 8-9.

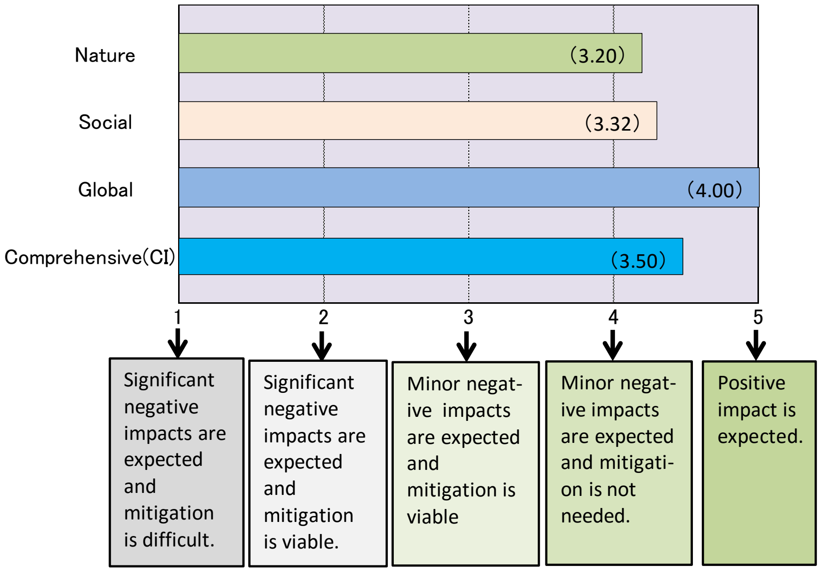
Table 8-9 Matrix of Environmental Impact Assessment (Biomass Power)

Name of Project	Natural Environment																	Sub	Social Environment			Sub	Global	Total
	Geology	Soil				Water Quality			Air Quality	Noise/Vibration		Aesthetic resources		Flora/Ecosystem	Terrestrial Fauna?Ecosystem		Protected Areas		Involuntary Resettlement		Socio-economic		Greenhouse Gases	
	Land-subsidence	Erosion	Compaction(Soil/Ash)	Spoil/Leak (Hazardous materials)	Disposal (Cleared debris)	Modification (Drainage patterns)	Sedimentation/River,Sea (Contamination)	Spile/leak (Hazardous materials)	Equipment emission/dust	Heavy equipment	Disruption/blast by trafic	Disruption (Views)	Degradation (Landscape)	Deforestation/destruction (vegetation)	Loss/fragmentation (Habitat-breeding,nesting)	Disturbance (migratory Bird/Spawning Fish)	Protected Areas		Displacement/Relocation	Sedimentation/River,Sea (Contamination)	Deterioration (Environmental standards, heitage)		Voluml of CO2	
Chiniot Power	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	50	3	4	3	10	4	4
RYK Mills	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	50	3	4	3	10	4	4
Hamza Sugar Mills	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	50	3	4	3	10	4	4
SSSJDBio energy	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	50	3	4	3	10	4	4
Kamalia Sugar Mills	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	50	3	4	3	10	4	4
Sugar Mills	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	50	3	4	3	10	4	4
Almoiz Industries	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	50	3	4	3	10	4	4
Layyah Sugar Mills	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	50	3	4	3	10	4	4
Etihad Power Gen.	3	3	3	3	3	3	3	3	3	3	2	3	3	3	3	3	3	50	3	4	3	10	4	4
Sub-Total	27	27	27	27	27	27	27	27	27	27	18	27	27	27	27	27	27		27	36	27		36	
Total																		450				90		36
Natural Evaluation 450x1/612 : 0.80x4(A)																		3.20						
Social Evaluation 90x1/108 : 0.83x4(B)																						3.32		
Global Evaluation 36x1/36 : 1 x4(C)																							4.00	
Comprehensive Evaluation (A+B+C)/3																								3.50

(Source : JICA Project Team)

(b) Analysis on matrix evaluation

Impact indicator to Natural Environment by biomass power is “3.20”, to Social Environment is “3.32”, and to Global Environment is “4.00”, and the comprehensive indicator to Environmental and Social Considerations is “3.50”.



(Source : JICA Project Team)

Figure 8-9 Indicator of Environmental & Social Consideration (Biomass Power)

(c) Evaluation of biomass power development projects from the viewpoints of SEA

1) Natural environment evaluation

There are no concerns of adverse impacts on natural environment, since they re-use bagasse or haulm of wheat as energy source.

2) Social environment evaluation

In view of direct and indirect economic benefits, opportunity of new employment for local people will be expected to increase in line with operation & maintenance.

3) Global environment evaluation

Biomass power project contributes to CO_2 reduction, since it is estimated as zero emission of GHG in total. Therefore, these facilities are thought to put the high development priority.

4) Comprehensive evaluation

Total indicator is 3.50 and it is classified into "Minor negative impact is expected and mitigation is viable".

8.3.2 Priority Power Development Scenario from the Viewpoints of SEA

Priority of project implementation of each project listed in LCP from the viewpoints of three aspects, Natural Environment, Social Environment and Global Environment, are described as follows (refer to Figure 8-10 and Figure 8-11).

- **Human-living environment (Social environment) priority scenario**

  Priority of power development from the viewpoints of human-living environment (Social Environment) is ordered as (i) Biomass power (i) Solar power (iii) Gas fired thermal power (iv) Coal fired thermal power (v) Wind power (vi) Hydropower (Pondage Type) (vii) Hydropower (Reservoir Type).

  The reasons of these order are:

  1) Indicators of Biomass Power and Solar Power are the same as 3.32 and it is classified into "Minor indirect negative impact is expected and Contribute to Environmental and Social Considerations". Because it is deemed that these power plants have no adverse impacts on human-living of local people and contribute to the local economy by yielding employment opportunities for them.
  2) Indicators of Coal Fired Thermal Power and Gas Fired Thermal Power are 2.84 and 3.00, respectively, and they are classified into "Minor negative impact is expected and mitigation is viable". These projects have little adverse impacts on human-living of local people, since their project site is located far from the local communities, and contribute to local economy by yielding employment opportunities for them.
  3) Indicator of Hydropower (Reservoir Type) is 2.60 and is ranked in low priority because there are concerns of resettlement or land acquisition. Indicator of Wind Power is 2.68 and is also ranked in low priority because that has negative impact of noise and so on and is likely not to yield employment opportunities for local people. But they are classified into "Minor negative impact is expected and mitigation is viable".

- **Natural environment conservation priority scenario**

  Priority of power development from the viewpoints of natural environment conservation is ordered as (i) Biomass power (i) Solar power (iii) Gas fired thermal power (iv) Hydropower (Pondage Type) (v) Hydropower (Reservoir Type) (vi) Wind power (vii) Coal fired thermal power.

The reasons of these order are:

4) Indicator of Biomass Power is 3.20, that of Solar Power is 2.88 and that of Gas fired TPP is 2.12. All of them are classified into "Minor negative impact is expected and mitigation is not needed".

5) Indicator of Coal Fire Thermal Power is the lowest as 2.12 and Indicator of Biomass Power is the highest as 3.20. There is about 1.5 times gap between them. Because the planned coal fired TPP may cause adverse impacts on the surrounding nature by removal of top-soil and unlimited stock of coal ash. Indicator of Wind Power is lower as 2.32 next to coal fired thermal power, because it has strong concerns of adverse impacts on migratory birds and aquatic birds by bird-strike, since most project sites are planned to locate near the important wetland or lakes in the south part of Pakistan which is used for birds to winter, breed and nest.

6) Indicator of Hydropower is not so low, as that of Reservoir type is 2.60 and that of Pondage type is 2.64. Because most hydropower projects stand off the important or sensitive areas for the nature such as the national parks or the wildlife reserve.

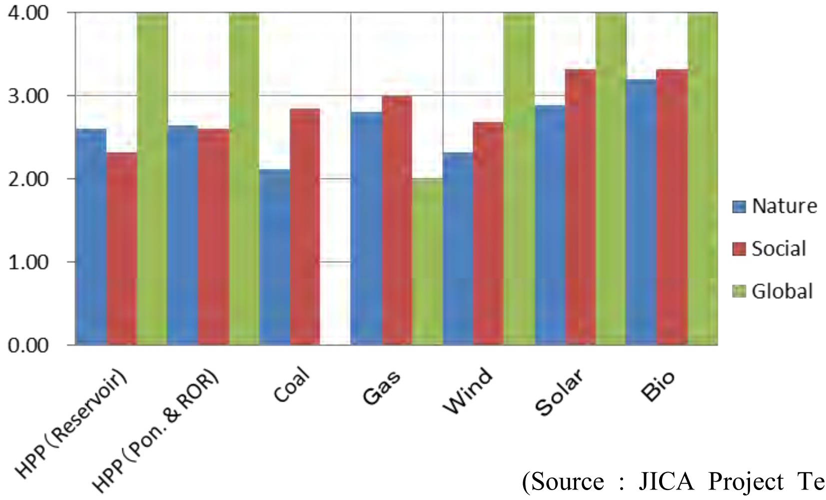
- **Global environment conservation priority scenario**

  Priority of power development from the viewpoints of global environment conservation is ordered as (i) Hydropower (Reservoir and Pondage type) (i) Biomass power (i) Solar power (i) Wind power (vi) Gas fired thermal power (vii) Coal fired thermal power.

The reasons of these order are:

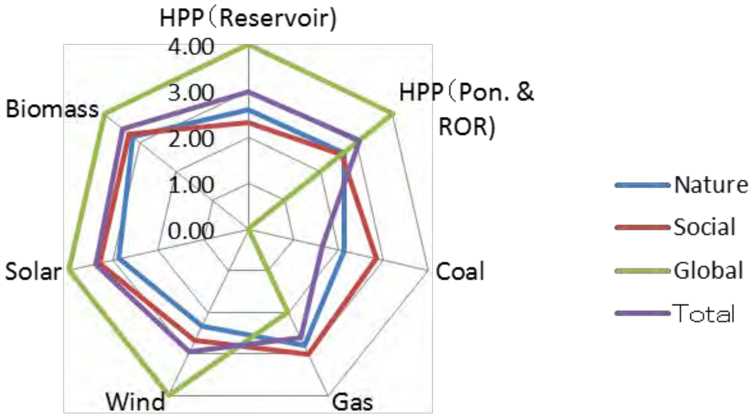
7) Indicator of Coal Fired TPP is 0.00, because carbon content of coal and its quantity of CO_2 per unit of generated energy are the highest among thermal power plants. A large amount of GHG is generated by coal fired TPP, even if the clean coal technologies such as ultra-supercritical (USC) technology and integrated gasification combined cycle (IGCC) are introduced. Therefore, it is classified into "Significant negative impact is expected and mitigation is difficult". Furthermore, 4 projects of Jamshoro, Lakhra, Port Qusim and Sahiwal are designed to use import coal which requires more primary energy for transportation of coal from an import harbor to the project sites, therefore, the priority order of these coal fired TPPs is to be lowered in view of global environment conservation.

8) Indicator of Gas Fired Thermal Power is 2.00 which is one third of that of coal fired thermal power, since CO_2 emission intensity of LNG fired thermal power of 0.0135tc/GJ is almost half of that of coal fired thermal power of 0.0247tc/GJ. It is classified into "Minor negative impact is expected and mitigation is viable".



(Source : JICA Project Team)

Figure 8-10 Indicator on Environmental & Social Environment Considerations of each Power Source Development



(Source : JICA Project Team)

Figure 8-11 Radar Chart of Indicator on Environmental & Social Environment Considerations of each Power Source Development

8.3.3 Environmental Impact Indicator of Each Power Source

Expected Environmental Impact Indicator and their Comprehensive Impact Indicator caused by implementation of each project planned in LCP are shown in the below table.

Table 8-10 Environmental Impact Indicator of Each Power Source

Indicator / Type of Power	Environmental Impact Indicator			
	Comprehensive Impact Indicator	Natural Environment	Social Environment	Global Environment
Hydro Power (Reservoir)	2.97	*2.60*	*2.32*	*4.00*
Hydro Power (Pondage)	3.08	*2.64*	*2.60*	*4.00*
Coal Fired T.P.P	1.65	*2.12*	*2.84*	*0*
Non Coal Fired T.P.P	2.60	*2.80*	*3.00*	*2.00*
Wind P.P	3.00	*2.32*	*2.68*	*4.00*
Solar P.P	3.40	*2.88*	*3.32*	*4.00*
Biomass P.P	3.50	*3.20*	*3.32*	*4.00*

8.3.4 Carbon Dioxide Emission of Base Scenario

CO_2 reduction by renewable energy power source development is estimated from the viewpoints of CDM, CO_2 reduction by wind power of 100MW (Gharo-Keti Bandar) can be 135,000 ton-CO_2/year (AEDB, 2025-Power Sector Situation in Pakistan). Solar power of 50MW (Cholistan, 79,147MWh) can contribute to CO_2 reduction of 41,500 ton-CO_2/year (Pakistan CDM Executive Board). And hydropower of 640MW (Azad-Pattan, 3,064GWh) can contribute to CO_2 reduction of 1,400,000 ton-CO_2/year.

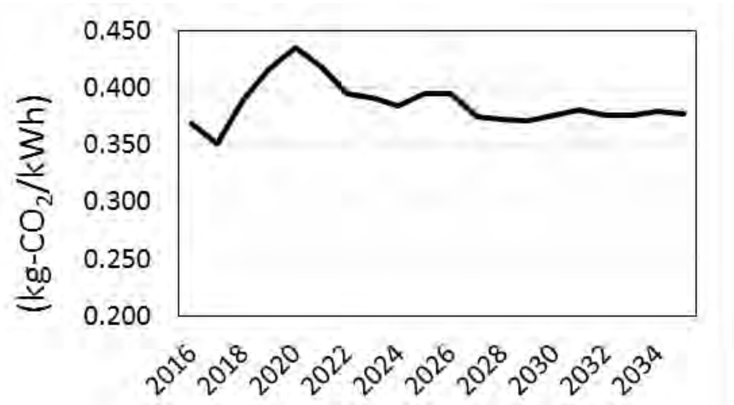
If all of power development projects listed in the base scenario of power development could be realized till 2035, the total amount of 80.3 million ton-CO_2 would be reduced by the renewable energy power sources as shown in Table 8-11.

Table 8-11 CO_2 Reduction by Renewable Energy Power Sources (Kyoto Protocol CDM Quantity Survey)

	Reduction amount ($t\text{-}CO_2$/)*	Installed Capacity (2035)[11]	Total
Wind power	135,000t / 100MW	2,201 MW	2,971,350 ≒ 2.97 mil. ton
Solar power	41,500t / 50MW	1,150 MW	954,500 ≒ 0.95mil. ton
Hydropower	1,500,000t / 640MW	32,589 MW	76,380,468 ≒ 76.38mil. ton
Total	-	-	80.30mil. ton

Note: * NEPRA Data

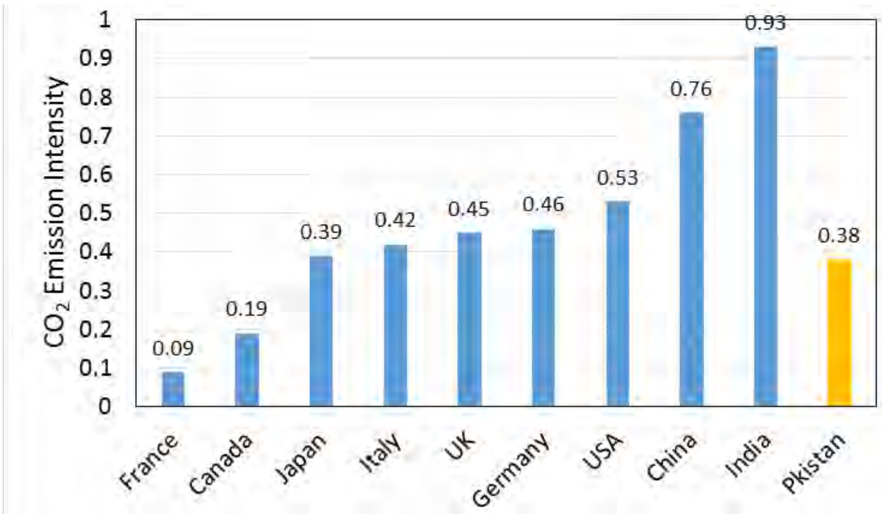
CO_2 emission intensity of the power sector in Pakistan will increase up to 0.44 kg-CO_2/kWh in 2020 due to development promotion of coal fired TPP, but decrease afterword in line with increase of composition rate of hydropower to 0.38 kg-CO_2/kWh in 2035, if the base scenario of power development could be realized, as shown in Figure 8-12.



(Source : JICA Project Team)

Figure 8-12 CO_2 Emission Intensity from 2016 to 2035

Figure 8-13 shows comparison of CO_2 emission intensity among the typical countries as of 2010 and Pakistan as of 2035. The CO_2 emission intensity of Pakistan of 0.38 kg-CO_2/kWh in 2035 is as small as those in Japan and Italy in 2010, since non-fossil fuel power plants such as hydropower and renewable energy power accounts for 45.3%.



Note : Emission intensity in Pakistan is computed value in 2035, the others are as of 2010.

(Source : The Federation of Electric Power Companies of Japan)

Figure 8-13 Comparison of Country-wise CO_2 Emission Intensity

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[11] Installed capacity (MW) is used, since Generated energy (MWh) is unavailable.

8.3.5 Priority Order of Proposed Each Scenario from the Viewpoints of SEA

As described in the above, Comprehensive Impact Indicator has been estimated by each power source. Project which has higher score of comprehensive impact indicator means the better practicable option and is recommended to implement prior to the other projects with lower score of comprehensive impact indicator. Table 8-12 shows the Comprehensive Impact Indicator of each scenario of power development plan. The Comprehensive Impact Indicator of "Base Scenario", "Scenario of Incorporation of hydropower to South system", and "Scenario of No power import" is 2.58, 2.64, and 2.59 respectively.

Scenario of " Incorporation of hydropower to South system" gets higher score of Comprehensive Impact Indicator than the others and it means the better practicable scenario in view of environmental and social considerations. Other scenarios of "Base Scenario" and "No power import" get almost same level of Comprehensive Impact Indicator and it means the same priority next to the scenario of " Incorporation of hydropower to South system".

Table 8-12 Comparison of Environmental Impact Indicator of Each Scenario

Power Type of Plant		Hydro		Thermal		Renewable Energy			Total	Priority in view of environment
		Reservoir	Pondage and ROR	Coal	Others	Wind	Solar	Biomass		
Environmental Impact Indicator		2.97	3.08	1.65	2.60	3.00	3.40	3.50		
Base Scenario	Supply Capacity（MW)	5,100	28,628	18,712	27,056	718	0	237	80,451	2
	Power Source Configuration Rate	6.3%	35.6%	23.3%	33.6%	0.9%	0.0%	0.3%	100%	
	Environmental Impact Indicator	0.19	1.10	0.38	0.87	0.03	0.00	0.01	2.58	
Scenario : Incorporation of Hydropower into South System	Supply Capacity（MW)	5,100	32,270	15,070	27,056	718	0	237	80,451	1
	Power Source Configuration Rate	6.3%	40.1%	18.7%	33.6%	0.9%	0.0%	0.3%	100%	
	Environmental Impact Indicator	0.19	1.24	0.31	0.87	0.03	0.00	0.01	2.64	
Scenario : No power import	Supply Capacity（MW)	5,100	29,628	18,712	28,056	718	0	237	82,451	2
	Power Source Configuration Rate	6.2%	35.9%	22.7%	34.0%	0.9%	0.0%	0.3%	100%	
	Environmental Impact Indicator	0.18	1.11	0.37	0.88	0.03	0.00	0.01	2.59	

Note1) : Expansion projects of the existing reservoirs are counted as a pondage type, since the reservoirs are not newly developed.
The Diamer Basha (4,500MW), Akhori (600MW) HPP are counted as a Reservoir type hydropower.
Note2): Power Imports are is not included in this table, since they do not give any impact on the national environment.

(Source : JICA Project Team)

8.3.6 Intended Nationally Determined Contributions (INDC) committed by Pakistan

Pakistan submitted the Intended Nationally Determined Contributions (INDC) to the United Nations Secretariat in November, 2015, and it was adopted by the Paris Agreement of COP21 in December, 2015. Pakistan's INDC is composed of seven official commitments. Among them, it is stipulated that "Pakistan is committed to reduce its emissions after reaching peak levels to the extent possible subject to affordability, provision of international climate finance, transfer of technology and capacity building. As such Pakistan will only be able to make specific commitments once reliable data on our peak emission levels is available.", accordingly, the targeted reduction value of GHG emission in 2020 is not specified.

If the power generation development could be implemented in accordance with the Optimum Power Development Plan (Base Scenario), the carbon dioxide emissions intensity in the power sector in Pakistan is estimated to be 0.44 kg-CO2/kWh in 2020 with a peak and to decrease gradually afterward to about 0.38 kg-CO2/kWh in 2027 in line with increase of the configuration rate of hydropower plants as shown in Figure 8-2. Accordingly, the Power System Development Plan is deemed as an effective reduction measure of GHG emission for INDC.

8.3.7 Results of Initial Environmental Survey

(1) Current situation of existing protected areas

a) Protected area

List of existing protected areas and their locations are shown in the below table and the locations are shown in Figure 8-14.

Table 8-13 List of Protected Areas in Pakistan

Province	National park	Wildlife Sanctuary	Wildlife Game Reserve	Area (ha)
Punjab	4	40	21	1,737,265
Sindh	1	33	13	1,755,600
KP	6	3	36	817,706
Balochistan	2	13	6	1,506,843
Capital	1	1	1	94,186
Gilgit Baltistan	5	6	9	2,182,830
AJK	7	-	7	6,518,700
Total	26	96	93	14,613,490

(Source : Conservator of Wildlife in MOCC)

b) Wetlands Ramsar Sites

It aims to promote the conservation of Wetlands of International Importance and there Waterfowl Habitat, 19 wetlands Ramsar sites has been designated in Pakistan as listed in the below table and the locations are shown in Figure 8-15.

Table 8-14 List of Wetlands Ramsar Sites in Pakistan

No.	Name	Area(ha)	Province	District	Remarks
1	Astola (haft Talar Island)	15,000	Balochistan		
2	Chashma Barrage	34,099	Punjab	Mianwali	
3	Deh Akro-II Desert Wetland Complex	20,500	Sindh		
4	Drigh Lake	164	Sindh		
5	Haleji Lake	1,704	Sindh		
6	Hub Dam	27,000	Sindh Balochistan		
7	IndUS$elta	472,800	Sindh		
8	IndUS$olphin Reserve	125,000	Sindh		
9	Jiwani Coastal Wetland	4,600	Balochistan		
10	Jubho Sujawai Lagoon	706	Sindh	Sujawal	Atlas
11	Kinjhar Lake	13,468	Sindh	Thatta	
12	Miani Hor	5,500	Balochistan	Lasbela	
13	Nurri Lagoon	2,540	Sindh	Badin	Atlas
14	Ormara Turtle Beaches	2,400	Balochistan		
15	Runn of Kutch	566,375	Sindh		
16	Tanda Dam	405	Khyber Pakhtunkhwa	Kohat	Atlas Wild/Sanc
17	Taunsa Barrage	6,576	Punjab	Muzaffargar	
18	Thanedar Wala	4,047	Khyber Pakhtunkhwa	Bannu	
19	Uchhali Complex	1,243	Punjab	Khushab	
Total		1,304,127			

(Source : MOCC)

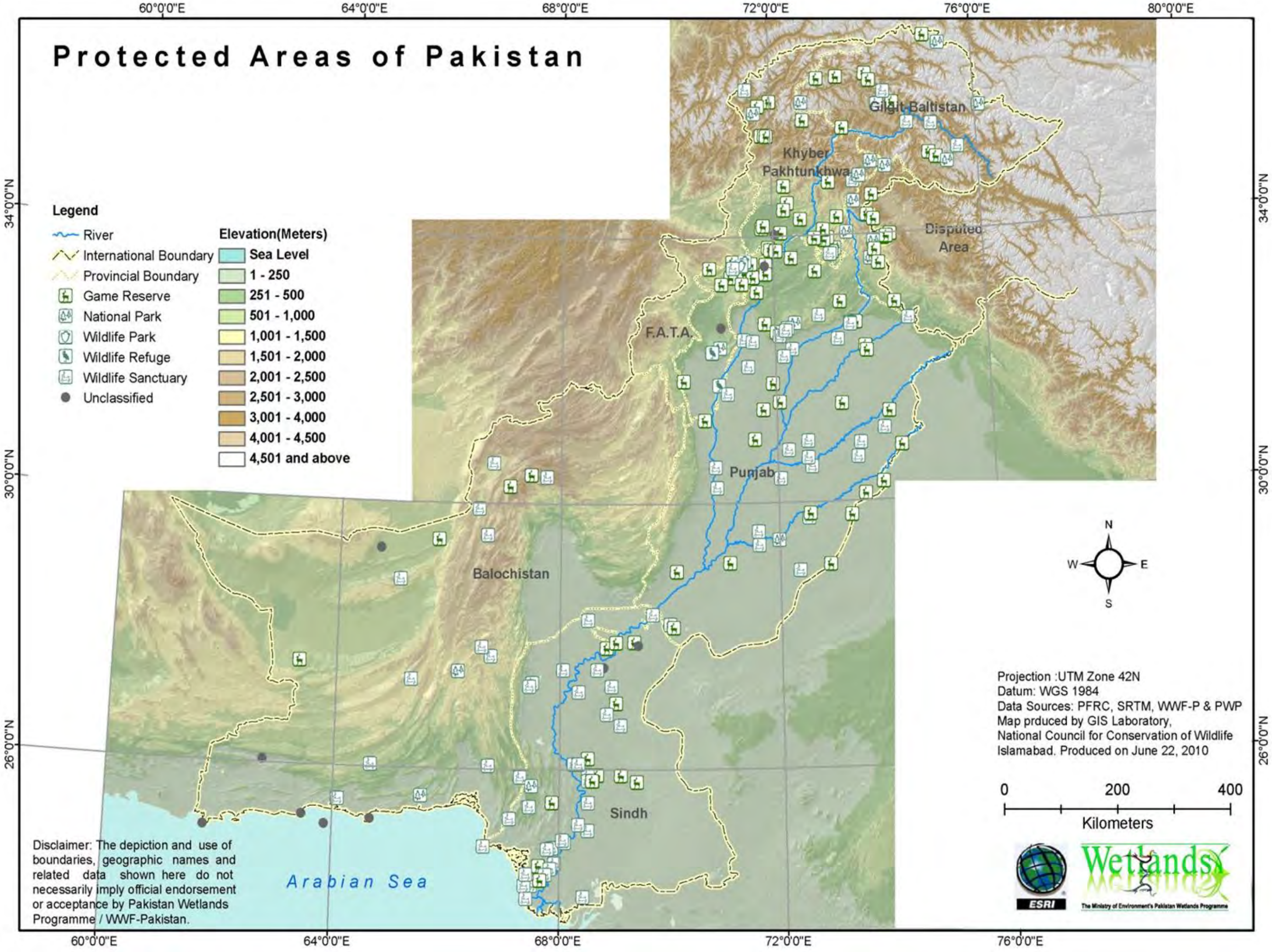
c) Important ecoregions in Pakistan designated by World Wide Fund for Nature (WWF)

World Wildlife Fund (WWF) designates the region in which a wide variety of endemic species (those that are not found in other regions of the Earth) inhabit as terrestrial ecoregions (= ecoregions) and has conserved. 200 regions were designated as of 2014 on the earth, five ecoregions are designated in Pakistan as listed in the below table. The locations are shown in Figure 8-16.

Table 8-15 Ecoregions in Pakistan Designated by WWF

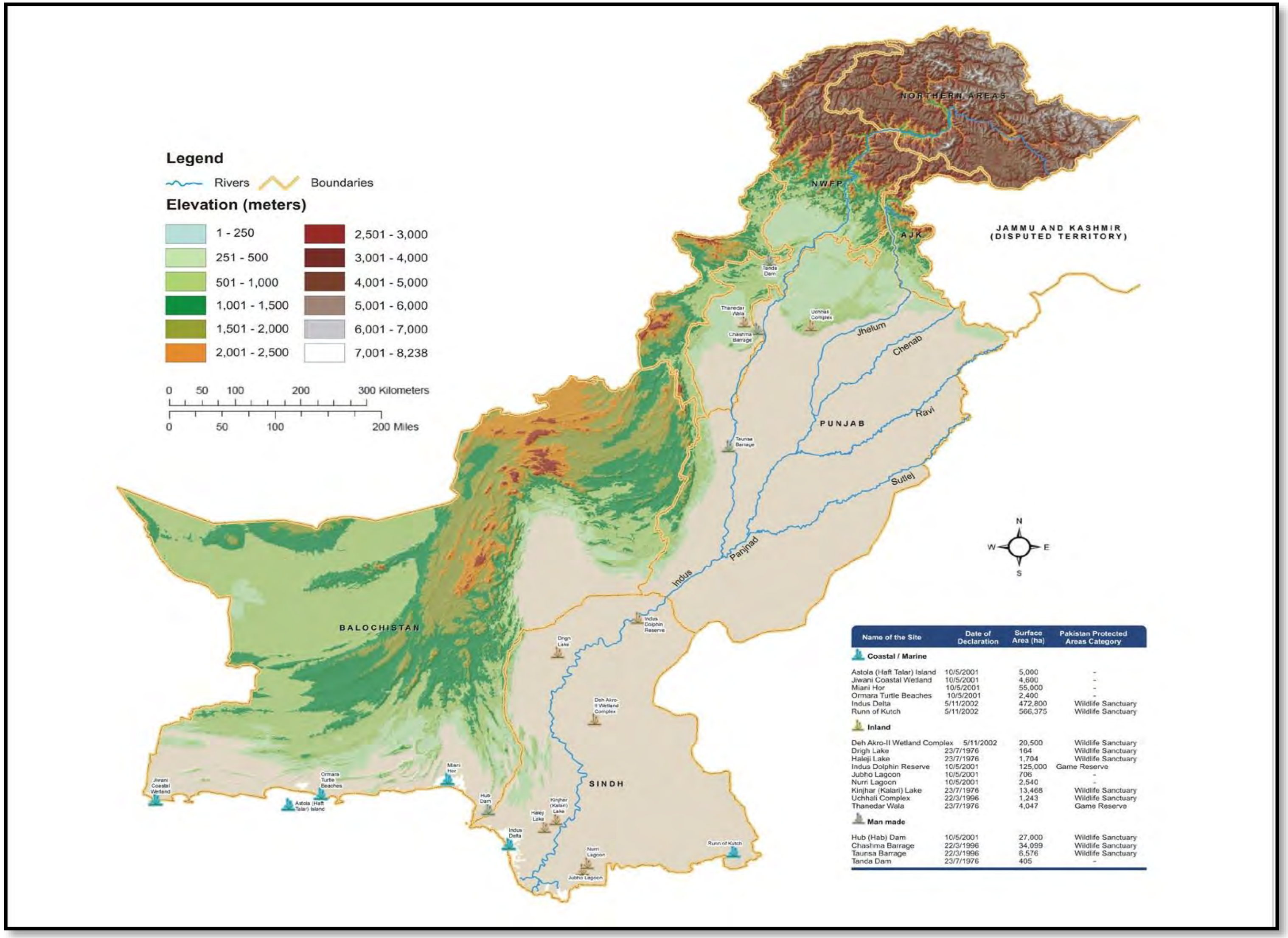
No.	Ecoregion	Ecozone	Biome	Region
1	Arabian Sea	Indomalayan	Mangrove	West of coastal range of Sindh
2	Indus River Delta	Indomalayan	Mangrove	West of coastal range of Sindh
3	Rann of Kutch Flooded Grassland	Indomalayan	Flooded grasslands and savannas	East of coastal range of Sindh
4	Tibetan Plateau Steppe	Indomalayan	Temperate broadleaf and mixed forests	West Himalaya (Azad Kashmir,north Punjab, north Khyber Pakhtunkhwa)
5	Westan Himalayan Temporate Forest	Indomalayan	Temperate Coniferous forests	West Himalaya (Azad Kashmir,north Punjab, north Khyber Pakhtunkhwa)

(Source：WWF Global 200 in Pakistan)



(Source : Conservator of Wildlife in MOCC)

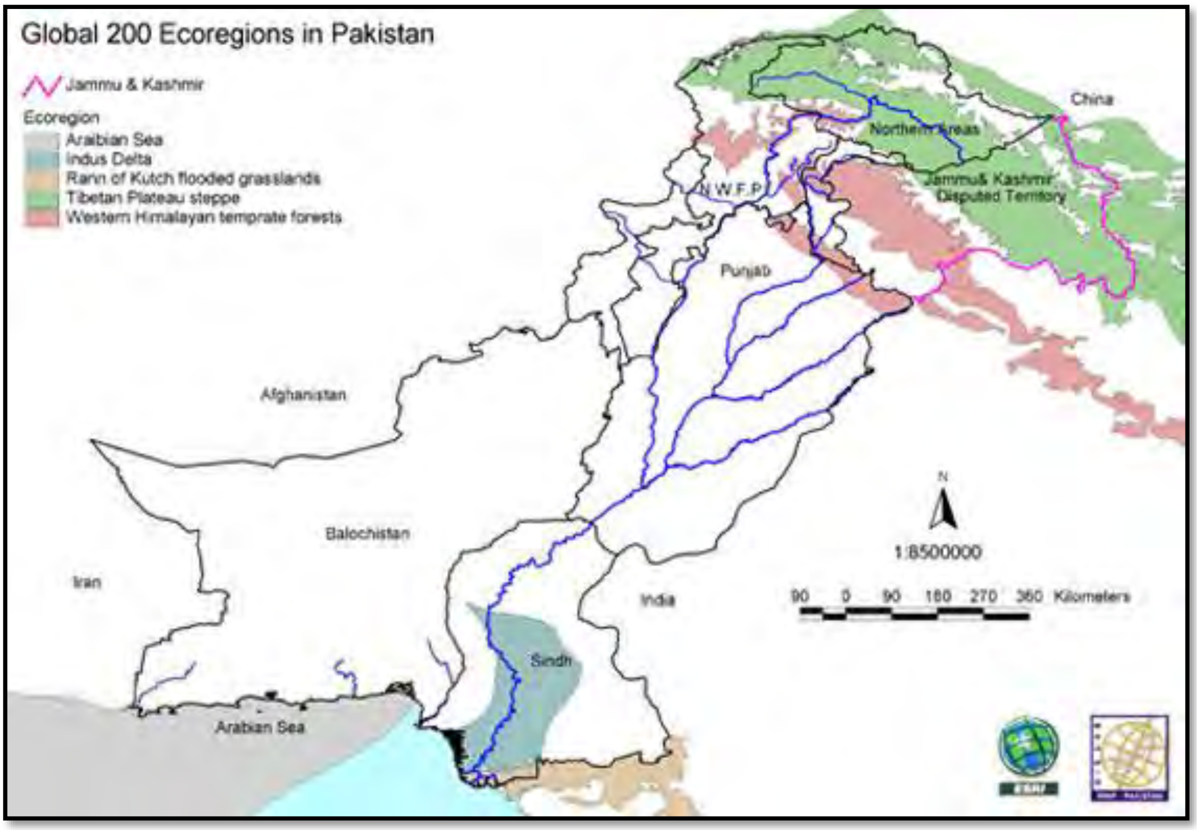
Figure 8-14 Locations of protected areas in Pakistan



Name of the Site	Date of Declaration	Surface Area (ha)	Pakistan Protected Areas Category
Coastal / Marine			
Astola (Haft Talar) Island	10/5/2001	5,000	-
Jiwani Coastal Wetland	10/5/2001	4,600	-
Miani Hor	10/5/2001	55,000	-
Ormara Turtle Beaches	10/5/2001	2,400	-
Indus Delta	5/11/2002	472,800	Wildlife Sanctuary
Runn of Kutch	5/11/2002	566,375	Wildlife Sanctuary
Inland			
Deh Akro-II Wetland Complex	5/11/2002	20,500	Wildlife Sanctuary
Drigh Lake	23/7/1976	164	Wildlife Sanctuary
Haleji Lake	23/7/1976	1,704	Wildlife Sanctuary
Indus Dolphin Reserve	10/5/2001	125,000	Game Reserve
Jubho Lagoon	10/5/2001	706	-
Nurri Lagoon	10/5/2001	2,540	-
Kinjhar (Kalari) Lake	23/7/1976	13,468	Wildlife Sanctuary
Uchhali Complex	22/3/1996	1,243	Wildlife Sanctuary
Thanedar Wala	23/7/1976	4,047	Game Reserve
Man made			
Hub (Hab) Dam	10/5/2001	27,000	Wildlife Sanctuary
Chashma Barrage	22/3/1996	34,099	Wildlife Sanctuary
Taunsa Barrage	22/3/1996	6,576	Wildlife Sanctuary
Tanda Dam	23/7/1976	405	-

(Source : Conservator of Wildlife in MOCC)

Figure 8-15 Locations of Wetlands Ramsar Sites in Pakistan



(Source : WWF Global 200 in Pakistan)

Figure 8-16 Locations of Ecoregions in Pakistan

(2) Ethnic Groups and their distribution in Pakistan

There are four major ethnic groups in Pakistan: Pashtuns, Baluchis, Punjabis, and Sindhis. Pashtuns reside mainly in North West Frontier Province, and Baluchis live mostly in the Baluchistan province. Punjabis reside in the North-East, namely in the Punjab province, and Sindhis in the South-East, the Sindh province.

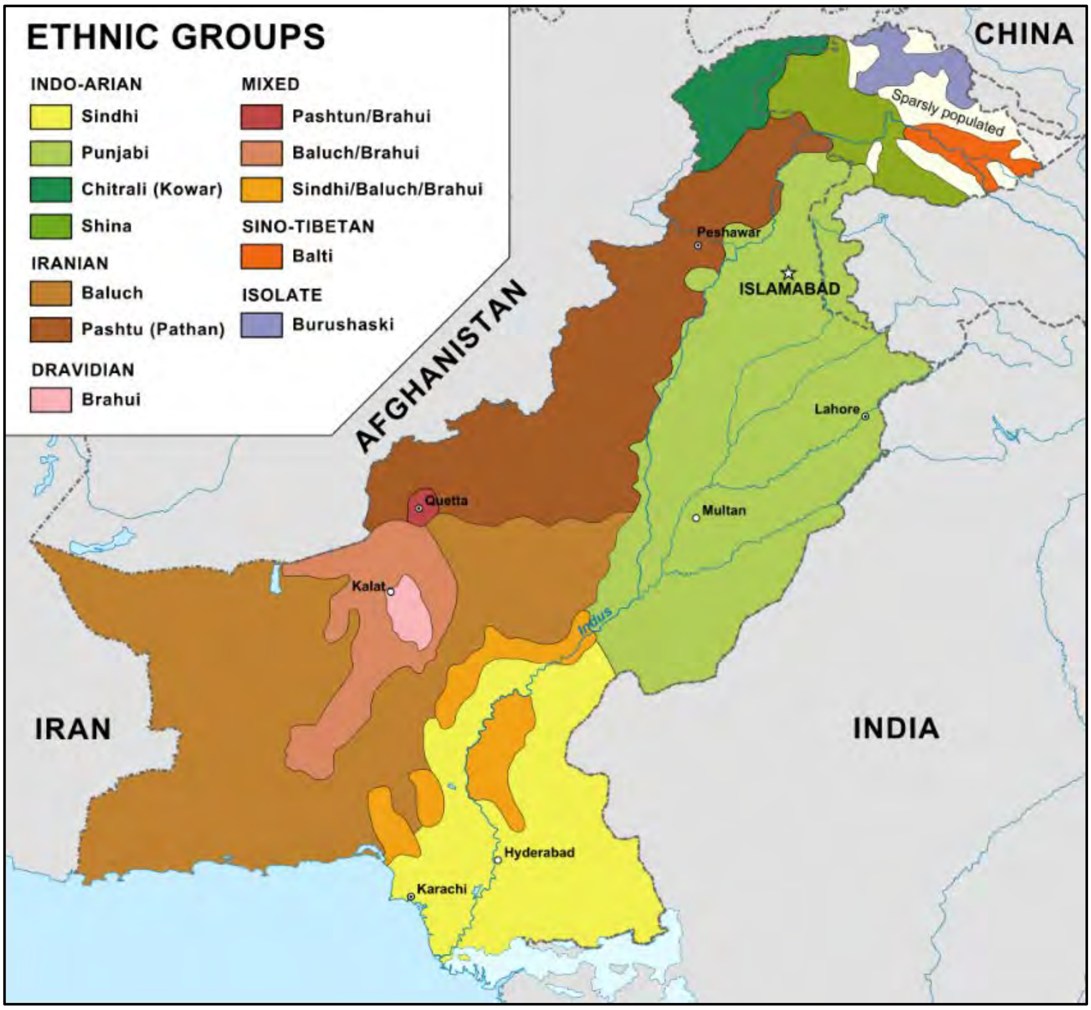
The population ratio by ethnic group is shown in the below table and the distribution map is shown in Figure 8-17.

Table 8-16 Status of Population Ratio by Ethnic Group

No.	Language	Population (2008)	Ratio(%)
1	Punjabi	76,367,360	44.17
2	Pashto	29,342,892	16.97
3	Sindhi	21,755,908	12.64
4	Saraiki	18,019,610	10.42
5	Urdu	13,120,540	7.59
6	Balochi	6,204,540	3.59
7	Others*	8,089,150	4.62
	Total	172,900,000	100

Others:Kashmiris,Hindkowans,Kalash,Burusho,Barahui,Khowar,Shina,Balti,Turwalis*

(Source: Wikipedia)



(Source : Wikipedia)

Figure 8-17 Current Distribution of Ethnic Groups in Pakistan

(3) Current situation of proposed power development projects

a) Current conditions of the natural and Social environment of proposed hydropower projects

Envisaged the natural and social environment impacts caused by implementation of proposed Hydropower Projects over 50MW are shown in the below table.

Table 8-17 Current Natural and Social Environment Situation of Proposed Hydropower Project

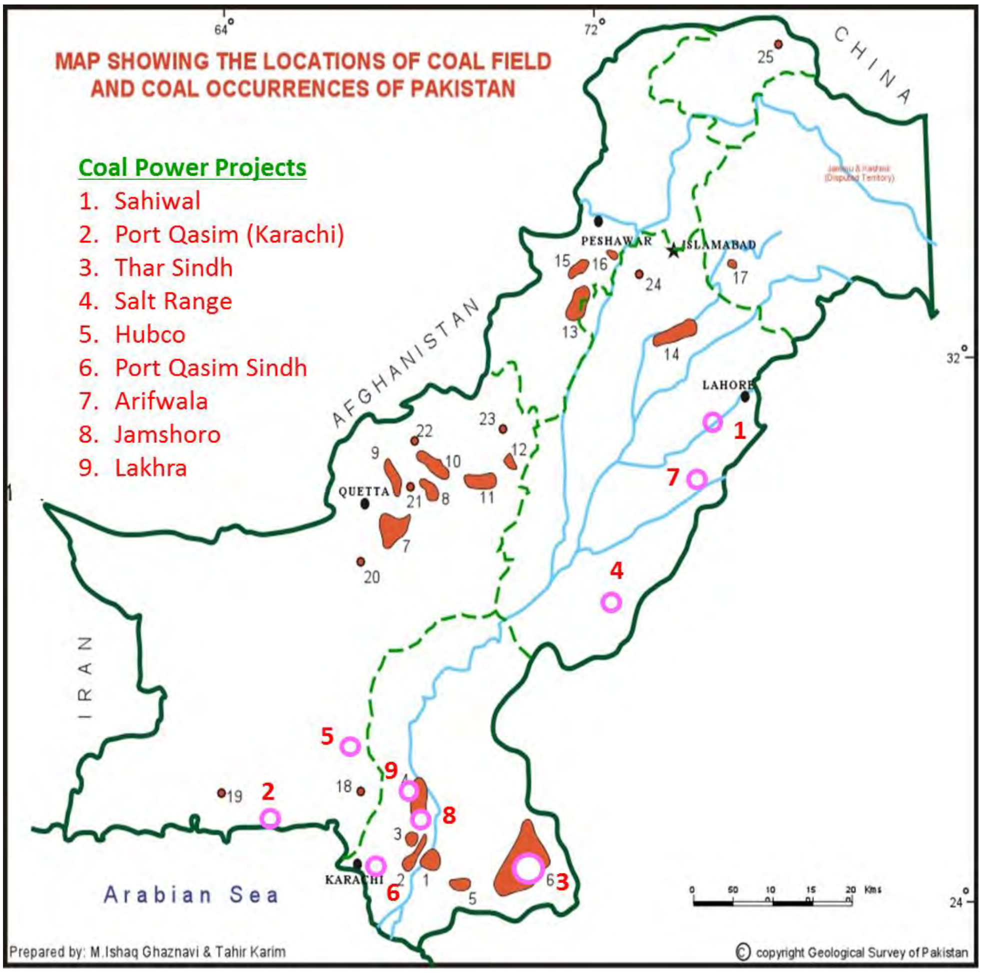
Province	No.	Project	Installed Capacity (MW)	Executive Agency	Project Status	Environment						Approval of EIA			Remarks		
						Nature			Social								
						Protected area			Resettlement						Target Year	Type of	Rivers
						a	b	c	0	<100	100<	A	B	C			
Gilgit-Baltistan	1	Bunji	7,100	WAPDA	Imple.	No protected area					600	X			?	Run of River	Indus
	2	Diamer Basha Dam	4,500	WAPDA	Imple.	No protected area					29000	X			2025	Storage Dam	Indus
	3	Phander	80	WAPDA(	Imple.	No protected area				X		X			2016	Run of River	Phander
		(TOTAL)	11,680														
	1	Mangla	1000	WAPDA	Ope.						X				Compl.	Storage Dam	Jhelum
		(TOTAL)	1,000														
Azad-Jammu & Kashmir	1	Neelum Jhelum	969	WAPDA	Imple.	No protected area					170				2016	Run of River	Nelum Jhelum
	2	Jagran-III	90	HEB/AJ&	Imple.	No protected area			X							Run of River	Jagran nullah
	3	Kohala	1100	PPIB	Imple.	No protected area				X						Run of River	Jhelum
	4	Azad-Pattian	650	PPIB	Imple.	No protected area				X					2020	Run of River	Jhelum
	5	Mahl	590	PPIB	Imple.	No protected area				X		feasibility study				Run of River	Jhelum
	6	Patrind	150	PPIB	Imple.	No protected area				X		under construction			2017	Run of River	Kunhar
	7	Chakoti-Hattian	139	PPIB	Imple.	No protected area				X		feasibility study				Run of River	Jhelum
	8	Rajdhani	132	PPIB	Imple.	No protected area				X		DED				Run of River	Poonch
	9	Sehra	130	PPIB	Imple.	No protected area				X						Run of River	
	10	Gulpur	100	PPIB	Imple.	Mahseer Breeding Site				X		DED			2019	Run of River	Poonch
	11	Kotli	100	PPIB	Imple.	Mahseer Breeding			X						2022	Run of River	Poonch
	12	New Bong Escape	84	PPIB	Imple.	No protected area			X			Completed				Run of River	Bong Escape,
		(TOTAL)	4,234														
	1a	Tarbela	3478	WAPDA	Ope.	No protected area					X	Operational				Storage	Indus
	1b	Tarbela 4th Ext: HP	1410	WAPDA	Imple.	No protected area			X			NOC accorded			2017	Storage	Indus
Khyber Pakhtunkhwa	1c	Tarbela 5th Ext: HP	1450	WAPDA	Imple.	No protected area			X			Feasibility Study			2018	Storage	Indus
	2	Warsak	240	WAPDA	Ope.	No protected area			X			Operational				Storage Dam	Kabul
	3	Malakand-III	81	SHYDO	Ope.	No protected area			X			Operational				Run of River	Swat
		(TOTAL)	6,659														
	1a	Dassu	4320	WAPDA	Imple.	Kaigah Nature Reserve						Approved				Run of River	Mainstrem Indu
	1b	Dassu(1st stage)	(2160)	WAPDA	Imple.	Kaigah Nature Reserve					3610	Approved			2020	Run of River	
	2	Chor Nullah System	1176	WAPDA	Imple.	Tropogon Reserve Pallas				X		Not accorded				Run of River	Chor Nullah
	3	Muhmand Dam	660	WAPDA	Imple.	No protected area				X		NOC accorded				Storage Dam	Swat
	4	Spat Gah (lower)	567	WAPDA	Imple.					X		Not Accorded				Run of River	Spatgah
	5	Spat Gah (middle)	501	WAPDA	Imple.					X		Not Accorded				Run of River	Spatgah Nullah
	6	Spat Gah (upper)	273	WAPDA	Imple.					X		Not Accorded				Run of River	Spatgah
	7	Duber Khwar	130	WAPDA	Ope.	No protected area				X		Not accorded 1997				Run of River	Duber Khwar
	8	Kayal Khwar	125	WAPDA	Imple.	No protected area				X		Accorded			2017	Run of River	Kayal Khwar
	9	Allai Khwar	121	WAPDA	Ope.	No protected area				X		Accorded 2000				Run of River	Allai Khwar
	10	Golen Gol	106	WAPDA	Const.	No protected area				X		Accorded 2009			2018	Run of River	Golen Gol
	11	Kurram Tangi dam	83	WAPDA	Imple.	No protected area				X		Accorded			2017	Storage	Kurram
	12	Khan Khwar	72	WAPDA	Ope.	No protected area			X			EIA in 1996				Run of River	Khan Khwar
	14	Sharmal	115	SHYDO	Imple.	No protected area				X					Prop.	Run of River	
	15	Matiltan	84	SHYDO	Imple.	No protected area				X						Run of River	
	16	Koto	52	SHYDO	Imple.												
	17	Suki kinari	840	PPIB	Imple.	Sensitive Kaghan valley s				X					2020	Run of River	Kunhar
	18	Kaigah	548	PPIB	Imple.										F/S	Run of River	Kaigah
	19	Asrit-kedam	215	PPIB	Imple.										Prop.		
	20	Kalam-Asrit	197	PPIB	Imple.										Prop.		
	21	Madian	157	PPIB	Imple.										F/S		
	22	Shushghai-Zhendoli	144	PPIB	Imple.										Prop.		
	23	Gabral Kalam	137	PPIB	Imple.										Prop.		
	24	Shogo-Sin	132	PPIB	Imple.										Prop.		
		(TOTAL)	10,755														
	1	Ghazi Barotha	1450	WAPDA	Ope.	No protected area					899	Approval accorded			Comp.	Run of River	Indus
	2	Chashma	184	WAPDA	Ope.	Ramsar wildlife sanctuary									Comp.	RoR/Storage	Indus
Punjb		(TOTAL)	1,634														
	1	Jinnah	96	WAPDA	Imple.	No protected area				X		NOC accorded			Comp.	Run of River	Indus
	2	Akhori Dam	600	WAPDA	Imple.	3 widlife protected areas					55000	Not yet				Storage	Indus
	3	Karot HPP	720	PPIB	Imple.					X		NOC accorded			2022	Run of River	Jhelum
	4	Taunsa HPP	120	PPOB	Imple.	Ramsar site					200	NOC accorded 2014					Indus
		(TOTAL)	1,536														
	0																
	0																
Balochistan		Thakot	2800			No protected area					X	F/S				Run of River	Indus
Sindh																	
KPK		Lawi	69	PPIB	Imple.	No protected area										Run of River	
KPK		Middle Palas	373	PPIB	Imple.	Palas valley protected are				X		EIA completed				Run of River	
KPK		Upper Palas	160	PPIB	Imple.	Palas valley protected are				X		EIA completed				Run of River	

Note) 🟥: High possibility of start of operation in 2025

(Source : WAPDA)

b) Proposed coal fired power plant projects by 2022

Location map of progressing coal fired power plant projects which aim to put into operation by 2022 is shown in the below figure.



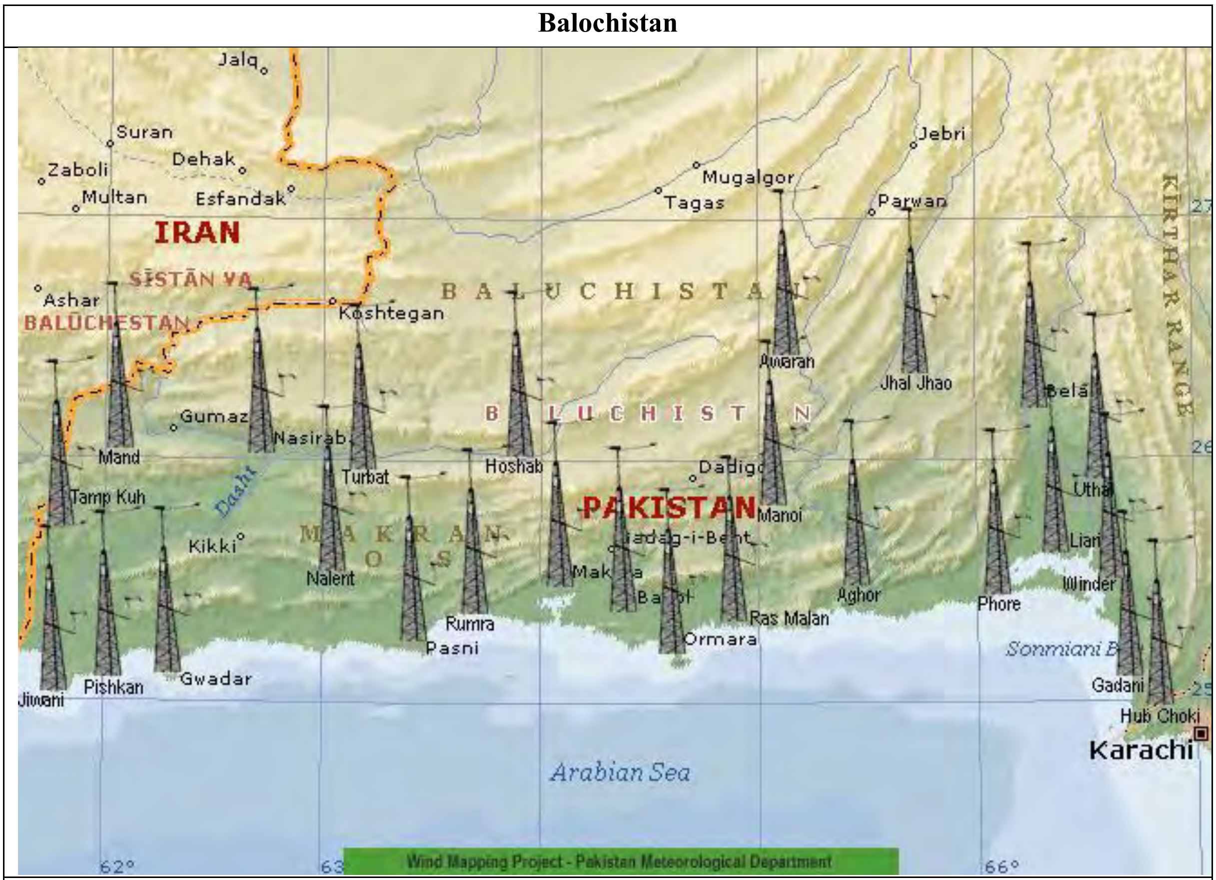
(Source : Prepared by JICA Project Team based on TCEB data)

Figure 8-18 Locations of Coal Fired Thermal PP Projects

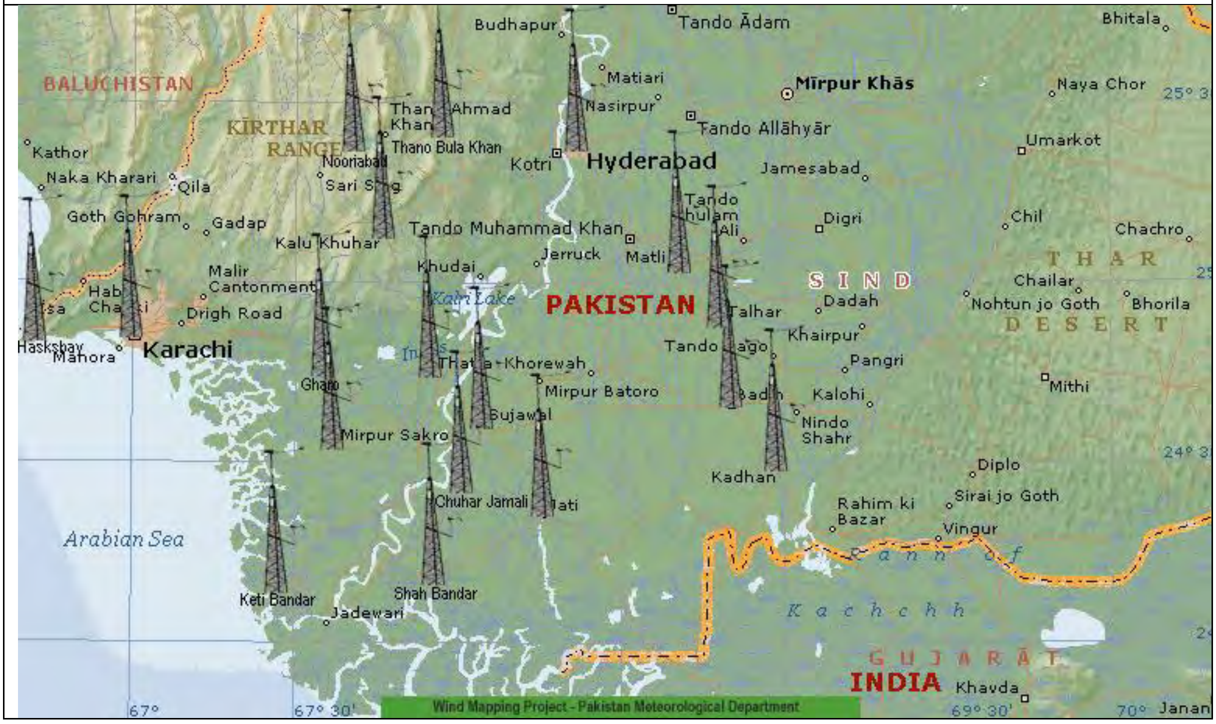
(b) Wind power development project sites

Pakistan government plans to wind power development of 3,150MW until 2020, as of 2015, the environmental impact assessment is being prepared or was carried out regarding the candidate sites of 47 in Sindh province, which is shown in Figure 8-19 (National Renewable Energy Laboratories -NREL-). 27 sites out of the 47 candidate sites are under implementation as shown in Table 8-7 (refer to the environmental impact assessment matrix for wind power). The installed capacity of 900MW will be commissioned in 2016 according to CPPAGL.

Balochistan

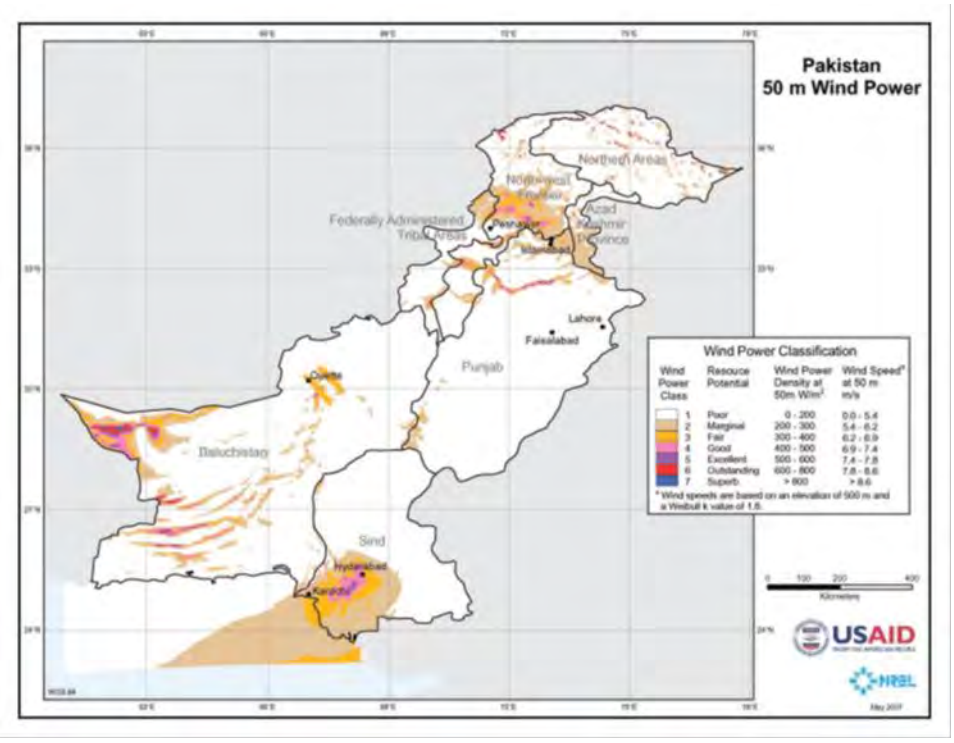


Sindh



(Source : NREL's SARI-Energy Activities)

Figure 8-19 Wind Power Project Sites



(Source : NREL's SARI-Energy Activities)

Figure 8-20 Distribution Map of Wind Power Potential

Chapter 9 Recommendations

9.1 New Organizational Structure

9.1.1 Preparation and Implementation of Power Sector Master Plan

At present, the organizational structures of the power sector and the energy sector are rather complicated. MWP holds jurisdiction over the power sector and MPNR holds jurisdiction over the primary energy sector and the inter-cordination between the power and the energy sector is insufficient.

As for the power sub-sector, generation, transmission and distribution subsectors are separated independently. The public companies and the private companies have performed development and O&M of power plants, and as the public companies, WAPDA for the hydropower, GENCOs for the thermal power and PAEC for the nuclear power have performed. Meanwhile, as for the transmission sub-sector, NTDC, the public company, has performed solely development, O&M of the power grids and dispatchment of power load. Besides, as for the distribution subsector, 10 DISCOs which have been under privatization have performed development and O&M of the local distribution systems.

Since the electric power is the special commodity which production and consumption is simultaneous, it is necessary that the power sector master plan should be developped in consideration of optimization of the total cost from generation to distribution. Furthermore, since it takes from five to seven years to develop the power infrustructures, it is important to prepare the middle - long power demand forecast and build up the power system development plan and implement them accordingly.

However, since it is unexplicit which organization shall bear the responsibility on the above preparation and implementation of the power sector master plan at present, it is recommended that a centralized organization performing preparation and implementation management of the power system development plan should be newly established.

Meanwhile, jt is required for executing the above study that various technologies and knowledge such as primary energy supply plan, power demand forecast, power development plan (hydropower, thermal & nuclear power, renewable energy power), power network expansion plan, economical & financial analysis and strategic environmental assessment.

It is recommended that based on the base scenario of this study, the middle & long term power facility development plan should be accordingly adjusted in line with the following recommendations after Section 9.2 in the future. Especially, the middle & long term power network expansion plan needs to be developed as soon as possible.

Furthermore, following this power sector master plan study, it is deemed that a rural electrification master plan and a energy saving master plan should be carried out, which measures and policies are are running late. It is desirable that the master plan studies should be carried out by the newly established organiation or institute which bears the aforementioned proper technologies and knowledge.

9.1.2 Least Cost Dispatching and Operation of Power System

It is important that load dispatching and system operation is executed efficiently and effectively on the basis of the concept of the above middle & long term power facility development plan (power sector master plan). For the purpose, countermeasures for forced outage of power facility such as frequency control and voltage control, check & maintenance schedule preparation and the least cost load dispatching plan to meet the power demand should be prepared, and then, the power system should be operated efficiently.

Accordingly, it is recommended that NPCC should master the technologies for the aforementioned optimal load dispatching and power system operation and improve the load dispatching, in consideration of efficient and effective utilization of SCADA system equipped.

9.2 Primary Energy Supply Analysis and Power Demand Forecast

9.2.1 Power Demand Forecast

(1) Collection and analysis of power demand actual data

Annual load factor of the power demand is normally forecasted based on the trend of the past records of annual load factor. However, DISCO-wise hourly computed power demand data in the year of 2014 could be only obtained. Therefore, it is recommended that the DISCO-wise hourly power demand records (8,760 hours) should be collected and cumulated, and daily load curve of monthly maximum demand (top 3 days average), weekday and holiday should be analyzed in the future.

In addition, since time zones when maximum power demand occurs are different among DISCOs due to Pakistani land shape being long in the north-south direction, the system-wise maximum demand should be analyzed in consideration of diversity factor among DISCOs.

Furthermore, there is a method to assume a daily load curves of each system by piling up a load curve based on the results of the sector-wise load curves such as, commercial and residential sector and the sector-wise electric energy forecast as a method to predict the maximum power demand. Therefore, it is recommended that the actual records of daily load curves by sector should be collected, cumulated and analyzed from now on.

(2) Energy saving

In the power demand forecast of the study, the energy saving and demand side management (DSM) were not considered, since the targets and effectiveness of them were unknown in Pakistan. Therefore, it is recommended that a master plan of energy saving should be formulated and reflected into the power demand forecast in the future.

9.2.2 Primary Energy Supply Analysis

The primary energy supply-demand balance is under the jurisdiction of MPNR, and DGOil controls oil supply, DGGas controls gas supply and TCEB controls the domestic coal of Thar coal area, respectively. There cannot be seen the comprehensive energy demand and supply plan including electric power. Therefore, it is desirable to formulate as energy master plan aiming at the national energy security including diversification of the energy sources. In the energy master plan, it is necessary to consider the results of feasibility (quantity and price) of the reserves of domestic energy resources including the shale / tight gas.

9.3 Power Development Plan and Power System Development Plan

9.3.1 Power Development Plan

(1) Least cost power development plan

It is recommended that based on the base scenario of this study, the concrete individual projects should be prioritized and the development pattern should be accordingly adjusted in line with the following recommendations of (2) ~ (5).

In addition, it is desirable that the three alternatives in Chapter 5 should be judged finally to adopt or not after reviewing its actuality and economic efficiency.

(2) Hydropower development plan

It is recommended that the following data should be collected, cumulated and analyzed as for the existing hydropower plants ; monthly firm (peak) capacity, monthly averaged generated energy, minimum output, forced outage rate, scheduled outage days (days in a year when the plant is scheduled to shut down for inspection, repair, etc.), station own use rate, AFC operation range, constraints in operation side (drawdown of reservoir water level for flood control, obligation of discharge for irrigation water, etc.) and difference of generated energy between day year and wet year.

In addition, it is recommended for planning large-scale hydropower plant projects over 1,000MW that economic comparison study by dispatching the power demand and supply balance operation should be executed, and accordingly type of generation, optimum development scale, regulating capacity (daily / weekly regulation or seasonal regulation) of the projects should be determined.

Furthermore, it is recommended that when a series of hydropower projects are developed in the same river system, the development scale and order of each project should be determined in consideration of comprehensive water use of the river system. Particularly, it is necessary to consider that reservoir type hydropower projects such as Dasu HPP and Basha HPP, which is located the upper stream of Tarbela HPP or Mangla HPP, are enable to regulate or adjust power supply capacity, since Tarbela or Mangla can re-regulate the discharge from the upper stream hydropower plants. Besides, it is necessary to consider that the run-of-river type hydropower plants located on the downstream of the above reservoir type hydropower plants are also enable to supply peeking power, since those hydropower plants generate power using regulated discharge of the upper stream reservoir type hydropower plants.

(3) Thermal power development plan

It is recommended that the following data should be collected, cumulated and analyzed as for the existing thermal and nuclear power plants ; fuel type, dependable capacity, generation efficiency, minimum output, daily start & stop capability, weekly start and stop capability, forced outage rate, scheduled outage days, station own use rate, AFC operation range, constraints in operation side (obligation of taking over fuel volume from fuel company, obligation of taking over power from IPP, etc.)

It is recommended as for new development projects that fuel transportation cost, the distance (expansion of the power supply lines) from the demand area, equipment transportation route and cost, securing of cooling water, natural and social environment consideration (IEE) and so on are to be taken into consideration comprehensively, and the development priority should be determined and F/S and EIA are to be carried out.

(4) Renewable energy power development plan

Since solar power can generate power only in the daytime, and the peak demand in Pakistan occurs generally from 19:00 to 20:00, the output cannot contribute for the supply capacity for the peak demand. In addition, the ancillary service functions such as automatic frequency control (AFC) and spinning reserve are required separately to secure system stability (fluctuation of frequency and voltage), because the output of solar power or wind power plant fluctuates largely depending on the weather conditions.

Meanwhile, it had been developed “Study to Determine the Limit of Integrating Intermittent Renewable (wind and solar) Resources onto Pakistan's National Grid” for USAID Energy Policy Program in November, 2015.

It is recommended that renewable energy generation is to be introduced positively form the viewpoints of prevention of the global warming, however, the study report stated that there is no need to make major reinforcement of the power grid up to the installed capacity of around 10% of the total installed capacity. Accordingly, in the case that the total installed capacity of wind and solar more than 10% of the total installed capacity of the power system is developed, following the aforementioned study report, the limit of integration of the wind / solar power is to be examined by comparing the cost with the benefit by introduction of power system stabilizers should be examined.

(5) Power import

As aforementioned in Section 5.3.2(3), it is recommended that the power import should be put down as much as possible from the viewpoints of supply reliability (increase of the forced outage rate due to the long-distance transmission and increase of overseas dependence) and economic efficiency (increase of transmission line cost by the long-distance transmission and the transmission loss). Especially, since Pakistan is endowed with abundant hydropower potential and hydropower plants of more than 30 GW could be developed in the future, the power import which power source is a hydropower plant should be put down from the viewpoints of national energy security.

9.3.2 Power System Development Plan

(1) Basic consideration terms

It is a basic condition to grasp precisely the present situation of facilities and the power system in order to formulate the optimum power system development plan, and at first, it is recommended that the present conditions of the bulk power system should be figured out including the power flow.

It is recommended that the generous tendency of the power flow should be figured out and dispatched to the power system based on the power development plan and power demand forecast, and accordingly the short, middle and long terms power system development plan should be formulated. In addition, it is necessary to review the short and middle terms development plan adversely based on the long-term development plan.

Besides, it is recommended that Gap electric wire should be considered to adopt in order to cope with the steep power demand growth. Since the Gap electric wire enables transmission capacity to be over twofold by replacing the electric wire in use of the existing steel tower, an environment impact assessment (EIA) can be curtailed and a construction period can be largely shorten.

In preparation of development plan, it is necessary to figure out precisely the situations of the electricity facilities especially the residual service life of the facilities concerned. Therefore, it is necessary to maintain the equipment ledger. In addition, it is necessary to introduce the predictive maintenance technology in order to secure high power supply reliability.

On the other hand, it is recommended that the substations should be operated with power factor of the transformer of over 0.95 and with the voltage level of higher than nominal voltage level in order to promote the reduction of the power loss and the effective utilization of generation facilities. In addition, it is necessary to include the following item in the technical standard of NTDC and unify the technical specifications.

1) Establishment of the appropriate back up system,
2) Periodical calibration of instruments and gauges,
3) Preparation of Load Map of major demand areas,
4) Securing reliable open motion of related breaker of bus line or transmission line during no-volt,
5) Introduction of automatic operation of On-Load Tap Changer (OLTC),
6) Communization of defacement grade diagram, regional natural condition and epicenter map,
7) Formulation of data base,
8) Set-up of the economic life of each facility,
9) Development of single diagram of the bulk substations,
10) Unification of substations name and colors of voltage classes,
11) Set-up of standards regarding high frequency, and
12) Set-up of standard transmission capacity of AC765kV.

(2) Proposal for study on long term power network expansion plan

In this project, the bulk power grid maps (over 500kV) were made for the years 2025 and 2035 based on the power grid generation plan aiming at estimate of the required cost for expanding the bulk power network system. It is recommended that the following study should be carried out to make a more accurate transmission and substation expansion plan of NTDC system (over 220kV) as soon as possible.

a) To collect precise data of transmission and substation facilities.
b) To make the future power grid map after transmission and substation facilities are expanded, based on the power demand forecast and the power development plan. Besides, the grid map which can secure power supply reliability is to be prepared based on the study results of the following power system analyses.
   ① Power flow calculation
   ② Short circuit and earth fault calculation
   ③ Power stability calculation
c) To verify efficiency and effectiveness of new technology such as DC lines and 765kV & 1,000kV AC, Power System Stabilizers (PSS) and Flexible Alternating Current Transmission System (FACTS) . If efficient and effective, the new technology would be incorporate into the power grid map.
d) To review the input data which is necessary for the above power system analyses. If needed, to support for preparation of power system analyses data.
e) To survey routes and places of main transmission lines and substations installed, including field survey.
f) To make transmission and substation expansion plan every fiscal year and to estimate required investment cost.

Moreover, in the case that the basic design of top priority project is carried out, the following study works are necessary.

g) To sort each project and to estimate every project cost based on the above expansion plan.
h) To make list of priority projects on the basis of verified prioritization criteria and to extract priority projects.

i) To formulate implementation structure of the priority projects.

The required work force for the above study on power network expansion plan is estimated as about 38MM in the case that basic design of priority projects and technology transfer, referring to the precedent projects.

Meanwhile, the required work force for the study in the minimum case is estimated as about 25MM, which is limited to the above subjects from a) to f).

9.4 Financial Analysis

(1) Continuation of Electricity Tariff Reform and Improvement of Tariff Collection

Since NEPRA Determined Tariff is based on full cost recovery, appropriate implementation of the tariff scheme enables reinvestment in the power sector. In the present situation, however, tariff collection is below full cost recovery and this causes circular debt. In order to explain about circular debt, this report pointed out three issues: 1) Subsidies to fill the gap between retail tariff and a fair price are not paid timely, 2) Non-payment is increasing in both the private sector and the public sector, and 3) Distribution loss is very high.

On the first issue, the on-going tariff reform aims at reduction of subsidies. It is appropriate to continue the electricity tariff reform in the current direction. On the second issue, it is critical to improve capacity of employees who conduct tariff collection in distribution companies. DISCOs' efforts on capacity development are essential and it is desirable for donors to support DISCOs' efforts. On the third issue, it is necessary to replace obsolete facilities in tandem with improvement of tariff collection. Furthermore, coping with second and third issues requires fair understating of the present situation. Thus, additional assessment on human resources and current facilities in DISCOs is needed.

(2) Further Investment by the Pakistan Government

Inadequate tariff collection put off capital expenditure for a long period and resulted in enormous accumulated demand for power facilities. For this reason, funding gap in the power sector is expected to remain very large until the mid-2020s. Privatization in the generation and distribution subsectors will bring a certain amount of investment from the private sector. Nevertheless, it is desirable for the Pakistan government to actively invest in the power sector.

Funding gaps are expected to occur in generation, transmission, and distrubution. An increase of generation capacity will necessitate ehnancement of facilities in transmission and distrubution. In the generation subsector, a wide variety of funding sources is likely to make avaible fund cover 80-90% of investment requirtement desipte a large amount of requirement. On the other hand, avaible funds are expected to be below 50% of investment requirement in transmission and distribution though these subsectors requires smaller investmemt. In particular, transmision requires financial support from the public sctor since privitization will not include the subsector. For this reason, Pakistan government's investment in the power sector needs to pay a careful attention to appropriate fund allocation to transmission in considertaion of investment in generation.

(3) Use of Concessional Loan

This report assumed a 10% discount rate for capital recovery factor, which is conventionally used in the power sector. The use of concessional loan will lower both discount rate and capital recovery factor and allow further reduction in FDC of electrify from the analysis of the report. In addition, a lower interest rate encourages capital expenditure among state-owned power utilities. It should be seriously considerted to utilize a consessional loan and lower a on-lending interst rate within the Pakistan government for the sake of reduction of elecricity tariff and smoother fund raising.

Chapter 10 Technology Transfer

10.1 Primary Energy Supply Analysis and Power Demand Forecast

The JICA project team transferred Simple-E program, which is the primary energy demand and power demand forecast assist tool, in the 4th mission to NTDC C/Ps. And the JICA project team transferred a series of methodology of Simple-E such as formulation of demand forecast model, input data and evaluation of output to NTDC C/Ps through 4days seminars during 5th mission.

10.2 Power Development Plan and Transmission Expansion Planning

(1) Transfer of power development plan assist tool (PDPAT II) and its technology

The JICA project team transferred PDPAT II and RETICS programs in the 3rd mission to NTDC C/Ps. And the JICA project team transferred the technology of power development planning and a series of methodology of PDPAT II and RETICS such as input data, computation logic, computation method and output method to NTDC C/Ps through 2days and 4days seminars during 4th mission and 5th mission, respectively.

(2) Transmission expansion planning

JICA project team reviewed the power system analyses of the transmission expansion plan of NTDC in 2021-22 with PSS/E program including input data and instructed review points of the system analyses to NTDC C/Ps.

10.3 Holding Workshops

10.3.1 First Workshop

1st Workshop was held at the Islamabad Club in Islamabad on 17th Dec. 2014, which was organized by NTDC. Relevant Pakistani authorities and organizations and the donor organizations such as JICA, WB, ADB and USAID were invited and JICA Project Team made presentation on the following theme and Questions and Answers sessions were followed. Number of participants was 58 excluding JICA project team. All the participants took active part in the workshop.

- Power Sector in Japan
- Primary Energy Supply Analysis and Power Demand Forecast
- Power Development Planning
- Power System Development Planning
- Strategic Environmental Assessment

At last, JICA project team presented a discussion paper on the development scenarios for LCP, and the following comments and requests were raised.

- It was suggested that CASA-1000MW project needs to be explored in detail.
- Latent demand by electricity load-shedding is to be examined and properly considered for the power demand forecast.
- Renewable energy power sources are to be considered in the plan.
- Nuclear power generation is also to be considered in the plan and “Integrated Energy Plan 2022” by Planning Commission of Pakistan is to be reviewed
- NTDC’s DC electricity plan needs to be reviewed

		
Presentation on PDP	Presentation on TDP	Presentation on SEA
		
Q&A session	Tea Break	Closing Remarks

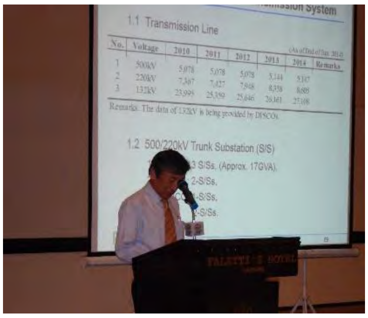
10.3.2 Second Workshop

2nd Workshop was held at the Faletti's Hotel in Lahore on 9th Jun. 2015, which was organized by NTDC. Relevant Pakistani authorities and organizations and the donor organizations such as JICA, WB, ADB and USAID were invited and JICA Project Team made presentation on the following theme and Questions and Answers sessions were followed. Number of participants was 84 excluding JICA project team. All the participants took active part in the workshop.

- Primary Energy Supply Analysis and Power Demand Forecast
- Power Development Planning
- Power System Development Planning
- Strategic Environmental Assessment

And, JICA Project Team presented a discussion paper on the development scenarios for LCP. At last, the following comments were raised from BOD of NTDC as a closing remarks.

- It is important to have a least cost power development plan in order to make a uniform policy for the decision makers.
- It is to avoid the situation, Pakistan faced from 2008 onward due to absence of such a plan and the whole country suffered from power shortage.

		
Opening Remarks (MD)	Presentation on PDP	Presentation on PSDP

		
Presentation on SEA	Presentation on Senarios	Q&A Session
		
Q&A Session	Lunch Break	Closing Remarks (BOD)

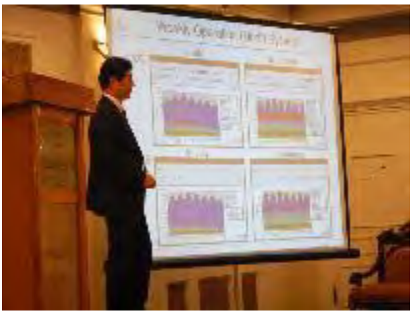
10.3.3 Third Workshop

3rd Workshop was held at the Hotel Margala in Islamabad on 5th Nov. 2015, which was organized by NTDC. Relevant Pakistani authorities and organizations and the donor organizations such as JICA, WB, ADB, USAID and KfW were invited and JICA Project Team made presentation on the following themes and Questions and Answers sessions were followed. Number of participants was 51 excluding JICA project team. All the participants took active part in the workshop.

- Power Demand Forecast and Primary Energy Supply Analysis
- Power Development Planning
- Power System Development Planning
- Strategic Environmental Assessment
- Financial Analysis

The main questions and comments raised are as follows;

- It is concerned that the amount of gas may not be available so a substitute plan should be in place in case gas will not be available.
- The project cost for each hydropower is different and should be taken accordingly.
- The capital recovery factor taken for financial evaluation is on the lower side.
- Either a complete transmission plan should be prepared for the projects or long term development plan of NTDC should be considered.

		
Opening Remarks (JICA)	Presentation on PDP	Presentation on PSDP
		
Presentation on SEA	Presentation on Finance	Q&A Session
		
Q&A Session	Tea Break	Lunch Break