National Transmission and Despatch Company Limited

National Power System Expansion Plan

2011 - 2030

Final Report

Main Report

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Prepared by

SNC-Lavalin International Inc.
in association with
National Engineering Services Pakistan (PVT) Limited

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LIST OF ABBREVIATIONS AND DEFINITIONS

Abbreviations:

ADB	Asian Development Bank
AEDB	Alternative Energy Development Board
cct-km	Circuit-kilometre
Consultant	SNC-Lavalin, Transmission and Distribution Group
DISCO	Distribution Company
DSM	Demand Side Management
GDP	Gross Domestic Product
GENCO	Generation Company
HPP	Hydel (or Hydro) Power Project
HSFO	High-Sulphur Furnace Oil
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEEE	Institute of Electrical and Electronic Engineers
kA	Kilo-ampere
KESC	Karachi Electric Supply Company
km	Kilometre
KPT	Karachi Port Trust
kV	Kilovolt
MMcfd	Million cubic feet per day
MOU	Memorandum of Understanding
MT	Metric Tonnes
MTOE	Million Tons of Oil Equivalent
MVA	Mega volt-amperes
MWh	Megawatt-hour or 1,000 kilowatt-hours
NEPRA	National Electric Power Regulatory Authority
NESPAK	National Engineering Services Pakistan (Pvt) Limited
NPP	National Power Plan, prepared by Acres International Limited in 1994
NTDC	National Transmission and Despatch Company
OGDCL	Oil and Gas Development Company Limited
P.P.	Power Project
PAEC	Pakistan Atomic Energy Commission
PARCO	Pak-Arab Refinery Company
PEPCO	Pakistan Electric Power Company

PPIB	Private Power and Infrastructure Board
PPL	Pakistan Petroleum Limited
PQA	Port Qasim Authority
PSO	Pakistan State Oil
PSS/E	Power System Simulation
RFO	Residual Furnace Oil
SIL	Surge Impedance Load
SNGPL	Sui Northern Gas Pipeline Limited
SSGCL	Sui Southern Gas Company Limited
SYPCO	Generation planning software (System Production Costing)
TAVANIR	The Iranian Electric Utility
WAPDA	Water and Power Development Authority

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1 INTRODUCTION

1.1 Objective of the National Power Systems Expansion Plan

As at 31 December 2010 the total installed capacity of Pakistan was around 21,420 MW. However rapid load growth and inadequate generation addition to the power pool created a gap between supply and demand resulting in significant load shedding.

Table 1-1 below shows the level of load shedding in recent years from no load-shedding in 1993 to almost 23% in 2010.

Table 1-1 Load Shedding Levels

Year	National Sales (GWh)	National Load Shedding (GWh)	Total National Demand (GWh)	Load Shedding %
2003	52,661	-	52,661	0.0%
2004	57,467	520	57,986	0.9%
2005	61,247	265	61,512	0.4%
2006	67,608	1,208	68,815	1.8%
2007	71,947	2,040	73,982	2.8%
2008	72,518	12,578	85,096	14.8%
2009	69,668	18,222	87,890	20.7%
2010	73,595	21,821	95,238	22.9%

In order to address this gap the National Transmission and Despatch Company (NTDC) of Pakistan identified the need to develop a National Power System Expansion Plan (NPSEP). The objective is to provide a plan for the development of hydroelectric, thermal, thermal nuclear and renewable energy resources to meet the expected load up to the year 2030. Given the chronic and ever increasing power shortage, the need for an expansion plan was urgent and thus only six months were allotted to prepare this revised plan. This plan was prepared during the period from December 1, 2010 through May 31, 2011.

1.2 Scope of Work

The scope of the NPSEP was to determine new generation facilities and transmission reinforcements required to meet future load growth using the latest available data. Based on a review of the load forecast (prepared by NTDC and reviewed by SNC-Lavalin), a least cost generation expansion plan was prepared taking into consideration government policies, environmental considerations and fuel constraints. An indicative transmission plan to evacuate power was developed using the generation expansion plan to 2030 and the network reinforcement requirements for the DISCOs in 2020. These generation and transmission plans were the key inputs in developing the financial plan and the annual revenue requirements to build and operate the system. The investments required by each DISCO to effectively reduce losses and optimize their systems were also calculated but they do not form a part of the overall investment requirements appearing in the NPSEP. They are provided as information to the DISCOs for their respective tariff preparation.

1.3 Structure of the report

The sections of the NPSEP report are as follows:

- Executive Summary
- Main Report (This Volume)
- Annexure 1: Fuel Supply, Port Handling and Fuel Pricing
- Annexure 2: Generation Plan
- Annexure 3: Transmission Plan
- Annexure 4: Distribution Plan
- Annexure 5: Financial Plan

2 POWER SECTOR ENVIRONMENT IN PAKISTAN

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2.1 Economy and the Energy Sector

Pakistan's economy grew by 4.1% on an inflation adjusted basis in 2009-10 after a growth of 1.2% in 2008-09. On a per section basis the industrial output grew by 4.9%, the Services sector grew by 4.4% while the Agriculture sector grew by 2%. Foreign Direct Investment (FDI) declined by 0.6% after a 5.5% increase in 2008-09. With large part of the decline in FDI was attributed to the Energy Sector and to Large Scale Manufacturing. FDI accounts for about 20% of gross fixed investment in the country.

Electricity and Gas Distribution was 3.9% of GDP in 1999-2000, which declined to 2% in 2009-10. Over the last six years, the GDP has varied from a high of 9% in 2004-05 to a low of 1.2% in 2008-09. For the same period, growth in the Electricity and Gas Distribution component of GDP has varied from a low of 26.6% in 2005-06 to a high of 30.8 in 2008-09 to. According to the Economic Survey 2010, the energy crisis is estimated to have reduced the overall GDP growth by about 2 % in 2009-10.

The total energy consumption declined by 5.2% in 2009 with electricity consumption in the industrial sector falling by 6.5% in 2009, and that of natural gas in the industrial sector falling by 2.6%.

2.2 Characteristics of the Energy Sector in Pakistan

Pakistan's energy supply includes natural gas, oil, coal and electriicy. The primary energy supplies by source in 2008-09 were:

Source	%
Natural Gas	48.3
Oil	32.0
Hydro and Nuclear	11.3
Coal	7.6
LPG	0.6

Source: *Energy Yearbook 2009*

The final energy consumption by source in 2008-09 was:

Source	%
Natural Gas	43.7
Oil	29.0
Hydro and Nuclear	15.3
Coal	10.4
LPG	1.5

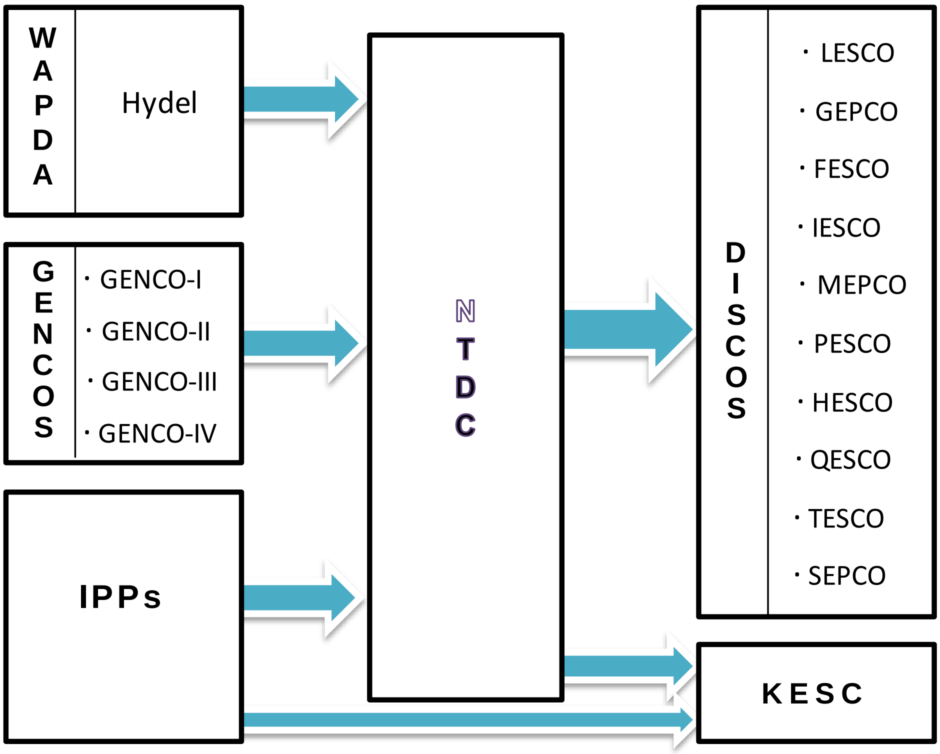
Source: *Energy Yearbook 2009*

Pakistan has a good indigenous resource base of natural gas (28.3 TCF as of January 2010), hydroelectric potential and the huge reserves of coal at Tharparkar. Due to a variety of reasons, there has been a lack of progress in development of all these resources with a consequent increase in the use of imported oil at a huge import cost.

2.3 The Current Power System

Since independence, Pakistan's power sector consisted of two vertically integrated utilities – WAPDA and Karachi Electricity Supply Company (KESC). The power sector has been restructured starting with the creation of Pakistan Electric Power Company (PEPCO) in 1998. Water and Power Development Authority (WAPDA) retained ownership of 14 hydro plants while WAPDA's thermal plants have been distributed to three Generation Companies (GENCOs). National Transmiission and Despatch Company (NTDC) acts as the bulk supplier of electricity and is responsible for the entire transmission network. The electricity is transmitted to ten Distribution Companies (DISCOs) for onward distribution to end consumers. The existing arrangment is shown below:

Pakistan Power Sector Structure



GENCO-I: Jamshoro Thermal Power Station
Kotri Thermal Power Station
GENCO-II: Guddu Thermal Power Station
Quetta Thermal Power Station
GENCO-III: Muzaffargarh Power Station
Faisalabad Thermal Power Station
Multan Thermal Power Station
Shahdara Power Plant
GENCO-IV: Lakhra Coal Power Plant

LESCO: Lahore Electric Supply Company
GEPCO: Gujranwala Electric Power Company
FESCO: Faisalabad Electric Supply Company
IESCO: Islamabad Electric Supply Company
MEPCO: Multan Electric Power Company
PESCO: Peshawar Electric Supply Company
HESCO: Hyderabad Electric Supply Company
QESCO: Quetta Electric Supply Company
TESCO: Tribal Electric Supply Company
SEPCO: Sukkur Electric Power Company

Note: KESC is an integrated utility with generation, transmission and distribution. It purchases power from both NTDC and IPPs.

Pakistan's power system is severely strained with widespread and unannounced loadshedding. In recent years, the lower availability of hydro resources and of gas for power has resulted in the increased use of imported and expensive oil, which has added to the financial strain of the sector. The gap between the cost of producing power and revenue derived from its sale has also widened. From 2003 to 2007, despite rising fuel costs GoP chose not to increase consumer tariffs. Compounding the problem is the cumulative effect of the inter – corporate circular debt in the energy supply chain.

In the late 1980s and early 1990s, Pakistan's total installed capacity remained at about 9,400 MW. The installed capacity of the country in 2010 was 18,892 MW of which 30% was hydro. The total electricity generation in 2010 was 10,544 GWh, the breakdown by source was:

Source	%
Oil	30.50
Gas	33.15
Hydro	33.33
Nuclear	2.85
Coal	0.16

Source*: Power System Statistics 2010 35th edition*

The power sector is a major consumer of petroleum products and natural gas. Of the total petroleum products consumed in Pakistan in 2008-09 of 17.9 million tonnes, 42.3% was consumed by the power sector. The corresponding percentage in 2003-04 was 20.4%, demonstrating the drastic increase in the use of petroleum products for power generation. The percentage share of total natural gas consumption for power generation was 44.7% in 2003-04 but this has declined to 31.8% in 2008-09, reflecting the Government of Pakistan's (GoP) policy of restricted allocation of gas for power generation.

The length of transmission lines in the country as of June 2009 was 5,078 ckM of 500-kV and 7,325 of 220-kV lines. Improvement of the transmission system to ensure system integrity and smooth supply to the consumers, is an ongoing process. Village electrification is an important part of Pakistan's power policy. In 2008-2009 9,868 villages were electrified.

The GoP through the Alternative Energy Development Board (AEDB) is encouraging the development of alternative and renewable energy projects. Several Letters of Intent have been signed for wind power projects, and active efforts are being made to encourage biodiesel, biomass, waste-to-energy, mini hydro and solar technologies.

GoP policy is to reduce dependence on imported oil and the development of indigenous resources. This can only be achieved by development of economic hydro resources, drilling for more gas and by following a determined approach to exploit the huge coal reserves at Tharparkar.

Sources:

- *Economic Survey of Pakistan 2009-10*
- *Pakistan Energy Yearbook 2009*
- *Electricity Marketing Data, 35th Issue, Planning Dept, NTDC*

3 SYSTEM PLANNING CRITERIA

3 SYSTEM PLANNING CRITERIA

3.1 Introduction

The key assumptions as well as the technical and economic criteria used in the development and analysis of the National Power System Expansion (NPSEP) are presented in this section.

3.2 Economic and Financial Parameters

The following economic and financial parameters were considered in the development of the plan:

Study Period and Reference Year for Discounting

The study horizon period for development of the NPSEP is 2011-12 to 2029-30, inclusive, a 19-year period. The reference year used for present worth costing was 2011-12. The costs including capital costs, operating costs and fuel prices have been estimated at 2010 price levels.

Discount rate

The discount rate was used to bring all the future costs to one reference time point using the time value of money concept. The basic real discount rate considered in the study is 10%. Additional discount rates of 8% and 12% were also considered for the sensitivity analysis.

Exchange Rate

The exchange rate used in this study is Rs. 80/US$, which was the average exchange rate for 2010.

Cost of un-served energy

Un-served energy represents the failure to meet the energy demand of existing and new customers. It takes the form of either planned or unplanned supply curtailments. The cost of un-served energy varies on a sector-by-sector basis. In this study, the target levels of system reliability have been established so that the levels of un-served energy for the different scenarios analyzed would be similar. The cost of un-served energy has been approximated as the cost of generation from the most expensive unit in the system. This approach most likely understates the cost of un-served energy. However, since the primary purpose of the analysis was the comparison of alternative expansion scenarios which by definition would have similar levels of un-served energy, this approximation was deemed appropriate.

Fuel Pricing

Given the shortage of supply of indigenous fuels, it is likely that petroleum products and gas would need to be imported for future power plants. Therefore the pricing for petroleum products and gas have been based on their imported equivalents.

Although Thar coal would be produced domestically, currently there is insufficient information to base firm mining costs on. Therefore Thar coal has been priced such that the cost of power generated at Thar using Thar coal would be equivalent to the cost of power from a coastal plant using imported coal.

3.3 Generation Planning Criteria

Reliability Criteria and Reserve

Reliability criterion to decide the capacity addition requirement for every year over the planning horizon is the basis for developing the generation plan. The reliability criterion determines the timing of new capacity additions required in the future. Currently the reliability of the system is not the primary concern for Pakistan as the country is experiencing huge shortages of power. NTDC is therefore planning to add capacity to meet demand requirements at a lower but acceptable reliability level. There are two reliability indices which are commonly used for the development of generation expansion plans. These indices are as follows:

- *Loss of Load Probability (LOLP):* LOLP is the risk associated with having insufficient generation to meet the forecasted load demand. It is generally expressed in hours/year;
- *Expected Un-served Energy (EUE):* EUE is the measure of energy that is not supplied in expected terms over the year. It is generally expressed in GWh per year.

Since the country is experiencing huge shortages of power and most of the new capacity will be available only after 2014-15 taking into account the lead time of at least three years for development of new power plants, it is not realistic to expect that the country could meet the pre-determined reliability target of 1% of LOLP (equivalent to a loss of load expectation of 87.6 hours/year) in a short time period. A further constraint for Pakistan to meet its reliability target is the limited funding available for power system expansion. A significant amount of investment is required for both generation and transmission systems expansion as well as for the strengthening and expansion of the distribution networks.

The primary index used for reliability criterion in this study is Loss of Load Probability (LOLP). The reliability criterion for this study was applied in a staged manner, as follows:

- Up to 2018-19: LOLP < 10% (equivalent to a loss of load expectation of 876 hours/year);
- 2019-20: LOLP < 5% (equivalent to a loss of load expectation of 438 hours/year);
- 2020-21 onwards: LOLP < 1% (87.6 hours/year).

Load Profile

Analysing annual hourly load profiles is an important aspect of generation planning to capture the hourly and seasonal variations in the load. The hourly load data is used to construct monthly load duration curves which are key inputs to generation planning for planning the future years. The normal assumption is that the future monthly/seasonal load variations would be similar to the past ones. However, the historical load duration curves for the recent years could not be directly used for the future years since these curves were based on supply availability. Therefore it was necessary to have information on unrestricted monthly load patterns and hourly load profiles to represent the future years. After reviewing historical data and previous studies, 2003-04 was selected as it had no planned load shedding and very little adjustment was required for unexpected load shedding.

3.4 Environmental Criteria

The development of the NPSEP has been based on the environmental criteria and standards as currently exist in Pakistan.

3.4.1 Thermal Generation Projects

The emission requirements for thermal power plants have been based on the National Environmental Quality Standards (NEQS) that include the following specific standards:

- National Environmental Quality Standards for Municipal and Liquid Industrial Effluents;
- National Environmental Quality Standards for Industrial Gaseous Emissions;
- National Environmental Quality Standards for Sulphur Dioxide and Nitrogen Oxide Ambient Air Requirements.

The emission requirements pertain to particulates, Nitrogen Oxides, Sulphur Dioxide, Liquid Effluents and Solid Wastes.

The NPSEP has included in its cost estimates water treatment equipment for all plants, FGD equipment for coal fired plants and has used Low Sulphur Fuel Oil for oil fired plants.

3.4.2 Hydroelectric Generation Projects

The range of adverse environmental and related social impacts that can result from hydroelectric dams is remarkably diverse. While some impacts occur only during construction, the most important impacts usually are due to the long-term existence and operation of the dam and reservoir. Other significant impacts can result from complementary civil works such as access roads, power transmission lines, and quarries and borrow pits. Adverse environmental and social impacts associated with dams and reservoirs include flooding of natural habitats, loss of terrestrial wildlife, involuntary displacement and deterioration of water quality. Twenty seven hydroelectric projects have been considered in the NPSEP. Of these, eighteen projects have undergone thorough feasibility studies. Eleven of the eighteen projects have feasibility studies which are more than three years old and need updating. Nine projects are at initial stages and their feasibility studies have not yet started.

For those projects that have been studied to feasibility level and for which environmental cost estimates were available, these cost estimates were escalated to 2010 price levels. For those projects which have not been studied to feasibility level and for which environmental cost estimates were not available, an approximation was made. The approximation was based on information for those projects for which the required information was available. The environmental cost as a percentage of total project cost averaged over all those projects for which information was available, was applied to those projects for which the total project cost was available but the environment cost was not.

3.4.3 Transmission Projects

Environmental criteria at the planning level are applied at the transmission line route selection.

In Pakistan, there is an identification of protected areas designated for the protection of endangered species, habitats, ecosystems, archaeological sites, monuments, buildings, and other cultural heritage sites. These areas can be broadly categorized into two groups as follows:

- Ecosystems;
- Archaeological and Cultural sites.

The following environmental criterion has been adopted to avoid environmentally sensitive areas and major resettlement issues for the proposed transmission line routes. These are mainly based on physical, ecological and socio-economic features:

- Avoidance of heavily populated areas/towns;
- Avoidance of indigenous or tribal settlements;
- Avoidance of cultural, religious and historical buildings;
- Minimum disturbance to the natural habitats of flora and fauna;
- Avoidance of major birds migratory routes;
- Avoidance of wildlife sanctuaries, National Parks, and Game Reserves;
- Avoidance of potentially security vulnerable areas;
- Appropriate distance from the sensitive receptors (for instance, minimum 500m);
- Avoidance of large water bodies like lakes, rivers or streams; and,
- Avoidance of airports, railway tracks and other similar structures and facilities.

3.5 Transmission Planning Criteria

The planning criteria used in the transmission planning studies were taken from the Planning Code section of the NTDC Grid Code (June, 2005).

3.5.1 Contingency Conditions

Planning for steady-state, were based on (N-0) and (N-1) contingency conditions. There were two base-case scenarios for each year; Summer-peak (High Water) and Winter-off-peak (Low Water).

Single contingency cases (N-1) were studied for each base case scenario. For the planning studies, an outage was defined as any one of the following:

- Outage of a 500/220/132 kV transmission circuit;
- Outage of a generator step-up transformer;
- Outage of a grid station transformer;
- Outage of a substation 500 kV or 220 kV bus section;
- Outage of a 500 kV shunt reactor.

Planning for dynamic performance (transient stability) was based on the occurrence of each of the following contingencies:

- Permanent three-phase fault on any 500/220 kV line and subsequent outage of the associated transmission line;
- Failure of a circuit breaker to clear a fault (“stuck breaker” condition) in 5 cycles, with back-up clearing in 9 cycles after fault initiation.

3.5.2 Component Loading

Under normal operating conditions (N-0), all transmission lines and transformers were loaded below their Normal Continuous Maximum ratings. Under contingency conditions (N-1), all transmission lines and transformers were loaded below their Emergency ratings.

3.5.3 Voltage

For steady-state conditions, all bus voltages shall be within the following ranges:

- Under normal operating conditions (N-0) ± 5% of nominal system voltage
- Under contingency conditions (N-1)± 10% of nominal system voltage

3.6 Distribution Planning Criteria

The planning of the secondary transmission system considered the operation of a power system under two possible situations as listed below:

- *Normal operating conditions (N-0):* the secondary transmission system (66-132 kV) infrastructure was entirely available (no equipment has been forced out of service);
- *Contingency operating conditions (N-1):* one of the secondary transmission system equipment (line or transformer) was out of service. In this study, only the outage of transmission lines rated at 132 kV (or 66 kV) within each DISCO was considered.

For each of these operating conditions, the following criteria were applied to the analyses.

3.6.1 System Voltage Criteria

The acceptable voltage range for operating the system based on factors such as equipment limitations and motor operation under normal and contingency conditions were as follows:

Condition	Acceptable Voltage Range
Normal System Conditions	95% - 105% (±5%)
Contingency Conditions	90% - 110% (±10%)

It is important to note that from an operational standpoint, healthy systems usually target a voltage close to 1.0 pu at 132 kV (or 66 kV) voltage levels.

3.6.2 Equipment Thermal Loading Criteria

The secondary transmission system was planned to allow all transmission lines and equipment to operate within the following limits for the following defined conditions:

Condition	Thermal Loading Limit
Normal System Conditions	Defined Normal Load Capacity
System Design Contingencies of Long Duration (i.e. an outage involving the failure of a transformer)	Defined Normal Load Capacity
System Design Contingencies of Short Duration (i.e. not involving a transformer)	Defined Emergency Load Capacity (120% of normal rating for 10 hours per year)

In line with NTDC requirements the line loading under contingency conditions (N-1 analysis) were based on the normal rating (Rating A).

3.7 Financial Planning Criteria

The overall objective for the financial plan was to determine the financial implications for the power sector over the course of the 20 year period (2010-11 to 2029-30) and to determine the level of impact on the average tariff.

The sales and load forecast and the system expansion plan comprising the generation and transmission expansion plans were the key inputs to the financial plan. The system expansion plan was the least cost economic plan to serve Pakistan’s load growth and current load over the period 2010-11 to 2029-30.

The costs underlying the generation expansion plan were economic costs and were in real terms (i.e. constant price levels excluding financing costs, taxes). For the financial plan, it was necessary to turn these economic costs of the generation and transmission into financial costs, taking into account taxes, depreciation, financing charges and profits. This involved determining the financing associated with the capital expenditures and then calculating the financial costs associated with the assets by including interest costs, depreciation, operation costs including fuel and maintenance costs, taxes, and appropriate returns to the investors. Since the financial plan was carried out in nominal terms, an inflationary component was also be added to the capital, and operating costs.

The financial plan indicates the overall investment and financing required for the generation and transmission expansion and the overall impact on the cost of power to the DISCOs and to KESC.

The analysis determined the tariff at the generation and transmission level required to recover the financial costs of the investments in the power sector in generation and transmission.

The key criteria used in the financial analysis are summarized in Table 3-1 below.

Table 3-1 Key Financial Criteria

Criteria	Value Used
Inflation Rate	2%
Discount Rate	10%
Rate of Return	15% on Equity
Cost of borrowing	8% per annum
Debt/Equity Ratio for financing	70% / 30%
Loan repayment period	10 years
Exchange rate	80 PAK Rupees = 1 US$ (2010)
Asset Life	
• Hydro	50 years
• Thermal	30 years
• Transmission	40 years

4 POWER DEMAND

4 POWER DEMAND

4.1 Introduction

Load forecasting entails the prediction of the future level of demand, and provides the basis for future supply side and demand side planning. Generation planning requires a load forecast for the country as a whole, while transmission and distribution planning requires more load–level and geographic detail to determine the location, timing and loading of individual lines, substations and transformation facilities. Geographic load detail is also a factor in the determination of the location of generation plants since it is generally desirable to locate generation sources close to the load centres.

This analysis was based on a complete review of historical data which included electricity consumption, electricity tariffs, Gross Domestic Product (GDP), population etc., covering the period 1970 to 2010.The forecast horizon is up to the year 2035.

Four forecast scenarios have been developed: the Base or Normal Case, the Low Case, the High Case and the Base Case with Demand Side Management. The forecast was prepared by NTDC and is summarized in the following sections.

4.2 Issues related to the load forecast

4.2.1 Load Shedding

There has been planned load shedding in the country since 2004 due to shortages of generation and reliability of the transmission and distribution systems. Statistics available on load shedding since 2004 are shown in Table 4-1.

Table 4-1 History of Planned Load Shedding

Year	National Sales (GWh)	National Load Shedding (GWh)	Total National Demand (GWh)	Shedding as % of National Demand
2003	52,661	-	52,661	0.0%
2004	57,467	520	57,986	0.9%
2005	61,247	265	61,512	0.4%
2006	67,608	1,208	68,815	1.8%
2007	71,947	2,040	73,982	2.8%
2008	72,518	12,578	85,096	14.8%
2009	69,668	18,222	87,890	20.7%
2010	73,595	21,821	95,238	22.9%

Source: *Power System Statistics 35th edition and National Power Control Centre*

The national demand combines sales by the PEPCO system and the sales by KESC.

Load shedding as a percentage of national demand reached an alarming 22.9% by 2010. In the derivation of the load forecast, the historical data was adjusted to take into account the load shedding. The forecast used the estimate of unconstrained demand as its starting point and therefore reflects the true energy and demand requirements of the customers.

4.2.2 Transmission and Distribution Losses

During the 1980's WAPDA introduced programs to reduce power and energy losses throughout its system, the implementation of which proved to be quite fruitful. After a few years of declining losses, system losses particularly distribution losses have risen again, thereby suggesting the need for remedial loss reduction efforts. Table 4-2 shows a summary of energy generation, sale, and auxiliary, transmission and distribution losses since 2000 for PEPCO.

Table 4-2 Historical Energy Generation, Sale and Losses – PEPCO

Year	Gross Generation	Auxiliary Consumption		Energy sent out	Transmission Losses		Distribution Losses		Units sold
	(GWh)	(GWh)	(%)	(GWh)	(GWh)	(%)	(GWh)	(%)	(GWh)
2000	55873	1201	2.1	54672	4017	7.2	9745	17.4	40910
2001	58455	1173	2.0	57282	4594	7.9	9304	15.9	43384
2002	60860	1315	2.2	59545	4600	7.6	9741	16.0	45204
2003	64040	1346	2.1	62694	4908	7.7	10365	16.2	47421
2004	69094	1397	2.0	67697	5054	7.3	11151	16.1	51492
2005	73520	1850	2.5	71670	5467	7.4	11925	14.9	55342
GR(2000-2005)	**5.6%**			**5.6%**					**6.2%**
2006	82225	1821	2.2	80404	5839	7.1	12160	14.8	62405
2007	87837	1850	2.1	85987	3268	3.7	15239	17.3	67480
2008	86269	1685	2.0	84584	2948	3.4	15097	17.5	66539
2009	84377	1672	2.0	82705	2962	3.5	14457	17.1	65286
2010	88880	1808	2.0	87072	2716	3.1	15478	17.4	68878
GR(2005-2010)	**3.9%**			**4.0%**					**4.5%**

Source: *Electricity Demand Forecast Period 2011-2035 by Planning Power NTDC.*

Note: *Gross Generation of PEPCO includes Export to KESC but auxiliary consumption of IPPs is not included*

The figures indicate that PEPCO distribution losses dropped from 17.4% to 14.8% of gross generation over the period 2000 to 2006. However, these increased to 17.3% in one year i.e. in 2007, and remained around that level from 2007 to 2010.

A summary of energy generation, sale, and losses since 2000 for the Karachi Electric Supply Company (KESC) is shown in Table 4-3.

Table 4-3 Historical Energy Generation, Sale and Losses - KESC

Year	Gross Generation	Auxiliary Consumption		Energy sent out	Transmission Losses		Distribution Losses		Units sold
	(GWh)	(GWh)	(%)	(GWh)	(GWh)	(%)	(GWh)	(%)	(GWh)
2000	11446	512	4.5	10934	286	2.5	4218	36.9	6430
2001	11677	534	4.6	11143	292	2.5	3928	33.6	6923
2002	12115	568	4.7	11547	303	2.5	4526	37.4	6718
2003	12616	581	4.6	12035	315	2.5	4744	37.6	6976
2004	13392	662	4.9	12730	335	2.5	4577	34.2	7818
2005	13593	661	4.9	12932	340	2.5	4176	30.7	8416
GR(2000-2005)	**3.5%**			**3.4%**					**5.5%**
2006	14500	685	4.7	13815	363	2.5	4392	30.3	9060
2007	14238	639	4.5	13599	372	2.5	3860	27.1	9367
2008	15189	610	4.0	14579	381	2.5	4147	27.3	10052
2009	15268	618	4.0	14650	390	2.5	4872	31.9	9396
2010	15805	591	3.7	15214	395	2.5	4914	31.1	9905
GR(2005-2010)	**3.1%**			**3.3%**					**3.3%**

Source: *Electricity Demand Forecast Period 2011-2035 by Planning Power NTDC and information from KESC.*

KESC distribution losses were significantly high and range from 27.1 to 37.6% (almost double the PEPCO system losses) during the past 10 years.

4.2.3 System Load Factor

The annual load factor gives the average value of the load to supply ratios as it changes over the year. The load depends mainly upon the electricity demand changes with time of day use, temperature, and season. It also depends on the composition of customer categories.

The load factors for the PEPCO system for the period 2005-2010 are given in Table 4-4.

Table 4-4 PEPCO Load Factor (Historical)

Period	Computed Gross Generation (GWh)	Computed Peak Demand (MW)	Load Factor (%)
2004-05	74257	12035	70.4%
2005-06	83579	13212	72.2%
2006-07	90116	15138	67.9%
2007-08	100143	16838	67.9%
2008-09	104532	17325	68.9%
2009-10	113035	17884	72.1%
Average Load Factor (2004-05 to 2009-10)			**69.9%**

Source: *Electricity Demand Forecast Period 2011-2035 by Planning Power NTDC.*

Note: *IPPs auxiliary consumptions are not included.*

These figures have been calculated on the basis of computed energy generation and computed peak demand for the two systems i.e. taking into account load management and excluding import/export of electricity between PEPCO and KESC. The load factors for the KESC System for the period 2005-2010 are shown in Table 4-5.

Table 4-5 KESC Load Factor (Historical)

Period	Computed Gross Generation (GWh)	Computed Peak Demand (MW)	Load Factor (%)
2004-05	13638	2197	70.86
2005-06	14697	2223	75.47
2006-07	14555	2354	70.58
2007-08	17285	2443	80.77
2008-09	18169	2462	84.24
2009-10	19169	2562	85.41
Average Load Factor (2004-05 to 2009-10)			**77.89**

Source: *Electricity Demand Forecast Period 2011-2035 by Planning Power NTDC & KESC letters*

The load factors for both PEPCO and KESC systems have been increasing in recent years, with the KESC system load factor significantly higher than that of PEPCO.

4.2.4 Load Characteristics

The electricity consumption pattern by sector over the last four decades is shown in Table 4-6.

Table 4-6 Electricity Consumption Pattern

	% Consumption			
Sector	**1980**	**1990**	**2000**	**2010**
Domestic	21	30	43	42
Industry	42	40	36	35
Agriculture	19	16	9	12
Commercial	8	6	5	7
Others	10	8	7	4

Source: *Electricity Demand Forecast Period 2011-2035 by Planning Power NTDC*

The domestic share of total electricity consumption is increasing over time, while that of the industrial sector is declining. As incomes are rising, the domestic sector consumption is increasing. However, the trend of decreasing industrial consumption is likely to have a negative impact on economic growth and therefore needs to be arrested.

Tariffs

The real price of electricity is, conceptually, very important in deriving an econometric forecast of electricity sales. Economic theory suggests that for any increase in the real price of a commodity there will be a corresponding decrease in its consumption. The link between the two is price elasticity. In Pakistan, as in many other jurisdictions, the derivation of the price elasticity of sales of energy is difficult for two reasons:

- The real price increases tend to be small and widely dispersed in time;
- From a pragmatic point of view, electricity is an inelastic product: once a consumer has electric power service, he or she is reluctant to go to alternative energy sources (from electric light to candles or kerosene lamps, electric motors to gas-powered motors or domestic beasts of burden, etc.).

The power sector has been chronically short of funds and will rely to a certain extent on tariffs to fund future expansion plans. Modest real increases in price have been used in the regression analysis based on the growth in real prices over the past years.

Electrification

Pakistan has been following a rural electrification program to enable the rural population to share the benefits of development. In 1980 30% of households were electrified which increased to 70% in 1998 as reported in the respective census reports.

4.2.5 Demand Side Management

Little formal work has been done on Demand Side Management (DSM) since the 1998 load forecast update study. As the benefits identified in this and other studies are assumed to have been implemented by 2010, the current long-term forecast assumes that while there may be no energy benefit in terms of either sales or generation, there could be a reduction in peak demand.

It is recognized that in a country with a scarcity of power, DSM is a crucial element in planning to meet the load. Such programs should be fostered and their results taken into account as programs are implemented.

4.3 Approach and Methodology

4.3.1 General

Two forecasts were prepared by the NTDC team a medium-term forecast up to the year 2020 for the PEPCO system and a long-term forecast up to 2035 for both the PEPCO system and the KESC system. The KESC system accounts for approximately 10% of the country's load.

The medium term forecast covers PEPCO service areas by category: domestic, commercial, industrial, agricultural, traction, street lighting and bulk sales. This includes all the DISCOs except KESC.

The long-term forecast was carried out on a country-wide basis; this was then separated into the PEPCO system and the KESC system. The medium term forecast contains a break-down by grid-station but the long-term forecast does not.

For purposes of the National Power System Expansion Plan (NPSEP), it was appropriate to consider the energy and capacity requirements of the country as a whole. The point of the forecast was to estimate the amount of power required by the current and prospective customers. The forecast therefore presented the unconstrained needs of the country.

The load forecast was used for two activities in the development of the NPSEP. The generation plan had to determine the least cost expansion plan that would meet the load forecast with an appropriate degree of reliability. The transmission plan was required to provide the least cost transmission plan that would transmit the power from the generation sources to the load centers. The forecast was therefore segregated by major load centre, defined as each DISCO and, within the DISCO, by each 132/11 kV grid station.

4.3.2 Medium-Term Forecast

The medium-term forecast followed a bottom-up approach. It started with the data of units billed by each category for each feeder within each DISCO, adjusted for load shedding. The medium-term forecast gave the peak demand for each grid station at the 132/11 kV level. This forecast gave the estimated consumption for each DISCO but did not include KESC.

This forecast estimated the value of energy and demand for the PEPCO system (KESC did not provide the required information for the development of this forecast for its system). Load factors were estimated for each category for each DISCO. The categories included were Domestic (42% of total sales in 2010), Industrial (35%), Agriculture (12%), Commercial (7%) and others (traction, street lighting and bulk - 4%).

The forecast was based on a survey of the DISCOs who provided their forecast by customer category and by area or sub-area. The NTDC Planning Department adjusted the forecast for load shedding and for demand-side management. Load shedding has been a factor in the power sector since the 1980's but had been virtually eliminated in the early 2000's. It has become significant again in 2005 and even more so in 2009. The last DSM study done was about 10 years ago and the current forecast was adjusted to take into account the results of that study.

The DISCOs provided feeder wise data for units billed for the base year, and data for expected spot loads (e.g. any new industry, housing scheme, commercial plazas and any new village etc.) for the future years. NTDC provided estimates of future growth from the units billed in the base year.

4.3.3 Long Term Forecast

The long-term forecast was done at a national level and included KESC as an integral part of the forecast. The following were some of the more relevant observations:

- It was based on historic data 1970 to 2010 and the forecast covered 2011 to 2035;
- In carrying out multiple regressions, care was taken to ensure that any econometric relationships selected were logical and had a strong statistical correlation;
- The software E-views was used to assist with the derivation of econometric relationships;
- The methodology used was first presented in the National Power Plan Pakistan in 1994. This approach has, in general terms, been retained;
- The relationships that were examined are in the following formula:

  $$Ln(S) = K + C_1 * Ln(V_1) + C_2 * Ln(V_2) + C_3 * Ln(V_3) + etc.$$

  Where: ***Ln*** = the natural logarithm

  S = sales in a specific category

  K = a constant

  V1, V2, V3, etc. are independent variables

  C1, C2, C3, etc. are coefficients derived from the least squares regression analysis
- This analysis was applied to the Domestic, Commercial, Industrial and Agricultural categories;
- The Domestic category included a grouping of the direct sales to PEPCO customers, the direct sales to KESC customers, an estimate of the bulk load that serviced residential households (i.e. as part of housing colonies) as well as an estimate of the unserved domestic load (i.e. a load shedding allowance);
- The Commercial category included all the same elements;
- The Industrial load (which included all the captive generation as contained in the records available) was based on the assumption that captive generation was used primarily by industries in the production of their goods and services;
- Street lighting was taken as a percentage of the sales by domestic and commercial customers;

- The remainder of the bulk sales was taken as a percentage of the industrial and commercial load;
- The traction load was extremely small and an allowance for such sales was made by the judgment of the analyst;
- The regression coefficients derived from the historical analysis of the four "category groups" as mentioned above were applied to projections of the independent variables for each year of the forecast period in order to obtain the forecast for the category for that year;
- The projections of the independent variables were usually obtained from authoritative sources external to the NTDC;
- Each of the four categories of country level sales, forecasted above, was then bifurcated into PEPCO and KESC. This was done according to the historical share of each category.

4.4 Key Independent Variables

The potential independent variables (demographic and economic) for regression analysis included:

- Total GDP;
- GDP by major sector (agriculture, manufacturing, trade, services, etc.);
- Electricity revenue per kWh sold by customer class (real price);
- Number of customers by consumption category; and
- Population.

These regressions were analyzed by province and power system (PEPCO and KESC), and was based on sales by customer category. The best-fit regressions were found to be based on a logarithmic relationship between the variables.

The relationships selected for the forecasts were:

- Domestic sales are related to Total GDP, Real Electricity Price and Domestic Sales Lagged (-1) and a dummy variable;
- Commercial sales are related to Commercial GDP, Real Electricity Price Lagged (-2) and Commercial Sales Lagged (-3);

- Industrial sales are related to Total GDP, Real Electricity Price Lagged (-1), and Industrial Sales Lagged (-1) and a dummy variable; and
- Agricultural sales are related to Agriculture GDP, Real Electricity Price, Agricultural Sales Lagged (-1) and a dummy variable.

4.4.1 Projections of Independent Variables

GDP Growth

A review of historical total real GDP growth rates from 1970 to 2010 was carried out in order to assess the reasonableness of the future projections, and to propose the values to extrapolate these projections up to the year 2035. This analysis suggested that the longest continuous period where the growth rate approximated 6.5% was for ten years, and the long-term average for the entire period was 5% per year. These boundaries were used to establish the Low and High Cases for future projections of GDP. For the Base Case GDP growth projections, official projections developed by the GoP Planning Commission were directly adopted.

These projections are shown in Table 4-7 for the Low, Normal and High scenarios.

Table 4-7 GDP Projections

Year	Low	Normal	High
2010 – 2014	4.0%	4.3-61%	6.5%
2015 – 2016	4.5%	6.6%	6.5%
2017 – 2020	5.0%	6.4-6.6%	6.5%
2021 – 2025	5.0%	6.0-6.2%	6.5%
2026 – 2030	5.0%	5.8-5.9%	6.5%
2031 – 2035	5.0%	5.8%	6.5%

The detailed GDP forecast by sector for the Normal case is shown in Table 4.8.

Table 4-8 Projected Real GDP Growth Rates – Normal Case

Year	Gross Domestic Product (%)				
	Total	Total / Capita	Commercial	Industrial	Agriculture
2010-11	4.3	2.4	4.5	4.2	3.9
2011-12	4.9	3.0	5.2	5.0	4.0
2012-13	5.5	3.6	5.9	5.9	4.1
2013-14	6.1	4.2	6.6	6.8	4.1
2014-15	6.6	4.7	7.1	7.6	4.1
2015-16	6.6	4.7	6.9	8.0	4.1
2016-17	6.6	4.7	6.8	8.2	4.1
2017-18	6.5	4.6	6.4	8.5	4.1
2018-19	6.5	4.6	6.3	8.8	4.1
2019-20	6.4	4.5	5.5	10.0	4.0
2020-21	6.2	4.4	5.1	10.0	4.0
2021-22	6.1	4.3	4.8	10.0	4.0
2022-23	6.1	4.3	4.7	10.0	3.8
2023-24	6.0	4.2	4.5	10.0	3.6
2024-25	6.0	4.2	4.4	10.0	3.5
2025-26	5.9	4.1	4.3	9.8	3.2
2026-27	5.9	4.1	4.4	9.6	3.0
2027-08	5.8	4.0	4.2	9.4	3.0
2028-29	5.8	4.0	4.2	9.2	3.0
2029-30	5.8	4.0	4.2	9.0	3.0
2030-31	5.8	4.1	4.2	9.0	3.0
2031-32	5.8	4.1	4.2	9.0	3.0
2032-33	5.8	4.1	4.2	9.0	3.0
2033-34	5.8	4.1	4.2	9.0	3.0
2034-35	5.8	4.1	4.2	9.0	3.0
ACGR(2010-35)	5.9	4.1	5.1	8.6	3.6

Source: *Electricity Demand Forecast – 2011-2035, NTDC Planning*

Number of Customers

The number of domestic customers was estimated by first projecting the population growth of Pakistan using the most recent historic growth rates. This was converted to the number of households using the size of households based on census data – 6.8 people per household. This household size was kept constant over the forecast period. This provides an estimate of the future number of domestic customers.

Electricity Prices

There is a direct relationship between the price of electricity and its consumption. There is also a relationship between the price of electricity and distribution losses. Real changes in future electricity prices will be determined by the capital investment program.

The power sector has been chronically short of funds and will rely to a certain extent on tariffs to fund future expansion plans. Modest real increases in price have been used in the regression analysis based on the growth in real prices over the past three years. The rates used were 2.2%, 2.2%, 0.6%, and 3.1% for domestic, commercial, industrial and agriculture sectors respectively for the first 10 years of the forecast. The increases were tapered down to 1.1%, 1.1%, 0.3% and 2.5% for the next 10 years of the forecast. And finally, no real increase has been assumed for the next five years for all sectors. Higher tariff increases were assured in earlier years as capital investments are expected to be higher in those years.

4.5 Load Forecasts

4.5.1 Sales Forecasts

The NPSEP sales forecasts for PEPCO and KESC by tariff category are shown in Table 4-9. These forecasts are based on the observed 2010 consumption levels and the annual growth rates determined from the growth in the independent variables and the coefficients established in the regression analysis. The average annual growth rate of electricity consumption over the 2010 to 2035 period is 8.05%. Table 4-9 shows that the category of largest growth is the Domestic sector, followed by the Industrial category and then by the Agricultural and Commercial sectors.

Year	Domestic		Commercial		Industrial		Agriculture		Public Light		Traction		Bulk		Total		Self Generation		Gross Total		
	PEPCO	KESC	PEPCO	KESC	PEPCO	KESC	PEPCO	KESC	PEPCO	KESC	PEPCO	KESC	PEPCO	KESC	PEPCO	KESC	PEPCO	KESC	PEPCO	KESC	Sum
Base Year (Recorded)																					
2009-10	**29479**	**4316**	**4465**	**1091**	**16372**	**3387**	**9585**	**104**	**371**	**87**	**5**	**0**	**3388**	**920**	**63665**	**9905**	**8890**	**2797**	**72555**	**12702**	**85257**
Energy Shed	**9450**	**1005**	**1431**	**263**	**5249**	**816**	**3073**	**25**							**19203**	**2109**			**19203**	**2109**	**21312**
Base Year (Computed)																					
2009-10	**38929**	**5321**	**5896**	**1354**	**21621**	**4203**	**12658**	**129**	**371**	**87**	**5**	**0**	**3388**	**920**	**82868**	**12014**	**8890**	**2797**	**91758**	**14812**	**106569**
Future Projections																					
2010-11	42732	6030	6246	1540	22808	4557	13881	147	497	118	4	-	3542	1065	89711	13457	9420	2964	99131	16421	115552
2011-12	46977	6629	6739	1661	24358	4866	15045	160	545	129	4	-	3802	1143	97470	14589	10060	3166	107529	17754	125283
2012-13	51639	7287	7305	1800	26178	5230	16291	173	598	141	4	-	4096	1232	106111	15864	10811	3402	116922	19266	136188
2013-14	56853	8023	7850	1935	28299	5654	17723	188	656	155	4	-	4420	1329	115806	17284	11687	3678	127493	20962	148455
2014-15	62742	8854	8476	2089	30748	6143	19398	206	722	170	4	-	4789	1440	126881	18902	12699	3996	139580	22899	162478
GR(2010-15)	**10.02%**	**10.72%**	**7.53%**	**9.06%**	**7.30%**	**7.88%**	**8.91%**	**9.79%**	**14.26%**	**14.35%**	**-2.90%**		**7.17%**	**9.38%**	**8.89%**	**9.49%**	**7.39%**	**7.39%**	**8.75%**	**9.10%**	**8.80%**
2015-16	69312	9781	9148	2255	33467	6686	21256	226	796	187	4	-	5196	1563	139180	20697	13822	4349	153001	25047	178048
2016-17	76568	10805	9815	2419	36448	7282	23258	247	876	206	4	-	5634	1694	152603	22653	15053	4737	167656	27389	195045
2017-18	84482	11922	10513	2591	39680	7927	25349	269	964	226	4	-	6103	1835	167096	24771	16388	5157	183484	29928	213411
2018-19	93047	13131	11238	2770	43196	8630	27514	292	1058	247	4	-	6606	1987	182663	27056	17840	5614	200503	32670	233172
2019-20	102216	14425	11904	2934	46994	9389	29708	315	1158	270	4	-	7129	2144	199113	29476	19408	6108	218521	35584	254105
GR(2015-20)	**10.25%**	**10.25%**	**7.03%**	**7.03%**	**8.85%**	**8.85%**	**8.90%**	**8.90%**	**9.89%**	**9.67%**	**0.00%**		**8.28%**	**8.28%**	**9.43%**	**9.29%**	**8.85%**	**8.85%**	**9.38%**	**9.22%**	**9.36%**
2020-21	112109	15821	12638	3115	51073	10204	32021	340	1265	294	4	-	7691	2313	216802	32086	21093	6638	237895	38724	276619
2021-22	122670	17311	13367	3294	55455	11079	34388	365	1380	320	4	-	8281	2490	235545	34860	22903	7207	258448	42067	300515
2022-23	133869	18892	14057	3465	60197	12026	36783	390	1500	347	4	-	8896	2675	255307	37796	24861	7823	280168	45619	325787
2023-24	145627	20551	14769	3640	65301	13046	39156	416	1627	376	4	-	9540	2869	276025	40897	26969	8487	302994	49384	352378
2024-25	157894	22282	15468	3812	70826	14150	41495	441	1758	406	4	-	10210	3070	297657	44160	29251	9205	326907	53365	380273
GR(2020-25)	**9.09%**	**9.09%**	**5.38%**	**5.38%**	**8.55%**	**8.55%**	**6.91%**	**6.91%**	**8.72%**	**8.49%**	**0.00%**		**7.45%**	**7.45%**	**8.37%**	**8.42%**	**8.55%**	**8.55%**	**8.39%**	**8.44%**	**8.40%**
2025-26	170572	24071	16135	3977	76769	15337	43756	465	1894	436	4	-	10897	3277	320028	47562	31705	9977	351733	57540	409273
2026-27	183592	25908	16820	4146	83198	16621	45930	488	2033	467	4	-	11609	3491	343186	51121	34360	10813	377546	61934	439480
2027-28	196836	27777	17477	4307	90106	18002	47978	509	2174	499	4	-	12333	3709	366909	54803	37213	11710	404122	66514	470636
2028-29	210224	29667	18111	4464	97572	19493	49894	530	2316	530	4	-	13071	3931	391193	58614	40297	12681	431489	71295	502785
2029-30	223665	31563	18749	4621	105656	21108	51667	548	2459	562	4	-	13823	4157	416023	62560	43635	13731	459658	76292	535950
GR(2025-30)	**7.21%**	**7.21%**	**3.92%**	**3.92%**	**8.33%**	**8.33%**	**4.48%**	**4.48%**	**6.94%**	**6.76%**	**0.00%**		**6.25%**	**6.25%**	**6.93%**	**7.21%**	**8.33%**	**8.33%**	**7.05%**	**7.41%**	**7.10%**
2030-31	237695	33543	19510	4809	114448	22865	53632	569	2609	596	4	-	14623	4397	442521	66780	47267	14874	489788	81654	571441
2031-32	252377	35615	20277	4998	123986	24770	55744	592	2765	631	4	-	15460	4649	470613	71255	51205	16114	521819	87369	609187
2032-33	267773	37788	21064	5191	134323	26835	57981	616	2930	668	4	-	16338	4913	500412	76011	55475	17457	555887	93469	649355
2033-34	283945	40070	21934	5406	145523	29073	60330	640	3102	707	4	-	17267	5193	532107	81089	60100	18913	592208	100002	692210
2034-35	300956	42471	22828	5626	157659	31498	62789	667	3284	748	4	-	18244	5486	565763	86495	65112	20490	630875	106985	737860
GR(2030-35)	**6.12%**	**6.12%**	**4.02%**	**4.02%**	**8.33%**	**8.33%**	**3.98%**	**3.98%**	**5.96%**	**5.86%**	**0.00%**		**5.71%**	**5.71%**	**6.34%**	**6.69%**	**8.33%**	**8.33%**	**6.54%**	**7.00%**	**6.60%**
GR(2010-35)	**8.52%**	**8.66%**	**5.56%**	**5.86%**	**8.27%**	**8.39%**	**6.62%**	**6.79%**	**9.11%**	**8.98%**	**-0.59%**		**6.97%**	**7.40%**	**7.99%**	**8.22%**	**8.29%**	**8.29%**	**8.02%**	**8.23%**	**8.05%**

The sectoral consumption pattern in 2010 and in 2035 is shown in Table 4-10.

Table 4-10 Consumption Patterns

	% of Sales 2010	% of Sales 2035
Domestic	42	46
Industry	35	37
Agriculture	12	9
Commercial	7	4
Others	4	4

Source: *Electricity Demand Forecast – 2011-2035, NTDC Planning*

The sectoral consumption pattern shows little change over time. The domestic sector will represent close to half of the total electricity consumption in 2035.

Pakistan's per capita consumption of electricity was 125 kWh in 1980, this improved to 640 kWh by 2010. It is projected that Pakistan's per capita consumption of electricity will rise to 2,538 kWh by 2035. This is still very low by international standards.

4.5.2 Generation Forecast

The NPSEP generation forecast is listed in Table 4-11.

The generation forecast was derived based on the sales forecast and the estimated power system losses, i.e. distribution losses and transmission losses, and the auxiliary consumption as well as the load factor for PEPCO and KESC system. These are discussed as follows:

<u>Transmission and Distribution Losses and Auxiliary consumption</u>

- PEPCO System

The present level of PEPCO transmission losses is 5.6% which consists of 3.0% at the 500 and 220 kV level (NTDC losses) and 2.6% at the 132kV level. DISCO"s losses have been gradually reduced from 2.6% in 2010 to 2.5% by the year 2015. NTDC transmission losses have also been gradually reduced from 3.0% in the year 2010 to 2.4% in the year 2015. These have been kept constant for the rest of the forecast period.

The present level of distribution losses is 14.6%. These losses have been reduced gradually to reach 8% by the year 2019, and have been kept constant up to the year 2035. Auxiliary consumption in the PEPCO system at present is 3.3% and this is kept constant throughout the forecast period.

- KESC System

The present level of KESC transmission losses (2.5%) is maintained throughout the forecast period. The distribution losses have been reduced gradually from the present 31.1% to reach 23.6% by the year 2015 and are kept constant for the rest of the forecast period. Auxiliary consumption in the KESC system is kept at 3.7% throughout the forecast period.

Load Factor

The present load factor is 69.3% for the PEPCO system and 85.4% for the KESC system. The average load factor for the PEPCO system for the period 2006 to 2010 is approximately 70%. The average load factor for the last six years for the KESC system is 78%. The computed load factor for both systems combined was gradually reduced to reach a target level of 67% by the year 2035, representing a system that would be free of supply constraints.

The NPSEP generation forecast is listed in Table 4-11. The results show that the average annual growth rate of electricity generation and peak demand of the country over the 2010 to 2035 period is 7.68% and 7.92%, respectively. The total generation and peak demand are expected to reach 889,583 GWh and 149,665 MW by the end of the period.

4.5.3 Forecast with DSM

It was not possible to explicitly include DSM initiatives in the medium term PMS model, or in the regression forecast. The impact of DSM on the forecast has been approximated by an improvement of the load factor to 70%, up from the 67% assumed in the Base Case. The NPSEP forecast with DSM is shown in Table 4-12.

Table 4-11 Load Forecast – Normal

Year	*PEPCO*			*KESC*			*PEPCO + KESC*			*Self Generation*			*Country*		
	Sale (GWh)	**Generation (GWh)**	**Peak (MW)**	**Sale (GWh)**	**Generation (GWh)**	**Peak (MW)**	**Sale (GWh)**	**Generation (GWh)**	**Peak (MW)**	**Sale (GWh)**	**Generation (GWh)**	**Peak MW**	**Sale (GWh)**	**Generation (GWh)**	**Peak MW**
Base Year (Recorded)															
2009-10	**68873**	**90052**	**13445**	**9905**	**15805**	**2082**	**78778**	**105857**	**15386**	**11687**	**12433**	**2028**	**90465**	**118290**	**17413**
Base Year (Computed)															
2009-10	**82868**	**108351**	**17847**	**12014**	**19170**	**2562**	**94882**	**127521**	**20223**	**11687**	**12433**	**2028**	**106569**	**139954**	**22251**
Future Projections															
2010-11	89711	115902	19115	13457	20970	2827	103168	136873	21743	12384	13174	2148	115552	150047	23891
2011-12	97470	124415	20547	14589	22215	3021	112058	146630	23353	13225	14069	2294	125283	160699	25648
2012-13	106111	133839	22133	15864	23617	3240	121975	157456	25142	14213	15121	2466	136188	172577	27608
2013-14	115806	144356	23904	17284	25169	3484	133090	169525	27139	15365	16346	2666	148455	185871	29804
2014-15	126881	156329	25921	18902	26938	3762	145783	183267	29414	16695	17761	2896	162478	201028	32310
G.R. (2010-15)	**8.89%**	**7.61%**	**7.75%**	**9.49%**	**7.04%**	**7.99%**	**8.97%**	**7.52%**	**7.78%**	**7.39%**	**7.39%**	**7.39%**	**8.80%**	**7.51%**	**7.75%**
2015-16	139180	171483	28472	20697	29496	4157	159877	199607	32332	18171	19331	3152	178048	218938	35485
2016-17	152603	184387	30656	22653	32282	4592	175256	216669	34927	19790	21053	3433	195045	237722	38360
2017-18	167096	199966	33291	24771	35301	5067	191867	235267	38009	21545	22920	3738	213411	258186	41747
2018-19	182663	218013	36344	27056	38558	5587	209719	256571	41549	23453	24950	4069	233172	281521	45618
2019-20	199113	237646	39671	29476	42007	6144	228589	279653	45398	25516	27145	4427	254105	306797	49824
G.R. (2015-20)	**9.43%**	**8.74%**	**8.88%**	**9.29%**	**9.29%**	**10.31%**	**9.41%**	**8.82%**	**9.07%**	**8.85%**	**8.85%**	**8.85%**	**9.36%**	**8.82%**	**9.05%**
2020-21	216802	258759	43253	32086	45726	6752	248888	304485	49550	27731	29501	4811	276619	333986	54361
2021-22	235545	281129	47056	34860	49679	7406	270405	330808	53967	30110	32032	5224	300515	362840	59190
2022-23	255307	304715	51073	37796	53863	8107	293102	358578	58642	32685	34771	5670	325787	393349	64313
2023-24	276025	329442	55293	40897	58283	8859	316922	387726	63568	35456	37719	6151	352378	425445	69719
2024-25	297657	355260	59707	44160	62934	9660	341817	418194	68736	38456	40910	6672	380273	459104	75408
G.R. (2020-25)	**8.37%**	**8.37%**	**8.52%**	**8.42%**	**8.42%**	**9.47%**	**8.38%**	**8.38%**	**8.65%**	**8.55%**	**8.55%**	**8.55%**	**8.40%**	**8.40%**	**8.64%**
2025-26	320028	381961	64282	47562	67782	10509	367590	449743	74110	41683	44343	7231	409273	494086	81342
2026-27	343186	409601	69027	51121	72853	11409	394307	482454	79705	45173	48056	7837	439480	530510	87542
2027-28	366909	437915	73900	54803	78101	12356	421712	516016	85471	48924	52047	8488	470636	568062	93958
2028-29	391193	466898	78898	58614	83532	13351	449807	550430	91410	52978	56359	9191	502785	606789	100601
2029-30	416023	496534	84021	62560	89155	14399	478583	585689	97524	57367	61029	9952	535950	646718	107477
G.R. (2025-30)	**6.93%**	**6.93%**	**7.07%**	**7.21%**	**7.21%**	**8.31%**	**6.96%**	**6.97%**	**7.25%**	**8.33%**	**8.33%**	**8.33%**	**7.10%**	**7.09%**	**7.34%**
2030-31	442521	528160	89495	66780	95168	15532	509301	623328	104071	62141	66107	10781	571441	689435	114852
2031-32	470613	561689	95307	71255	101546	16749	541868	663235	111037	67319	71616	11679	609187	734851	122716
2032-33	500412	597254	101481	76011	108325	18059	576424	705579	118453	72932	77587	12653	649355	783166	131106
2033-34	532107	635083	108057	81089	115561	19475	613197	750644	126372	79013	84056	13708	692210	834701	140080
2034-35	565763	675253	115050	86495	123265	21002	652258	798517	134814	85602	91066	14851	737860	889583	149665
G.R. (2030-35)	**6.34%**	**6.34%**	**6.49%**	**6.69%**	**6.69%**	**7.84%**	**6.39%**	**6.40%**	**6.69%**	**8.33%**	**8.33%**	**8.33%**	**6.60%**	**6.58%**	**6.85%**
G.R. (2010-35)	**7.99%**	**7.59%**	**7.74%**	**8.22%**	**7.73%**	**8.78%**	**8.02%**	**7.61%**	**7.88%**	**8.29%**	**8.29%**	**8.29%**	**8.05%**	**7.68%**	**7.92%**

Table 4-12 Load Forecast with Demand Side Management

Year	PEPCO			KESC			PEPCO + KESC			Self Generation			Country		
	Sale (GWh)	Generation (GWh)	Peak (MW)	Sale (GWh)	Generation (GWh)	Peak (MW)	Sale (GWh)	Generation (GWh)	Peak (MW)	Sale (GWh)	Generation (GWh)	Peak MW	Sale (GWh)	Generation (GWh)	Peak MW
Base Year (Recorded)															
2009-10	68873	90052	13445	9905	15805	2082	78778	105857	15386	11687	12433	2028	90465	118290	17413
Base Year (Computed)															
2009-10	82868	108351	17847	12014	19170	2562	94882	127521	20223	11687	12433	2028	106569	139954	22251
Future Projections															
2010-11	89711	115902	19082	13457	20970	2827	103168	136873	21710	12384	13174	2148	115552	150047	23858
2011-12	97470	124415	20476	14589	22215	3021	112058	146630	23283	13225	14069	2294	125283	160699	25577
2012-13	106111	133839	22018	15864	23617	3240	121975	157456	25028	14213	15121	2466	136188	172577	27494
2013-14	115806	144356	23739	17284	25169	3484	133090	169525	26975	15365	16346	2666	148455	185871	29641
2014-15	126881	156329	25697	18902	26938	3762	145783	183267	29192	16695	17761	2896	162478	201028	32088
G.R. (2010-15)	8.89%	7.61%	7.56%	9.49%	7.04%	7.99%	8.97%	7.52%	7.62%	7.39%	7.39%	7.39%	8.80%	7.51%	7.60%
2015-16	139180	171483	28177	20697	29496	4157	159877	199607	32040	18171	19331	3152	178048	218938	35192
2016-17	152603	184387	30285	22653	32282	4592	175256	216669	34559	19790	21053	3433	195045	237722	37993
2017-18	167096	199966	32831	24771	35301	5067	191867	235267	37554	21545	22920	3738	213411	258186	41291
2018-19	182663	218013	35780	27056	38558	5587	209719	256571	40990	23453	24950	4069	233172	281521	45059
2019-20	199113	237646	38986	29476	42007	6144	228589	279653	44720	25516	27145	4427	254105	306797	49146
G.R. (2015-20)	9.43%	8.74%	8.69%	9.29%	9.29%	10.31%	9.41%	8.82%	8.91%	8.85%	8.85%	8.85%	9.36%	8.82%	8.90%
2020-21	216802	258759	42433	32086	45726	6752	248888	304485	48737	27731	29501	4811	276619	333986	53548
2021-22	235545	281129	46083	34860	49679	7406	270405	330808	53002	30110	32032	5224	300515	362840	58226
2022-23	255307	304715	49930	37796	53863	8107	293102	358578	57509	32685	34771	5670	325787	393349	63179
2023-24	276025	329442	53960	40897	58283	8859	316922	387726	62247	35456	37719	6151	352378	425445	68398
2024-25	297657	355260	58166	44160	62934	9660	341817	418194	67209	38456	40910	6672	380273	459104	73881
G.R. (2020-25)	8.37%	8.37%	8.33%	8.42%	8.42%	9.47%	8.38%	8.38%	8.49%	8.55%	8.55%	8.55%	8.40%	8.40%	8.49%
2025-26	320028	381961	62512	47562	67782	10509	367590	449743	72357	41683	44343	7231	409273	494086	79588
2026-27	343186	409601	67009	51121	72853	11409	394307	482454	77705	45173	48056	7837	439480	530510	85542
2027-28	366909	437915	71613	54803	78101	12356	421712	516016	83205	48924	52047	8488	470636	568062	91693
2028-29	391193	466898	76322	58614	83532	13351	449807	550430	88858	52978	56359	9191	502785	606789	98049
2029-30	416023	496534	81135	62560	89155	14399	478583	585689	94664	57367	61029	9952	535950	646718	104617
G.R. (2025-30)	6.93%	6.93%	6.88%	7.21%	7.21%	8.31%	6.96%	6.97%	7.09%	8.33%	8.33%	8.33%	7.10%	7.09%	7.20%
2030-31	442521	528160	86268	66780	95168	15532	509301	623328	100874	62141	66107	10781	571441	689435	111654
2031-32	470613	561689	91708	71255	101546	16749	541868	663235	107471	67319	71616	11679	609187	734851	119150
2032-33	500412	597254	97477	76011	108325	18059	576424	705579	114485	72932	77587	12653	649355	783166	127138
2033-34	532107	635083	103610	81089	115561	19475	613197	750644	121965	79013	84056	13708	692210	834701	135673
2034-35	565763	675253	110119	86495	123265	21002	652258	798517	129928	85602	91066	14851	737860	889583	144779
G.R. (2030-35)	6.34%	6.34%	6.30%	6.69%	6.69%	7.84%	6.39%	6.40%	6.54%	8.33%	8.33%	8.33%	6.60%	6.58%	6.71%
G.R. (2010-35)	7.99%	7.59%	7.55%	8.22%	7.73%	8.78%	8.02%	7.61%	7.72%	8.29%	8.29%	8.29%	8.05%	7.68%	7.78%

4.5.4 Summary of Forecasts

A summary comparison of the four forecasts developed for the selected years is presented in Table 4-13 below.

Table 4-13 Summary of Forecasts for Selected Years for Country

	2010	2020	2035	Growth Rate (2010 – 2035)
Sales (GWh)				
Base Case	106,569	254,105	737,860	8.1 %
Base Case with DSM	106,569	254,105	737,860	8.1 %
Low Case	106,569	217,348	551,314	6.8 %
High Case	106,569	280,299	916,155	9.0 %
Generation (GWh)				
Base Case	139,954	306,797	889,583	7.7%
Base Case with DSM	139,954	306,797	889,583	77%
Low Case	139,954	262,518	665,210	6.4 %
High Case	139,954	338,663	1,106,567	8.6 %
Peak Demand MW				
Base Case	22,251	49,824	149,665	7.9%
Base Case with DSM	22,251	49,146	144,779	7.8%
Low Case	22,251	42,612	111,906	6.7%
High Case	22,251	54,998	186,228	8.9%

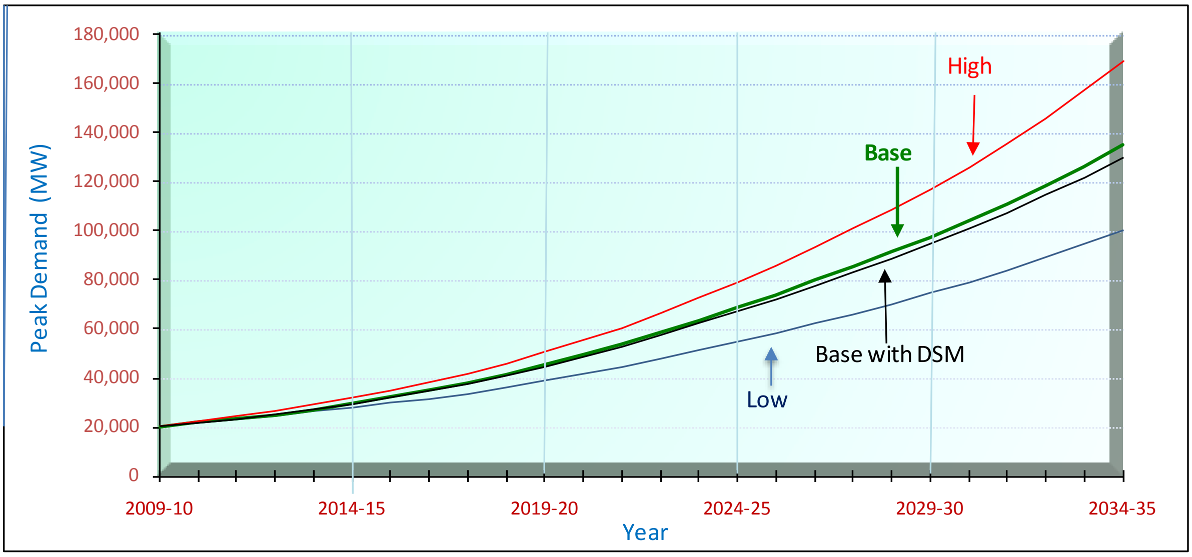
The detailed summary comparison is shown in Table 4-14.

Table 4-14 Summary of Forecasts

YEARS	Sales in GWh				Generation in GWh				Peak Demand in MW			
	Low	Base	DSM	High	Low	Base	DSM	High	Low	Base	DSM	High
	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	MW
History												
2009-10	90465	90465	90465	90465	118290	118290	118290	118290	17413	17413	17413	17413
2009-10	106569	106569	106569	106569	139954	139954	139954	139954	22251	22251	22251	22251
Forecast including allowance for load shedding												
2010-11	115510	115552	115552	117349	150319	150043	150047	152705	24112	23891	23858	24496
2011-12	124609	125283	125283	129566	159855	160695	160699	166204	25512	25648	25577	26528
2012-13	133972	136188	136188	143188	169800	172573	172577	181470	27161	27608	27494	29034
2013-14	143569	148455	148455	158259	179797	185868	185871	198193	28825	29804	29641	31784
2014-15	153914	162478	162478	174761	190481	201025	201028	216299	30607	32310	32088	34768
G.R. (2010-15)	**7.63%**	**8.80%**	**8.80%**	**10.40%**	**6.36%**	**7.51%**	**7.51%**	**9.10%**	**6.58%**	**7.75%**	**7.60%**	**9.34%**
2015-16	164853	178048	178048	192738	202773	218935	218938	237103	32854	35485	35192	38433
2016-17	176790	195045	195045	212266	215545	237719	237722	258840	34768	38360	37993	41769
2017-18	189573	213411	213411	233348	229432	258183	258186	282464	37082	41747	41291	45673
2018-19	203103	233172	233172	256013	245309	281517	281521	309290	39732	45618	45059	50118
2019-20	217348	254105	254105	280299	262518	306797	306797	338663	42612	49824	49146	54998
G.R. (2015-20)	**7.15%**	**9.36%**	**9.36%**	**9.91%**	**6.63%**	**8.82%**	**8.82%**	**9.38%**	**6.84%**	**9.05%**	**8.90%**	**9.61%**
2020-21	232761	276619	276619	306851	281141	333981	333986	370779	45736	54361	53548	60347
2021-22	249137	300515	300515	335484	300923	362835	362840	405410	49064	59190	58226	66132
2022-23	266429	325787	325787	366187	321808	393344	393349	442541	52588	64313	63179	72352
2023-24	284678	352378	352378	399029	343847	425440	425445	482256	56318	69719	68398	79025
2024-25	303774	380273	380273	433896	366903	459100	459104	524413	60233	75408	73881	86131
G.R. (2020-25)	**6.92%**	**8.40%**	**8.40%**	**9.13%**	**6.92%**	**8.40%**	**8.40%**	**9.14%**	**7.17%**	**8.64%**	**8.49%**	**9.39%**
2025-26	323687	409273	409273	470763	390939	494082	494086	568978	64328	81342	79588	93668
2026-27	344434	439480	439480	509644	415972	530506	530510	615966	68609	87542	85542	101641
2027-28	365936	470636	470636	550431	441906	568058	568062	665242	73059	93959	91693	110032
2028-29	388165	502785	502785	593070	468702	606785	606789	716735	77675	100602	98049	118833
2029-30	411115	535950	535950	637527	496354	646713	646718	770400	82457	107477	104617	128039
G.R. (2025-30)	**6.24%**	**7.10%**	**7.10%**	**8.00%**	**6.23%**	**7.09%**	**7.09%**	**8.00%**	**6.48%**	**7.34%**	**7.20%**	**8.25%**
2030-31	435821	571441	571441	685629	526122	689431	689435	828461	87617	114852	111654	138026
2031-32	462070	609187	609187	737206	557741	734847	734851	890700	93114	122716	119150	148763
2032-33	489943	649355	649355	792517	591309	783162	783166	957430	98966	131105	127138	160309
2033-34	519701	692210	692210	852128	627146	834697	834701	1029342	105231	140080	135673	172787
2034-35	551314	737860	737860	916155	665210	889583	889583	1106567	111906	149665	144779	186228
G.R. (2030-35)	**6.04%**	**6.60%**	**6.60%**	**7.52%**	**6.03%**	**6.58%**	**6.58%**	**7.51%**	**6.30%**	**6.85%**	**6.71%**	**7.78%**
G.R. (2010-35)	**6.79%**	**8.05%**	**8.05%**	**8.99%**	**6.43%**	**7.68%**	**7.68%**	**8.62%**	**6.67%**	**7.92%**	**7.78%**	**8.87%**

The peak demand forecasts for the combined PEPCO and KESC systems for the different scenarios considered is shown in Figure 4-1 below:

Figure 4-1 Summary of Forecast Results (MW) – PEPCO and KESC



5 FUEL SUPPLY, PORT HANDLING AND FUEL PRICING

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5 FUEL SUPPLY, PORT HANDLING AND FUEL PRICING

5.1 Introduction

The key objective of this section is to provide an assessment of the fuel supply and demand situation and the fuel supply infrastructure in Pakistan. This assessment is based on the information gathered during visits to the gas companies and ports, as well as information obtained from secondary sources, such as available reports and websites. The current situation with respect to all the major fuels, namely natural gas, oil and coal along with the plans to enhance the supply of various fuels and the steps being taken to implement these plans are also presented.

As the capacity of ports to handle the fuel supply is an important factor for the assessment of the fuel supply infrastructure, this section also provides information on the current capacity of various ports to handle the fuel and the plans to enhance this capacity. The scope of this work is restricted to the review of the fuel supply infrastructure/port handling facilities and specific recommendations for the development of fuel supply infrastructure and port handling facilities as it is outside the scope of the mandate.

Considering that the analysis of prices of various fuels is an important subject with regard to the development of the power sector and this analysis of the current pricing of various fuels and fuel price projections is also included in this section.

A detailed analysis on the supply of fuel, its infrastructure and pricing is provided in Annexure 1 along with a list of sources consulted.

5.2 Fuel Supply

5.2.1 Natural Gas

Domestic Gas Production

Presently there are 14 gas production companies operating in Pakistan producing a total of a little over 4,000 MMcfd[1] (million cu-ft per day). There are 10 major gas production fields and several smaller ones. Unless there are new discoveries, domestic supply of gas is expected

[1] Source: Based on information provided in Pakistan Energy Yearbook 2009 and Integrated Energy Sector Recovery Report and Plan, FODP Energy Task Force, 2010.

to decline while the demand for gas by all sectors is increasing. There are already load management measures currently in effect.

A number of options are being considered to enhance the supply of gas. These include:

- Enhancing the domestic production;
- Import of gas from Iran;
- Import of gas from Turkmenistan;
- Import of gas from Qatar; and
- LNG Imports.

Options for the import of gas are described in the following section.

SNGPL has declared that some gas reserves have been discovered in the Khyber Pakhtun-Khawa (KPK) province with a current potential estimated to be 350 MMcfd. Efforts need to be made to obtain a more accurate estimate of the gas reserves and to tap this source for enhancing the domestic supply of gas. In addition, infill drilling technology can be used on the existing gas fields in order to recover more gas from existing gas reservoirs for an estimated 500 MMcfd of gas using this method.

Concerted and well-planned efforts need to be made to review the different options of gas supply and decisions for the implementation of these options should made quickly so that the situation of gas supply in the country can be improved.

The current policy of the prioritization of gas supply to different sectors also needs to be reviewed. Currently, the policy allows gas allocation according to the following priority:

- Domestic and commercial sectors;
- Fertilizer industry;
- Power generation having FSAs (Fuel Supply Agreement);
- Industry and CNG;
- Other power plants; and
- Cement industry

The above policy shows that gas allocation for the power sector has a relatively low priority. This policy needs a review considering the added value of gas for its utilization in different sectors.

Options for Import of Gas

Considering that the indigenous sources for the supply of natural gas would not be sufficient to meet the growing requirements of natural gas, a number of options for the import of gas are being studied / implemented. For the time being, these include:

- Import of gas from Iran;
- Import of gas from Turkmenistan; and
- Import of gas from Qatar.

Import of gas from Iran to the tune of 750 MMcfd is the option which is at a relatively advanced stage and if implemented will circumvent the shortage of the gas supply to a certain extent. The work on the Iran-Pakistan line is underway and the project is expected to be completed by 2015. The gas pipe line would enter Pakistan from Gwader area and would terminate at Nawabshah. According to the plans, the imported gas from Iran will mainly be used for power generation and initial estimates suggest that it could be used to generate about 5,000 MW generation capacity.

The import of gas from Turkmenistan via Afghanistan is the other import route that is being considered. In this regard recent contacts between the governments of the participating countries were made and the necessary agreements have been signed. The participating countries include Turkmenistan, Afghanistan, Pakistan and India. The project is known as TAPI project and its estimated cost is US $ 7.6 billion. The gas pipe line is envisaged to provide 38 million cu-m per day to Pakistan and India. This is equivalent to 1,342 MMcfd. According to the agreements signed recently, its completion is expected in 2014. However, the geo-political risks regarding the implementation of the project should not be ignored, which might hinder or delay the planned implementation of the project.

A submarine pipeline from Qatar is the other option that was under consideration for the import of gas in the 1990s. According to the plans, Pakistan was supposed to import 2,400 MMcfd from Qatar through a pipeline link of about 1,700 km. Most of the proposed link was offshore. However, this plan never materialized and for the time being is not being actively considered. According to the reports, Qatar has also expressed its inability to provide such a large quantum of gas. An alternative option that has been considered in the recent past is the import of LNG from Qatar. According to the information available, import of 1.5 million tonnes of LNG is under consideration, which is equivalent to 200 MMcfd. This gas is proposed for use by the power sector.

Gas Transportation and Distribution

Currently there are two gas transportation and distribution companies, namely Sui Southern Gas Company limited (SSGCL) and Sui Northern Gas Pipelines Limited (SNGPL). These companies are also involved in the marketing of gas.

SSGCL has the responsibility for the southern part of the country including Sind and Baluchistan provinces. The total transmission capacity of the SSGCL network is 1,643 MMcfd. Its distribution system is quite extensive and covers over 4,200 km. Its design capacity is 2,442 MMcfd (SSGC website).

SSGCL accounts for about 30% of the total gas supply in the country. According to the Pakistan Oil Report by OCAC the gas supplied by SSGCL during the year 2009-10 was 1,065 MMcfd. Of the 1,065 MMcfd of total gas supply, the share of the supply to the power sector was about 30%.

SNGPL transmission system extends from Sui in Baluchistan to Peshawar in Khyber-Pakhtunkhwa and passes though Punjab. It accounts for about 48% of the gas supply. In year 2009-10, SNGPL gas supplies were 1812 MMcfd as reported in the Pakistan Oil Report by OCAC.

Both SSGCL and SNGPL currently supply a combined volume of 2,945 MMcfd, which is equivalent to 78% of the total gas supply. The remaining 22% of the gas supply is transported by various independent systems. The total gas transportation infrastructure consists of about 11,000 km of transmission line and approximately 102,000 km of gas distribution lines. The appropriate compression system is in place to facilitate the transportation of gas over long distances.

5.2.2 Fuel Oil

Fuel Oil Production and Imports

The oil reserves in the country that are recoverable are 314 million barrels, which is equivalent to 42 MTOE (million tons of oil equivalent). The current production in the country is about 66,000 bbl/day[2].

The domestic oil production in the country is not sufficient to meet the growing requirements for fuel in the country. Therefore, the country is dependent on the import of fuel to meet the demand of fuel and to bridge the gap between the demand and supply. About 84% of the total oil requirements are imported.

The total crude oil production in the country in the year 2008-09 was 3.2 MTOE while the imports in the country were 18.4 MTOE, out of which 8.3 MTOE were crude oil imports and 10.1 MTOE were Product imports[3].

OGDCL has the largest production of crude oil in the country followed by BP and PPL. In the year 2008-09, OGDCL's crude oil production was 40,485 bbl/day, while the crude oil production by BP and PPL was 9,745 bbl/day and 4,696 bbl/day respectively. The two main fuels used in the country are high speed diesel (HSD) and fuel oil. HSD is mainly used in transportation while fuel oil is used for power generation. As domestic production and refining capacity are insufficient to meet the domestic demand, 4.4 million tonnes of HSD and 5.1 million tonnes of fuel oil were imported in the financial year 2008-09[4].

Petroleum Products Consumption, Refining and Marketing

The biggest consumption of petroleum products takes place in the transportation sector followed by the power sector. Fuel oil consumption in the power sector in the years 2006-07, 2007-08 and 2008-09 was 6.74 million tonnes, 7.08 million tonnes and 7.57 million tonnes respectively.

[2] Source: Based on information provided in Integrated Energy Sector Recovery Report and Plan, FODP Energy Task Force, 2010 and Pakistan Energy Yearbook, 2009.
[3] Source: Based on information provided in the Pakistan Energy Yearbook, 2009
[4] Source: Based on information provided in the Pakistan Energy Yearbook, 2009, OGDC website and Integrated Energy Sector Recovery Report and Plan, FODP Energy Task Force, 2010

There are 7 refineries in the country with a total refining capacity of about 13.887 million tonnes per year as reported in Pakistan Oil Report by OCAC. The refining capacity in the country is able to cater for about half of the total demand, while the remaining demand is met by the oil imports.

The key marketing company which supplies oil to both the transportation and power sectors is Pakistan State Oil (PSO) which enjoys a market share of 70%. In addition to PSO, the other marketing companies include Shell, Caltex, Attock Petroleum Limited, BPPL, HASCOL, ASKAR and OOTC Land Total-PARCO. These companies are free to import oil to meet the local demand.

5.2.3 Coal

Coal Reserves and Production

Making use of the available coal resources for power generation and meeting the growing energy needs of the country is one of the cornerstones of the power policy. The total coal resources of Pakistan are estimated to be 185 billion tonnes[5].

The total estimated reserves of Thar coal are 175 billion tones and are spread over a geographically contained area of about 9,000 sq.km. The other major fields in Sindh are Lakhra, Sonda-Jherruck and Indus East. The coal reserves in these fields are estimated to be 1,328 million tonnes, 5,523 million tonnes, and 1,777 million tonnes respectively.

Thar coal field has the potential of generating about 100,000 MW based on the assumption of 536 million tonnes of coal production per year. While the potential of power generation of Lakhra and Sonda fields are 1,000 MW and 500 MW respectively. These are based on coal consumption of 4.60 million tonnes per year and 2.3 million tonnes per year respectively. Other coal fields have the potential of generating 25 – 50 MW of power. This fuel source for power generation could contribute hugely to the security and diversity of indigenous fuel supply for power generation[6].

According to the Energy Yearbook, the production of coal in 2008-09 was 3.37 million tones (MT) while 4.65 MT was imported.

[5] Source: Based on information provided in the Pakistan Energy Yearbook, 2009

[6] Source: Based on information provided in the document Thar Coal Field, Facts and Figures, 2008, PPIB document on 450 MW Lakhra Coal Project (Project Profile), 2005

Apart from the power sector, the main consumers of coal are the cement industry, steel industry and brick-kiln industry. In the year 2008-09, the power sector consumed only 1.3 % of the total supply of coal[7].

5.3 Capacity of Ports and Fuel Logistics

The major ports in the country include Karachi Port and Port Qasim. These ports located at Karachi serve as the major hub for the import and export of commodities. Both the ports have the facilities to handle fuel oil as well as coal.

Karachi Port Trust

KPT is the main port that deals with the imports and exports of liquid bulk cargo and dry bulk cargo. KPT handled imports of bulk liquid cargo of about 9.84 million tonnes in the year 2009-10. The imports of crude oil, diesel and furnace oil handled by the port in the year 2009-10 were 6.12 million tonnes, 0.6 million tonnes and 1.17 million tonnes respectively. Currently KPT has the capacity to handle 24 million tonnes of all types of fuels. Currently the capacity of KPT to handle liquid cargo is under-utilized and less than half of the available capacity is being used. KPT has plans to increase the fuel handling capacity to 28 million tonnes per annum in the future, however considering that its present capacity is under-utilized, there are no immediate plans to enhance this capacity. KPT also has the storage capacity of 1 million tonnes of liquid fuel. There are no plans to increase this storage capacity.[8]

With regards to the handling of coal, KPT handled the import of 3.65 million tonnes of coal in the year 2009-10. The available capacity to handle coal is 4 million tonnes per annum. It has no plans to enhance this capacity as the Port Qasim Jetty is planned to be utilized for coal handling. KPT also has the storage facility for 0.7 million tonnes of coal.

KPT has also signed an MOU with PSO for laying a fuel oil pipeline from Keamari to Korangi[9].

[7] Source: Based on information provided in the Pakistan Energy Yearbook, 2009
[8] Source: Based on information received from KPT during the meetings with them.
[9] Source: Based on information received from KPT during the meetings with them.

Port Qasim Authority

Port Qasim, the second busiest port in the country handling about 40% of the nation's cargo (17 million tonnes per year) is located near Karachi at a distance of 35 km from the city centre.

At Port Qasim, the terminal that deals with the handling of fuel oil is FOTCO (Fauji Oil Terminal and Distribution Company) is capable of handling 9 million tonnes of furnace oil per annum (750,000 tonnes per month) with a growth potential to handle more than 27 million tonnes with three additional berths. HSD and crude oil are also imported at FOTCO terminal after commissioning of the PAPCO oil pipeline. The facility mainly comprises a jetty capable of handling up to 75000 DWT vessels, product pipelines, loading arms and a 4 km long trestle that connects the jetty with the shore. The terminal has the capability to berth tankers with 63,000 tonnes ship-load. For liquid fuel storage, 77 acres of land has been earmarked.

FOTCO has a capacity to handle 15 tankers per month. Infrastructure limitations of FOTCO restrict the large size vessels. However, due to inadequate port and storage facilities at other terminals belonging to KPT and PQA, it is expected that 20-23 cargoes per month will be handled at FOTCO which will result in congestion at the FOTCO terminal. The terminal is designed to cater for four additional berths and four product pipelines to meet the current and future fuel handling requirements of the country.

There is a separate Iron Ore and Coal berth that deals with the imports of coal. The design capacity of the berth is 3.36 million tonnes per annum. The berth has a handling capacity of 1400 tonnes per hour. Currently vessels of 55,000 tonnes payload are being handled here.

PQA has developed plans to increase port parameters to accommodate larger vessels to benefit from economies of scales, and to build additional berths/terminals. Some of the development projects relevant to fuel handling include establishment of an LPG terminal and coal & clinker/cement terminal[10].

[10] Source: Based on information received from PQA during the meetings with them.

Fuel Logistics

The transmission and storage network for fuel oil adequately covers most of the major cities as well as remote areas. A pipeline network of about 2000 km exists for supplying crude oil as well as refined fuel products. The crude oil pipeline belongs to PARCO, while the pipelines for the refined products are owned by PAPCO, Shell, PSO and other oil companies.

The rail road capacity to transport oil is presently 1.2 million tonnes/annum. This is about 4,000 MT/day. As the railroad capacity is not sufficient, a significant quantity of oil is transported up-country through road tankers. Currently about 4 million tonnes of fuel oil per annum is being transported by road tankers[11].

Among the fuel oil suppliers, PSO is the largest supplier of fuel oil to the power generation sector. It has a relatively large fuel oil logistic capacity. Its capacity to transport oil by pipelines, road and rail is 5 million tonnes/year, 6.5 million tonnes/year and 1.5 million tonnes/year respectively.

As regards the future strategy to supplement the existing storage and transportation capacities for fuel oil, a number of measures have been planned. These include:

- PSO and KPT plan to connect the Port Qasim with Karachi Port via a 52 km pipe line;
- Enhancement of port infrastructure to handle increased number of vessels;
- Agreement between Pakistan Railways and PSO to increase the railroad capacity from 120,000 MT/month to 250,000 MT per month; and
- Up-gradation of storage and transportation infrastructure.

5.4 Pricing of Fuels

The current fuel prices, transportation and handling costs and the projection of future fuel prices are presented in this section. Full references to data sources, the basis of cost computation and detailed analyses are presented in Annexure 1.

[11] Source: Based on information provided in Integrated Energy Sector Recovery Report and Plan, FODP Energy Task Force, 2010.

Current Fuel Pricing

The current prices of various types of fuel are provided in Table 5-1. The prices presented represent both the domestic and international fuels.

Table 5-1 Current Fuel Prices

Fuel	Price	Unit
Crude Oil (imported)	80	$ / bbl
Domestic Gas	400	Rs / MMBtu
LNG (imported)	7.95	$ / MMBtu
Furnace Oil	506.89	$ / M.ton
Diesel	60.77	Rs / litre
Imported Coal	115	$ / M.ton
Nuclear Fuel (U_3O_8)	50	$ / lb

Source: *Based on data from Energy Information Administration, International Energy Agency, Platts, OGRA, WAPDA and PSO*

Fuel Transportation & Handling Costs

Power sector fuels may be transported by road, rail, or pipeline. Historically, coal and fuel oil are primarily transported by rail and road, natural gas is transported by pipeline, and diesel is transported by pipeline and road. Table 5-2 shows the current costs for the various modes of fuel transport.

Table 5-2 Fuel Transportation Costs

Mode of Transport	Cost	Unit
Road	3.50	Rs / M. Ton / km
Rail	2.20	Rs / M. Ton / km
Pipeline (Gas)	0.00116	$ / MMBtu / km
Pipeline (Liquid)	0.01029	$ / m^3 / km
LNG Shipping	0.52	$ / MMBtu

Source: *Based on data from Platts, and OGRA and calculation of SNC-Lavalin Inc.*

The port handling costs for crude oil and other liquid petroleum products, LNG and coal are provided in Table 5-3. These costs are considered to remain fixed in 2010 dollars up to the year 2030.

Table 5-3 Fuel Handling Costs at Port

Fuel	Price	Unit
Imported Crude Oil	10.18	$ / M. ton
Imported LNG	0.35	$ / MMBtu
Imported Furnace Oil	8.82	$ / M.ton
Imported Diesel	1.06	Rs / litre
Imported Coal	3.00	$ / M.ton

Source: *Based on data from NEPRA, EIA and calculation of SNC-Lavalin Inc.*

<u>Future Fuel Price Projections</u>

Many agencies project future fuel prices – the notable ones are Energy Information Administration (EIA), International Energy Agency (IEA) and Platts. In general, these projections take into account the world economy, supply and demand situation, market volatility and political considerations. The long-term fuel price forecasts for different fuels in mixed units are provided in Table 5.4.

Table 5-4 Long-Term Fuel Price Forecasts to the Year 2030 (Mixed Units)

Fuel	Unit	Current 2010	Projection			
			2015	2020	2025	2030
Crude Oil	$ / bbl	80	95.73	109.67	116.56	125.08
Imported Natural Gas	$ / MMBtu	9.25	10.59	11.87	12.50	13.28
Imported LNG	$ / MMBtu	7.95	13.22	13.97	14.68	16.83
Furnace Oil (HSFO)	$ / MT	506.89	511.11	585.51	622.33	667.81
Furnace Oil (LSFO)	$ / MT	557.58	562.22	644.06	684.57	734.59
Diesel	Rs. / Ltr	60.77	66.42	75.89	80.58	86.37
Imported Coal	$ / MT	115	147.39	164.50	151.28	139.90
Thar Coal (Mined)	$ / MT	43.86	43.86	43.86	43.86	43.86
Thar Syngas (UCG)	$ / GJ	2.71	2.71	2.71	2.71	2.71
Nuclear Fuel (U_3O_8)	$ / lb	50	80	60	60	60

Source*: Based on data from EIA, Pakistan Energy Yearbook 2009, and ISGS (Inter State Gas Systems), IEA,*
Notes: *All prices are at 2010 price levels*

The Thar coal costs above have been derived from the Rheinbraun Engineering 2004 feasibility study, escalated to 2010 price levels. For the generation planning analysis, Thar coal has been priced such that the cost of power from a plant using Thar coal would be equivalent to the cost of power from a coastal plant using imported coal.

The fuel prices in $/MMBtu are provided in Table 5-5. The computational basis of these price forecasts are provided in Annexure 1.

Table 5-5 Long-Term Fuel Price Forecasts to the Year 2030 ($/MMBtu)

Fuel	Unit	Current 2010	Projection			
			2015	2020	2025	2030
Crude Oil	$/MMBtu	13.75	16.46	18.85	20.05	21.51
Imported Natural Gas	$/MMBtu	9.26	10.60	11.87	12.51	13.29
Imported LNG	$/MMBtu	7.96	13.23	13.98	14.68	16.84
Furnace Oil (HSFO)	$/MMBtu	12.48	12.57	14.41	15.32	16.44
Furnace Oil (LSFO)	$/MMBtu	13.72	13.84	15.85	16.85	18.07
Diesel	$/MMBtu	19.84	21.68	24.78	26.31	28.20
Imported Coal	$/MMBtu	4.83	6.19	6.91	6.36	5.88
Thar Coal (Mined)	$/MMBtu	3.99	3.99	3.99	3.99	3.99
Thar Syngas (UCG)	$/MMBtu	2.86	2.86	2.86	2.86	2.86
Nuclear Fuel (U_3O_8)	$/MMBtu	0.23	0.36	0.27	0.27	0.27

Source: *Based on data from EIA, Pakistan Energy Yearbook 2009, and ISGS (Inter State Gas Systems)*

The data presented in the above table illustrates that the prices of various types of liquid fuels and natural gas are envisaged to increase over the planning period. The price of imported coal is projected to increase till 2020, and after then it is projected to decline slightly based on the coal price projections by EIAC (Energy Information Administration, USA).

The current fuel transportation infrastructure needs to be examined in light of the changing requirements of all types of fuel. This has implications on the development of current rail, port and road infrastructure. The generation planning section provides details of the level of each fuel type that will be required for the current plan which serves as a key input to any infrastructure policy and plan that will need to be developed at the national level. In case of fuel availability restrictions and inadequate development of fuel supply infrastructure, revisions would possibly be required in the generation plan.

6 GENERATION PLANNING

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6 GENERATION PLANNING

6.1 Introduction

The key objective of the generation expansion planning activity was to develop a long range least-cost generation expansion plan for Pakistan for the period 2011-12 to 2029-30 to meet the maximum load demand and energy consumption whilst taking into account government policies and identified constraints.

This section describes the key parameters and results of the generation planning study and is structured as follows:

- Strategic and Policy Considerations;
- General Approach and Methodology;
- Planning Basis;
- Review of the Existing and Committed System;
- Generation Options Available and Screening;
- Scenarios Considered for Generation Expansion;
- Development and Analysis of the Base Case Expansion Plan;
- Comparison of the Base and Alternative Cases;
- Sensitivity Analysis for the Base Case; and
- Conclusions.

6.2 Strategic Considerations

In order to develop an effective generation plan that will meet the power needs of the country, both the strategic considerations and constraints faced by Pakistan have to be taken into account. In developing the National Power System Expansion Plan (NPSEP) careful consideration has been given to the Government of Pakistan (GoP) policy guidelines as well as fuel and infrastructure constraints that affect the power sector development.

As outlined in their document “Policy for Power Generation Projects Year 2002” the GoP Power Policy has three key objectives as listed below:

- To provide sufficient capacity for power generation at the least cost, and to avoid capacity shortfalls;
- To encourage and ensure exploitation of indigenous resources, which include renewable energy resources; and
- To be attuned to safeguarding the environment.

The GoP has two other policy documents that impact on the development of power system expansion plans. The Natural Gas Allocation and Management Policy 2005 states that, as part of their demand management policy, “Power Plants would get gas supply after meeting the requirements of domestic, commercial, fertilizer and industrial sectors”. The demands of these other sectors are increasing rapidly, thus the availability of domestic gas for future power plants is likely to be limited. The Policy for Development of Renewable Energy (RE) for Power Generation 2006 mentions as a target to “Increase the deployment of renewable energy (defined as wind, solar and small – less than 50 MW – hydro) technologies so that RE provides a minimum of 9,700 MW by 2030”.

Pakistan faces several constraints as it strives to meet its current and expected power demand. Perhaps the most significant constraint is the scarcity of capital, which has affected not only power sector development but also the development of other infrastructure critical to power sector development.

In the short term the main focus has been the reduction of load shedding, and this focus has often taken attention away from an optimum long term growth strategy. it is accepted that it will probably take several years for the target reliability level of 1 % Loss of Load Probability to be achieved. The short term focus is on rehabilitation of existing plants, on demand side management, and the implementation of fast track projects to reduce load shedding.

In the long term, it is assumed that the GoP’s policy will continue to focus on the development of indigenous resources, particularly Tharparkar coal and hydro projects, as well as increasing the use of renewable resources and keeping power tariffs at affordable levels. Also barring major gas discoveries, the GoP policy of allocating gas will remain unchanged and future gas based power generation will be based on imported gas or LNG.

The development of the Base Case described later in this section has taken the foregoing policy guidelines, and the least cost approach into consideration. Also considered are fuel availability, infrastructure and other constraints.

6.3 Approach and Methodology

The development of the least cost generation plan is the process of optimizing the additions of generation supply options in order to determine the optimal development sequence, which would meet the projected demand and would satisfy the specified reliability criteria.

The first step was to review the existing and committed system, and to review the range of generation addition options available to meet the future demand. The next key step was to determine the economically attractive generation options and generation mix using simplified screening curves. The purpose of the screening curves was to compare the unit cost of different plants at different plant factors. The Base Case and Alternative Cases to be analysed were then defined. The last step was the development of the least cost plan under the Base Case and alternative scenarios using the System Planning and Production Costing Software (SYPCO).

6.4 Planning Basis

In order to ensure that all the developed scenarios met uniform requirements in terms of performance and to also enable all the scenarios to be compared on a similar technical basis, specific planning criteria was adopted. These criteria are summarized in Table 6-1 below and are discussed in detail in Annexure 2.

Table 6-1 Planning Criteria

Criteria	
Loss of Load Probability (LOLP)	Up to 2018-2020 5 to 10% 2020-21 onwards 1%
Discount Rate	10% Real
Reference Year	All costs expressed at 2010 price levels
Cost of Unserved Energy	Approximated by the cost of power from the most expensive unit in the system
Fuel Pricing	Based on imported fuel equivalents
Economic Life:	
• Gas Turbines	20 yrs
• Combined Cycle Plants	25 yrs
• Steam Plants	30 yrs
• Nuclear Plants	40 yrs
• Hydro Plants	50 yrs

Load Profile and Forecast

Analysing annual hourly load profiles is an important aspect of generation planning to capture the hourly and seasonal variation in the load. The hourly loads are used to construct the monthly load duration curves which are one of the key inputs to generation planning. The historical monthly load duration curves are used for planning the future years. The assumption is that the future monthly/seasonal load variations would be very similar to the past ones. However, the historical load duration curves in the recent years cannot be directly used for future years since these curves are restricted by supply availability. Therefore it is necessary to have information on unrestricted monthly load patterns and hourly load profiles to represent the future years. After reviewing the historical data and previous studies,

2003-04 was selected as it had no planned load shedding and very little adjustment was required for unexpected load shedding.

The load forecast developed for the NPSEP forecast is based on multiple regression techniques, and considers three scenarios – low, normal, high and another case where the normal forecast is adjusted for demand side management (DSM) measures. The load forecast is presented in Section 4 of this Report.

Fuel Pricing

The prices for different fuels is one of the critical inputs for developing the least cost generation plan since the quantum of fuel used and its cost has a significant impact on the economic attractiveness of the thermal candidate units. The fuel price forecast for the study period is summarized in Table 6-2.

Table 6-2 Summary of Fuel Price Forecast to 2030

Fuel	Unit	Current 2010	Projection			
			2015	2020	2025	2030
Crude Oil	$/MMBtu	13.75	16.46	18.85	20.05	21.51
Imported Natural Gas	$/MMBtu	9.26	10.60	11.87	12.51	13.29
Imported LNG	$/MMBtu	7.96	13.23	13.98	14.68	16.84
Furnace Oil (HSFO)	$/MMBtu	12.48	12.57	14.41	15.32	16.44
Furnace Oil (LSFO)	$/MMBtu	13.72	13.84	15.85	16.85	18.07
Diesel	$/MMBtu	19.84	21.68	24.78	26.31	28.20
Imported Coal	$/MMBtu	4.83	6.19	6.91	6.36	5.88
Thar Coal (Mined)	$/MMBtu	3.99	3.99	3.99	3.99	3.99
Thar Syngas (UCG)	$/MMBtu	2.86	2.86	2.86	2.86	2.86
Nuclear Fuel (U_3O_8)	$/MMBtu	0.23	0.36	0.27	0.27	0.27

Notes: *All prices are in 2010 US$*

These fuel price projections are based on the Annual Energy Outlook (2010) prepared by the Energy Information Administration (EIA) and other sources, and restated in 2010 price levels. Details are given in Section 5 of this Report. In Table 6-2, the handling cost for imported coal and furnace oil (LSFO) were estimated based on the costs used in NPP 1994 (US$ 10/ton for imported coal and US$ 1.5/barrel for oil) escalated by 3% each year considering both the impacts of inflation and the advancement of the technologies. The handling costs were added to the price of imported coal and oil for screening curve analysis and generation production costing.

Given the shortage of supply of indigenous fuels, it is likely that at the margin petroleum products and gas will need to be imported for future power plants. Thus pricing for petroleum products and gas have been based on their imported equivalents.

Although Thar coal would be produced domestically, currently there is insufficient information to base firm mining costs on. Thar coal has been priced such that the cost of power generated at Thar using Thar coal would be equivalent to the cost of power from a coastal plant using imported coal. Based on this analysis, Tharparkar coal would need to be priced at or below $ 56 / MT in the first year, or $70 / MT on average over the life of the generating plant. The breakeven analysis is shown in Table 6-3.

Table 6-3 Breakeven Price for Tharparkar Coal

	Coastal Plant Burning Imported Coal	Mine-Mouth Plant Burning Tharparkar Coal
Capacity	600 MW	600 MW
Capital Cost	$1,850 / kW	$ 2,050 / kW
Fixed O&M	$ 30 / kW / yr	$ 35 / kW / yr
Variable Cost	$ 3 / MWh	$ 3.6 / MWh
Plant Efficiency	37.5 %	36.9 %
Capacity Factor	70 %	70 %
Delivered Coal Price (Avg)	$ 6.99 / MMBtu $ 166 / MT	$ 6.35 / MMBtu $ 70 / MT
Cost of Power (Avg)	10.8 ¢ / kWh	10.8 ¢ / kWh
Delivered Coal Price (First Year Price)	$ 5.68 / MMBtu $ 135 / MT	$ 5.14 / MMBtu $ 56 / MT
Heat Content	23.8 MMBtu / ton	11.0 MMBtu / ton

The premise is that the Tharparkar coal should be priced such that the cost of power from a mine – mouth plant is competitive with the cost of power from a plant located on the coast burning imported coal.

Environmental Criteria

The environmental criteria for the NPSEP are presented in Section 3 of this Report.

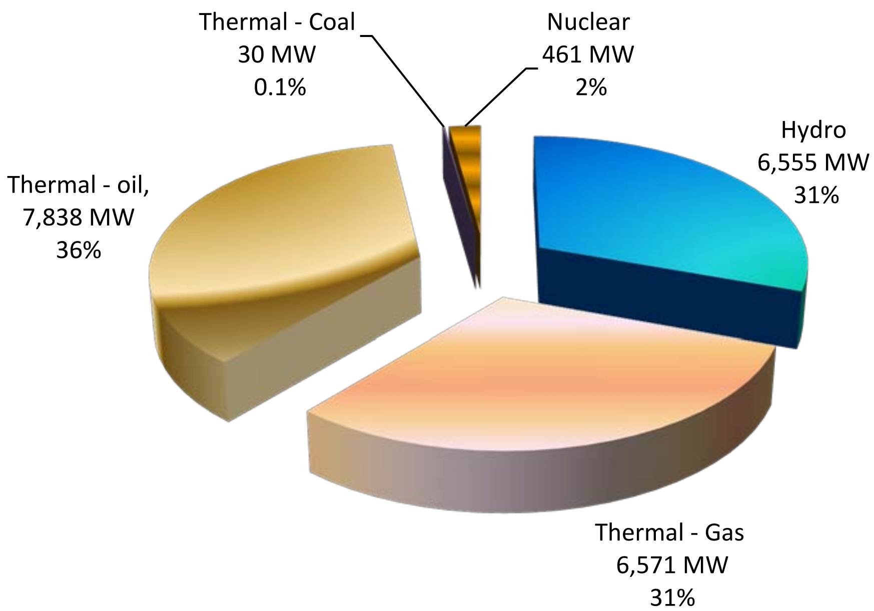
The emission requirements for power plants have been based on the National Environmental Quality Standards (NEQS) of Pakistan. The emission requirements pertain to Particulates, Nitrogen Oxides, Sulphur Dioxide, Liquid Effluents and Solid Wastes. The NPSEP has included in its cost estimates water treatment equipment for all plants, Flue Gas Desulphurisation equipment for coal fired plants and has used Low Sulphur Fuel Oil for oil fired plants.

The range of adverse environmental and related social impacts that can result from hydro dams is remarkably diverse. Twenty seven hydroelectric projects have been considered in the NPSEP. Of these, eighteen projects have undergone thorough feasibility studies. Eleven of the eighteen projects have feasibility studies which are more than three years old and need updating. Nine projects are at initial stages and their feasibility studies have not yet been started. For those projects that have been studied to feasibility level and for which environmental cost estimates are available, these environmental cost estimates have been escalated to 2010 price levels. For those projects which have not been studied to feasibility level and for which environmental cost estimates are not available, an approximation has been made. The approximation is based on information for those projects for which the required information is available. For example, the environmental cost as a percentage of total project cost averaged over all those projects for which information is available is applied to those projects for which the total project cost is available but the environment cost is not. These costs are shown in Table 6-11 of Section 6.7.

6.5 Existing and Committed Units

The total installed capacity of existing hydro and thermal generation units for the PEPCO and KESC systems including IPPs is about 21,455 MW as at the end of 2010. However, due to the seasonal variation of water inflows for hydro plants and the capacity de-rating of thermal units, the dependable capacity for the systems are estimated to be 15,254 during winter. The installed capacity of hydro plants accounts for about 31%, thermal capacity for 67%, and nuclear capacity less than 2%. The total installed capacity from IPPs is about 38% of the total installed capacity. This breakdown is shown in Figure 6.1:

Figure 6-1 Installed Capacity in 2010



6.5.1 Existing Hydro Plants

The total existing hydro capacity in the country is 6,555 MW. However, due to the seasonal variation of water inflows, the existing hydrol plants can only provide 2,414 MW dependable capacity during winter. The summary of existing hydro plants is provided in Table 6-4.

Table 6-4 Summary of Existing Hydro Plants

Type	Nominal Capacity (MW)	Capacity in Winter (MW)
WAPDA Hydro Plants	6,444	2,303
IPPs	111	111
Total Hydro Capacity	**6,555**	**2,414**

The detailed information of the existing hydro plants is provided in Annexure 2.

6.6 Existing Thermal Plants

The existing thermal plants in the country are owned by PEPCO, KESC and IPPs. Table 6-5 provides a summary of the status of existing thermal plants in the system as at the end of 2010.

Table 6-5 Summary of Existing Thermal Capacity

Type	Nominal Capacity (MW)	De-rated Capacity* (MW)
PEPCO total (excluding nuclear)	4,829	3,580
IPPs serving PEPCO	7,475	6,909
Rental units	113	113
Nuclear - PEPCO system	325	300
Total Thermal – PEPCO system	**12,742**	**10,902**
KESC Thermal	1,655	1,463
Nuclear – KESC System	136	122
IPP serving KESC	367	353
Total Thermal – KESC system	**2,158**	**1,938**
Total Thermal Capacity	**14,900**	**12,840**

**De-rated capacity = Gross dependable capacity*

The detailed information of the existing thermal plants is provided in Annexure 2.

The plant-wise information of existing thermal units and existing hydro units under public and private sectors for the PEPCO system is presented in Table 6-6.

Table 6-6 Existing Generation Capacity of PEPCO System

<table>
<tr><th colspan="2" rowspan="2"></th><th rowspan="2">No.</th><th rowspan="2">Name Of Power Station</th><th rowspan="2">Fuel</th><th rowspan="2">Installed Capacity (MW)</th><th colspan="2">Capability* (MW)</th></tr>
<tr><th>Summer</th><th>Winter</th></tr>
<tr><td rowspan="27">Public Sector</td><td rowspan="7">Hydro</td><td>1</td><td>Tarbela</td><td></td><td>3,478</td><td>3,521</td><td>1,101</td></tr>
<tr><td>2</td><td>Mangla</td><td></td><td>1,000</td><td>1,014</td><td>409</td></tr>
<tr><td>3</td><td>Ghazi Barotha</td><td></td><td>1,450</td><td>1,405</td><td>580</td></tr>
<tr><td>4</td><td>Warsak</td><td></td><td>243</td><td>171</td><td>145</td></tr>
<tr><td>5</td><td>Chashma Low Head</td><td></td><td>184</td><td>91</td><td>48</td></tr>
<tr><td>6</td><td>Small Hydros</td><td></td><td>89</td><td>64</td><td>20</td></tr>
<tr><td></td><td>Sub-Total (WAPDA Hydro)</td><td></td><td>6,444</td><td>6,266</td><td>2,303</td></tr>
<tr><td rowspan="17">Thermal (GENCOs)</td><td>7</td><td>TPS Jamshoro #1-4</td><td>Gas/FO</td><td>850</td><td colspan="2">700</td></tr>
<tr><td>8</td><td>GTPS Kolri #1-7</td><td>Gas</td><td>174</td><td colspan="2">140</td></tr>
<tr><td></td><td>Sub-Total GENCO-I</td><td></td><td>1,024</td><td colspan="2">840</td></tr>
<tr><td>9</td><td>TPS Guddu Steam #1-4</td><td>FO</td><td>640</td><td colspan="2">270</td></tr>
<tr><td>10</td><td>TPS Guddu C.C. #5-13</td><td>Gas</td><td>1,015</td><td colspan="2">885</td></tr>
<tr><td>11</td><td>TPS Quetta</td><td>Gas</td><td>35</td><td colspan="2">25</td></tr>
<tr><td></td><td>Sub-Total GENC0-II</td><td></td><td>1,690</td><td colspan="2">1,180</td></tr>
<tr><td>12</td><td>TPS Muzaffargarh #1-6</td><td>Gas/FO</td><td>1,350</td><td colspan="2">1,130</td></tr>
<tr><td>13</td><td>NGPS Multan #1&2</td><td>Gas/FO</td><td>195</td><td colspan="2">60</td></tr>
<tr><td>14</td><td>GTPS Faisalabad #1-9</td><td>Gas/HSD</td><td>244</td><td colspan="2">210</td></tr>
<tr><td>15</td><td>SPS Faisalabad #1&2</td><td>FO</td><td>132</td><td colspan="2">100</td></tr>
<tr><td>16</td><td>Shahdra G.T.</td><td>Gas</td><td>44</td><td colspan="2">30</td></tr>
<tr><td></td><td>Sub-Total GENC0-III</td><td></td><td>1,965</td><td colspan="2">1,530</td></tr>
<tr><td>17</td><td>FBC Lakhra</td><td>Coal</td><td>150</td><td colspan="2">30</td></tr>
<tr><td></td><td>Sub-Total GENCO-IV</td><td></td><td>150</td><td colspan="2">30</td></tr>
<tr><td></td><td>Sub Total GENCOs</td><td></td><td>4,829</td><td colspan="2">3,580</td></tr>
<tr><td></td><td>Sub Total (WAPDA+GENCOs)</td><td></td><td>11,273</td><td>9,846</td><td>5,883</td></tr>
<tr><td rowspan="2">Nuclear</td><td></td><td>Nuclear Plants</td><td></td><td></td><td colspan="2"></td></tr>
<tr><td>18</td><td>Chashma Nuclear (PAEC)</td><td></td><td>325</td><td colspan="2">300</td></tr>
<tr><td></td><td></td><td>Total Capacity (Public)</td><td></td><td>11,598</td><td>10,146</td><td>6,183</td></tr>
<tr><td rowspan="5">Private Sector</td><td rowspan="3">Hydro</td><td>19</td><td>Jagran Hydro</td><td></td><td>30</td><td colspan="2">30</td></tr>
<tr><td>20</td><td>Malakand-III Hydro</td><td></td><td>81</td><td colspan="2">81</td></tr>
<tr><td></td><td>Sub-Total (Hydro-IPPs)</td><td></td><td>111</td><td colspan="2">111</td></tr>
<tr><td rowspan="2">Therma l</td><td>21</td><td>KAPCO</td><td>Gas/FO</td><td>1,638</td><td colspan="2">1,386</td></tr>
<tr><td>22</td><td>Hub Power Project (HUBCO)</td><td>FO</td><td>1,292</td><td colspan="2">1,200</td></tr>
</table>

	No.	Name Of Power Station	Fuel	Installed Capacity (MW)	Capability* (MW)	
					Summer	Winter
	23	Kohinoor Energy Ltd. (KEL)	FO	131	124	
	24	AES Lalpir Ltd.	FO	362	350	
	25	AES Pak Gen (Pvt) Ltd.	FO	365	350	
	26	Southern Electric Power Co. Ltd. (SEPCOL)	FO	135	119	
	27	Habibullah Energy Ltd. (11C PC)	Gas	140	129	
	28	Uch Power Project	Gas	586	551	
	29	Rouch (Pak) Power Ltd.	FO	450	395	
	30	Fauji Kabirwala (FKPCL)	Gas	157	151	
	31	Saba Power Company	FO	134	125	
	32	Japan Power Generation Lid	FO	135	120	
	33	Liberty Power Project	Gas	235	211	
	34	Altern Energy Ltd, (AEL)	Gas	31	31	
	35	Attock Generation PP	FO	163	156	
	36	ATLAS Power	Gas	219	219	
	37	Engro P.P. Daharki, Sixth	Gas	227	217	
	38	Saif P.P. Shalwal, Punjab	RFO/Gas	225	225	
	39	Orient P.P. Balloki, Punjab	RFO/Gas	225	225	
	40	Nishat P.P. Near Lahore, Punjab	RFO	200	200	
	41	Nishat Chunian Proj. Near Lahore	RFO	200	200	
	4 2	Sapphire P.P. Muridke, Punjab	RFO/Gas	225	225	
		Sub-Total (Thermal IPPs)		**7,475**	**6,909**	
	43 44	Gulf Rental RP, Gujranwala, Punj. Walters Naudero Sindh	RFO Gas	62 51	62 51	
		Sub-Total (Rental)		**113**	**113**	
		Total Thermal (IPPs)		7,588	7,022	
		Total Capacity (Private)		7,699	7,133	
		Total Hydro (Public and Private)		6,555	6,377	2,414
		Total Thermal (Public and Private)		12,742	10,902	
		Total (PEPCO System)		**19,297**	**17,279**	**13,316**

**De-rated capacity (MW) for Thermal Plants*

The summary of existing thermal units in the KESC system is presented in Table 6-7 below:

Table 6-7 Existing Units – KESC System

No.	Plant Name	Unit Type	Number of Units	Plant Capacity		Primary
				Nominal (MW)	De-rated (MW)	Fuel Type
	KESC Thermal					
1	Bin Qasim	Steam Turbine	6	6 x 210	1,120	Gas/HFO
2	SGTPS	Reciprocating Gas Engines	32	32 x 2.739	88	Gas
3	KGTPS	Reciprocating Gas Engines	32	32 x 2.739	88	Gas
4	KCCPP	Combined Cycle GT	4 GTs, 1 ST	4 x 48.4 + 1x26	167	Gas
	KESC IPP Thermal					
5	Gul Ahmed Energy	Engines	9	128.5	128	HSFO
6	Tapal Energy Ltd	Engines	12	127	124	HSFO
7	DHA Cogen	CC	1	80	71	Gas
8	IIL (19 MW)	Engines	6	19	19	Gas
9	Anoud Power	Engines	2 Oil, 1 Gas	12	12	Gas
10	KANUP	Nuclear	1	136	122	Uranium
	Total (KESC and IPPs)			**2,158**	**1,938**	

Retirement of Existing Plants

There is no retirement plan for the existing units in the PEPCO and KESC systems. For planning purposes, the following retirement schedule in Table 6-8 was used taking into account the current condition of the existing units and the typical service lifetime of unit types.

Table 6-8 Retirement Schedule of Existing Plants

Year	Plant Name	Number of Units	Unit Capacity (MW)	Plant Capacity (MW)
2011-12				
2012-13	KESC Coal-Oil Conversion[12]	2	176	352
2013-14	Sumundri (Rental)	1	132	132
2014-15				
2015-16				
	Gulf (Rental)	1	60	60
	Walters (Rental)	1	50	50
	Karkey (Rental)	1	203	203
	Reshma (Rental)	1	177	177
2016-17				
2017-18				
2018-19				
2019-20				
	Guddu, # 11, 12, 13	3	285	285
	Faisalabad GTPS, # 5,6,7,8,9	5	129	129
	KESC Gul Ahmed, all units	9	14	122
	KESC Tapal, all units	12	12	138
2020-21				
	Jamshoro, # 1	1	170	170
	Jamshoro, # 2,3,4	3	164	492
	KESC Kannup, # 1	1	114	114
2021-22				
	Shadara, # 3,4,5	3	9	27
	Kotri, # 1,2	2	9	18
	Faisalabad GTPS, # 1,2,3,4	4	18	72
	Quetta, # 1	1	25	25
	Kotri, # 3,4,5,6,7	5	120	120
	Multan, # 1,3	2	28	55
	Faisalabad SPS, # 1,2	2	46	92
	Guddu, # 1,2	2	58	116

[12] *Two oil-fired steam turbine units at Bin Qasim power plant are planned to be converted from oil to coal in 2012-13.*

Year	Plant Name	Number of Units	Unit Capacity (MW)	Plant Capacity (MW)
	Guddu, # 3,4	2	147	294
2022-23				
2023-24	Guddu, # 5,6,7,8,9,10	6	215	429
2024-25	Muzaffargarh. # 1,2,3,5,6	5	167	836
2025-26	Lakhra, # 1	1	28	28
2026-27	Kot Addu, # 1	1	244	244
2027-28				
	KESC-Anoud, # 1,2,3	3	4	12
	Muzaffargarh, # 4			240
	KESC-Bin Qasim, # 1,2,3,4	4	177	708
	Kohinoor, # 1,2,3,4,5,6	6	12	72
2028-29	KESC-IIL, # 1,2,3,4,5,6	6	19	113
2029-30				
	KESC-SGTPS, # 1 to 32	32		87
	KESC-KGTPS, # 1 to 32	32		87
	Kot Addu, # 2,3,4	3	240	721
	SEPCOL, # 1,2,3,4,5,6	6	19	115
Total				**6,935**

It is important to notice that the utilization of state owned generation complexes on retirement is dependent on the policies in place. According to our understanding, there does not exist any clear policy regarding the retirement of generation plants and utilization of the generation complexes after retirement of these plants. Broadly speaking, the Regulator can play a pivotal role in the development and implementation of such policies which takes into account the technical, economic and environmental considerations.

As regards the utilization of generation complexes after retirement of the plant, the key factors that generally need to be considered are the state of cooling water and fuel supply infrastructure, and electric switchyard. In case the condition of the cooling water and fuel supply infrastructure, and electric switchyard is satisfactory, and can economically support the operation of the new generation plant for a sufficient number of years, then it might be prudent to make use of the existing plant land for developing the new generation plant. Utilizing the existing space would also result in avoidance of paying land cost and obtaining the requisite site and environmental permits. The existing transmission lines can also be used for the evacuation of power from the new plant. If the plant at a given location is retired and not replaced, additional transmission may be required in neighbouring areas to ensure reliability of supply.

Committed Hydro and Thermal Units

The following plants have been considered in the NPSEP as committed projects, based on the criterion that the projects are under construction or have reached financial close.

Hydro - Public Sector	Installed Capacity	Commissioning Year
Mangla Dam Raising	644 GWh[13]	2010-11
Khan Khwar	72 MW	2010-11
Allai Khwar	121 MW	2010-11
Duber Khwar	130 MW	2010-11
Jinnah Barrage	96 MW	2010-11
Satpara Dam	15.8 MW	2010-11
Gomal Zam	17.4 MW	2011-12
Neelum Jhelum	969 MW	2015-16
Kurram Tangi	83 MW	2013-14
Total	**1,504 MW**	

Source: *Hydro Potential in Pakistan, WAPDA, November 2010*

Hydro - Private Sector	Installed Capacity	Commissioning Year
New Bong Escape	84 MW	2013-14

Source: *Letter from General Manager (WPPO) dated February 23, 2011*

Thermal - Public Sector	Installed Capacity	Commissioning Year	Fuel Type
Nandipur Power Project	425 MW	2011-12	RFO
Chashma Nuclear	340 MW	2011-12	Nuclear
UAE GT, F/Abad	320 MW	2012-13	Gas
Guddu CC Sind	750 MW	2013-14	Gas
Total	**1,835**		

Source: *NTDC List of Future Generation Projects, GENCO (projects up to serial no. 30 are considered committed).*

[13] *The project only provides additional energy.*

Thermal - IPP/Rental	Installed Capacity	Commissioning Year	Fuel Type
Karkey Project Karachi (Rental)	232 MW	2010-11	RFO
Fauji Foundation	202 MW	2010-11	Gas
Hub Power Narowal	225 MW	2010-11	RFO
Halmore Power Bhikki	225 MW	2010-11	RFO
Reshma (Rental)	200 MW	2010-11	RFO
Santiana F/Abad (Rental)	201 MW	2010-11	RFO
Zorlu	50 MW	2011-12	Wind
Fauji Fertilizer	50 MW	2011-12	Wind
Total	**1,385 MW**		

Sources:
NTDC List of Future Generation Projects for Rental projects
Letter from General Manager (WPPO) dated February 23, 2011 for IPPs
Status as of Feb 2011 of Projects being processed by PPIB, PPIB website

KESC	Installed Capacity	Commissioning Year	
Bin Qasim CC	560 MW	2012-13	Gas
Retrofit Bin Qasim	420 MW[14]	2012-13	Coal
KESC Bio Waste to Energy	25 MW	2012-13	Bio Waste
Total Committed Additional Capacity	**585**		

***Source**: Data provided by KESC.*

The total installed capacity of the above committed hydro and thermal plants is estimated to be 5,393 MW.

6.7 New Generation Options

The basic supply options which are available for the expansion of the generation system are coal, fuel oil, natural gas, nuclear, hydro and wind plants.

6.7.1 Hydro Projects and Screening

The candidate new hydroelectric plants are taken from the PEPCO future generation projects list issued in March 2011. These include hydro plants to be installed by both WAPDA and the IPPs. There are also hydro projects that are being promoted by the

[14] *Two oil-fired existing steam turbine units are planned to be converted into coal-fired units. Therefore the net capacity addition is zero*

Alternative Energy Development Board (AEDB) for implementation by the provinces; but these are less than 50 MW and have not been considered in the expansion plan.

The possible commissioning schedule and capital and operational cost data of the identified new hydroelectric projects were reviewed. These projects were then ranked in terms of economic costs including their capital and O&M costs.

Identified Future Hydro Projects

In future, there will be three general groups of hydro plants:

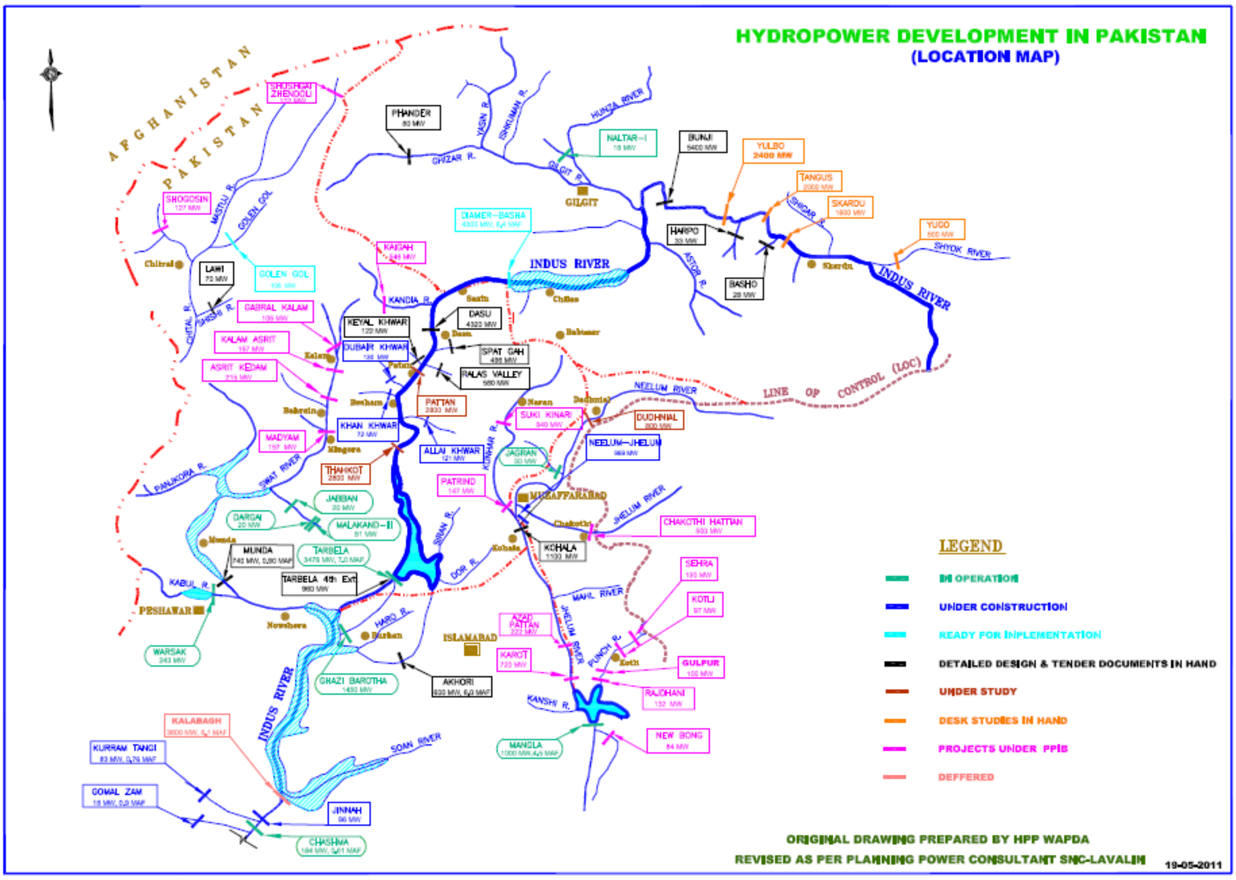
- WAPDA will be responsible for large multi-purpose plants;
- The provinces will be encouraged to develop hydroelectric generation for their own use in plants of 50 MW installed capacity or smaller; and
- The PPIB (Private Power and Infrastructure Board) will promote the development by IPPs of all non multi-purpose hydroelectric projects, but with emphasis on small / medium sized plants larger than 50 MW.

There are twenty-three WAPDA hydro projects, totalling 37,057 MW[15], and eighteen IPP hydro projects, totalling 5,519 MW, that have been identified and proposed on the future projects list provided by NTDC. There are an additional two hydro projects, Kalabagh 2,776 MW and Doyian 490 MW, that are not on the WAPDA list but the feasibility studies have been completed in 1987 and 2004, respectively. The total capacity of the future hydro potential is 43,676 MW.

The location of the future hydro plants in Pakistan is presented in Figure 6-2.

[15] On the WAPDA future projects list, two projects (Basho and Harpo), with an installed capacity of less than 50 MW, were included in this generation planning study.

Figure 6-2 Location of Hydro Projects



Project data sheets of the WAPDA hydro projects summarizing key data including the technical characteristics and cost data from the available feasibility study reports and information provided by Hydro Planning, WAPDA are included in Annexure 2. The technical and cost data for IPP hydro projects are based on information provided by WAPDA Power Privatization Organisation (WPPO), NTDC and the State of Industry Report by NEPRA (www.nepra.org.pk).

The summary table and detailed monthly capacity and energy data of each of the future hydro projects are provided in Annexure 2.

<u>Earliest Commissioning Dates of Future Hydro Projects</u>

After a review of the provided implementation schedule of the hydro projects, it was found that the expected commissioning dates for some of the projects would need to be adjusted to take into account their current stage of development. For the generation planning study the basic criteria listed in Table 6-9 was applied to estimate the earliest possible commissioning date for project at different stages of development.

Table 6-9 Lead Time of Future Hydro Projects by Category

Status Category	Current Status	Lead Time
A	Under construction	as per the schedule given
B	Ready for implementation	construction period + 1~2 years
C	Detailed design & tender documents	construction period +4 years
D	Under study	construction period + 6 years
E	Desk studies	construction period + 8 years

The earliest possible commissioning dates, installed capacities and average annual energy data of future hydro projects are presented in Table 6-10.

Table 6-10 Identified Future Hydro Projects

No.	Project Name	Status Category	Installed Capacity (MW)	Average Annual Energy (GWh)	Earliest Commissioning Date
WAPDA					
1	Diamer Basha	B	4,500	18,072	2022-23
2	Golen Gol	B	106	437	2017-18
3	Kurram Tangi	A	83	350	2013-14
4	Tarbela 4th Ext.	B	960	2,000	2017-18
5	Munda	C	740	2,272	2022-23
6	Keyal Khwar	C	122	426	2021-22
7	Phander	C	80	350	2020-21
8	Basho	C	26	131	2019-20
9	Harpo	C	33	187	2019-20
10	Lawi	C	70	303	2021-22
11	Dasu	B	4,320	23,189	2023-24
12	Bunji	B	7,100	24,129	2022-23
13	Akhori	C	600	2,156	2022-23
14	Lower Spat Gah	C	496	2,106	2023-24
15	Palas Valley	C	665	2,635	2022-23
16	Pattan	C	2,800	15,230	2024-25

Table 6-10 Identified Future Hydro Projects (Cont'd)

No.	Project Name	Status Category	Installed Capacity (MW)	Average Annual Energy (GWh)	Earliest Commissioning Date
		IPPs			
17	Thakot	D	2,800	14,095	2024-25
18	Dudhnial	D	800	5,425	2025-26
19	Yulbo	E	3,000	12,058	2026-27
20	Tungas	E	2,200	9,583	2026-27
21	Skardu	E	1,650	7,130	2026-27
22	Yugo	E	520	2,012	2026-27
23	Kalabagh	D	2,776	11,749	2023-24
24	Taunsa	C	120	665	2020-21
25	Doyian	D	490	2,419	2021-22
26	New Bong Escape	A	84	470	2013-14
27	Gul Pur	B	100	466	2015-16
28	Rajdhani	B*	132	664	2015-16
29	Kotli HPP	B*	97	479	2016-17
30	Patrind HPP	B*	147	675	2016-17
31	Sehra HPP	B*	130	513	2016-17
32	Karot HPP	B*	720	2,575	2017-18
33	Asrit-Kedam HPP	B*	215	911	2017-18
34	Madian HPP	B*	157	784	2017-18
35	Azad Pattan	B*	222	781	2018-19
36	Chakothi HPP	B*	500	2,459	2018-19
37	Kalam - Asrit HPP	B*	197	881	2018-19
38	Gabral Kalam HPP	B*	101	445	2018-19
39	Shogosin HPP	B*	127	583	2018-19
40	Shushgai Zhendoli HPP	B*	102	368	2018-19
41	Suki Kinari HPP	B*	840	2,958	2019-20
42	Kaigah HPP	B*	548	1,975	2019-20
43	Kohala HPP	C	1100	3,964	2021-22

B: Detailed information of the project status is not available. However, since the construction of the project has not started and the earliest commissioning date of the projects was postponed by 2 year based on the commissioning date on the PEPCO future project list considering the lead time for project preparation and construction.*

Compared to the original implementation schedule provided by NTDC, the earliest commissioning dates of WAPDA hydro projects before 2020-21 are expected to be delayed by three to five years and of IPP hydro projects by two years considering their current development status. The projects with the earliest commissioning dates after 2020-21 have sufficient lead time and may be scheduled on the proposed dates depending of the attractiveness of the projects.

Environmental and Socioeconomic Aspects

As discussed in Section 6.2 Environmental and Socio-economic costs have been estimated by restating at 2010 price levels the costs for those projects that have been studied to feasibility level and for whom the original environmental cost estimates are available. Proportions, based on projects that have the necessary data, have been applied to estimate the environmental cost estimates for the other projects. These are summarized in Table 611.

Table 6-11 Summary of Environmental Costs

Sr. No	Project Name	Current Status	Gross Storage (Million Acre Feet)	Potential Capacity (Mega Watt)	Costs (Million US $)	Total (E&R*) (Million US $)	Final (E&R*) (Million US
1	Doyian Hydropower Project	Feasibility study completed 2003	0.007	490	428.19	1.30	1.30
2	Basho Hydropower Project	Feasibility study completed 2001	0	28	40.00	0.12	0.12
3	Taunsa Hydropower Project	Feasibility study completed 2000	0	120	181.00	0.75	0.75
4	Palas Valley Hydropower Project	Feasibility study completed 2009	0.0024	665	763.62	4.47	4.40
5	Bunji Hydropower Project	Feasibility study Completed 2008	0	7,100	6,840.00	57.00	56.99
6	Kohala Hydropower Project	Feasibility study completed 2009	0.013	1100	2,212.00	8.84	8.84
7	Munda Dam Multipurpose Project	Feasibility study completed 1992	1.29	740	1,401.00	7.50	7.50
8	Tarbela Fourth Extension Hydropower Project	Feasibility Study not prepared	0	960	705.00	0.00	13.29
9	Suki Kinari Hydropower Project	Feasibility study not prepared	0	840	925.00	0.00	15.72
10	Lower Spat GahHydropower Project	Feasibility study completed 2009	0.0017	496	702.00	12.80	12,80
11	Tungas Dam Project	Feasibility study not prepared	0	2,200	4,200.00	0.00	64,75

Sr. No	Project Name	Current Status	Gross Storage (Million Acre Feet)	Potential Capacity (Mega Watt)	Costs (Million US $)	Total (E&R*) (Million US $)	Final (E&R*) (Million US
12	Phandar Hydropower Project	Feasibility study completed 2003	0	80	70.00	2.47	2.47
13	Keyal Khwar Hydropower Project	Feasibility study completed 2008	0	122	247.50	3.87	3,87
14	Patan Hydroelectric Project	Feasibility study not prepared	0	2,800	6,000.00	0.00	91.09
15	Lower Thakot Dam Project	Feasibility study not prepared	0	2,800	6,000.00	0.00	91,09
16	Dudhnial	Feasibility study not prepared	0	800	1,800.00	0.00	27,16
17	Yulbo Dam Project	Feasibility study not prepared	0	2,800	6,750.00	0.00	101,04
18	Diamer Basha Dam Project	Feasibility study completed 2004	8.1	4,500	11,178.00	207.16	207,15
19	Lawi Hydropower Project	Feasibility study completed 2006	0	69	93.00	3.33	3,33
20	Harpo Hydropower Project	Feasibility study 2002	0	33	45.00	2.00	1,99
21	Golen Gol Hydropower Project	Feasibility study Completed 1997	0	106	130.00	6.77	6,77
22	Skardu Dam Project	Feasiblity not prepared	0	1650	8,250.00	0.00	116,22

Sr. No	Project Name	Current Status	Gross Storage (Million Acre Feet)	Potential Capacity (Mega Watt)	Costs (Million US $)	Total (E&R*) (Million US $)	Final (E&R*) (Million US
24	Shyok(Yugo) Hydropower Project	Feasibility study not prepared	0	500	3,000.00	0.00	41,85
23	Kala Bagh Dam Project	Feasibility study completed 1987	7.9	2,776	2,650.40	244.22	244,22
25	Dasu Hydropower Project	Feasibility study completed 2009	1.15	4,320	5,206.00	392.50	392,50
26	Kurram Tangi Multipurpose Project	Feasibility study completed 2004	0.93	63	700.00	37.50	37,50
27	Akhori Dam Project	Feasibility Study completed 2005	7.6	600	3,300.00	795.00	795,00

** The values shown in this column are the original feasibility cost estimates escalated to 2010 price levels. For those projects showing no original estimate, the approximation has been applied. The final column shows the costs used in the NPSEP.*

Preliminary Screening of Future Hydro Projects

In order to develop the least cost generation plan for Pakistan, one of the key steps is to rank the candidate hydro projects in terms of their economic costs including capital and O&M costs. The capital cost and O&M costs of the future hydro projects were estimated based on their feasibility study reports and adjusted for environmental and resettlement costs. The unit cost of energy for each of the hydro projects was then estimated based on the annualized capital costs over the project lifetime (50 years) plus the O&M costs for the year divided by the average annual energy produced.

Among the future hydro projects, there are four multipurpose hydro projects whose cost should not be fully allocated to power generation:

- Diamer Basha 4,500 MW
- Kalabagh 2,776 MW
- Munda 740 MW
- Kurram Tangi 84 MW

According to a study done in December 1985 by Kalabagh Consultants for the Kalabagh Dam Project, it was determined that 65% of the project capital cost should be allocated to power generation, with the remaining 35% allocated to irrigation and flood control. While this analysis was done specifically for the Kalabagh Dam, it is assumed that a similar proportion could be applied for the other multipurpose projects, however with the caveat that this estimate should be firmed up for the other projects during their detailed feasibility studies. This percentage allocation was also adopted by the National Power Plan in 1994 and has also been used for the NPSEP.

The derived unit cost of energy in an ascending order for the future hydro projects is presented in Table 6-12.

Table 6-12 Summary of Future Hydro Projects

No.	Project Name	Installed Capacity (MW)	Capital Cost[16] (US$/kW)	O&M Costs (US$/kW-yr)	Unit Cost of Energy (US$/MWh)	Capacity Factor
WAPDA						
1	Kalabagh	2,776	621	9.3	16	48%
2	Doyian	490	874	13.1	19	56%
3	Phander	80	875	8.8	20	50%
4	Dasu	4,320	1,205	18.1	24	61%
5	Harpo	33	1,333	13.3	24	65%
6	Basho	26	1,391	13.9	28	57%
7	Taunsa	120	1,515	22.7	29	63%
8	Golen Gol	106	1,226	12.3	30	47%
9	Palas Valley	665	1,147	17.2	31	45%
10	Bunji	2,367	963	17.6	31	39%
11	Lawi	70	1,200	30.0	32	49%
12	Dudhnial	800	2,284	22.8	34	77%
13	Lower Spat Gah	496	1,405	21.1	35	48%
14	Tarbela 4th Extension	960	748	7.5	37	24%
15	Pattan	2,800	2,175	21.8	41	62%
16	Munda	740	1,231	12.3	41	35%
17	Diamer Basha	2,250	1,615	17.4	41	46%
18	Thakot	2,800	2,175	21.8	44	57%
19	Tungas	2,200	1,939	29.1	47	50%
20	Keyal Khwar	122	2,025	20.2	59	40%
21	Yulbo	3,000	2,284	34.3	61	46%
22	Skardu	1,650	5,070	76.1	125	49%
23	Kurram Tangi	83	5,456	54.6	132	48%
24	Akhori	600	5,500	55.0	156	41%
25	Yugo	520	5,850	87.8	161	44%

[16] *Capital cost includes the adjusted environmental and resettlement costs*

Table 6-12 Summary of Future Hydro Projects (cont'd)

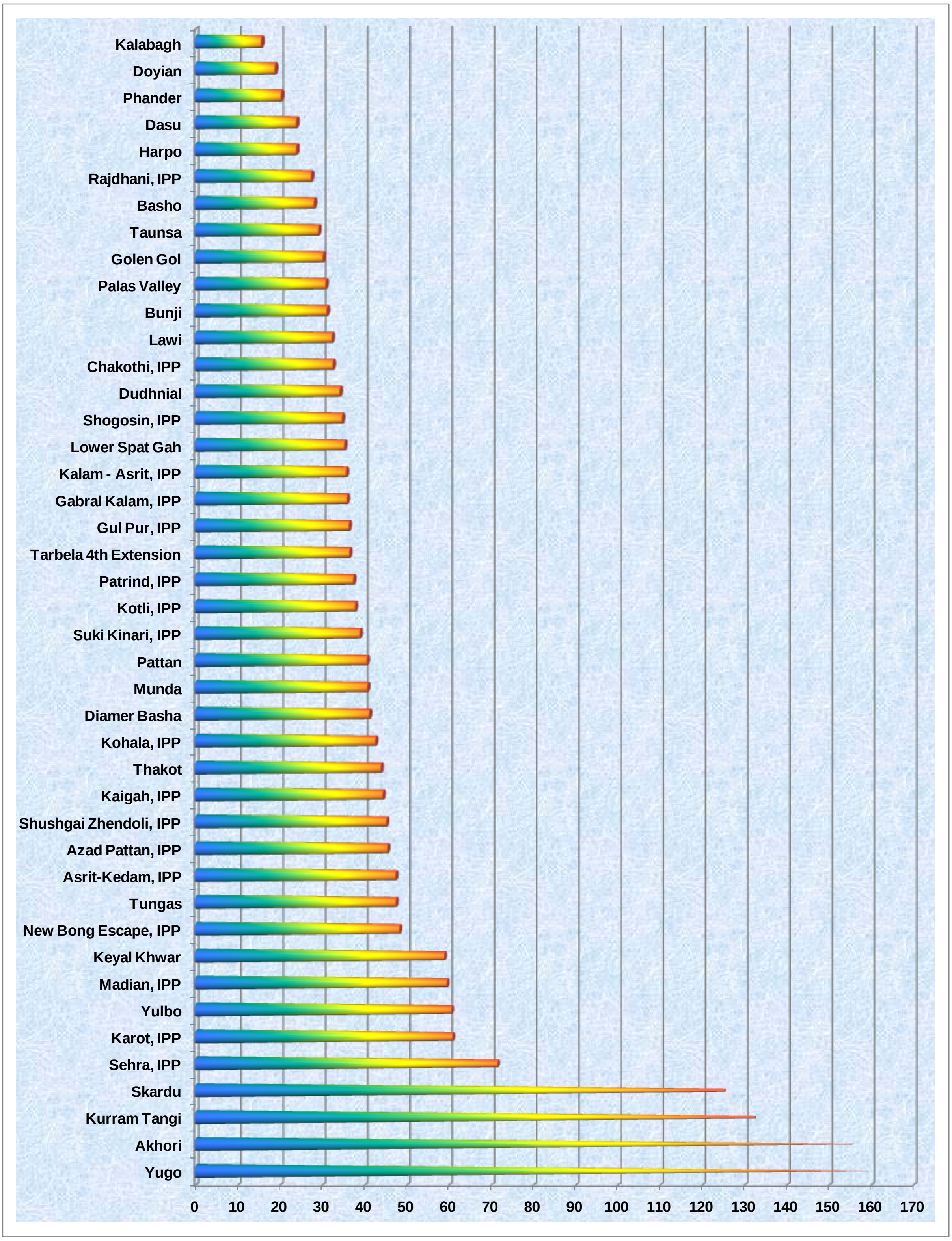
No.	Project Name	Installed Capacity (MW)	Capital Cost[17] (US$/kW)	O&M Costs (US$/kW-yr)	Unit Cost of Energy (US$/MWh)	Capacity Factor
IPPs						
26	Rajdhani, IPP	132	1,295	19.4	27	57%
27	Chakothi, IPP	500	1,504	22.6	33	56%
28	Shogosin, IPP	127	1,496	22.4	35	52%
29	Kalam - Asrit, IPP	197	1,497	22.5	36	51%
30	Gabral Kalam, IPP	101	1,485	22.3	36	50%
31	Gul Pur, IPP	100	1,590	23.9	36	53%
32	Patrind, IPP	147	1,612	24.2	37	52%
33	Kotli, IPP	97	1,753	26.3	38	56%
34	Suki Kinari, IPP	840	1,287	19.3	39	40%
35	Kohala, IPP	1,100	2,011	24.1	43	56%
36	Kaigah, IPP	548	1,500	22.5	44	41%
37	Shushgai Zhendoli, IPP	102	1,529	22.9	45	41%
38	Azad Pattan, IPP	222	1,500	22.5	45	40%
39	Asrit-Kedam, IPP	215	1,884	28.3	47	48%
40	New Bong Escape, IPP	84	2,536	38.0	48	64%
41	Madian, IPP	157	2,790	41.8	60	57%
42	Karot, IPP	720	2,042	30.6	61	41%
43	Sehra, IPP	130	2,646	39.7	72	45%

The results show that the unit costs of energy for most of the identified future hydro projects are less than US$ 60/MWh, which is generally more economically attractive than the thermal generation options operating at the same capacity factors. However, four WAPDA hydro projects, Akhori, Kurram Tangi, Skardu and Yugo have a higher unit cost. Kurram Tangi was included since it is under construction. Akhori, Skardu and Yugo were not considered further in the NPSEP.

All the future hydro projects including WAPDA hydro projects and IPPs are ranked and presented in terms of the unit cost of energy in Figure 6-3.

[17] *Capital cost includes the adjusted environmental and resettlement costs*

Figure 6-3 Ranking of Hydro Projects



Implementation of Hydro Projects

An implementation schedule, shown in Table 6-13, was developed for the future hydro projects based on their unit costs of energy and earliest available commissioning dates.

Given the short duration to complete this Expansion Plan, the prioritization was based on a static analysis using annual capacity factors to develop a preliminary ranking. This level of analysis is sufficient to obtain indicative costs for the generation. However, it is recommended that future updates of the optimized ranking be based on a system analysis that takes the contribution of seasonal nature of hydro plants into consideration. This system analysis takes considerably longer than the static analysis as it requires much more detailed simulation.

Table 6-13 Implementation of Hydro Plants

No.	Name	Installed Capacity (MW)	Number of Units	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25	25-26	26-27	27-28	28-29	29-30	Capacity Factor
WAPDA																										
1	Khan Khwar	72	1x4+2x34				71																			49%
2	Jinnah	96	8x				95																			81%
3	Allai Khwar	121	2x60.5					120																		44%
4	Duber Khwar	130	2x65					129																		52%
5	Kurram Tangi	83	3x12.25+2x5.3+2x8.4						83																	48%
6	Neelum Jhelum	969	4x								959															62%
7	Tarbela 4th Ext.	960	2x										950													24%
8	Munda	740	1															733								35%
9	Phander	80	4x													79										50%
10	Bunji	5400*	20x													1782	1782	1782								39%
11	Golen Gol	106	3x										105													47%
12	Palas Valley	580*	3x															574								45%
13	Dasu	4320	8x															2138	2138							56%
14	Harpo	33	3x												33											65%
15	Lawi	70	3x														69									49%
16	Basho	28	3x												28											57%
17	Lower Spat Gah	496	3x																491							48%
18	Keyal Khwar	122	2x														121									40%
19	Diamer Basha	4500	12x375													2228		2228								46%
20	Tungas	2000*	10																			1980				50%
21	Thakot	2800	8x																	2772						57%
22	Pattan	2800	8x																	2772						62%
23	Dudhnial	800	1																		792					77%
24	Taunsa	120	1																		119					59%
25	Yulbo	2400*	10																			2376				46%

Table 6-13 Implementation of Hydro Plants (Cont'd)

No.	Name	Installed Capacity (MW)	Number of Units	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21	21-22	22-23	23-24	24-25	25-26	26-27	27-28	28-29	29-30	Capacity Factor
IPPs																										
26	New Bong Escape, IPP	84	1						83																	64%
27	Gul Pur, IPP	100	1								99															53%
28	Rajdhani, IPP	132	1								131															57%
29	Kotli, IPP	97	1									96														56%
30	Patrind, IPP	147	1									146														52%
31	Sehra, IPP	130	1									129														45%
32	Karot, IPP	720	1										713													41%
33	Asrit-Kedam, IPP	215	1										213													48%
34	Madian, IPP	157	1										155													57%
35	Azad Pattan, IPP	222	1											220												40%
36	Chakothi, IPP	500	1											495												56%
37	Kalam - Asrit, IPP	197	1											195												51%
38	Gabral Kalam, IPP	101	1											100												50%
39	Shogosin, IPP	127	1											126												52%
40	Shushgai Zhendoli, IPP	102	1											101												41%
41	Suki Kinari, IPP	840	4x												832											40%
42	Kaigah, IPP	548	4x												543											56%
43	Kohala	1100	4x														1089									56%

As shown in the schedule, most of the future hydro projects are scheduled to be implemented as soon as they are available. The following four projects were postponed as the system had reached the LOLP reliability target and further additions were not required in that year:

- Kohala: 2020-21 to 2021-22;
- Taunsa: 2020-21 to 2025-26;
- Pattan: 2022-23 to 2024-25; and,
- Dudhnial: 2024-25 to 2025-26.

Process of Detailed Screening of Hydro Projects

The preliminary screening of hydro projects was carried out based on the unit cost and feasible due date earlier in this section. The above derived unit cost of future hydro projects provides the generating cost of each hydro project at a specific capacity factor. Most of the future hydro projects have a plant capacity factor in a range of 40% to 50%. The ranking of hydro projects based on the preliminary screening provides a good indication and start point to develop the generation expansion plan. However, this preliminary screening analysis does not take into account the seasonal or daily load variations and the operating patterns of the hydro plants in the particular system being studies.

To complete detailed screening of hydro projects taking into account the seasonal load variation and operating patterns of the hydro plants would require a greater level of details and significant efforts of SYPCO simulations and iterations depending on the size of the system and the number of candidate hydro projects. The key steps to carry out the detailed screening of hydro projects are briefly described as follows.

1. Determine the unit cost and the earliest commissioning date of candidate hydro projects;
2. Formulate the first set of generation plan including only thermal units using SYPCO;
3. Introduce hydro plants one by one for a certain year into the first set of generation plan formulated in Step 2 while keeping the LOLP at the same level. The hydro plants will replace the most expensive units, usually gas turbine units, to meet the demand and the reliability criteria;
4. Compare the present worth of the total costs for each generation plan by introducing the hydro plants one by one derived from SYPCO simulations. If Project A gives the least cost generation plan, Project A is the cheapest project among the candidate

hydro projects. The other hydro projects can be ranked based on the present worth of the total costs for its generation plan;

5. If adding a hydro project, the present worth of the total costs increases, this hydro project should be postponed to the next year for testing or re-investigated in terms of economic viability; and
6. Repeat Step 3 and 4 for the following years of the study period and complete the screening of the candidate hydro projects.

6.7.2 New Thermal Options

New thermal options include Gas Turbines (GTs), Combined Cycle Gas Turbines (CCGTs) and Steam Turbines using furnace oil (FO) or coal. To develop a least cost generation expansion plan, it is necessary to examine the economic attractiveness of each thermal option and select the least cost supply options taking into account technical characteristics and operational requirements.

The choice of generation options has to take into account system size, variation in daily and seasonal peak loads, system reliability requirements, operational and maintenance constraints, fuel availability, synergy with the existing system, and requisite generation mix. In addition to the power system factors that are important for the selection of generation units, the technical and economic characteristics of the generating units have to be taken into consideration. These include operational and maintenance requirements, fuel efficiency, emission levels, construction schedule, and investment and O&M costs.

Achieving economies of scale plays a major role in reducing the cost of generation. However technical limits with regards the size of the units has to also be considered. Sudden loss of a large generating unit and sudden pick up of a large block of load introduces perceptible drops in frequency and may endanger the stability of the power system. The technical limit thus imposed has a significant influence on the economics of introducing large units into a power system. Therefore, there has to be a balance between economies of scale and system requirements when choosing the appropriate size of the generating units.

The following sections provide the typical characteristics of each of the generating units and the rationale behind its selection.

Steam Turbine Thermal Plants

For fossil-based thermal power plants three sizes were considered, 600MW, 400 MW and 200 MW.

NTDC has specified the capacity size of 1,200 MW for coal-fired units to be located in Karachi and Thar regions. Therefore, 2x600 MW units and 3x400 MW units are suitable configurations for these coal-based power plants. Considering economies of scale and flexibility in performing maintenance tasks, 600 MW steam turbine units were selected for the screening curve analysis.

In addition to the 600 MW sizes, 200 MW units operating fuel oil have been considered for the screening analysis. 200 MW steam power plants are already in operation in Pakistan so local experience for operation and maintenance already exists. This size could be beneficial in terms of reliability of the system and flexibility required for maintenance.

These thermal plants should ideally be located on coast lines close to large quantities of water in light of their cooling requirements. Plants operating on imported coal as well as natural gas and fuel oil can be located near the coast. However, plants operating on Thar coal would need to be located near the coal mines.

The capital costs of coal-based and oil-based plants are based on prices prepared in 2008 by the World Bank in their "Study of Equipment Prices in the Power Sector". Cost data available from other recently completed studies, and other publications were also reviewed and taken into consideration.

The World Bank Study compares the costs of various types of power plants in USA, India and Romania. An escalation of 5% per year has been applied to the costs of 2008 to arrive at the cost as at December 2010. The total costs take into account equipment; material and labor cost, and also include environmental mitigation equipment, engineering and home office cost, project contingency and indirect costs. Further adjustments were then made to the costs to take into account the size of the plant and application of economies of scale.

Considering that Thar coal will have relatively poor quality which will require a larger boiler size as well as coal and ash handling equipment and storage facilities, it was decided to increase its capital cost by 16% as compared to an imported coal-based plant located on the coast near Karachi.

The costs for the 600 MW coal-based thermal units, using imported coal and Thar coal, and the 200 MW oil-based units are provided in Table 6-14.

The construction time for coal-based thermal plants is assumed to be four years with the following cash flow;

Year 1: 20%; Year 2: 30%; Year 3: 30%; Year 4: 20%

For oil-based thermal plant the construction period is assumed to be three years. The distribution of the cash flow is as follows:

Year 1: 30%; Year 2: 40%; Year 3: 30%

Nuclear Power Plants

The cost and technical data for the nuclear plants is based on information provided by the Pakistan Atomic Energy Commission (PAEC). PAEC has suggested a unit size of 1x1000 MW. However, in view of reliability considerations, and technology and sourcing constraints, the 500 MW unit size was also selected for the screening curve analysis in this study.

PAEC has suggested a capital cost range of US$ 3,000 – 4,000 per kW for the 1,000 MW nuclear power plant excluding the decommissioning cost. Based on this information and taking into account a 15% allowance for the decommissioning cost, the specific investment cost for this type of nuclear power plant is assumed to be US$ 4,600 per kW. The capital cost of 500 MW units at US$ 5,175 per kW is assumed to be 12.5% more than the capital cost of 1,000 MW units.

The construction time for nuclear power plants is assumed to be six years with the following cash flows.

Year 1: 5%; Year 2: 15%; Year 3: 25%; Year 4: 30%; Year 5: 20%; Year 6: 5%

Combined Cycle Plants

Three sizes of Combined Cycle Power Plants (CCPP) were considered for the expansion planning. The International Standards Organization (ISO) ratings of these combined cycle plants are 786 MW, 507 MW and 239 MW. The nominal site ratings of these combined cycle plants will be less than the ISO ratings depending on the ambient conditions. These sizes were selected based on the system size, efficiency of the plants, economies of scale and flexibility for operation and maintenance. The sizes selected are suitable for intermediate as well as base load operation.

The proposed configuration is two gas turbines, two HRSGs and one steam turbine. This configuration is selected as it provides the necessary flexibility in the operation and maintenance of the CCPP.

As regards the choice of fuel, natural gas is the most suitable fuel for gas turbines as the operation of gas turbines on natural gas results in substantially less maintenance costs. However, fuel oil (usually distillate) can be considered as a back-up fuel in case of a shortage of gas supply.

It is not necessary to locate CCPP on the coast as the requirements of cooling water are substantially less as compared to the steam-based thermal plants. However, proximity to a cooling water source is still an important consideration. Ideally, the CCPP should be located close to the load centers if the availability of cooling water is not an issue.

The specific capital costs of CCPP were derived mainly from the Gas Turbine World Handbook of 2010 which provides the most recent information on various types and sizes of these plants and their investment costs. The specific investment costs given in the handbook are budgetary costs and mainly comprise of equipment costs. To derive the total capital costs including engineering and construction services, adjustments were made to the costs from the handbook. These costs were increased by 80% to establish the specific investment costs of CCPPs. These costs are provided in Table 6-14:

The construction time for combined cycle plants is assumed to be three years with the following cash flows:

Year 1: 30%; Year 2: 40%; Year 3: 30%.

Gas Turbine Plants

For gas turbine plants, two sizes, 182 MW (ISO rating) and 70 MW (ISO rating), were selected. The nominal site ratings of these plants will be lower than the ISO ratings depending on the ambient conditions. The gas turbines selected can also be used for the CCPPs of 507MW and 239 MW. This is advantageous as it provides the opportunity of spare parts interchangeability and also operational experience on a similar plant. In addition, if needed, these plants can be easily converted to combined cycle plants.

Gas turbine plants were selected for peaking operation. For peaking operation, fuel efficiency is relatively unimportant as the capacity factors of these machines are low. Start-up reliability, start-up time and availability take precedence over thermal efficiency.

As gas turbine power plants are peaking plants and there is no requirement for cooling water, these plants should be located near the load centers in order to minimize the investment on transmission lines.

The specific capital costs of gas turbine power plants are derived mainly from the Gas Turbine World Handbook of 2010 which provides the most recent information on various types and sizes of gas turbine power plants and their capital costs. The Specific investment costs given in the handbook are budgetary costs and mainly comprise of equipment costs. To derive the total specific capital costs including engineering and construction services adjustments were made to these costs by enhancing the costs given in the Handbook by 80%. These costs are provided in Table 6-14.

The construction time for gas turbine plants is assumed to be two years with the following cash flows:

Year 1: 40%; Year 2: 60%

Key Characteristics of the Candidate Thermal Options

The main characteristics of the thermal addition plants are summarized in Table 6-14.

Table 6-14 Summary of Candidate Thermal Units

Unit Type	Fuel Type	Size (MW)		Capital Cost (USD/kW)		Fixed O&M	Variable O&M	Site	Plant Life	Investment Cash Flow (%, middle of the year)						Heat Rate	Equivalent Forced Outrage Rate
		ISO	Site Rating	ISO	Site	($/kW-y)	($/MWh)	Efficiency	Years	Y-1	Y-2	Y-3	Y-4	Y-5	Y-6	(Btu/kWh)	
GT-60	Gas	70	60	500	588	24	1.7	34.2%	20	40%	60%					9,985	6.8%
GT-155	Gas	182	155	420	494	19	1.5	37.4%	20	40%	60%					9,120	6.8%
CC-215	Gas	239	215	990	1,100	31	2.3	55.6%	25	30%	40%	30%				6,140	4.6%
CC-456	Gas	507	456	820	911	28	2	53.0%	25	30%	40%	30%				6,435	4.6%
CC-707	Gas	786	707	780	867	27	1.8	57.1%	25	30%	40%	30%				5,980	4.6%
ST-200-Oil	Oil	200	200	1,520	1,520	25	2.8	36.2%	30	30%	40%	30%				9,420	7.0%
ST-600-Thar	Thar coal	600	600	2,050	2,050	35	3.6	36.9%	30	20%	30%	30%	20%			9,250	9.5%
ST-600-Imp	Imported coal	600	600	1,850	1,850	30	3	37.5%	30	20%	30%	30%	20%			9,100	9.0%
Nuclear-500	Yellow cake	500	500	5,175	5,175	32	3	33.5%	40	5%	15%	25%	30%	20%	5%	10,200	11.0%
Nuclear-1000	Yellow cake	1,000	1,000	4,600	4,600	28	2.7	35.2%	40	5%	15%	25%	30%	20%	5%	9,690	11.0%

Note: *GT – Gas Turbine; CC – Combined Cycle; ST – Steam Turbine*

Earliest Commissioning Date of Candidate Thermal Units

The lead time for candidate thermal units are estimated based on the type and the size of the units, and taking into account the time required for the feasibility study, tender documents preparation and contract negotiations. The lead time for new thermal units is presented in Table 6-15.

Table 6-15 Lead Times for Thermal Plants

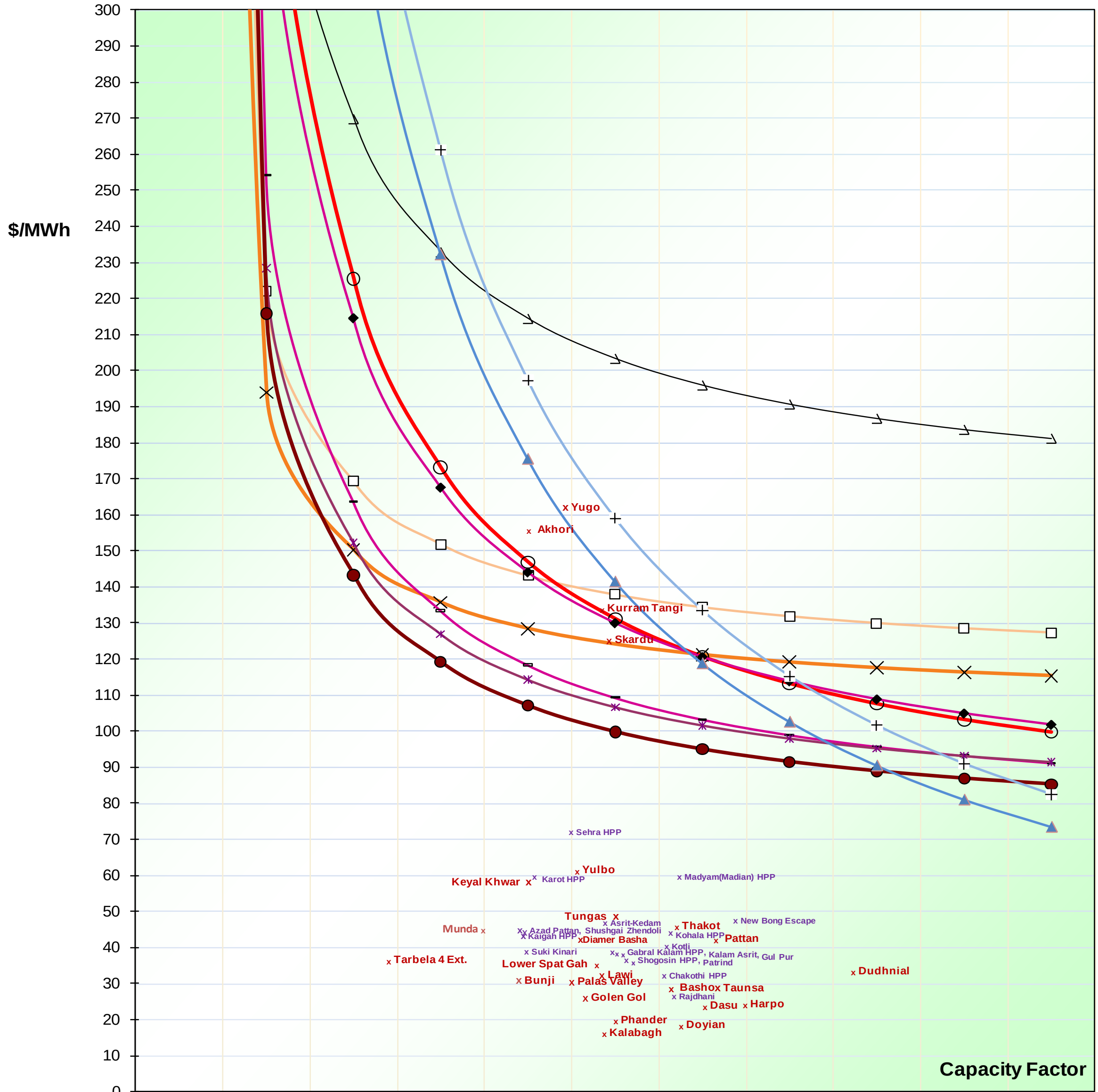
Unit Type (unit type – site rating)	Construction Period	Preparation for Construction	Total Lead Time	Earliest On-power Date
	Years			
GT- 60	2	1	3	2014
GT- 155	2	1	3	2014
CC- 215	3	1	4	2015
CC- 456	3	1	4	2015
CC- 707	3	1	4	2015
ST- 200 (Oil)	3	1	4	2015
ST- 600 (Thar coal)	4	1	5	2016
ST- 600 (Imported coal)	4	1	5	2016
Nuclear – 500	6	2	8	2019
Nuclear-1,000	6	2	8	2019

Screening Curve Analysis of Thermal Options

The candidate units were assessed and ranked in terms of annualized unit costs by developing screening curves, showing unit costs for different capacity factors.

This optimization is based on representing the average annual utilisation only over the life of the plant and hence has certain limitations. The screening curves do not directly consider the existing system, the changing capacity factor through time, or the unit operating constraints. Nevertheless, the screening curves do give a good first indication of what plants should be considered in formulating the generation expansion plans. The curves for the different thermal supply options are presented below.

Figure 6-4 Screening Curves



	1%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
GT-60	1167.6	221.9	169.4	151.9	143.1	137.9	134.4	131.8	130.0	128.5	127.3
GT-155	978.5	193.9	150.3	135.7	128.5	124.1	121.2	119.1	117.6	116.4	115.4
CC-215	1883.1	254.1	163.6	133.4	118.4	109.3	103.3	99.0	95.7	93.2	91.2
CC-456	1598.3	228.4	152.3	126.9	114.3	106.6	101.6	97.9	95.2	93.1	91.4
CC-707	1521.4	215.8	143.3	119.1	107.0	99.8	94.9	91.5	88.9	86.9	85.3
ST-200-Oil	2380.0	380.9	269.9	232.9	214.4	203.3	195.8	190.6	186.6	183.5	181.0
ST-600-Thar	3211.6	382.6	225.5	173.1	146.9	131.2	120.7	113.2	107.6	103.2	99.7
ST-600-Imp	2892.1	355.4	214.5	167.5	144.0	129.9	120.5	113.8	108.8	104.9	101.7
Nuclear-500	7662.6	771.6	388.7	261.1	197.3	159.0	133.5	115.3	101.6	91.0	82.5
Nuclear-1000	6806.3	685.5	345.5	232.2	175.5	141.5	118.8	102.6	90.5	81.0	73.5

HYDEL IPPS
WAPDA HYDEL

The screening curve analysis results show that the GT–155 MW is the lowest cost option operating at less than 17% of capacity. From 17% to 80%, CC–707 MW is the least cost option and above 80% Nuclear–1,000 MW becomes the cheapest option. However, considering the forced outage rate of 11% and an 8-week maintenance period, the nuclear units cannot realistically operate at a capacity factor above 80%. Therefore, the screening curve analysis suggests that the CCGT-707 is the least cost option whenever the units operate above a 17% capacity factor.

The costs of hydro units are also plotted in the figure. Since hydro units operate at certain capacity factors determined by the average energy and capacity, the unit cost of hydro units are plotted as separate dots instead of lines.

6.7.3 Other Generation Options

Power Import Options

PEPCO future projects list includes two interconnection projects, designed to provide power to Pakistan from neighbouring countries in the region:

- The import of 1,000 MW from Zahedan, Iran to Quetta, Pakistan via a ± 500 kV HVDC bipole (Draft feasibility study report was issued in August, 2010); and
- The import of 1,000 MW from Sangtuda, Tajikistan via Kabul, Afghanistan to Peshawar, Pakistan via a ± 500 kV HVDC 3-terminal bipole. The feasibility study of a 1,300 MW interconnection from Tajikistan to Afghanistan (300 MW) and Pakistan (1,000 MW) was completed in 2008 and updated in 2010.

The commissioning dates of both projects are expected to be in the year 2016-17 considering the current status of the projects and time required for project development. These two projects are not considered as alternatives to be compared; rather they are complementary and are designed to relieve the medium-term shortages foreseen in Pakistan.

For the import from Iran, the study considered an import of up to 1,000 MW from a dedicated combined-cycle power plant close to Zahedan in Iran to be delivered to a new 220 kV substation in Quetta, Pakistan involving approximately 680 km of transmission (95 km in Iran and 585 km in Pakistan. The supply from the combined-cycle plant in Iran is essentially a dedicated supply to Pakistan and will be available year round. The import from Iran can be considered as a firm import operating at 88% capacity factor.

The supply from Tajikistan will be subject to the seasonal variations in hydro capability and will be restricted to the summer months. For planning purposes, it is assumed that the import from Tajikistan will be 1,000 MW maximum and 3,816 GWh per year, restricted to the summer months of April to September.

Wind Energy

The only renewable energy source included in the current expansion plan is wind (with a very small amount of bagasse) in addition to hydroelectric options. Wind energy is now being recognized as a potential new power option in the country. In Pakistan, studies have been under way for a number of years. One of the wind resource studies carried out by National Renewable Energy Laboratories (NREL) of USA under the USAID assistance program in 2007 has developed a meso scale map of Pakistan showing the wind speed potential available at 50m height. According to this study, Pakistan has a potential of more 300,000 MW of wind energy in the entire country.

The Government of Pakistan has introduced a Policy for Development of Renewable Energy for Power Generation 2006 to provide guidelines for the development of the wind energy sector. There are more than forty eight (48) national and international private investors currently possessing Letters of Intent (LOI) for wind power projects issued by the Alternative Energy Development Board (AEDB). AEDB has so far allocated land to more than eighteen (18) IPPs for wind power generation projects of 50 MW each. Twelve (12) 50 MW wind power projects (IPPs) have completed feasibility studies. Eight IPPs have obtained generation license from NEPRA. NEPRA has announced tariff determinations for four IPPs:

- Green Power
- Dawood Power Ltd.
- Zorlu Enerji Pakistan
- Arabian Sea

Tariff petitions of one IPP Fauji Fertilizer Company Ltd., is under the process for approval by NEPRA.

In the NPSEP, Zorlu Enerji (50 MW) and Fauji Fertilizer Co. (50 MW) are recognized as committed plants. Future wind power projects have also been proposed on the PEPCO projects list. The capital cost of wind power projects varies from US$ 2,500 - 3,000 per kW. In this study, the capital cost of wind power projects was assumed to be US$3,000 per kW with a maintenance cost of 2% of capital cost per year. The corresponding generation cost of wind power was estimated to be US$ 0.15 per kWh.

Other Renewable Energy Resources

- Biomass

  Biomass electrical energy will normally result as a by-product from other industrial operations, so its cost will be affected by the economics of the overall operation. Typically the total generation costs of biomass generation plants range from US$ 0.10 to 0.15 per kWh. This is expected to be above other viable electricity supply costs in Pakistan. Further investigation and studies should be carried out to examine the potential and generation cost of biomass resource.

  There are two committed projects, Jamal Din Wali R. Y. Khan in Punjub (80 MW) using bagass and KESC Bio Waste to Energy project (25 MW) which have been considered in the NPSEP.

- Solar

  Solar (photovoltaic) generation has not been considered in the NPSEP as it is considered expensive, particularly when setting up a system to provide 24 hour service in alternating current[18].

  However, its absence from the NPSEP does not imply that solar generation can be ignored. It should be considered for small off-grid uses where direct current applications are appropriate.

- Geothermal

  There is a geologic fault that runs through the Tarbela project and continues on to Iran. Along that fault 128 mud volcanoes have been identified, of which 20 are located in Pakistan. There appears to be a potential for the development of geothermal energy although no studies have been published on the potential of that resource. Geothermal is also not considered in the NPSEP.

[18] This was confirmed during a visit with the AEDB in December 2010

6.8 Generation Expansion Plans

6.8.1 Short-Term Plans

The short term emphasis is on reduction of load shedding, with minimum deviation from the long term strategy. For the short term, the NPSEP has assumed that:

- Demand side management programs should be aggressively pursued;
- All plants expected to retire in the next five years will undergo rehabilitation to extend their service lives by a further 10 years; and
- During the early years, the building of plants with less gestation periods should be encouraged.

New additions for the next five years are listed in Table 6-16. This short term generation expansion plan would be common to all alternatives being compared.

Table 6-16 Generation Additions for First Five Years

Year	Name of Project	Unit Additions			Annual Total (MW)
		Type	Number of Units	Net Unit Capacity (MW)	
2011-12	Nandipur Power project	CC	1	364	950
	CHASHNUPP-II, Punjab	Nuclear	1	320	
	Khan Khwar	Hydro	1	71	
	Jinnah	Hydro	1	95	
	Fauji and Zorlu	Wind	2	50	
2012-13	UAE G.T, F/Abad Punjab	GT	2	134	1,515
	Jamal Din Wali R.Y. Khan	Bagass	1	76	
	BQPS 560, KESC	CC	1	546	
	KESC Bio Waste to Energy	Bio Waste	1	23	
	Bin Qasim, KESC (2x210 MW oil to coal conversion)	Coal	2	176	
	Allai Khwar	Hydro	1	121	
	Duber Khwar	Hydro	1	130	
2013-14	Guddu-New	CC	2	329	824
	Kurram Tangi	Hydro	1	83	
	New Bong Escape, IPP	Hydro	1	83	
2014-15	Haveli	GT	12	153	2,241

Year	Name of Project	Unit Additions			Annual Total (MW)
		Type	Number of Units	Net Unit Capacity (MW)	
	Candidate wind PP	Wind	8	50	
2015-16	Haveli	GT	12	-153	4,110
	Haveli	CC	6	497	
	Sahiwal	CC	2	689	
	Neelum Jhelum	Hydro	4	240	
	Gul Pur, IPP	Hydro	1	99	
	Rajdhani, IPP	Hydro	1	131	
	Candidate wind PP	Wind	8	50	

Due to the current significant shortage of power and the long lead time of developing power plants, the power system of Pakistan is expecting a high LOLP level of 50% to 60%, equivalent to a loss of load expectation of 4,300 – 5,300 hours/years for the first 5 years until 2015-16.

6.8.2 Development of the Base Case

An unconstrained least cost plan would conceivably select all gas fired combined cycle plant additions. While this would provide a theoretical measure of the least cost option, such quantities of gas would not realistically be available, nor would it likely be desirable to have most generation based on a single source of fuel supply, and that also probably imported. It is therefore considered prudent to introduce some constraints that would place an upper limit on the different power generation options. These constraints are taken into consideration in the development of the Base Case.

The Base Case has been developed keeping in view the policy and strategic considerations described earlier in this report. The short term approach focuses on those measures that would help alleviate load shedding, i.e. rehabilitation of existing plants and construction of plants with shorter lead times. The long term analysis adheres to the least cost principle, allowing for policy guidelines and some real constraints.

For the Base Case, future capacity additions to the system will be selected on a least cost basis within the following guidelines:

- Peaking capacity additions will be gas turbines using natural gas with diesel as a backup fuel;

- Plants planned to be retired in the first five years of the analysis are assumed to undergo a rehabilitation program to extend their service lives by 10 years;
- It is assumed that increased quantities of imported or domestic gas would become available for the power sector. Specifically, it is assumed that about 1.5 BCFD of gas would be available starting 2015 which would be sufficient to provide 6,000 MW of electric capacity. This assumption is supported by (1) the detailed planning work done for three gas import pipeline proposals (from Iran, Turkemenistan and Qatar), (2) the attention being recently given to onshore and offshore LNG regasification plants, and (3) Pakistan is considered to be a gas prone country with a relatively high past drilling success rate. Given improved security conditions and attractive exploration incentives, there should be a good possibility of new discoveries, and (4) given the concern over both load shedding and the tariff levels, it is possible that the existing gas allocation criteria could at some point in time be revised in favour of more gas to the power sector . The earliest availability date of 2015 is supported by the understanding that for one of the options (pipeline gas from Iran), the pipeline to a point close to the border is almost complete;
- Based on a similar assessment done as part of the National Power Plan project in 1994, it is assumed that LSFO could be transported upcountry by upgrading the existing rail line on both sides of the Indus River. It is further assumed that this could permit the transportation of about 10 million tones of LSFO which would be sufficient to locate about 6,000 MW of steam plant at the headponds of existing barrages where a year round supply of cooling water would also be available. Given that the upgrading of the rail is beyond the control of the power sector, this option is considered to only be available beginning at the year 2018;
- PAEC / NTDC has provided information indicating a schedule for the addition of two 340 MW units at Chashma in 2017 and 2018. Beyond that, it is assumed that nuclear capacity additions would be of two 1000 MW plants in pairs, each plant one year apart, as per PAEC information. It is also assumed that the pairs would be installed 5 years apart to allow for site selection and development, and that the additions would be either at Karachi or at Chashma. The maximum nuclear plant additions assumed are:
    - 340 MW at Chashma 2016-17
    - 340 MW at Chashma 2017-18

  - 1000 MW at Chashma 2019-20
  - 1000 MW at Qadirabad 2020-21
  - 1000 MW at Karachi 2023-24
  - 1000 MW at Karachi 2024-25
  - 1000 MW at Karachi 2027-28
  - 1000 MW at Chashma 2028-29;

- There is presently little coal in Pakistan's power generation mix. Tharparkar coal offers the encouraging opportunity of introducing indigenous, large scale coal based generation into the power mix. Assessments of the viability of mining coal at Tharparkar were done by the John T Boyd Company of the United States in 1994, and Rheinbraun Engineering of Germany in 2004. Currently, studies are underway by Sindh Engro Coal Mining company, and a pilot project to generate a small amount of power based on UCG technology is nearing completion. It is likely that reliable cost estimates for mining or gasification of Tharparkar coal will become available in the near future. At the present time, however, there is insufficient data to determine mining costs with confidence;
- In terms of transmission requirements to evacuate power to energy deficient load centers, a Tharparkar coal fired plant would be similar to a coastal plant. The screening analysis suggests that a coal fired plant would be more economic as compared to an oil fired plant, with both plants located on the coast. It is therefore considered that a Tharparkar coal plant would need to be competitive with an imported coal based plant located at the coast. On this basis, the economic price of Tharparkar coal is estimated based on what it would need to be to produce power at the same cost as an imported coal fired coastal plant. This would then serve as a benchmark price, at or below which it would be economic to produce Thar coal. This benchmark price could also be used as a tool by policy makers to decide if and how much of a premium could be added to this benchmark price, to encourage use of this domestic resource;
- Given the abundant reserves of coal available at Thar, the large worldwide supply options for imported coal, and the policy drive to increase coal (especially indigenous coal) in the energy mix, it is assumed that 40,000 to 50,000 MW could eventually be generated using Tharparkar and / or imported coal. GoP may however not wish to have such large amounts of generation from a single fuel source, or at one

geographic location. This power source could become available starting 2016, which is determined by the 5 year lead time needed to build a coal fired plant;

- Pakistan has abundant hydroelectric resources and the policy objective is to increase the hydroelectric share of the power mix. There are 27 projects of various sizes studied to varying levels of detail that are available for consideration. The total capacity of these projects is about 42,000 MW. However, many of these projects have first to be studied to feasibility level prior to firming up their costs, environmental impacts and construction schedules. All 27 projects have been considered for inclusion in the NPSEP, with due time allowance for required supporting studies. As per GoP policy, the Kalabagh hydroelectric project has not been considered in the Base Case;
- In accordance with the January 2011 study by Parsons Brinkerhoff “Feasibility Study for Evacuation of Power from 26 Hydropower Projects in the North”, the capacity of Bunji has been reduced from 7100 MW to 5400 MW, that of Yulbo from 3000 MW to 2400 MW, of Tungas from 2200 MW to 2000 MW, and the capacity of Palas Valley has been reduced from 665 MW to 580 MW. These have been reduced due to power evacuation limitations; and
- Pakistan has an active Alternative Energy Development policy. A 6 MW wind power plant is in operation, another 50 MW wind plant has reached financial close and another 50 MW plant is nearing financial closure. For this study, it is assumed that renewable energy (wind, solar, mini-hydro, geothermal, biomass etc) will continue to be encouraged and will form 5 % of the total generating capacity by the year 2030.

The sequence of capacity additions under the Base Case represents the least cost additions within the above guidelines that meet the established reliability criteria.

Analysis of the Base Case

The screening analysis has demonstrated that, for off-peak load operation with capacity factor above 17%, the least cost options are combined cycle plants using gas, followed by nuclear plants and coal fired steam plants. LSFO fired steam plants are more expensive and have been screened out. Early additions under the Base Case are therefore CCGTs until the quantum of gas assumed to be available has been used up. In addition, as existing plants using natural gas are retired, it is assumed that the gas allocated to the retired plants will be available for new CCGTs.

The total net capacity addition throughout the study period is estimated to be 98,120 MW, consisting of 35.7% of hydro power, 38.1% of steam turbines using Thar coal, 10.3% of CCGT, 6.7% of nuclear, 2% of interconnections, and the rest for gas turbines and renewable energy sources. The wind power only contributes to the energy production and the capacity from wind power has not been considered for system reliability determination.

In developing the least cost generation plan for the Base Case, the hydro projects were added to the system first in economic order. The plant with the shortest lead time is the GT. In 2014, 12 GTs of 155 MWs each were added to the system. These were then converted in 2015 into 6 CCGT units of 510 MW each by adding one steam turbine for each two GT units. In the initial years, the system requires base and medium load additions instead of peak load units. Two more CCGT-707 units were also added to the system in 2015.

Starting from 2016-17, as the quantum of gas assumed to be available is used up, the system calls upon the next least cost option, 600 MW steam plants using Thar coal to close the demand supply gap. The annual capacity additions range from 5,000 MW to 6,000 MW including STs, hydro projects and nuclear units in the period 2015-16 to 2019-20. In the event that development at Tharparkar is delayed, the Thar plant planned for 2016 should be replaced by a plant of the same capacity using imported coal located at the coast. This call should be made in early 2012.

From 2020-21, the system is expected to reach the targeted LOLP level. Six CCGT units are planned to replace the retired CCGTs and STs in order to take advantage of the already allocated gas supply and other existing infrastructure for the retired plants.

Six GT units are planned in the late years of the study period to meet the peak load demand.

The derived least cost generation expansion plan under the Base Case is summarized in Table 6-17.

Table 6-17 Capacity Additions under Base Case

Year	Load	Net Capacity Additions								
		Units								Subtotal
	(MW)	GT	CCGT	ST400	ST600*	Nuclear	Hydro	Wind	Interc.	(MW)
2011-12	22,567		364			320	166	100		950
2012-13	24,295	267	546	452**			249			1,513
2013-14	26,225		658				165			823
2014-15	28,423	1,841					0	400		2,241
2015-16	31,018	*-1,841*	4,363				1,189	400		4,110
2016-17	33,750				2,835	320	370	500	2,000	6,025
2017-18	36,728				2,268	320	2,136	300		5,024
2018-19	40,149				3,969		1,236	100		5,305
2019-20	43,867				3,969	940	1,435			6,344
2020-21	47,879				2,268	940	4,089			7,297
2021-22	52,147		1,379		567		3,061	400		5,407
2022-23	56,665						5,316	400		5,716
2023-24	61,424				2,268	940	4,768	400		8,376
2024-25	66,418					940	5,544	400		6,884
2025-26	71,610	307			3,402		911	400		5,020
2026-27	77,015		1,379				4,356	400		6,135
2027-28	82,586				5,670	940	0	400		7,010
2028-29	88,324	307			4,536	940	0	400		6,183
2029-30	94,231	307	1,379		5,670		0	400		7,756
	Total	1,188	10,067	452	37,422	6,600	34,991	5,400	2,000	98,120

Note: * Steam turbines using Thar coal.

** Including 76 MW Jamal Din Wali R. Y. Kham, Punjab (Bagass) and 24 MW Bio Waste plant and 352 MW converted from oil to coal in KESC sysem.

The change over time in the capacity mix of the system is shown on Table 6-18.

Table 6-18 Generating Capacity Mix (%) – Base Case

	2010-11	2019-20	2029-30
Hydro	31	26	37
Thermal			
• Gas	31	23	11
• Oil	37	14	6
• Coal	0.1	26	34
Nuclear	2	5	6
Wind	0	3	5
Imports	0	4	2

The new projects planned to be added to the system for the Base Case generation plan are presented in Table 6-19 and in Figure 6-5.

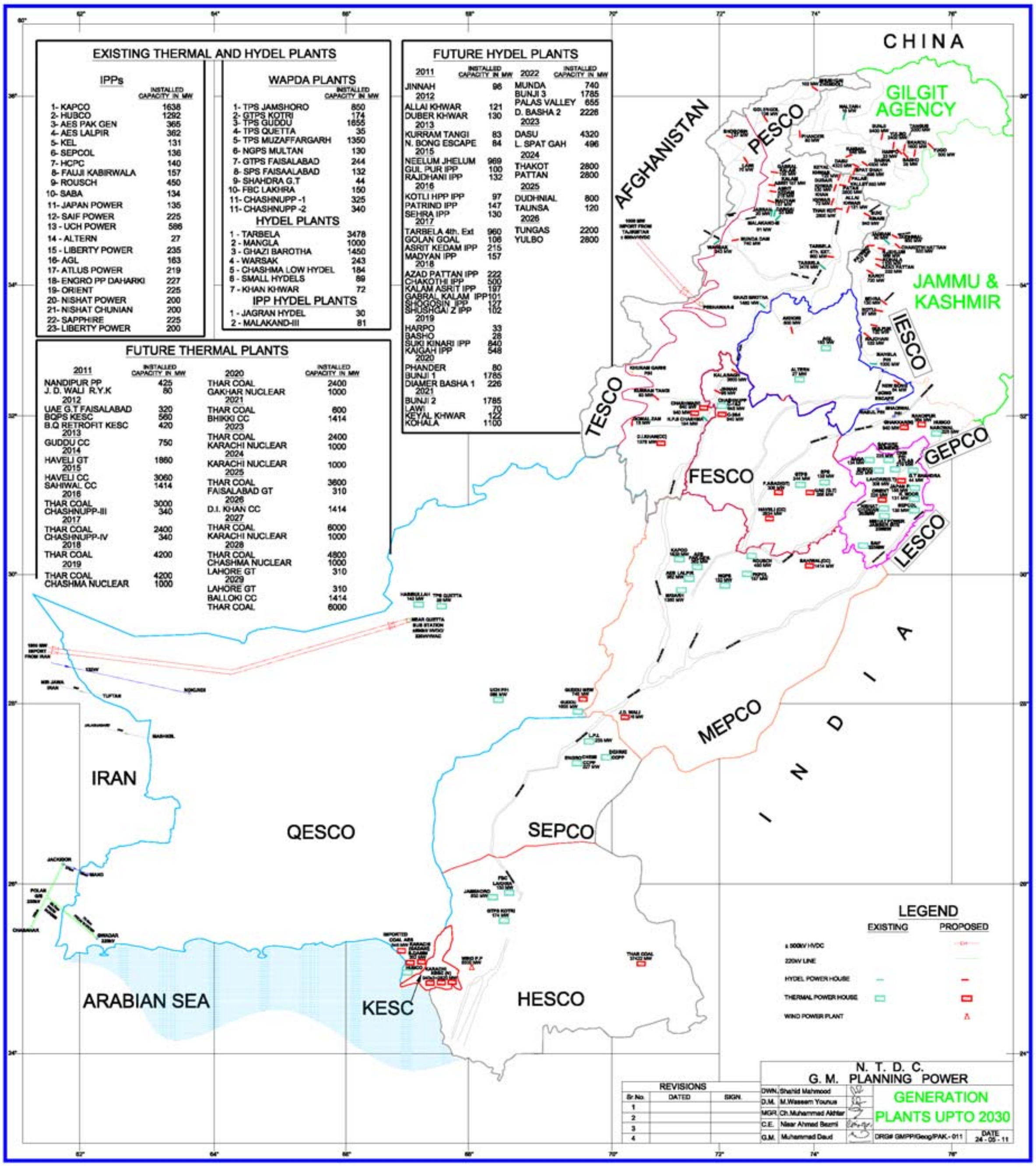
Table 6-19 List of Future Projects under Base Case

Year	Name of Project	Unit Additions			Annual Total (MW)
		Type	Number of units	Net Unit Capacity (MW)	
2016-17	Thar #1 or Imported coal plant	Coal	5	567	6,025
	CHASHNUPP-III, Punjab	Nuclear	1	320	
	Kotli HPP, IPP	Hydro	1	96	
	Patrind HPP, IPP	Hydro	1	146	
	Sehra HPP, IPP	Hydro	1	129	
	Candidate wind PP	Wind	10	50	
	Iran - Pakistan and CASA	I/C	2	1,000	
2017-18	Thar # 2	Coal	4	567	5,024
	CHASHNUPP-IV, Punjab	Nuclear	1	320	
	Tarbela 4th Ext.	Hydro	2	475	
	Golen Gol	Hydro	3	35	
	Karot HPP, IPP	Hydro	1	713	
	Asrit-Kedam HPP, IPP	Hydro	1	213	
	Madian HPP, IPP	Hydro	1	155	
	Candidate wind PP	Wind	6	50	
2018-19	Thar # 3	Coal	7	567	5,306

Year	Name of Project	Unit Additions			Annual Total (MW)
		Type	Number of units	Net Unit Capacity (MW)	
	Azad Pattan HPP, IPP	Hydro	1	220	
	Chakothi HPP, IPP	Hydro	1	495	
	Kalam - Asrit HPP, IPP	Hydro	1	195	
	Gabral Kalam HPP, IPP	Hydro	1	100	
	Shogosin HPP, IPP	Hydro	1	126	
	Shushgai Zhendoli HPP, IPP	Hydro	1	101	
	Candidate wind PP	Wind	2	50	
2019-20	Thar # 4	Coal	7	567	6,345
	Chashma	Nuclear	1	940	
	Harpo	Hydro	1	33	
	Basho	Hydro	1	28	
	Suki Kinari HPP, IPP	Hydro	4	208	
	Kaigah HPP, IPP	Hydro	1	543	
2020-21	Thar # 5	Coal	4	567	7,297
	Qadirabad	Nuclear	1	940	
	Phander	Hydro	4	20	
	Bunji 1	Hydro	7	255	
	Diamer Basha 1	Hydro	6	371	
2021-22	Bhikki	CC	2	689	5,406
	Thar # 6	Coal	1	567	
	Bunji 2	Hydro	7	255	
	Lawi	Hydro	3	23	
	Keyal Khwar	Hydro	2	61	
	Kohala	Hydro	4	272	
	Candidate wind PP	Wind	8	50	
2022-23	Munda	Hydro	1	733	5,717
	Bunji 3	Hydro	7	255	
	Palas Valley	Hydro	3	191	
	Diamer Basha 2	Hydro	6	371	
	Candidate wind PP	Wind	8	50	
2023-24	Thar # 7	Coal	4	567	8,376
	Karachi	Nuclear	1	940	
	Dasu	Hydro	8	535	

Year	Name of Project	Unit Additions			Annual Total (MW)
		Type	Number of units	Net Unit Capacity (MW)	
	Lower Spat Gah	Hydro	3	164	
	Candidate Wind PP	Wind	8	50	
2024-25	Karachi	Nuclear	1	940	6,884
	Thakot	Hydro	8	347	
	Pattan	Hydro	8	347	
	Candidate Wind PP	Wind	8	50	
2025-26	Faisalabad	GT	2	153	5,018
	Thar # 8	Coal	6	567	
	Dudhnial	Hydro	1	792	
	Taunsa	Hydro	1	119	
	Candidate Wind PP	Wind	8	50	
2026-27	D.I.Khan	CC	2	689	6,135
	Tungas	Hydro	10	198	
	Yulbo	Hydro	10	238	
	Candidate Wind PP	Wind	8	50	
2027-28	Thar # 9	Coal	10	567	7,010
	Karachi	Nuclear	1	940	
	Candidate Wind PP	Wind	8	50	
2028-29	Lahore	GT	2	153	6,181
	Thar Thar # 10	Coal	8	567	
	Chashma	Nuclear	1	940	
	Candidate Wind PP	Wind	8	50	
2029-30	Lahore	GT	2	153	7,756
	Balloki	CC	2	689	
	Thar # 11	Coal	10	567	
	Candidate Wind PP	Wind	8	50	

Figure 6-5 Base Case Generation Additions



The Base Case generation additions will cost the country over $ 500 billion in 2010 constant US Dollars over the planning horizon – an average of about $ 25 billion a year. The present worth of the total costs are about $ 289 billion. To put these figues in context, Pakistan's current GDP is about $ 170 billion.

The Base Case will require over the study period 9.2 million MMcf of natural gas, 79 million tonnes of furnace oil and 1,621 million tonnes of coal. The power sector will need to coordinate on an ongoing basis with the fuel and infrastructure providers to ensure that sufficient fuel supplies and infrastructure will be available to implement the power sector expansion plan.

The annual consumption of different fuels (natural gas, coal, fuel oil, nuclear fuel) for the base case expansion plan is provided in **Error! Reference source not found.** 6-20.

Table 6-20 Fuel Consumption for Base Case Expansion Plan

	NG	NG	FO	Thar Coal	Dies	U_3O_8
	$1,000m^3$	MMcf	Ton	Ton	Ton	Ton
2011-12	15,404,411	543,930	7,974,978	248,587	45,078	91
2012-13	16,595,538	585,988	7,688,603	2,454,665	50,566	95
2013-14	17,783,992	627,953	7,664,332	2,448,049	52,938	96
2014-15	21,361,273	754,266	7,564,436	2,450,532	53,421	95
2015-16	23,509,702	830,127	6,782,769	2,453,015	45,582	96
2016-17	21,636,446	763,983	5,099,654	20,419,537	16,457	142
2017-18	20,372,339	719,347	4,442,321	34,801,168	11,647	199
2018-19	17,879,606	631,329	3,585,418	59,892,939	7,094	199
2019-20	14,186,884	500,939	2,754,720	84,891,604	5,925	363
2020-21	10,891,397	384,575	2,454,724	99,122,839	3,012	517
2021-22	12,064,188	425,986	2,511,867	104,216,818	0	501
2022-23	12,796,491	451,844	2,591,828	104,336,019	0	502
2023-24	9,211,707	325,265	2,451,650	119,057,657	0	660
2024-25	8,375,353	295,734	2,521,771	116,692,302	0	818
2025-26	8,117,377	286,624	2,533,087	137,757,908	0	818
2026-27	9,861,369	348,205	2,658,442	137,053,266	0	818
2027-28	7,804,330	275,571	2,568,353	168,772,386	0	976
2028-29	7,117,507	251,319	2,535,943	195,315,789	0	1,134
2029-30	6,481,985	228,879	2,406,396	228,213,644	0	1,134
Total	**261,451,897**	**9,231,863**	**78,791,292**	**1,620,598,723**	**291,719**	**9,253**

6.8.3 Alternative Development Scenarios

Two alternative development scenarios have also been analysed as part of the NPSEP. One scenario presents the results of the sequence of additions proposed in the PEPCO / NTDC List of Additions, and the other scenario assumes the absence of any policy or strategic constraints. These scenarios include the short term assumptions of the Base Case, and are described below.

PEPCO List of Additions Case

PEPCO, in consultation with other agencies involved in the power generation sector, has prepared a sequence of plant additions. This list has been prepared in consultation with WAPDA, GENCOs, KESC, PPIB and PAEC. This scenario is entirely based on this PEPCO list of addition without any modifications to their provided commissioning dates.

Listed in Table 6-21 are the capacity additions as per the future project list provided by NTDC.

Table 6-21 Capacity Additions under the PEPCO List of Additions Case

Year	Load	Net Capacity Additions								
		Units								Subtotal
	(MW)	GT	CCGT	ST400	ST600*	Nuclear	Hydro	Wind	Interc.	(MW)
2011-12	22,567		364	94		320	166	100		1,044
2012-13	24,295	267	828	452**			332	200		2,078
2013-14	26,225		1,792				181	200		2,173
2014-15	28,423		1422		1,328		477	250		3,476
2015-16	31,018		2,107	95	4,867		3,247	150		10,465
2016-17	33,750					320	4,209	50	2,000	6,578
2017-18	36,728				2,268	320	545			3,132
2018-19	40,149					940	2,228			3,168
2019-20	43,867					940	2,343			3,283
2020-21	47,879						2,719			2,719
2021-22	52,147						3,003	200		3,203
2022-23	56,665					940	2,343	200		3,483
2023-24	61,424						594	200		794
2024-25	66,418						5,544	200		5,744
2025-26	71,610				2,268	1880	792	200		5,140
2026-27	77,015				5,670		4,277	200		10,147
2027-28	82,586				1,134	940	2,970	200		5,244
2028-29	88,324				5,103	940	0	200		6,243
2029-30	94,231				1,701		4,326	200		6,227
		267	6,512	640	24,339	7,539	40,295	2,750	2,000	84,341

Note: * Steam turbines using Thar coal, except for 2,268 MW using imported coal in 2015-16 .

** Including 76 MW Jamal Din Wali R. Y. Kham, Punjab (Bagass) and 24 MW Bio Waste plant and 352 MW converted from oil to coal in KESC sysem.

The total capacity added in this Case is 84,340 MW including 47.8% hydro, 28.8% of STs using Thar and imported coal, 8.9% nuclear, 7.7% of CCGTs with the rest consisting of wind, interconnection etc. The simulation results and analysis show that the current deficit in installed capacity will be eliminated by 2016-17 and will provide acceptable generation reliability levels up to 2019-20. After that time, the reliability levels would fall short without adequate new capacity.

The detailed generation expansion plan including the retirement plan for this Scenario is provided in Annexure 2.

Unconstrained Scenario

A scenario was considered in which no constraints or policy guidelines were applied. It was assumed that unlimited quantities of gas and other fuels would be available, infrastructure would be developed as required, Kalabagh (2,776 MW) and Doyian (490 MW) hydroelectric projects would be included if economic and Renewable Energy would only be pursued if economic. The capacity limitations imposed in the Base Case on Bunji, Yulbo, Tungas and Palas Valley hydropower projects were withdrawn for this case.

Details on the capacity additions of the unconstrained least cost generation plan are listed in Table 6-22.

The total capacity additions throughout the study period are around 92,100 MW consisting of 44.3% of hydro power, 50.6% of CCGT, 1.3% of GT and 1% of nuclear and 2% of interconnections. The detailed generation expansion plan, the retirement plan and the breakdown of total costs for the Unconstrained Scenario are provided in Annexure 2.

Table 6-22 Capacity Additions under Unconstrained Case

Year	Load	Net Capacity Additions								
		Units								Subtotal
	(MW)	GT	CCGT	ST400	ST600*	Nuclear	Hydro	Wind	Interc.	(MW)
2011-12	22,567		364			320	166	100		950
2012-13	24,295	267	546	452**			249			1,513
2013-14	26,225		658				165			823
2014-15	28,423	1,841								1,841
2015-16	31,018	*-1,841*	4,363				1,189			3,711
2016-17	33,750		2,757			320	370		2,000	5,448
2017-18	36,728		2,068			320	2,136			4,524
2018-19	40,149		3,447				1,237			4,683
2019-20	43,867		5,515				1,435			6,949
2020-21	47,879		2,757				4,650			7,407
2021-22	52,147	614					4,108			4,721
2022-23	56,665						5,963			5,963
2023-24	61,424		689				7,516			8,205
2024-25	66,418		689				5,544			6,233
2025-26	71,610		3,447				911			4,357
2026-27	77,015		689				5,148			5,837
2027-28	82,586		6,893							6,893
2028-29	88,324	307	4,825							5,132
2029-30	94,231		6,893							6,893
		1,188	46,601	452		960	40,786	100	2,000	92,086

Note: * Steam turbines using Thar coal.

** Including 76 MW Jamal Din Wali R. Y. Kham, Punjab (Bagass) and 24 MW Bio Waste plant and 352 MW converted from oil to coal in KESC sysem.

6.9 Summary of Reliability Levels and System Expansion Costs

The capacity mix and fuel requirements of the Base and Alternative Cases are given in Table 6-23 and Table 6-24.

Table 6-23 Capacity Additions over 2011-12 to 2029-30

	Base Case	Unconstrained Case	PEPCO Additions Case
Total Capacity added in MW	98,120	92,086	84,341
% Capacity Added			
• Hydro	35.7	44.3	47.8
• Gas (GTs and CCGTs)	11.5	51.9	8.0
• Coal (STs)	38.6	0.5	29.6
• Nuclear	6.7	1.0	3.3
• Wind	5.5	0.1	3.3
• Imports	2.0	2.2	2.4

Table 6-24 Fuel Consumption 2011-12 to 2029-30

	Base Case	Unconstrained Case	PEPCO Additions Case
Natural Gas (million MMcf)	9	22	108
Furnace Oil (Million tonnes)	79	83	110
Coal (Million tonnes)	1,621	43	1,118
Diesel (Thousand tonnes)	292	297	198
Nuclear Fuel (Thousand tonnes)	9	3	10

<u>Reliability Levels Achieved</u>

The Base Case and the Unconstrained Case have been developed to meet the target reliability levels and are therefore comparable. In both Cases, the target reliability level of 1 % LOLP is reached by the year 2020-21. For the PEPCO Additions Case, capacity additions have been taken as given. The capacity additions under the PEPCO Additions Case are not adequate to meet the reliability criterion for most of the years throughout the study period. However, during the period 2016 to 2019, the system is found to have excess generating capacity.

The LOLP and effective capacity reserve margin of each year for the Base Case, the PEPCO Additions List Scenario and the Unconstrained Scenario are presented in Table 6-25.

Table 6-25 Reliability Levels

Year	Peak Load	PEPCO Preliminary Projects			Unconstrained Scenario			Base Case		
		Effective Capacity	Reserve Margin	LOLP (hours)	Effective Capacity	Reserve Margin	LOLP (hours)	Effective Capacity	Reserve Margin	LOLP (hours)
2011-12	22,567	21,278	-5.7%	4,174	21,008	-7%	4,333	21,008	-7%	4,333
2012-13	24,295	21,203	-6.0%	4,140	20,933	-7%	4,374	20,933	-7%	4,321
2013-14	26,225	22,377	-7.9%	4,593	22,093	-9%	4,597	22,093	-9%	4,517
2014-15	28,423	24,570	-6.3%	3,840	22,785	-13%	5,249	22,785	-13%	5,249
2015-16	31,018	27,796	-2.2%	3,960	24,626	-13%	5,149	24,626	-13%	5,149
2016-17	33,750	37,540	21.0%	656	27,846	-10%	4,360	27,846	-10%	4,357
2017-18	36,728	44,068	30.6%	0.4	33,368	-1%	2,046	33,371	-1%	2,156
2018-19	40,149	47,200	28.5%	2.4	37,892	3%	1,238	38,095	4%	1,269
2019-20	43,867	50,368	25.5%	5.4	42,576	6%	842	43,300	8%	754
2020-21	47,879	52,977	20.8%	16.9	48,851	11%	269	48,970	12%	401
2021-22	52,147	54,911	14.7%	227	55,473	16%	35	55,482	16%	85
2022-23	56,665	57,094	9.5%	971	59,375	14%	75	59,669	14%	81
2023-24	61,424	60,378	6.6%	1,396	65,338	15%	40	64,985	15%	56
2024-25	66,418	60,542	-1.4%	2,057	73,114	19%	38	72,532	18%	48
2025-26	71,610	65,250	-1.8%	3,484	78,511	18%	29	78,180	18%	28
2026-27	77,015	70,162	-2.0%	2,511	82,840	16%	51	82,771	16%	56
2027-28	82,586	79,864	3.7%	1,590	88,433	15%	70	88,261	15%	53
2028-29	88,324	83,876	1.6%	1,843	94,295	14%	53	93,839	14%	66
2029-30	94,231	89,806	1.7%	2,661	99,314	12%	76	99,509	13%	83

Comparative System Expansion Costs

The total development costs including investment costs, fixed and variable O&M costs, and fuel costs for the study period have been estimated for the Base Case and the Unconstrained Case. The PEPCO Additions Case is not comparable to the other two Cases since it doesn't meet the same reliability criteria.

The present worth of total development costs under the Base Case is US$ 289,039 million, or 8%, higher than the costs of US$ 267,656 million under the Unconstrained Case. The difference in cost of $21.4 billion is the value of providing the additional gas and hydro to the country. The GoP could spend up to $21.4 billion on finding more gas and developing some additional hydro projects.

6.10 Sensitivity Tests

The NPSEP Base Case has been developed based on the foregoing criteria and assumptions. To test the robustness of the Base Case, the impact of variations in key input parameters was assessed. The following sensitivity tests were carried out:

- Discount rates: 8%,10%(Base Case), and 12%;
- Fuel cost: -10% and +10% of Base Case values;
- Capital cost: -10% and +10% of Base Case values; and
- High and low load forecast scenarios.

These sensitivity analyses are summarized below.

Discount Rate

Items	Discount Rates (%)		
	8%	10%	12%
Present worth of total costs (US$ million)	357,308	289,039	241,264
Percentage change from the Base Case (%)	+24%	100%	-17%

Fuel cost

Items	% Increase(+)/Decrease(-) in Fuel Cost		
	-10%	Base Case	+10%
Present worth of total costs (US$ million)	271,405	289,039	306,896
Percentage change from the Base Case (%)	-6%	100%	+6%

Capital cost

Items	% Increase(+)/Decrease(-) in Capital Cost		
	-10%	Base Case	10%
Present worth of total costs (US$ million)	280,640	289,039	298,490
Percentage change from the Base Case (%)	-3%	100%	+3%

Changes in the discount rate, fuel cost and capital cost do not change the sequence and timing of capacity additions in the Base Case.

High and Low Load Forecast Scenario

Sensitivity studies were carried out to examine the impacts of high and low load forecast on the Base Case least cost generation plan. Among the candidate projects, additions of nuclear projects and renewable energy sources are governed by energy policies and / or strategic constraints, thus their sequence of additions remains the same as in the Base Case. The hydro, gas-fired GTs and CCGTs, and coal-fired steam turbines are the flexible additions which are affected by the increase or decrease in the power demand.

The generation plan under the high load forecast scenario is presented in Table 6-24.

Table 6-26 Generation Plan under High Load Forecast Scenario

Year	Load (MW)	Net Capacity Additions: Units – GT	CCGT	ST400	ST600*	Nuclear	Hydro	Wind	Interc.	Subtotal (MW)	Effective Capacity (MW)	Eff. Cap. Reserve Margin	LOLP (hrs/yr)
2011-12	23,355		364			320	166	100		950	21,054	-10%	5,066
2012-13	25,578	267	546	452**			249			1,513	22,116	-14%	5,549
2013-14	28,018		658				165			823	22,895	-18%	6,567
2014-15	30,665	1,841					0	400		2,241	24,920	-19%	6,700
2015-16	33,702	*-1,841*	4,363				1,189	400		4,110	28,306	-16%	6,035
2016-17	36,889				3,969	320	370	500	2,000	7,159	35,194	-5%	3,355
2017-18	40,354				3,969	320	2,136	300		6,725	41,757	3%	1,613
2018-19	44,314				5,103		1,236	100		6,439	48,143	9%	827
2019-20	48,665				5,103	940	1,435			7,478	54,946	13%	376
2020-21	53,435				3,402	940	4,089			8,431	62,592	17%	69
2021-22	58,589		1,379		1,701		3,061	400		6,541	68,097	16%	58
2022-23	64,124						5,316	400		5,716	73,597	15%	88
2023-24	70,054				3,402	940	4,768	400		9,510	82,462	18%	77
2024-25	76,355				1,134	940	5,544	400		8,018	89,427	17%	55
2025-26	83,021	307			5,670		911	400		7,288	96,470	16%	66
2026-27	90,053		1,379		1,134		4,356	400		7,269	103,278	15%	86
2027-28	97,428				7,938	940	0	400		9,278	111,308	14%	86
2028-29	105,132	307			7,371	940	0	400		9,018	119,997	14%	75
2029-30	113,154	307	1,379		7,938		0	400		10,024	128,794	14%	70
	Total	1,188	10,067	452	57,834	6,600	34,991	5,400	2,000	118,532			

Note: * Steam turbines using Thar coal

** Including 76 MW Jamal Din Wali R. Y. Kham, Punjab (Bagass) and 24 MW Bio Waste plant and 352 MW converted from oil to coal in KESC sysem.

The total net capacity addition throughout the study period is estimated to be 118,532 MW consisting of 29.5% of hydro power, 48.8% of steam turbines using Thar coal, 8.5% of CCGT, 5.6% of nuclear and the rest for gas turbines and wind energy sources as well as 1.7% of interconnections. The total net capacity additions would increase by 21% of the additions under the Base Case. The present worth of total costs has increased by 22% and reached US$ 351,455 million throughout the planning period.

The generation plan under the low load forecast scenario is presented in Table 6-25.

Table 6-27 Generation Plan under Low Load Forecast Scenario

Year	Load	Net Capacity Additions									Effective	Eff. Cap.	LOLP
		Units								Subtotal	Capacity	Reserve	
	(MW)	GT	CCGT	ST400	ST600*	Nuclear	Hydro	Wind	Inter-C	(MW)	(MW)	Margin	(hrs/yr)
2011	22,454		364			320	166	100		950	21,054	-6%	4,216
2012	23,910	267	546	452**			249			1,513	22,116	-8%	4,263
2013	25,371		658				165			823	22,895	-10%	4,634
2014	26,928	614					0	400		1,014	24,920	-7%	5,195
2015	28,711	*-614*	2,373				1,189	400		3,348	28,306	-1%	4,495
2016	30,567		2,068			320	370	500	2,000	5,258	31,792	4%	1,987
2017	32,582				1,134	320	2,136	300		3,890	34,953	7%	1,195
2018	34,905				2,835		1,236	100		4,171	39,071	12%	668
2019	37,432				2,268	940	1,435			4,643	43,039	15%	425
2020	40,174				1,134	940	4,089			6,163	48,417	21%	61
2021	43,091		689				3,061	400		4,150	52,221	21%	52
2022	46,176						4,009	400		4,409	57,721	25%	37
2023	49,435						6,075	400		6,475	62,244	26%	41
2024	52,848						5,544	400		5,944	67,135	27%	14
2025	56,406	307	689				911	400		2,307	68,508	21%	58
2026	60,114		689				4,356	400		5,445	74,182	23%	30
2027	63,953		689		2,268	940	0	400		4,297	76,542	20%	58
2028	67,918	307			2,835	940	0	400		4,482	80,695	19%	63
2029	72,006	307	1,379		3,969		0	400		6,055	85,523	19%	48
	Total	1,188	10,144	452	16,443	4,720	34,991	5,400	2,000	75,338			

Note: * Steam turbines using Thar coal

** Including 76 MW Jamal Din Wali R. Y. Kham, Punjab (Bagass) and 24 MW Bio Waste plant and 352 MW converted from oil to coal in KESC sysem.

The total net capacity additions throughout the study period is estimated to be 75,338 MW consisting of 46.4% of hydro power, 21.8% of steam turbines using Thar coal, 13.5% of CCGT, 6.3% of nuclear and the rest for gas turbines and renewable energy sources as well as 2.7% of interconnections. The total net capacity additions decreased by 25% of the additions under the Base Case. Some of the GT units and CCGT units in 2014-15 and 2015-16 were postponed by one year. The decreases, totalling 22,782 MW, are from the removal of 2 nuclear units and deduction of ST-600 additions using Thar coal. The present worth of total costs decreased by 21% and reached US$ 227,129 million throughout the planning period.

6.11 Summary, Conclusions and Recommendations

The Base Case has been tested under a range of scenarios, varying key parameters. The Base Case is fairly robust and the sequence and timing of capacity additions does not change. The changing of the discount rate by 10% has significant impact on the present worth of the total project costs. The changing of fuel cost and capital cost by 10% has insignificant impact on the present worth of the total project costs.

A comparison of the Base Case with the Unconstrained Case confirms the attractiveness of gas – fired generation and hydro power. The difference in the net present value of the Base Case and the Unconstrained Case is $ 21 billion – this is a measure of the value to Pakistan of providing additional gas to the power sector, and of developing some additional hydroelectric projects.

Conclusions

The following are the main conclusions of the study:

- The short term goal is the reduction of load shedding. But care should be taken to ensure that continued fire fighting does not deter from following a long term optimum power development path.
- Indigenous gas, hydroelectric power and Tharparkar coal are the preferred power generation options, from an economic point of view. They are the least cost options, in line with GoP policy and provide fuel diversity and security. Moreover, nuclear power option has been included in the NPSEP to have diversity in generation technologies.
- Tharparkar coal offers the exciting prospect of large scale power generation using an indigenous resource. Contrary to the global trend, there is negligible coal in Pakistan's power mix. Tharparkar will reverse that trend. The first plant may be difficult but will pave the way for future development.

Pakistan is a gas prone country as demonstrated by its drilling success ratio history. The NPSEP has demonstrated the attractiveness of gas for power. Gas fired generation offers the only opportunity of locating generation close to load centers, and is the only practical fuel for the high efficiency combined cycle plants. The first choice is indigenous gas. But if fuel for power is to be imported, preference should be given to gas over oil.

Pakistan has enviable hydroelectric resources, but large attractive multipurpose projects have not been developed. The multipurpose projects are economically attractive for power, let alone the critical requirement for irrigation purposes. It is becoming harder to fund storage projects due to lending agencies concerns with resettlement, thus continued inaction will assure that this resource is wasted.

Recommendations

Action will be required immediately if the least cost projects are to materialize. The following actions are needed immediately:

- Closely spaced drilling and testing at Thar is needed. This can be done with some international support. Bankable feasibility studies are needed. The GoP may consider allowing a higher tariff for initial development at Thar, as tariffs for additional plants will likely decline.
- Hydropower projects identified in the NPSEP that have not yet been studied to feasibility level should be studied to feasibility level. Feasibility studies that are more than three years old should be updated. And those projects that are part of the least cost plan and have been studied recently to feasibility level should be immediately implemented.
- The GoP should be approached and convinced of the attractiveness of gas for power generation. A coordinated plan should be devised to encourage exploration for new gas, and the GoP should be requested to revisit the gas allocation policy. Additionally, gas import pipelines should be implemented on a priority basis as should LNG imports. Every sector of the economy is negatively impacted by gas shortages.

7 TRANSMISSION PLANNING

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7 TRANSMISSION PLANNING

7.1 Introduction

The key objective of the transmission expansion plan is to ensure that the planned generation can be delivered to the load centres throughout the country:

The specific tasks undertaken were as follows:

- To identify technical and or economic requirements that might require the introduction of any new voltage levels and/or transmission types into the existing transmission network,
- To determine the reinforcements required in the transmission network to meet the growing demand of the load centres by developing new grid stations and their associated transmission lines at 500 kV and 220 kV levels interconnecting with the transmission lines emanating from the proposed power plants.
- To fulfil the reliability criteria of NTDC Grid Code approved by NEPRA in terms of acceptable voltage, frequency, loading of lines and transformers for normal (N-0) and contingency (N-1) conditions both under disturbed dynamic/transient conditions and steady state conditions.
- To determine the long-term impacts on fault levels throughout the transmission network and to examine mitigating measures to deal with excessive fault levels.
- To check the transient and dynamic stability of 500 kV HVAC or above, and HVDC systems catering for the bulk transmission of power from major power plants to the major load centres to verify the adequacy of network for normal and disturbed conditions.
- To estimate the economic cost of these reinforcements in a staged manner. Such costs were then added to the cost of the new generation required to provide the basic input data to the financial analysis and the examination of the impact on tariffs.

7.2 Planning and Performance Criteria

The transmission system expansion plans are required to satisfy the Grid Code of NTDC approved by NEPRA, the regulatory authority of electrical power in Pakistan. The following are the planning and performance criteria laid down in the Grid Code:

Steady State

Adequacy evaluation of planning studies for steady-state system performance was based on equipment loading, congestion management, fault levels and voltage regulation. Steady-state planning studies for steady state load flow studies were deemed acceptable if they did not result in any voltage violations or overloads based on predetermined loading limits for Normal (N-0) and Emergency (N-1) contingency conditions.

Dynamic/Transient Conditions

System stability should be maintained following the disturbances listed below:

- Permanent three-phase faults on any primary transmission line and associated components. It is assumed that a fault will be cleared by circuit breaker action in 5 cycles.
- Failure of a circuit breaker to clear a fault ("Stuck Breaker" condition) in 5 cycles, with back up clearing in 9 cycles after fault initiation

If the System is found to be unstable, then mitigation measures shall be identified and incorporated into the system improvement plans for future years.

Grid Frequency Variations

The Frequency of the NTDC Transmission System is nominally 50Hz and was maintained within the limits of 49.8 to 50.2 unless exceptional circumstances prevailed.

Grid Voltage Variations

Under (N-0) normal operating conditions, System Operating Voltages of the Total System were maintained within the bandwidth of +8% to –5% of Nominal System Voltage.

Under (N-1) contingency operating conditions, the voltage variation was in the range of +10% and –10% of Nominal System Voltage

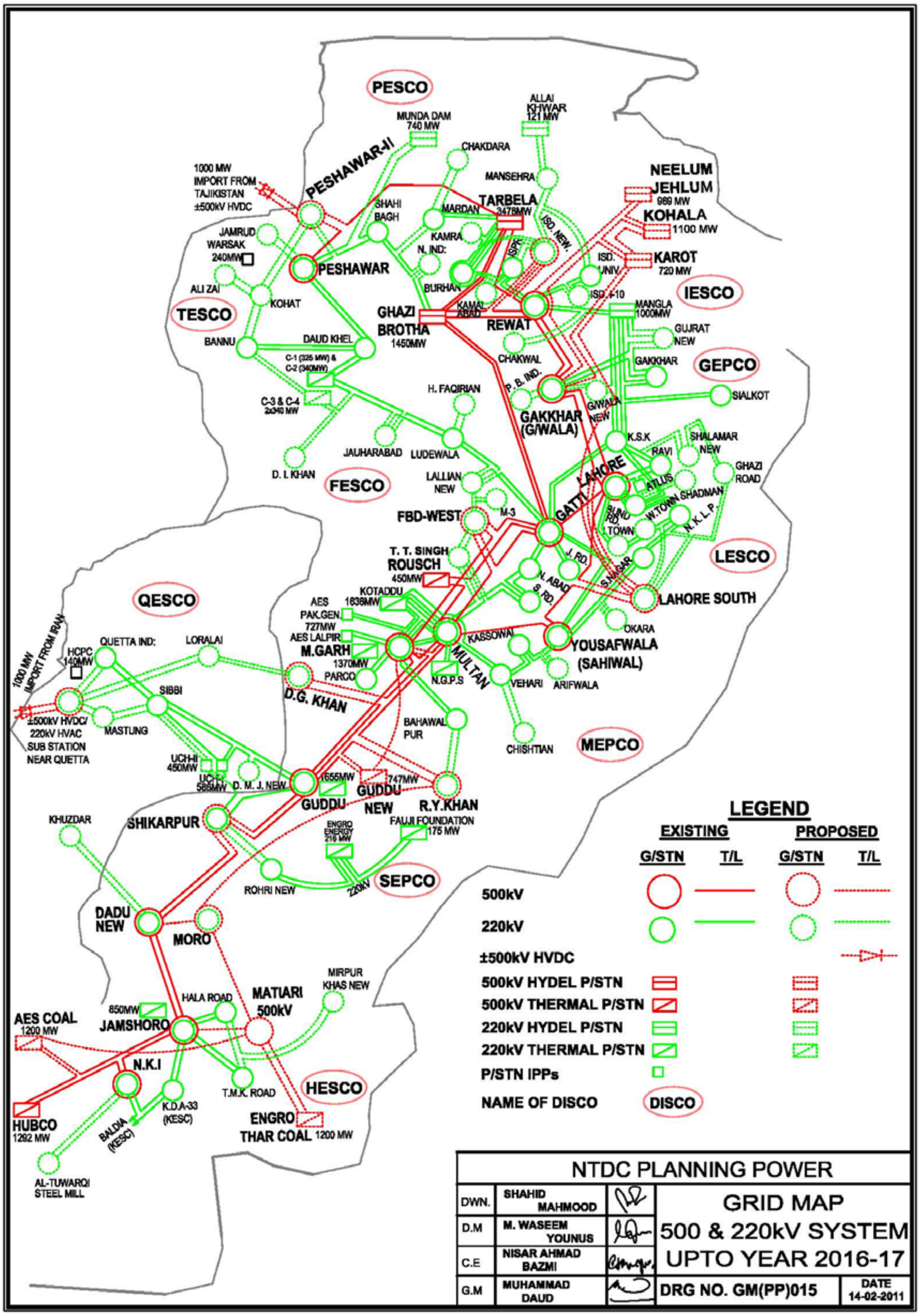
Short Circuit (Fault Levels)

Short circuit calculations were prepared for each study year, and adequacy of fault interrupting capability and short circuit withstand capacity were ensured.

7.3 Typical Characteristics of NTDC Longitudinal Network

Pakistan is geographically a longitudinal country i.e. more likes a vertical rectangle and the same is true for the primary network of NTDC. The 500 kV network runs from Peshawar in the North to HUBCO near Karachi in the South (see Figure 7-1)

Figure 7-1 Existing/Committed/Planned 500/220 kV System



The maximum load is concentrated in the middle of the country where local generation potential is limited because of lack of fossil fuel resources and meagre hydropower potential in the plains. Hydropower generation potential is located in the North and thermal power generation sources are mainly in the South. The least cost Generation Plan (Base Case) developed for this Expansion Plan Study also envisages maximum hydropower generation located up in the North whereas the major thermal power plants based on indigenous and imported fossil fuel are located in South. Therefore during high water months when hydro power is at the maximum the power flows from the North to South, whereas in low water months when the thermal power in the South is run at its maximum, the power flow is reversed to be from the South to North. Long HVAC (500 kV or above) and HVDC lines are required to pump power from far North and far South to mid country where the maximum load is concentrated.

With insignificant local generation in mid-country, the huge reactive power (MVAR) demand would not be advisable to be supplied from power plants in the far North and far South as excessive flow of VARs would cause severe voltage drop across long and heavily loaded lines, therefore sufficient VAR sources would be required to be installed in terms of shunt capacitor banks at distribution level and, if required, at transmission level as well. Other dynamic VAR compensation devices such as SVCs, SVS, and other FACTS devices might be required to be installed at appropriate locations in mid-country.

In high water season when power flows mainly from hydropower plants in the North, the HVAC circuits in the South would be lightly loaded because of low dispatch of thermal power from the South and *vice versa*. The lightly loaded HVAC lines generate excessive VARs due to their high charging current and would require sufficient amount of shunt reactors, line connected or bus connected depending on the requirement. Therefore very careful levels of compensations, inductive and capacitive, are to be studied and planned.

7.4 Approach and Methodology

7.4.1 Inputs

The following input data has been assumed for the study cases:

- Load Forecast, base case scenario, prepared by NTDC and validated by SNC- Lavalin.
- Base Case Generation Expansion Plan developed for the NPSEP.

- Transmission network data file in PSS/E format supplied by NTDC for the years 2010 and 2014.
- All the ongoing and committed or planned transmission expansion plans of NTDC envisaged up to the year ~~2017-18~~ 2016-17.
- Inputs from the other ongoing feasibility studies that have been incorporated are as follows:
    - o ± 500 kV HVDC Bipole for 1000 MW import of power from Iran (conducted by NESPAK and SNC Lavalin)
    - o ± 500 kV HVDC Bipole for 1300 MW import of power from CASA (conducted by NESPAK and SNC Lavalin)
    - o Transmission scheme based on 500 kV double circuits using quad bundled Martin conductor for the evacuation of power from 26 hydropower plants to be located on the Indus River and its tributaries in Northern Areas of Pakistan (being conducted by PB/PPI/MAES)
- Transmission scheme for evacuation of power from indigenous and imported coal based thermal power plants in the South (Thar and Karachi) connecting with the Southern Grid at 500 kV and at ± 600 kV HVDC from South to mid-country (being conducted by NESPAK and SNC Lavalin)

7.4.2 Development of Study Cases

The study cases considered are described below:

- The spot years for the study was identified in agreement with NTDC corresponding to different intervals in which major generation additions occur as per Base Case Generation Expansion Plan, which are 2016, 2020, 2025 and 2030 respectively.
- The Base Case of the year 2020 was developed as a reference to develop the other spot years' cases. The DISCO transmission expansion plan upto 132 kV level was developed till the year 2020 and used as the fundamental base case, superimposing the NTDC transmission infrastructure of 220 kV and 500 kV adequate to meet the DISCO transmission needs with proposed extensions, augmentations and construction of new 500/220 kV and 220/132 kV substations

- The Case for the year 2030 was developed to determine the ultimate scope of 220 kV and 500 kV transmission additions in the system to meet the projected forecast and the corresponding generation additions. The expansion of the DISCO transmission network up to 132 kV level was assumed frozen at the year 2020 and future projections of loads were assumed lumped at new 220/132 kV substations proposed to be constructed between 2020 and 2030.
- The cases for intermediate years of 2016 and 2025 were developed to determine the scope of transmission system expansion during the intermediate years.
- Standard tools of analysis for transmission expansion planning i.e. load flow, short circuit and transient stability analyses were employed using the software PSS/E of Siemens-PTI.
- Two cases each for high water (high hydro) and low water (high thermal) were studied for each spot year of study i.e. 2016, 2020, 2025 and 2030. Load flow simulations were carried out for normal (N-0) and contingency (N-1) conditions for each case to determine the adequacy of the proposed transmission facilities for each seasonal pattern of power flow
- Short circuit analysis was carried out for the calculation of maximum 3-phase and single-phase fault currents for the years 2020 and 2030 using IEC 909 as employed in PSS/E software.
- Transient stability analysis was carried out for the system of 500 kV for the years 2020 and 2030 employing the following standard worst case disturbance:
    - 3-phase fault at bus bar with fault clearing time of 5 cycles
    - Trip of the heavily loaded circuit emanating from the bus bar
    - Monitor post fault damping of transients of rotor angles and power swings with recovery of voltage and frequency of the system

7.5 Transmission Expansion upto 2016-17

The major generation additions, including the committed and planned additions, requiring additional transmission facilities by the year 2016-17 summarized in below:

Power Plants	Type	Installed Capacity, MW	Commissioning Year
Guddu New	CC	747	2013-14
Haveli Bahadur Shah	CC	3000	2015-16
Sahiwal	CC	1450	2015-16
Neelum-Jehlum	Hydro	969	2015-16
Thar/Imported Coal	Coal	3000	2016-17
CHASHNUPP-III & IV	Nuclear	680	2016-18
Import from Iran and CASA	Import	2000	2016-17
Wind Power (Gharo/Jhimpir)	Wind	1400	2012-17

To meet the forecasted demand and facilitate the evacuation of power from the committed and planned power plants by the year 2016-17, a corresponding transmission expansion plan was developed.

NTDC has provided their in-house developed transmission expansion plan till the year 2017-18. The plan envisages removing the present bottlenecks in the existing 500 kV and 220 kV network and substations which presently face severe congestions, overloadings and violations of Grid Code criteria. This plan has been incorporated in the load flow simulations for 2016-17 with some changes proposed for the evacuation of power from the New Hydropower Plants (PB/PPI/MAES Study) and for the Thar Coal and Imported Coal based thermal power plants (SNC-Lavalin/NESPAK Study).

Load flow studies for high hydro (low thermal) and low water (high thermal) have been performed for normal (N-0) and contingency (N-1) conditions for each case. The methodology of the study, the results and the detailed analysis are attached as part of Annexure 3.

The addition of transmission network necessary for the evacuation of power from the major power plants identified in the NPSEP by 2016-17 would be as follows:

- For Guddu–New (CCPP)
    - 500 kV Guddu New CCPP – M. Garh S/C
    - In-Out of Guddu – Multan 500 kV S/C at Guddu New (CCPP)

  - In-out D.G. Khan – Multan 500 kV S/C at M. Garh
- For Haveli Bahadur Shah (CCPP)
  - 500 kV Haveli Bahadur Shah CCPP – Faisalabad-West D/C
  - In/Out of M. Garh – Faisalabad-West S/C at Haveli Bahadur Shah CCPP
- For Sahiwal (CCPP)
  - In/Out of Sahiwal–Multan 500 kV S/C at Sahiwal (CCPP)
- For Neelum-Jehlum (Hydro)
  - Neelum-Jehlum to existing Gujranwala (Gakhar) 500kV grid station 500kV D/C
- For Thar (Coal)
  - Thar to Matiari switching station 500 kV D/C
- For Imported Coal (AES and Public Sector)
  - In/Out of Hub-Jamshoro 500 kV S/C at AES
  - AES to Matiari 500 kV D/C
  - In–out of AES-Matiari 500 kV S/C at Public Sector (Imported Coal)
  - In-out of 500 kV Jamshoro-Moro S/C at Matiari
- For import of power from Iran
  - ± 500 kV HVDC Bipoles from Zahedan to Quetta
  - Quetta - Quetta Ind. 220 kV D/C
  - Quetta – Mastung 220 kV D/C
  - Quetta – Loralai 220 kV D/C
- For import of power from CASA
  - ± 500 kV HVDC Bipoles from Tajikistan to Peshawar
  - In-out of Tarbela – Peshawar 500 kV S/C at Peshwar-2 (new 500/220kV substation)
  - In-out of 220 kV Peshawar – Shahibagh S/C at Peshawar-2
- For CHASHNUPP-III and IV
  - 220 kV Chashma New – Bannu D/C
  - In-out of 220 kV D.I. Khan – Jauharbad S/C at Chashma New

- For two clusters of wind power plants at Gharo and Jhimpir
  - o 220 kV Jhimpir – T.M Khan Road D/C
  - o 220 kV Gharo – Jhimpir D/C

The new 500/220 kV grid stations at load centres planned to be added in the system by 2016-17 are: R. Y. Khan, D. G. Khan, Shikarpur, Peshawar-2, Islamabad-West, Lahore-South and Faiselabad-West. Their connectivity with detailed load flow results is discussed in Annexure 3. There would be 38 new 220/132 kV grid stations planned to be added by 2016-17. The additions, augmentations, extensions at the 500 kV and 220 kV systems planned till 2016-17 to resolve congestion and overloading in the system are described in detail in Annexure 3 with the load flow study results.

7.6 Transmission Expansion from 2017-2020

The following are the major additions of power plants between 2017 and 2020 proposed in NPSEP:

Power Plants	Type	Installed Capacity, MW	Commissioning Year
Thar	Coal	2400	2017-18
Tarbela 4th Extension	Hydro	960	2017-18
Karot	Hydro	720	2017-18
Asrit-Keddam	Hydro	215	2017-18
Madyan	Hydro	157	2017-18
Thar	Coal	4200	2018-19
Azad Pattan	Hydro	222	2018-19
Chakothi	Hydro	500	2018-19
Kalam-Asrit	Hydro	197	2018-19
Gabral-Kalam	Hydro	101	2018-19
Shogosin	Hydro	127	2018-19
Shushgai	Hydro	102	2018-19
Thar	Coal	4200	2019-20
Chashma	Nuclear	1000	2019-20
Suki Kinari	Hydro	840	2019-20
Kaigah	Hydro	543	2019-20
Thar	Coal	2400	2020-21
Qadirabad	Nuclear	1000	2020-21
Diamer Basha 1	Hydro	2250	2020-21
Bunji 1	Hydro	1800	2020-21
Wind Power (Total)	Wind	400	2017-2021

Detailed load flow studies for high hydro (low thermal) and low water (high thermal) have been performed for normal (N-0) and contingency (N-1) conditions for each case. The already proposed interconnection schemes by NTDC for Neelum Jhelum and Karot hydro power plants in this time period as well as for Kohala hydropower plant in future have been modified. The study results and analysis with attached plotted results are part of Annexure 3.

The transmission additions necessary for the evacuation of power from the major power plants in the NPSEP between 2016-17 and 2020-21 would be as follows:

- For Thar Coal
    - ± 600 kV HVDC 4000 MW Bipoles from Thar to Lahore-South with two converter stations of same capacity on both ends
    - ± 600 kV HVDC 4000 MW Bipoles from Thar to Faiselabad-West with two converter stations of same capacity on both ends
    - 500 kV D/C from Thar to Karachi new 500/220 kV substation at KDA-33
- For Karot
    - In-out of one circuit of 500 kV D/C Neelum-Jehlum to Gujranwala via Aliot
- For Azad Pattan
    - In-out of one circuit of 500 kV D/C Neelum-Jehlum to Gujranwala via Aliot
- For Diamer-Basha 1 and Bunji 1
    - Basha-Chilas 500 kV D/C
    - Basha-Mardan New 500 kV D/C via Swat Valley
    - Bunji-Chilas 500 kV D/C
    - Three 500 kV Switching Stations/Substations at Chilas, Aliot and Mardan with the following arrangements:
        - Mardan New 500/220 kV substation to feed local loads
        - Aliot 500/220 kV substation to connect to Chakothi HPP at 220 kV
    - In-out Neelum Jehlum - Gujranwala 500 kV D/C at Aliot Switching Station
    - Aliot to Islamabad West 500 kV D/C
    - Aliot to Lahore North 500 kV D/C (with a new 500/220 kV substation of Lahore North)
- For Gabral-Kalam, Kalam-Asrit, Asrit-Kedam, and Madyan (Swat Valley HPPs)
    - In-out one each of Basha-Mardan New 500 kV D/C at each of Swat HPPs
- For Shogosin, Shushgai and Golen Gol (Chitral Valley HPPs)

  - Chitral 220/132 kV substation to collect power from all HPPs at 132 kV
  - Chitral-Chakdara 220 kV D/C
- For Suki Kinari
  - In-out of one circuit of 500 kV D/C Chilas-Aliot
- For Chakothi
  - Chakothi-Aliot 220 kV D/C
- For Chashma Nuclear
  - Chashma-Ludewala 500 kV D/C
- For Qadirabad Nuclear
  - Qadirabad Nuclear Power Plant to Gujranwala (Gakkhar) 500 kV D/C
- For Kaigah
  - Kaigah-Mardan New 500 kV D/C (operated as an interim arrangement until the commissioning of 2nd stage of Basha).

    (This plant would be advisable to be built in the timeline of 2nd stage of Basha. In that case, its interconnection would be In-out of Basha-Mardan 500 kV S/C at Kaigah.

The expansion of the 500 kV network in and around big load centres such as Peshawar, Islamabad, Lahore, Faisalabad and Karachi has been proposed in such a manner that a ring of 500 kV encircles them with stage by stage additions for the new 500/220 kV substations as needed in future years described below:

- Peshawar-2 - Mardan New 500 kV D/C
- Islamabad-West:- Aliot 500 kV D/C
- Lahore-South to be built as big power-hub of HVDC and HVAC connecting with 500kV ring around Lahore.
- Lahore-North with D/C 500 kV ring connecting with, Gujranwala, Lahore-South and Lahore-Old
- Faisalabad-West to be built as big power-hub of HVDC and HVAC connecting with 500 kV ring around Faisalabad. It will have 500/220/132 kV substation as well.
- 500/220 kV at Karachi (near KDA-33) connecting with NKI, HUB and new Coal-based plants to form a ring of 500 kV around Karachi.

Other significant additions, augmentations and extensions of 500/220 kV and 220/132 kV substations are:

- New 500/220/132 kV grid stations at Gujrat, Ludewala and Vehari connected respectively as follows:
  - In-Out Aliot-Lahore-N 500 kV S/C at Gujrat
  - Chashma-Ludewala 500 kV D/C
  - In-Out Sahiwal-Multan 500 kV S/C at Vehari
- Augmentations/Extensions at 500/220 kV grid stations of Peshawar-2, Islamabad-W, Gujranwala, Lahore-S, Rewat, Sahiwal, Matiari, Moro and NKI
- New 220/132 kV grid stations at Qasimpur (Multan), New Larkana, New Hala, Bhakkar and Sh. Manda (Quetta)
- Twenty three (23) Augmentations/Extensions at 220/132 kV grid stations
- The sizes of 500/220 kV transformer banks are to be multiples of 750 MVA or 1000 MVA for all the new 500/220 kV grid stations and multiples of 250 MVA or 350 MVA for all the new 220/132 kV substations as per requirement

The results of detailed load flow studies with connectivity of all the new 500kV and 220 kV grid stations are discussed in Annexure 3.

7.7 Transmission Expansion from 2021-2030

For the period from 2021-22 to 2029-30, the major generation additions comprise major chunks of thermal power at Thar coal fields and hydro power plants in the Northern Areas across the Indus and its tributaries. The major plants are as follows:

Power Plants	Type	Installed Capacity, MW	Commissioning Year
Bhikki	CC	1400	2021-22
Thar	Coal	600	2021-22
Bunji 2	Hydro	1800	2021-22
Kohala	Hydro	1100	2021-22
Munda	Hydro	735	2022-23
Bunji 3	Hydro	1800	2022-23
Diamer Basha 2	Hydro	2250	2022-23
Palas Valley	Hydro	580	2022-23

Power Plants	Type	Installed Capacity, MW	Commissioning Year
Thar	Coal	2400	2023-24
Dasu	Hydro	4320	2023-24
Lower Spatgah	Hydro	496	2023-24
PAEC (Karachi)	Nuclear	1000	2023-24
Thakot	Hydro	2800	2024-25
Pattan	Hydro	2800	2024-25
PAEC (Karachi)	Nuclear	1000	2024-25
Thar	Coal	3600	2025-26
Dhudnial	Hydro	792	2025-26
Tungas	Hydro	2000	2026-27
Yulbo	Hydro	2400	2026-27
D. I. Khan	CC	1400	2026-27
Thar	Coal	6000	2027-28
PAEC (Karachi)	Nuclear	1000	2027-28
Thar	Coal	4800	2028-29
Chashma	Nuclear	1000	2028-29
Thar	Coal	6000	2029-30
Balloki	CC	1400	2029-30
Wind Power(Total)	Wind	3600	2021-30

Detailed load flow studies for high hydro (low thermal) and low water (high thermal) have been performed for normal (N-0) and contingency (N-1) conditions for each case. The study results and the analysis with the attached plotted results are part of Annexure 3.

The essential transmission additions for the evacuation of power from the major power plants in NPSEP between 2020-21 and 2030 would be as follows:

- For Bhikki
  - In-out Lahore-Gatti 500 kV S/C
- For Thar Coal
- For Thar Coal
  - Three ± 600 kV HVDC 4000 MW Bipoles from Thar to Lahore-South with six converter stations of same capacity on both ends

- Two ± 600 kV HVDC 4000 MW Bipoles from Thar to Faisalabad with four converter stations of same capacity on both ends
- One ± 600 kV HVDC 4000 MW Bipoles from Thar to Multan with two converter stations of same capacity on both ends
- Three 500 kV D/Cs from Thar to Matiari
- Two 500 kV D/Cs from Matiari to Moro-
- 500 kV D/C from Moro to R. Y. Khan
- Two 500 kV D/Cs from Thar to Karachi (Karachi-East)

- For Bunji 2 and 3
  - 500 kV D/C from Bunji to Chilas
  - 500 kV D/C from Chilas to Aliot
- For Basha-2
  - In-out Basha-1 to Chilas 500 kV D/C
- For Munda
  - In-Out Peshawar-2 (Pajjagi Rd.) - Ghalanai 220 kV S/C
  - Munda – Mardan New (Charsaddah) 220 kV D/C
- For Kohala
  - In-out Neelum-Jehlum to Aliot 500 kV D/C
- For Palas Valley
  - Palas-Valley to Mansehra 500 kV D/C
- For Dasu
  - Dasu-Mansehra 500 kV D/C
  - Dasu to Palas-Valley 500 kV D/C
- For Lower Spatgah
  - In-Out one circuit of Dasu-Palas Valley 500 kV D/C
- For PAEC Karachi
  - 500 kV D/C from PAEC to Karachi-South
  - 500 kV D/C from Karachi-South to Karachi-East

- For Wind Power Cluster at Jhimpir
    - In-Out one circuit of Karach East-Matiari 500 kV D/C
- For Wind Power Cluster at Gharo
    - In-Out Thar-Karachi-East 500 kV D/C
- For Thakot
    - Thakot-Mansehra 500 kV D/C
- For Pattan
    - Pattan-Thakot 500 kV D/C
    - Thakot-Mardan 500 kV D/C
- For Dhudnial
    - Dhudnial - Neelum Jehlum 500 kV D/C
- For D.I. Khan (CCPP)
    - Connect at 220 kV substation of D.I. Khan
- For Yulbo
    - Yulbo-Bunji 500 kV 3 circuits (one D/C and One S/C)
- For Tungus
    - Tungus-Yulbo 500 kV D/C
- For Chashma (Nuclear)
    - Chashma-Bannu 500 kV D/C
- For Balloki
    - In-Out Lahore-South to Okara (Sahiwal) 500 kV D/C

A switching station/substation of 500/220 kV is proposed to be built at Mansehra to collect power from Dasu and its neighbouring Lower Spatgah and Palas Valley HPPs. It will also collect part of power from Pattan and Thakot HPPs.

Since the bulk of big hydropower plants in the Northern Areas at the Indus and its tributaries have been added during 2021-2030, and all that power is being collected at the intermediate stations of Aliot, Mansehra and Mardan, more circuits would be required to be built from the intermediate stations to the main load centres as follows:

- 500 kV D/C Aliot to Lahore-North (as already mentioned);

- 500 kV D/C from Aliot to Islamabad-North;
- 500 kV D/C from Mansehra to Gujranwala via Qadirabad Nuclear PP
- 500 kV D/C from Mansehra to Faisalabad–West;
- 500 kV D/C from Mansehra to Faisalabad–East;
- 500 kV D/C from Mardan to Bannu 500 kV S/S
- 500 kV D/C from Mardan to Faisalabad-West.

New 500/220 kV grid stations have been proposed to be added in the 500 kV ring proposed earlier around the big load centres of Islamabad, Lahore, Faiselabad and Karachi as follows:

- 500/220 kV Islamabad North grid station: with in-out of Aliot-IslamabadWest 500 kV D/C and one direct 500 kV D/C of to Rewat to complete the 500 kV ring around Islamabad.
- 500/220 kV Lahore–East grid station connected by looping in-out 500 kV D/C between Lahore-North and Lahore-South.
- 500/220 kV Faisalabad–East (or North-East) grid station connected through 500 kV D/C connections with Gatti and Faisealabad-W to complete the 500 kV ring around Faiselabad.
- Two 500/220 kV grid stations at Karachi-South and Karachi-East connected to each other through 500 kV D/C ring already connecting KDA, NKI, HUB and new coal-based and nuclear power plants to form a strong ring of 500 kV around Karachi.

Other significant additions, augmentations and extensions of 500/220 kV and 220/132 kV substations are:

- New 500/220/132 kV grid stations at Sialkot, Okara and Bannu connected respectively as follows:
    - In-out Aliot-Lahore-N 500 kV S/C at Sialkot
    - In-Out Balloki-Sahiwal 500 kV D/C at Okara
    - Bannu-Mardan New and Bannu Chashma 500 kV D/Cs (already discussed above)
- Twenty nine (29) Augmentations/Extensions at 500/220 kV grid stations.
- Sixty one (61) New 220/132 kV grid stations.
- Sixty Eight (68) Augmentations/Extensions at 220/132 kV grid stations.

- The sizes of 500/220 kV transformer banks are to be multiples of 1000 MVA or 750 MVA for all the new 500/220 kV grid stations to be added between 2021and 2030. Also the multiples of 250 MVA or 350 MVA for all the new 220/132 kV substations to be used as per requirement.

The results of detailed load flow studies with connectivity of all the new 500kV and 220 kV grid stations are discussed in Annexure 3.

7.8 Short Circuit Analysis

The Short Circuit Analysis was carried out for the years 2020 and 2030. The standard IEC 909 technique was used as embedded in PSS/E to calculate the maximum short circuit currents under 3-phase and single-phase fault conditions at all the bus bars of 500 kV and 220 kV. The results are plotted and tabulated in Annexure 3.

The fault levels that resulted from this analysis indicated some very high fault currents at big hydropower plants such as Bunji, Basha, Yulbo, Tungus who are grouped together, and at Thar coal field where current sources are quite closely grouped. For hydropower plants, due to constraints of transmission corridors, they have been grouped together as described and may require the breaker's rupturing capacities of 63 kA. However for Thar coal power plants, the different blocks of power plants can be kept isolated electrically to mitigate the fault levels within the available standard breaker's ratings of 63 kA.

7.9 Stability Studies

Transient stability studies have been performed for the years 2020 and 2030 as follows:

- 3-phase faults on a bus cleared in 5 cycles followed by the tripping of heavily loaded 500kV circuit emanating from that bus;
- All the loads were modelled as static loads with maximum stringent assumptions of 100 % constant current for active power and 100 % constant impedance for reactive power;
- Power System Stabilizers (PSS) were assumed on all the new proposed generating units and at some existing power plants South of Multan;
- The values monitored and recorded in simulations were:
    - Rotor Angles of Generators;

- Power flow swings on the healthy circuit or circuits impacted to carry maximum power flow due to trip of the faulted circuit;
- Voltage; and,
- Frequency.

- All the results of stability simulations are discussed and attached in Annexure 3. In general, from the stability study results, it is observed that there is no problems of angular stability in the system. All the transients damp down within 2-3 seconds after the clearance of faults in almost all the simulations.

7.10 Recommendations

- The expansion plan has progressively assumed to adopt higher ratings of equipment as follows:
  - 500/220 kV transformers to be 750 MVA in general and 1000 MVA for grid stations in big load centres such as Lahore, Karachi and Faisalabad
  - 220/132 kV transformers to be 250 MVA in general and 350 MVA for grid stations in big load centres such as Lahore, Karachi, Islamabad, Peshawar, Faiselabad and Multan.
  - 500 kV lines to be double circuit quad bundled using Martin conductor (ACSR) in North and mid country; and Araucaria (AAAC) in South.
  - The space in the existing 500/220 kV and 220/132 kV grid stations should be utilized for conversion, augmentation and/or extension to enhance their capacity to have at least four transformers each of 500/220 kV and 220/132 kV depending on the availability of space
  - Reconductoring or replacement of all existing 220 kV lines of single conductor to twin-bundled Rail or Greeley conductors
  - 220/132 kV grid stations have been proposed in thickly populated areas of big load centres through:
    - GIS grid stations of 220/132 kV
    - Underground cables (XLPE) of 220 kV to interconnect these grid stations with the main NTDC grid.

- Short circuit analysis has been carried out for the spot years of 2020 and 2030 and uprating of switchgear has been proposed at existing and future grid stations as follows:
    - o 500 kV: short circuit ratings to be 63 or 50 kA
    - o 220 kV: short circuit rating to be 63 or 50 kA
    - o 132 kV: short circuit rating to be 50 or 40 kA
- Transient stability study has been performed for the spot years of 2020 and 2030 by applying the most severe 3-phase permanent fault and final trip of the faulted circuit. It is recommended to have;
    - o Power System Stabilizers (PSS) to be installed at all the existing and future new power plants.
    - o Dynamic System Monitors (DSM) to be installed at all the 500/220 kV grid stations for real time recording of voltage, currents, frequency etc. to be used for post-mortem analysis and for tuning of dynamic data of generators and dynamic loads in the system.
- The upcoming problem in the NTDC longitudinal problem having sources of generation in the far North or far South and load concentrated in mid-country, would be the deficiency of reactive power (VAR) supply for the load centres. To overcome this problem the following assumptions were made:
    - o Switched shunt capacitor banks at all levels 11 kV, 132 kV and 220 kV if necessary. However the bottom line should be to provide reactive power compensation as close to the load as possible.
    - o Dynamic reactive power compensation devices such as SVC, SVS and other FACTS controllers. The present plan has quantified the requirement and locations in terms of switched shunt capacitor banks, which can be categorized in terms of SVC, SVS and/or FACTS through a detailed voltage stability study.
- Detailed voltage stability study is required to be carried out for the entire NTDC system using carefully selected composite load model comprising mix of dynamic and static loads, to optimally quantify and locate the dynamic reactive power compensation to overcome slow recovery of voltage after fault clearance, a phenomena common in the system where air-conditioning load is significantly

increasing which is now commonplace in Pakistan.

- Complimentary studies considering HVDC faults are to be undertaken with both single pole and bipole outages. These studies are intended to assess the system stability and indicate, if necessary, the requirement to provide overload capacity on the HVDC lines and converters.
- Capacity building of NTDC Planning engineers for the upcoming challenges and new devices proposed in the expansion plan, especially SVC, FACTS and HVDC.

7.11 Cost Estimate of Transmission Expansion

7.11.1 Total requirement (BOQs) between 2017 and 2030

The following table shows the total additional reinforcements required for the NTDC network till the year 2030 over and above the ongoing, committed and planned till 2016-17:

Items*	Between 2017-2020	Between 2021-2030
220 kV D/C lines (kM)	270	2,623
500 kV D/C Lines (kM)	5394	6700
220/132 kV transformers/substations (MVA)	19,850	79,600
500/220 kV transformers/substations (MVA)	25,800	68,150
± 500 kV HVDC Bipole Converters (MW)	2X(1X1,000)	_
±500kV HVDC Bipole Transmission line (kM)	654	-
± 600 kV HVDC Bipole Converters (MW)	2X(2X4,000)	6x(2x4,000)
±600kV HVDC Bipole Transmission line (kM)	2000	5770

**Lengths for lines crossing international boundaries only include Pakistan component*

7.11.2 Total Cost

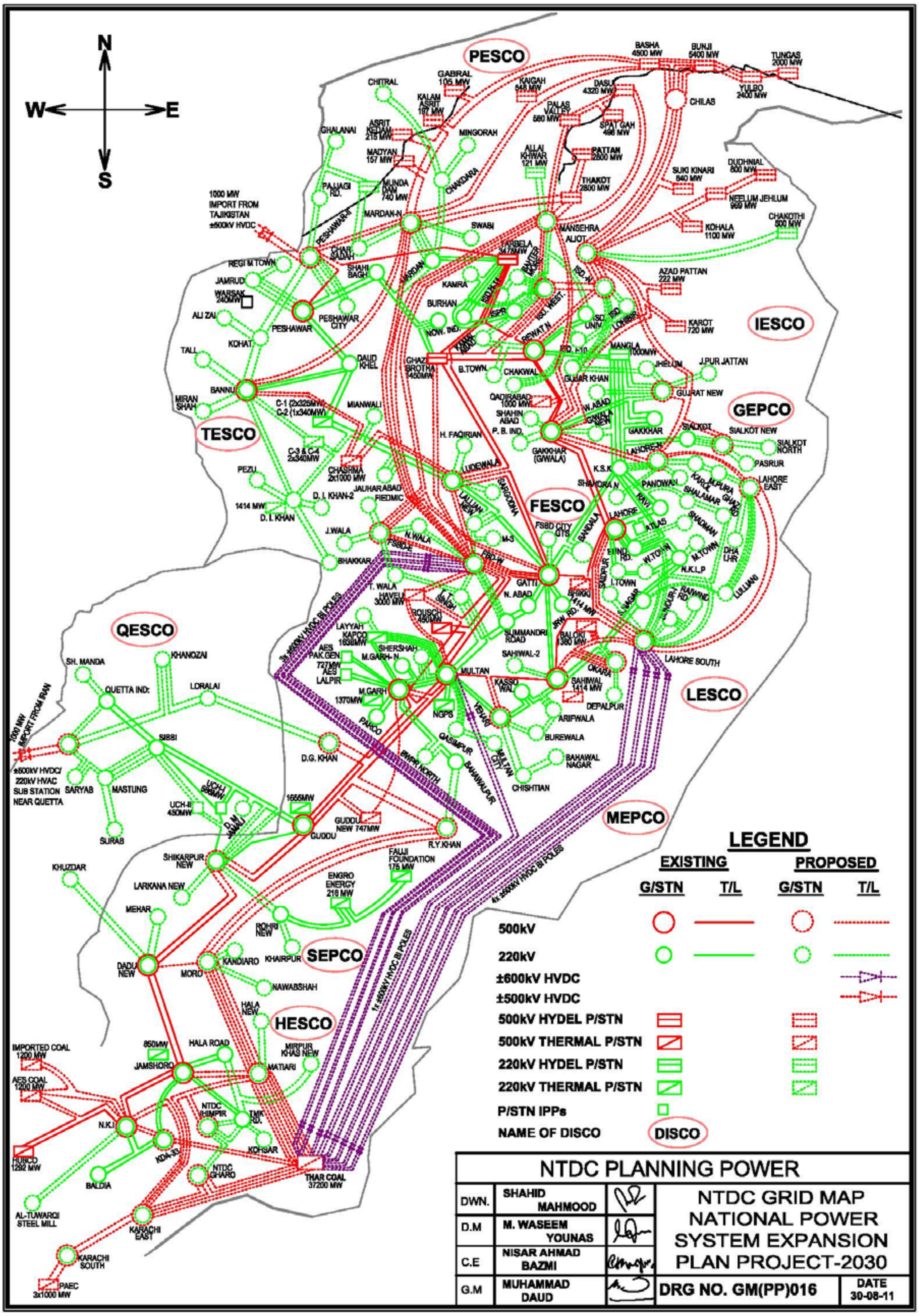
The following table indicates the total investments required till 2030

Item*	Million PKR	Million USD
Projects already committed /Planned to be completed by 2017-18 but not yet funded	428,000	5,350
Projects proposed from 2017 to 2020	569,440	7,118
Projects proposed from 2021 to 2030	1,163,360	14,542
Total	2,160,800	27,010

**Cost for lines crossing international boundaries only include Pakistan component. Costs are based on US$ 1= PKR 80*

7.12 Transmission Network in 2030

The network in horizon year of the study (2030) is shown is shown on the next page.


N
W
E
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PESCO
IESCO
GEPCO
TESCO
FESCO
QESCO
LESCO
MEPCO
SEPCO
HESCO
BASHA 4500 MW
BUNJI 5400 MW
TUNGAS 2000 MW
YULBO 2400 MW
CHILAS
DASU 4320 MW
GABRAL 105 MW
KAIGAH 548 MW
CHITRAL
PALAS VALLEY 580 MW
SPAT GAH 496 MW
PATTAN 2800 MW
THAKOT 2800 MW
MINGORAH
CHAKDARA
MARDAN-N
SWABI
MANSEHRA
ALLOT
SUKI KINARI 840 MW
DUDHNIAL 800 MW
NEELUM JEHLUM 969 MW
KOHALA 1100 MW
CHAKOTHI 500 MW
AZAD PATTAN 222 MW
KAROT 720 MW
1000 MW IMPORT FROM TAJIKISTAN ±500KV HVDC
TARBELA 3478MW
PESHAWAR
PESHAWAR CITY
JAMRUD
WARSAK 240MW
KOHAT
BANNU
MIRAN SHAH
DAUD KHEL
GHAZI BROTHA 1450MW
B.TOWN
CHAKWAL
MANGLA 1000MW
JHELUM
J.PUR JATTAN
GUJAR KHAN
GUJRAT NEW
SIALKOT NEW
SIALKOT NORTH
PASRUR
LAHORE EAST
C-1 (2x325MW) C-2 (1x340MW)
MIANWALI
C-3 & C-4 2x340MW
CHASHMA 2x1000 MW
H. FAQIRIAN
LUDEWALA
PEZU
D. I. KHAN-2
D. I. KHAN
1414 MW
J.WALA
BHAKKAR
GATTI
LAHORE SOUTH
T. WALA
HAVELI 3000 MW
MULTAN
SAHIWAL 1414 MW
DEPALPUR
ARIFWALA
BUREWALA
BAHAWAL NAGAR
CHISHTIAN
KASSOWAL
VEHARI
QASIMPUR
BAHAWALPUR
M.GARH
NGPS
D.G. KHAN
R.Y.KHAN
GUDDU
GUDDU NEW 747MW
1655MW
FAUJI FOUNDATION 175 MW
ENGRO ENERGY 216 MW
SH. MANDA
KHANOZAI
QUETTA IND.
LORALAI
SIBBI
MASTUNG
SARYAB
SURAB
±500kV HVDC/ 220kV HVAC SUB STATION NEAR QUETTA
1000 MW IMPORT FROM IRAN
UCH-II 450MW
KHUZDAR
SHIKARPUR NEW
LARKANA NEW
MEHAR
DADU NEW
MORO
KANDIARO
KHAIRPUR
ROHRI NEW
NAWABSHAH
HALA NEW
MIRPUR KHAS NEW
MATIARI
HALA ROAD
JAMSHORO
850MW
IMPORTED COAL 1200 MW
AES COAL 1200 MW
HUBCO 1292 MW
N.K.I.
BALDIA
KDA-33
NTDC GHARO
KOHSAR
THAR COAL 37200 MW
AL-TUWARQI STEEL MILL
KARACHI EAST
KARACHI SOUTH
PAEC 3x1000 MW
LEGEND
EXISTING
PROPOSED
G/STN
T/L
500kV
220kV
±600kV HVDC
±500kV HVDC
500kV HYDEL P/STN
500kV THERMAL P/STN
220kV HYDEL P/STN
220kV THERMAL P/STN
P/STN IPPs
NAME OF DISCO
DISCO
NTDC PLANNING POWER
DWN. SHAHID MAHMOOD
D.M M. WASEEM YOUNAS
C.E NISAR AHMAD BAZMI
G.M MUHAMMAD DAUD
NTDC GRID MAP NATIONAL POWER SYSTEM EXPANSION PLAN PROJECT-2030
DRG NO. GM(PP)016
DATE 30-08-11

8 EXPANSION PLAN FOR DISCO TRANSMISSION

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8 EXPANSION PLAN FOR DISCO TRANSMISSION

8.1 Objectives

The already proposed distribution system upgrades in each of the DISCOs will be further upgraded in coordination with the development of the National Power System Expansion Plan (NPSEP). The additional reinforcements required at the secondary voltage levels for the years 2015, 2016, 2018 and 2020 were identified for each DISCO. In addition, an estimate of the capital investments required to accept the power as delivered on the high voltage system and to transmit it to the load centres they serve was prepared working closely with teams of counterparts from each DISCO.

The objective of the DISCO was to determine the reinforcement required during the planning horizon, to evaluate the performance of the DISCO Secondary Transmission System expansion plans in four study years of 2015, 2016, 2018 and 2020, as well as to prepare an estimate of the investment costs.

This was accomplished through the following activities:

- A load flow analysis was performed for each DISCO network based on the load forecast at each study year and the local expansion plans using agreed upon planning criteria. The required system reinforcements proposed were selected to alleviate the bus voltage and/or line overloading problems in the most technically and cost effective way.
- The short circuit calculations were performed for each DISCO only for the last developed year (Year 2020) to check the value of the fault current at each bus. Any recorded short circuit problems encountered would be solved by reconfiguring the system at these specific locations.

The specific tasks of the secondary transmission expansion plan were to:

- Expand the 132 kV and 66 kV systems;
- Identify the 132/11 kV and 66/11 kV new substations as well as extensions and augmentations for the existing 132/11 kV and 66/11 kV transformers ;
- Verify that the 132 kV and 66 kV systems satisfy the planning criteria;
- Verify that the short circuit levels at the 132 kV and 66 kV systems are within the permissible limits.

8.2 Study Cases

In the context of the master plan, the secondary transmission system expansion plan provides the system upgrade required for the spot years 2015, 2016, 2018 and 2020 that will allow the planned generation to serve the forecasted load under both normal and contingency conditions.

While short circuit calculations were performed only for the year 2020 peak load case, load flow analysis was performed for the following four peak load study years:

- June 2015 peak load case
- June 2016 peak load case
- June 2018 peak load case
- June 2020 peak load case

Each case has been analyzed under both normal and contingency conditions. System reinforcements including transmission lines and reactive power compensations were defined as appropriate.

8.3 Input Data

The following served as input data for the studies:

- Existing 2010 or 2011 system data
- Load forecasts, individual grid stations and DISCO peaks (diversified), up to the year 2020
- Planned/committed system expansions of DISCOs up to 2015.
- Load flow base cases for year 2010 and 2014 provided by NTDC

The above data / information was used for building the base cases for the future years of 2015, 2016, 2018 and 2020.

8.4 Load Forecast

For each Distribution Company (DISCO), load forecast for each grid station was developed as summarized in the following steps (more details are presented in the Load Forecast Report):

- Data used is the 11 kV feeder-wise and tariff category-wise sales. It also includes the maximum demand of medium and large industries for the base year.
- These sales are converted into peak demand using the load factors and diversity factors.
- Growth rate on each category is applied and spot loads are added.

This way the peak demand of the next year at a grid station is forecasted. A diversity factor would be applied to each DISCO peak to get the diversified DISCO peak load, as given in Table 8-2 (e.g. 25,970 MW by Year-2015). The latter (diversified DISCO peak) is the value to be used in DISCO transmission planning (66-132 kV network).

As can be seen from Tables 8-1 and 8-2, the average diversity factor used for all DISCOs was 88%. A further diversity factor among the DISCO peaks was applied to get the "System Peak" which is the value to be used on the transmission level (220 kV and higher). This diversity factor is in the range of 90-96%.

Table 8-1 Load forecast: Non-diversified DISCO Totals

DISCO		Total Load (MW)				
No.	**Name**	**2015**	**2016**	**2018**	**2020**	**DF ***
1	PESCO	3516	3658	3943	4203	88%
2	IESCO	3407	3710	4405	5037	85%
3	GEPCO	2787	2944	3284	3657	90%
4	LESCO	5965	6290	7003	7755	84%
5	FESCO	3985	4233	4818	5583	83%
6	MEPCO	4233	4438	4868	5387	91%
7	HESCO	3083	3282	3722	4261	85%
8	QESCO	1767	1857	2054	2284	98%
10	TESCO	1097	1169	1322	1450	88%
	Total	**29839**	**31580**	**35419**	**39617**	

** - DF: Diversity factor*

Table 8-2 Load forecast: Diversified DISCO totals

DISCO		Total Load (MW)			
No.	**Name**	**2015**	**2016**	**2018**	**2020**
1	PESCO	3091	3211	3452	3674
2	IESCO	2891	3148	3738	4273
3	GEPCO	2500	2641	2945	3279
4	LESCO	5027	5302	5905	6538
5	FESCO	3289	3493	3974	4604
6	MEPCO	3860	4045	4432	4902
7	HESCO	2607	2773	3143	3596
8	QESCO	1738	1827	2020	2246
10	TESCO	968	1031	1166	1278
	Total	**25970**	**27471**	**30773**	**34391**

8.5 Secondary Transmission Planning Criteria

The planning of the Secondary Transmission System considers the operation of a power system under two possible situations, that is:

- ***Normal operating conditions (N-0)***: the Secondary Transmission System (66-132 kV) infrastructure is entirely available (no equipment has been considered out of service).
- ***Contingency operating conditions (N-1)***: one of the Secondary Transmission System equipment (line or transformer) is out of service. In this study, only outage of transmission lines rated at 132 kV (or 66 kV) within each DISCO was considered.

For each of these operating conditions, the following criteria were applied to the analyses:

System Voltage Criteria

The acceptable voltage range for operating the system based on factors such as equipment limitations and motor operation under normal and contingency conditions is as follows:

Condition	Acceptable Voltage Range
Normal System Conditions	95% - 105% (±5%)
Contingency Conditions	90% - 110% (±10%)

It is important to note that from an operational standpoint, healthy systems usually target a voltage close to 1.0 pu at 132 kV (or 66 kV) voltage levels.

<u>Equipment Thermal Loading Criteria</u>

The Secondary Transmission System shall be planned to allow all transmission lines and equipment to operate within the following limits for the following defined conditions:

Condition	Thermal Loading Limit
Normal System Conditions	Defined Normal Load Capacity
System Design Contingencies of Long Duration (i.e. an outage involving the failure of a transformer)	Defined Normal Load Capacity
System Design Contingencies of Short Duration (i.e. not involving a transformer)	Defined Emergency Load Capacity (120% of normal rating for 10 hours per year)

However; as per discussion with the NTDC Planning Engineers, the line loading under contingency conditions (N-1 analysis) will be based on the normal rating (Rating A).

8.6 Methodology

The methodology followed to accomplish the objectives of this project is summarized in the following steps;

1. The load flow case representing the current system (either 2010 or 2011) has been modified to include the 11 kV network. Each 132 kV or 66 kV bus was expanded to model the 132/11 kV or 66/11 kV transformers. Loads have then been placed at the 11 kV side along with the shunt capacitor banks, if any. The actual measured values of bus voltages, power factors, active and reactive power 9energy), and loadings on lines and transformers were matched with the simulated solutions to determine the actual power factors of loads at different substations. These calibrated power factors were used for modelling of loads (MW/MVAR) while developing the simulation cases of each spot year.
2. For building the Year-2015 case, each DISCO network in the starting base case of Year-2014 was replaced by the detailed model developed at step-1.
3. Loads were updated based on the load forecast values for Year-2015, including the addition of the new grid stations as appropriate and the established load power

factor. All the`` sub-projects planned under ADB Tr-I, Tr-2 and PSDP or 6th STG would be a part of the interconnected network in the Year-2015 base case.

4. The generation schedule on the transmission level (220 kV and higher) would be increased (if necessary) to match the load level. By completing this step, each DISCO would have an updated load flow case for Year-2015.
5. For each updated Year-2015 DISCO case, the 132 and 66 kV systems were analysed under both normal (N-0) and contingency (N-1) conditions. As a result of this analysis, system reinforcements were added as necessary. Then the new Year-2015 case with reinforcements was re-analysed under (N-0) and (N-1) conditions to make sure that the system satisfy the planning criteria.
6. The DISCO base cases for Year-2016 were built starting from the Year-2015 cases. Then steps 3-5 described above were followed. The process continues for building the other two cases for years 2018 and 2020.
7. Short circuit calculations were performed only for the last study year; by combining all DISCO cases in one composite simulation case for year 2020. Maximum short circuit currents were calculated using IEC 909 standards.
8. State of art software PSS/E of Siemens-PTI was used for all simulation analysis of load flow and short circuit analysis.

8.7 Study Results

8.7.1 Load Flow Study Results

The results for each DISCO are provided in Annexure 4 which shows the reinforcements required for each of the years.

The base case for each DISCO was developed using the existing 2010 or 2011 system data, the starting NTDC base case for 2014, the load forecast (2015-2020), and planned/ committed system expansions of DISCOs up to 2015.

The load flow results are given for each DISCO independently in three main activities:

- Analyzing the developed case under both normal (N-0) and contingency (N-1) conditions;
- Identifying system reinforcements as appropriate; and,

- Re-checking the system under (N-0) and (N-1) with system reinforcements.

8.7.2 Short Circuit Study for Year-2020 Base Case

The three-phase and single-phase-to-ground symmetrical fault currents were calculated based in IEC 909 Standards for each DISCO. An updated Year-2020 load flow case including all DISCO networks was used in the calculations. The calculations considered the maximum thermal generation in South and the maximum hydro generation in North.

For the short circuit calculations, the following assumptions were made:

a) Bus voltages are set at 1.1+j0.0 pu;

b) Generator outputs are set at zero;

c) Pre-fault loading conditions are neglected;

d) Transformer turns ratios are set at 1.0 and phase shifts are not modelled;

e) Line charging and positive sequence shunt admittances are neglected;

The complete short circuit results for grid stations of DISCOs are given in Annexure 4.

8.8 Cost Estimate

The cost estimate for each DISCO's future projects was prepared on the following basis:

a) The same unit cost (with a little mismatch) was used for all DISCOs;

b) The cost estimate was prepared for each study year; 2015, 2016, 2018 and 2020; and,

c) The cost estimate was first prepared in PKR, and then converted to USD at a rate of 1.0 USD is equal to 80.0 PKR.

8.8.1 Unit Cost

A general unit cost sheet was prepared for all DISCOs, as given in The unit costs for DISCO Transmission Expansion are given in Table 8.3. A summary of the cost estimates of all DISCOs is given in Table 8-4 in MPKR and in Table 8-5 in MUSD.

Table 8-3. A slight modification was made in some cases for more accurate cost estimate based on the prices at each DISCO. The following grid station notations were used in The unit costs for DISCO Transmission Expansion are given in Table 8.3. A summary of the cost estimates of all DISCOs is given in Table 8-4 in MPKR and in Table 8-5 in MUSD.

Table 8-3:

a) *Augmentation:* replacement of an existing power transformer in a grid station with a larger one, including the switchgear, if needed;

b) *Extension:* addition of a power transformer to an existing grid station, including the switchgear if needed;

c) *Fixed Capacitors:* the capacitor banks would be switched manually; and

d) *Switched Capacitors:* the capacitor banks would be switched automatically based on the voltage settings.

8.8.2 Cost of Reinforcements

The cost of the proposed system reinforcements was estimated to be 116,092 MPKR which is equal to US$ 1,451 million for all the DISCOs combined. While this costing information is not directly used in the NPSEP, it does indicate the level of investment that the DISCOs must make so NTDC can strengthen, reinforce and expand the existing transmission plan as per the NPSEP.

The unit costs for DISCO Transmission Expansion are given in Table 8.3. A summary of the cost estimates of all DISCOs is given in Table 8-4 in MPKR and in Table 8-5 in MUSD.

Table 8-3 Unit Cost for DISCO Systems Expansion

Sr. No	Type of Investment		Estimated Cost in Million Rs	Estimated Cost in Million US $
1	**Augmentations**	26 MVA	49.200	0.615
		40 MVA	62.730	0.784
		60 MVA*		
2	**Extensions**	13 MVA	42.560	0.532
		26 MVA	53.200	0.665
		40 MVA	67.830	0.848
		60 MVA*		
3	**New Sub-Station**	GIS	520.000	6.500

Sr. No	Type of Investment		Estimated Cost in Million Rs	Estimated Cost in Million US $
	with 2x40 MVA PTRFs	AIS Turnkey	260.000	3.250
		AIS Departmentally	173.333	2.167
4	**New Sub-Station with 2x26 MVA PTRFs**	GIS	480.000	6.000
		AIS Turnkey	220.000	2.750
		AIS Departmentally	146.667	1.833
5	**New D/C T/Line with Rail Conductor per Km**	On Poles, D/C per Km	14.500	0.181
		One Towers, D/C per Km	9.000	0.113
6	**New D/C Cable per Km**	D/C 800mm2	200.000	2.500
7	**Fixed Capacitors (11 kV)**	New (7.2 MVAR)	4.430	0.055
		Addition (1.2 MVAR)	0.250	0.003
		Addition (2.4 MVAR)	0.837	0.010
		Addition (3.6 MVAR)	3.160	0.040
		Replacements/additions		
	Fixed Capacitors (132 kV)	New (12 MVAR)	8.433	0.105
		New (24 MVAR)	16.866	0.211
		New (36 MVAR)	25.300	0.316
		New (48 MVAR)	33.733	0.422
	Switched Capacitors (11 kV)	New (7.2 MVAR)	6.645	0.083
		Addition (1.2 MVAR)	0.375	0.005
		Addition (2.4 MVAR)	1.256	0.016
		Addition (3.6 MVAR)	4.740	0.059
		Replacements/additions		
	Switched Capacitors (132 kV)	New (12 MVAR)	12.650	0.158
		New (24 MVAR)	25.299	0.316
		New (36 MVAR)	37.950	0.474
		New (48 MVAR)	50.600	0.633

***Assumed 125 % of the cost of 40 MVA transformers**

Table 8-4 DISCOs Cost Estimate 2015-2020 in MPKR

No.	DISCO	Year-2015	Year-2016	Year-2018	Year-2020	Total
1	FESCO	3,968.7	1,571.9	3,711.9	3,052.3	**12,305**
2	GEPCO	1,996.3	872.9	62.7	696.5	**3,628**
3	HESCO	14,944.4	5,540.6	3,970.0	2,296.0	**26,751**
4	IESCO	893.7	2,096.7	1,880.2	428.8	**5,299**
5	LESCO	8,952.7	938.5	1,197.1	5,346.4	**16,435**
6	MEPCO	11,201.6	5,556.1	2,583.2	3,071.7	**22,413**
7	PESCO	3,135.0	788.8	4,088.7	3,490.1	**11,503**
8	QESCO	6,614.3	940.3	2,209.6	5,239.2	**15,003**
9	TESCO	1,761.6	52.3	694.0	248.0	**2,756**
Total		**53,468**	**18,358**	**20,397**	**23,869**	**116,092**

Table 8-5 DISCOs Cost Estimate 2015-2020 in MUSD

No.	DISCO	Year-2015	Year-2016	Year-2018	Year-2020	Total
1	FESCO	49.6	19.6	46.4	38.2	**154**
2	GEPCO	25.0	10.9	0.8	8.7	**45**
3	HESCO	186.8	69.3	49.6	28.7	**334**
4	IESCO	11.2	26.2	23.5	5.4	**66**
5	LESCO	111.9	11.7	15.0	66.8	**205**
6	MEPCO	140.0	69.5	32.3	38.4	**280**
7	PESCO	39.2	9.9	51.1	43.6	**144**
8	QESCO	82.7	11.8	27.6	65.5	**188**
9	TESCO	22.0	0.7	8.7	3.1	**34**
Total		**668**	**229**	**255**	**298**	**1,451**

8.9 Recommendations

a) Following uprating of equipment should be considered in medium to long term perspective:

i. 132/11 kV transformers of 31.5/40 MVA should at least be used for urban centres. The next factory standard higher size of 60/67 MVA size may be also be considered to be used in thickly populated urban centre grid stations.

ii. For 132 kV lines the twin bundled circuits using Rail or Greeley conductors may be considered especially in big urban centres.

iii. For 132 kV switchgear, the symmetrical short circuit rating should be 40 kA or higher.

b) The capacitor banks should always be specified as follows:

i. Switched shunt instead of fixed

ii. Switching of the steps of capacitor banks should be controlled by Programmable Logic Controller (PLC) to regulate voltage within permissible range during high and low load conditions

iii. The current limiting reactors should be used in series with the capacitor banks to limit the in-rush current at the time of switching of the capacitor banks.

iv. The detuning capacitors may also be used in series with the capacitor banks if parallel-resonance of odd harmonics is found to occur at any substation

c) All T-Off connections of substations should be changed to proper in-out looping of the circuit. The present practice of connecting the substations through T-Off may be abandoned in future, only proper in-out looping should be used.

d) The present expansion plan has applied N-1 criteria on lines only and not at 132/11 kV transformers due to huge investment anticipated. However policy should be laid down to achieve N-1 criteria at 132/11 kV transformers in long term perspective.

e) The updating of DISCO Transmission Expansion Plan should be an ongoing activity. The present structure of Planning sections in DISCOs is flawed in terms of the fact that planning and studies is not considered as an ongoing continuous activity. The engineers supposed to be busy on this continuous activity are assigned on many other field related tasks such as project monitoring etc. and they are not dedicated for the activity of planning and studies. A dedicated Planning and Studies Section must be restructured for this purpose.

Capacity building of Planning and Studies engineers of DISCOs should also be carried out on regular basis in terms of updating of software such as PSS/E including the modules of load flow, short circuit analysis and dynamic stability analysis. Also they should be equipped with modern load forecasting techniques and respective software.

9 FINANCIAL PLAN

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9 FINANCIAL PLAN

9.1 Introduction

This section is concerned with the Financial Plan for the National Power System Expansion Plan and provides its salient features. The key objective of the Financial Plan is to provide an indication of the annual investment requirements to implement the generation and transmission expansion plans, and to assess its impact on the tariffs.

In order to have an assessment of the current financial situation of the power sector of Pakistan, the section at first presents an overview of the financial performance of the power sector of Pakistan. This is followed by the description of the methodology for developing the financial plan. Next, data inputs and assumptions used for the development of the financial plan are outlined.

The generation and transmission plans are the key inputs to develop the financial plan and to determine the annual revenue requirements to build and operate the system. Based on the investment and operational costs of the generation and transmission expansion plans, total and annual financing requirements including debt and equity components were estimated and are provided in the section. The impact on end-consumer tariff due to total power supply costs is also included in the section. Finally, the section presents the analysis of the financial results and provides the conclusions.

It is to be noted that the results of the financial analysis are indicative and provide an overall assessment of the financial impact of the investments on the tariffs.

An annexure to the main report (Annexure 5: Financial Plan) was also prepared, which provides the necessary details and analysis of the financial plan and its impact on tariffs.

9.2 Overview of the Financial Performance of the Pakistan Power Sector in 2010

The current financial performance and cost structure of the Pakistan Power sector is important to the Financial Plan since the current tariff is based on these costs, and is the reference point for future tariff increases.

Furthermore, the embedded costs or the current operational costs attributed to the existing assets need to be included in the financial analysis along with the investment and operational costs of the new assets in order to develop the financial plan. In the same context, the inclusion of the operational costs associated with the existing assets was essential as these costs have a significant impact on the tariffs. It is also worthwhile to review the current level of tariff and costs at the various transfer points to see if these tariffs adequately reflect the costs of supply at generation, transmission and distribution levels.

The annual and other available reports and relevant data of the various companies in the Pakistan power sector for the year 2009-10 were reviewed to determine the financial performance of the sector.

It is pointed out that KESC has its own power system and the financial performance of the KESC is treated separately.

9.2.1 Cost of Generation

The total cost of generation in 2010 which includes all the investment and operating costs amounted to 577,237 million Rupees. WAPDA had the lowest cost of production - the average cost of production amounting to 1.03 Rupees/kWh. This was followed by the GENCOs thermal power plants that have an all inclusive cost of generation of 8.50 Rupees/kWh. The IPPs and other generation were the most expensive having a generation cost of 9.58 and 9.79 Rupees/kWh respectively. The average blended cost of generation in 2010 was 6.60 Rupees/kWh. The amount of energy sent out in 2010 was 87,455 GWh.

9.2.2 Cost of Transmission

The total costs attributable to the transmission system for 2010 were 18,627 million Rupees. The wheeling cost of the power delivered to the DISCOs and to KESC was 0.221 Rupees/kWh based on the total of 84,367 GWh energy transmitted on the transmission network.

9.2.3 Cost of DISCOs

The costs for the DISCOs are composed of the purchased power costs and the DISCOs own costs. DISCOs own costs include the costs for operating and maintaining the distribution network, costs for meter reading, billing and collection, and financial costs including depreciation and interest expenses.

The costs of distribution in 2010 were 62,784 million Rupees. This translates to 1.014 Rupees/kWh based on the sales 61,904 GWh of energy for all the DISCOs.

9.2.4 Summary of PEPCO Costs

The power supply chain costs including the cost of generation, transmission and distribution are provided in Table 9.1 below. The table also presents the energy values for the estimation of unit costs. As can be seen from the data provided in the table the total power supply costs for the year 2010 were 658,648 million Rupees and in per energy unit basis it amounts to 9.81 Rupees/kWh.

Table 9-1 Generation, Transmission and Distribution Costs

	Energy (GWh)	Total Costs (million Rupees)	Unit Costs (Rupees/kWh)
Generation	87,455	577,237	6.60
Transmission	84,367	18,627	0.22
Distribution	61,904	62,784	1.01
Total	67,091*	658,648	9.81

*includes 5,187 GWh energy transmitted to KESC.

In 2010, PEPCO reported a total revenue of 618,958 million Rupees from the sales by Discos and sale of electric power to KESC. This implies that in the year 2010, PEPCO suffered a loss of 39,690 million Rupees or 0.59 Rupees per unit of energy (KWh) sold.

9.2.5 Financial Performance of KESC

KESC is the electric utility responsible for supplying power to Karachi and surrounding areas. KESC has its own generation plants, and transmission and distribution network. The company generates half of its power requirements and purchases the balance form NTDC, IPPs and the Karachi Nuclear Power Plant.

KESC generated 7,373 GWh and purchased 7,841 GWh of energy in the year 2010. Transmission and distribution losses were 34.9% in 2010. Total energy sales in 2010 were 9,905 GWh.

KESC total revenues for 2010 were 103,396 million Rupees including a tariff adjustment or subsidy of 33,221 million Rupees. The total costs for the year were 118,597 million Rupees which resulted in a net loss of 14,641 million Rupees. When this loss is added to the subsidy the total costs which were not recovered by tariffs in the KESC system increases to 47,862 million Rupees. Thus the losses in the KESC system in 2010 are significantly higher than those in the PEPCO system.

9.3 Methodology for Developing Financial Plan

The methodology adopted for developing the financial plan is graphically illustrated in Figure 9.1. Broadly speaking, the model developed for the financial plan consists of three modules, namely Input Module, Process Module, and Output Module. The Input Module consists of the following key data:

- Assumptions used for financial plan, e.g., discount and inflation rates;
- Annual capital and operational expenditures derived from the generation plan;
- Annual capital and operational expenditures derived from the transmission plan;
- Discos cost; and
- Existing cost structure of the hydro, thermal, and IPPs generation plants, as well as transmission company and Discos.

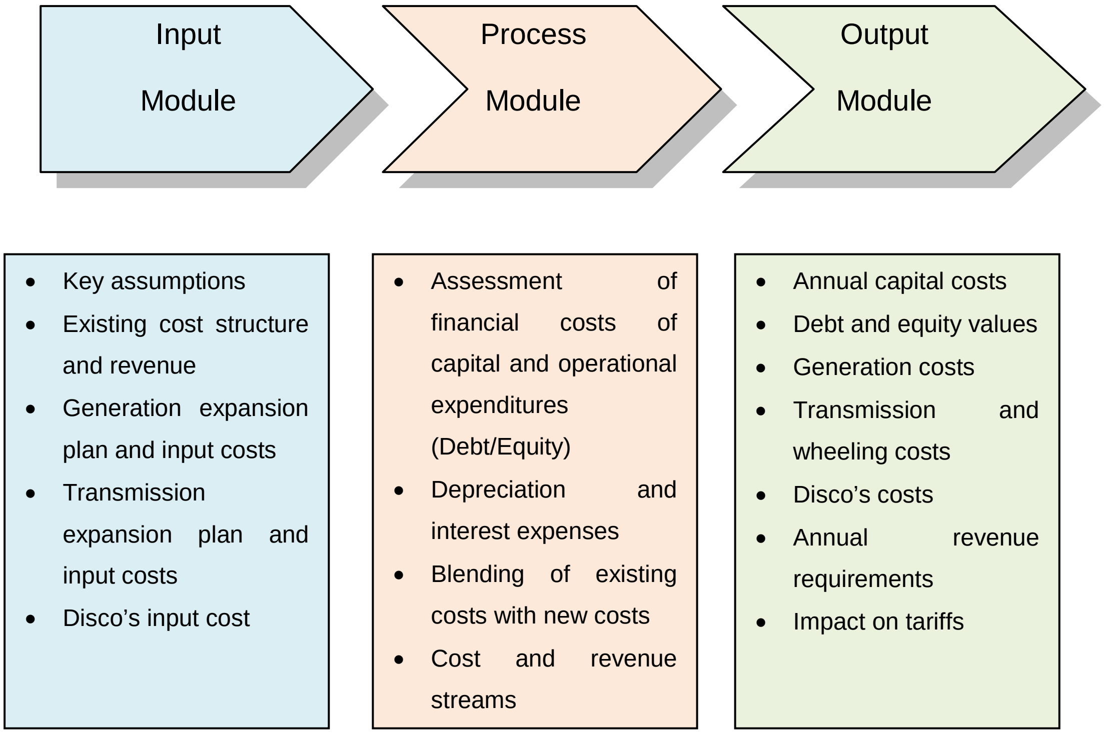
The Process Module makes use of the information/data provided in the Input Module and mainly converts the investment and operational costs into financial costs. In addition, it blends the existing costs with the costs determined for the development of generation and transmission expansion plans as well as Discos. The process module also computes the revenue streams of the generation and transmission companies and Discos.

The Output Module provides the following major results:

- Annual capital and fuel costs of the generation system;
- Annual power transmission costs and costs of Discos;
- Average cost of production;
- Debt and equity values; and
- Annual revenue requirements and its impact on tariff.

The output module of the model produces the following reports: (i) financing report, (ii) an annual cost report, and (iii) a cost of supply and annual revenue requirements report. The financial model is fully described in Annexure 5: Financial Plan.

Figure 9-1 Graphical Illustration of the Methodology for Developing Financial Plan



In order to determine the overall cost structure of the existing system and the level of subsidies currently applicable to the system, the current costs and revenues for the year 2009-10 were reviewed and assessed. The existing or embedded costs form a critical component of the financial requirements for the operation and maintenance of the power system especially in the early years.

The costs associated with the generation and transmission expansion plans provided in the previous sections are economic costs in real terms (i.e. at constant price levels excluding financing costs, taxes, etc.). For the financial plan, these economic costs of the generation and transmission plans were converted into financial costs, taking into account financing charges, interest expense, depreciation, income taxes and profit. The financial planning is carried out in nominal terms and an inflationary component was also added to the capital, and operating costs. Since the study is carried out in US dollars, the allowance for inflation in the United States (2% per year) was used.

The financial plan provides the investment requirements, both in terms of debt and equity, required to finance the generation and transmission projects to be developed over the next 20 years. It is important to note that the capital expenditures associated with the distribution system are not considered in the financial plan and was also not included in the National Power System Expansion Plan. Nevertheless, the capital expenditures for the DISCOs form a component of the overall costs. A provisional amount of 1.18 US ¢/kWh, which is the average cost of the DISCOs, has been added to the overall cost of supply of power for covering the costs of the distribution system.

The interest rate for debt is assumed as 8 % with a repayment period of ten years. Given that the life of the distribution assets is assumed to be 25 years, it is assumed that the existing loans will be refinanced over the financial planning period.

The financial plan provides the overall investment and financing required for the generation and transmission expansion plans and the overall impact on tariffs for the end-consumer of the DISCOs and for KESC.

9.4 Data Input and Assumptions for Developing Financial Plan

In order to develop the financial plan, the generation and transmission expansion plans were used as the basic inputs. In addition, the sales and load forecasts were also considered for the development of the financial plan.

The overall financing plan has been developed on a commercial basis with the funding for investments provided by debt and equity. However, this may not be the case for the new hydro projects that may be funded by the government, and also for thermal power plants that will be developed by the private sector. Nonetheless, in order to reflect the true cost of power from thermal and from hydro plants, and to maintain consistency in the analysis, the same financing assumptions have been assumed for both hydro and thermal projects to ensure that all the projects are on the same commercial footing.

The costs for owning and operating the DISCOs will be added to the costs of generation and transmission to determine the overall cost of supply to the final customer. The distribution costs reflect the current operating, maintenance, billing, and commercial costs of the distribution systems with an adjustment for improved efficiency.

The key financial assumptions used for the development of the financial plan are summarized in Table 9-2.

Table 9-2 Key Financial Assumptions

	Value Used
Inflation Rate	2%
Discount Rate	10%
Rate of Return	15% on Equity
Cost of borrowing	8%/ per annum
Debt/Equity Ratio for financing	70% / 30%
Loan repayment period	10 years
Exchange rate	80 PAK Rupees = 1 US$ (2010)
Asset Life	
• Hydro	50 years
• Thermal	30 years
• Transmission	40 years

In addition to the above-mentioned assumptions, there are other inputs required for the development of the financial plan. The key data inputs, mainly taken from the data and assumptions provided in the base case generation and transmission expansion plans include the following:

- Sales and load forecast;
- Fuel prices;
- Capital and operating costs of the generation expansion plan;
- Capital and operating costs of the transmission expansion plan;
- Existing assets, debt and generation cost structure of WAPDA;
- Existing assets, debt and generation cost structure of GENCOs;
- Existing tariffs from IPPs;
- Existing assets, debt and transmission cost structure of NTDC;
- Existing assets, debt and distribution cost structure for the DISCOs;
- Existing tariffs on an average basis, costs and subsidies; and
- System losses and future demand projections as provided in the load forecast.

It is important to note that the level of the investment requirements for both the generation and transmission plans developed to meet the electricity demand are huge as substantial generation and transmission capacity needs to be added to the system. In view of the mammoth investment requirements, access to investment funds may be a constraint. However, for the purpose of developing the financial plan, these funding constraints have not been considered.

9.5 Cost Estimates for the Generation, Transmission and Distribution Plans

9.5.1 Investment and Operational Cost Estimates for the Generation Plan

The investment and the operational cost estimates of the generation plan for the entire period were calculated using SYPCO program. It shows that over US$ 500 billion is required to build and operate the generation system over the next 20 years. The investment, fuel, and operation and maintenance costs (O&M) are summarized in Table 9-3. The fuel prices used in the financial plan are taken from the generation plan. These costs are in constant 2010 USD. (Please note that these are economic costs that form the basis of the financial presented in later sections).

Table 9-3 Investment, Fuel and O&M Costs of the Generation Plan (million USD)

Investment and Production Costs	2011-12 to 2020-21	2021-22 to 2029-30	Total
Investment Costs	103,667	87,734	191,402
Fuel Costs	129,907	161,085	290,992
O&M Costs	11,500	26,809	38,309
Total Generation Costs	245,074	275,628	520,703

9.5.2 Cost Estimates of the Transmission Plan

The cost of implementing the transmission upgrades is nearly US$ 30 billion. These costs for different durations during the planning period are summarized in Table 9-4. These costs are in constant 2010 USD. It is to be noted that the cost for lines crossing international boundaries only include Pakistan component.

Table 9-4 Cost of Transmission Upgrades

Item*	Million PKR	Million USD
Projects already committed /Planned to be completed by 2017-18 but not yet funded	428,000	5,350
Projects proposed from 2017 to 2020	569,440	7,118
Projects proposed from 2021 to 2030	1,163,360	14,542
Total	2,160,800	27,010

**Cost for lines crossing international boundaries only include Pakistan component. Costs are based on US$ 1= PKR 80*

9.5.3 Cost Estimates for the Distribution System

The cost of the proposed system reinforcements was estimated to be 108,640 million Rupees which is equivalent to 1,358 Million USD for all the DISCOs combined. While this cost information is not directly used in the NPSEP, it does indicate the level of investment that the DISCOs would require to have an adequate distribution system to achieve the requisite reliability level of the distribution system.

9.6 Financial Projections and Results

The financial projections for the Pakistan power sector for the period 2011 through to 2030 were prepared based on the assumptions and input data obtained and using the financial model developed for the study. Thus making use of the data inputs taken from the generation and transmission plans and taking into account all the investments and operating expenses that are required to be incurred to support the generation and transmission expansion plans the financial projections over the period were developed.

The principal outputs from the financial model include:

- The annual capital investments and operating expenses both with and without discounting;
- The financing required for each year for hydro and thermal projects;
- The financing required for each year for transmission projects;
- The cost of power from hydro and thermal plants over the study horizon;
- The annual cost of transmission and the unit wheeling costs;

- The cost of power sold to the DISCOs and to KESC; and
- The average cost of power sold to the final customer and comparison to the existing tariffs.

9.6.1 Investments and Operating Costs of the Generation and Transmission Plans

The total investment and operating costs for the period 2011 to 2030 of the generation and transmission plans are presented in Table 9-5 both with and without discounting. Hydro Capital expenditure over the period is expected to be 85 billion USD, while the thermal capital expenditure will total 148 billion USD. On the operating side, total hydro operating costs are projected to be 12 billion USD, while thermal operating costs are estimated as 38 billion USD. In addition, fuel costs for the thermal power plants are computed to be 365 billion USD.

The capital expenditure for the transmission plan is estimated to be about 27 billion USD over the 20 year period, with about 13 billion USD occurring in the first ten year period. Transmission operating expenditures are projected to be about 7 billion USD over the study period.

The total generation and transmission financial costs are estimated to be over 647 billion USD and over 34 billion USD respectively. For both the generation and transmission expansion plans the combined financial cost is projected to be about 682 billion USD. When these costs were discounted to 2011 using a discount rate of 10%, the total Present Value (PV) costs of the generation and transmission expansions plans are estimated to be about 263 billion USD.

Table 9-5 Generation and Transmission Costs (Million USD)
(Capital and Operating Costs 2011-2030)

	Without Discounting			With Discounting at 10%		
	2011-12 to 2019-20	2020-21 to 2029-30	Total	2011-12 to 2019-20	2020-21 to 2029-30	Total
Hydro - Capex	39 677	45 730	85 407	22 704	14 353	37 057
Hydro - Op Exp	1 789	10 278	12 068	1 046	2 427	3 473
Thermal - Capex	62 269	85 746	148 015	36 841	22 480	59 321
Thermal - Op Exp	8 935	28 615	37 550	5 256	6 908	12 164
Thermal–Fuel Exp	127 667	236 950	364 617	77 855	58 974	136 829
Total Generation	**240 337**	**407 319**	**647 657**	**143 702**	**105 142**	**248 844**
Transmission Capex	12 764	14 764	27 033	7 991	3 791	11 782
Transmission-Op Exp	1 481	5 755	7 236	802	1 395	2 197
Total Transmission	14 245	20 024	34 269	8 794	5 186	13 998
Total Gen & Trans	**254 581**	**427 344**	**681 125**	**152 496**	**110 328**	**262 823**

9.6.2 Annual Investment for Generation and Transmission Plans

As can be seen from the information given in Table 9-5, significant capital investments are required to be made in the hydro and thermal projects as well as for the expansion of the transmission system to increase the overall generation and transmission capacity of the power supply system. The annual investments to be made over the period 2011 to 2030 in hydro and thermal generation projects, and transmission projects are provided in Table 9-6. The annual debt and equity requirements are also given in this table. Figure 9-2 graphically depicts the annual investment requirements, while Figure 9-3 illustrates the debt and equity requirements over the planning period. The average annual financing requirement is determined to be 11.5 billion USD per year.

Table 9-6 Annual Capital Investments and Financing Requirements (million USD)

Year	Hydro Investments	Thermal Investments	Transmission Investments	Total Capital Investments	Debt Financing	Equity Financing	Total Financing
2010	0	0	0	0	0	0	0
2011	0	0	306	306	214	92	306
2012	379	359	315	1053	737	316	1053
2013	1783	3201	977	5960	4172	1788	5960
2014	3525	5745	1907	11178	7824	3353	11178
2015	4367	8208	2724	15298	10709	4589	15298
2016	5163	9477	2966	17606	12324	5282	17606
2017	5012	9947	1365	16325	11427	4897	16325
2018	4141	8728	1500	14369	10058	4311	14369
2019	5537	6125	1296	12959	9071	3888	12959
2020	6000	4995	1371	12367	8657	3710	12367
2021	8336	4712	1300	14348	10044	4305	14348
2022	7674	5592	1715	14980	10486	4494	14980
2023	6529	5373	2585	14487	10141	4346	14487
2024	5234	7316	2553	15104	10573	4531	15104
2025	3239	10451	1984	15674	10972	4702	15674
2026	2358	12005	2108	16471	11529	4941	16471
2027	1224	10895	2304	14423	10096	4327	14423
2028	1224	6662	2043	9929	6951	2979	9929
2029	735	2978	1542	5255	3678	1576	5255
2030	0	0	1179	1179	825	354	1179
Total	**72460**	**122769**	**34041**	**229270**	**160489**	**68781**	**229270**

Figure 9-2 Annual Investments in Generation and Transmission

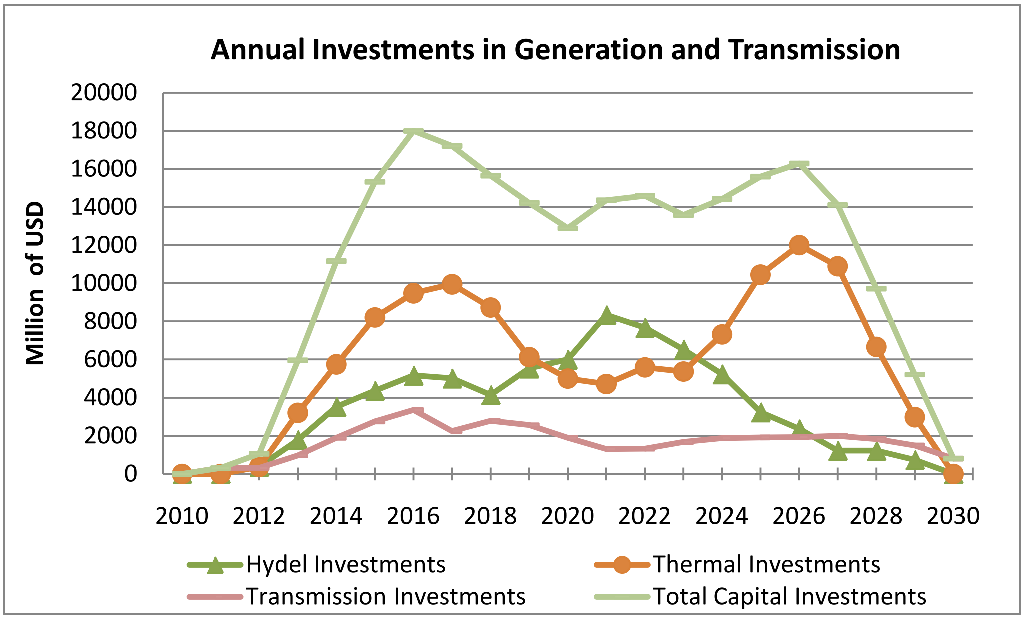


Figure 9-3 Annual Debt and Equity Financing

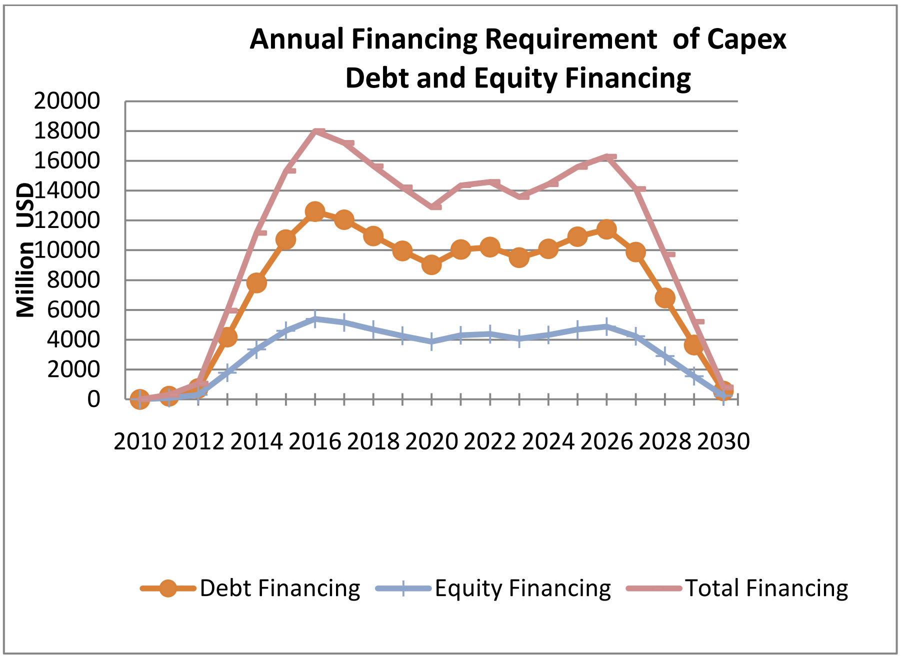


Table 9-7 provides the summary of the debt, equity and total financing requirements divided over the five-year period. The financing requirements will be highest during the five year period of 2015-16 to 2019-20 as substantial investment would be required in the generation and transmission projects to increase the generation and transmission capacity during this period to meet the increasing electricity demand.

Table 9-7 Total Debt and Equity Financing for Different Periods (billion USD)

	2010-11 to 2014-15	2015-16 to 2019-20	2019-20 to 2024-25	2025-26 to 2029-30	2010-11 to 2029-30
Debt	23.7	51.5	52.2	33.1	160.5
Equity	10.1	22.1	22.4	14.2	68.8
Total Finance	**33.8**	**73.6**	**74.6**	**47.3**	**229.3**

9.6.3 Estimation of Unit Generation Cost from Hydro and Thermal Generation.

The financial model developed calculates the unit cost of power for all the years during the planning horizon separately for the hydro and thermal generation. This is based on the calculation of the Annual Revenue Requirements (ARR). The ARR is computed by using the following equation.

Annual Revenue Requirements = O&M + Depreciation Exp + Interest Exp + Income Taxes + Net Income (Return on Equity).

Table 9-8 presents the unit cost of generation from hydro generation plants for the selected years. The unit cost of hydro generation is assessed to be 6.49 US ¢/kWh, 9.31 US ¢/kWh, 6.36 US ¢/kWh, and 5.67 US ¢/kWh in the years 2015, 2020, 2025 and 2030 respectively. For comparison purposes it may be mentioned that hydro costs from existing plants are about 1.2 US ¢/kWh.

Table 9-8 Cost of Power from Hydro Plants for Selected Years

Year	Oper. Expense	Depr. Expense	Interest Expense	Income Taxes	Return on Equity	Ann Rev Req.	Hydro Prod.	Hydro Unit Costs
	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(GWh)	(US ¢ /kWh)
2015	146	264	383	381	888	2061	31776	6.49
2020	353	930	1503	841	1963	5590	60028	9.31
2025	1051	1859	2637	1486	3468	10501	165170	6.36
2030	1515	2100	1984	1649	3848	11097	195686	5.67

Similarly, the unit costs of power from thermal projects for the selected years were also computed based on the Annual Revenue Requirement. The Annual Revenue Requirements for thermal projects for selected years are given in the Table 9-9. The unit cost of power from thermal projects is determined to be 12.05 US ¢/kWh, 12.90 US ¢/kWh, 14.09 US ¢/kWh, and 14.19 US ¢/kWh in the years 2015, 2020, 2025 and 2030 respectively.

Table 9-9 Cost of Power from Thermal Plants for Selected Years

Year	Oper. Expense	Fuel Expense	Depr. Expense	Interest Expense	Income Taxes	Return on Equity	Ann. Reven. Req.	Thermal Prod.	Thermal Unit Costs
	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(GWh)	(US ¢ /kWh)
2015	146	13741	417	540	183	426	15453	128294	12.05
2020	353	18655	2201	2379	996	2323	26907	208599	12.90
2025	1051	20799	3377	2808	1529	3568	33132	235194	14.09
2030	1515	33574	5182	3663	2352	5487	51774	364924	14.19

Comparison of the unit cost of generation from thermal plants with the unit cost of generation from the hydro plants shows that the unit cost of thermal generation is substantially higher as compared to the hydro generation costs.

9.6.4 Estimation of Unit Transmission Cost

The unit cost of transmitting power, or alternatively wheeling cost, was calculated based on the Annual Revenue Requirement for the transmission network. The Annual Revenue Requirements for transmission for selected years are given in the Table 9-10. The wheeling cost of power is evaluated to be 0.54 US ¢/kWh, 0.99 US ¢/kWh, 1.06 US ¢/kWh, and 1.03 US ¢/KWh for the years 2015, 2020, 2025 and 2030 respectively.

Table 9-10 Cost of Transmission for Selected Years

Year	Oper. Expense	Depr. Expense	Interest Expense	Income Taxes	Return on Equity	Ann. Rev. Req.	Energy Trans.	Wheeling Costs
	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(Million USD)	(GWh)	(US ¢ /kWh)
2015	171	120	232	87	202	811	151149	0.54
2020	456	479	804	344	802	2886	227703	0.99
2025	672	691	874	493	1150	3879	338445	1.06
2030	910	931	961	663	1547	5012	471469	1.03

9.6.5 Unit Cost of Power to the DISCOs and to KESC

The unit blended cost at which the power will be sold to the DISCOs and to KESC is determined by adding the revenue requirements computed for the generation (both hydro and thermal generation) and transmission and dividing it by the power delivered to the DISCOs and to KESC.

The unit cost (generation and transmission) of providing power to Discos and KESC is provided in Table 9-11 for the 5-year periods. The highest unit cost is assessed for the period 2019-20 to 2024-25, which is 14.6 ¢/kWh.

Table 9-10 Unit Supply Cost for Selling to Discos and KESC (¢/kWh)

	2010-11 to 2014-15	2015-16 to 2019-20	2019-20 to 2024-25	2025-26 to 2029-30	2010-11 to 2029-30
Hydro	4.9	8.6	7.6	5.8	6.8
Thermal	10.9	12.7	13.6	14.6	13.1
Generation (avg.)	9.6	11.8	11.5	11.2	11.1
Transmission	0.3	0.9	1.1	1.1	0.8
Blended Total	**10.6**	**14.6**	**14.6**	**14.4**	**13.6**

Notes: *The cost of generation is at the generation level. The cost of transmission is the wheeling costs. As a result the, blended total which is the costs out of transmission does not add because of transmission losses, thus effectively increasing the cost of power out of transmission. The blended total is the cost of power sold to the DISCOs and to KESC.*

9.7 Supply Cost of Power and Impact on the Customer Tariffs

The impact on the tariffs for the end-customer depends on a number of factors including the future capital and operating costs for the generation and transmission expansion plans, the costs of the distribution system, level of losses incurred in the transmission and distribution system, and the government policies regarding subsidies. The stated policy of the government is to have a power sector that does not require subsidies and is able to raise and repay its finances. It is obvious that investors will only provide investment funds, both debt and equity financing, if the entity is able to generate positive cash flows and achieve appropriate returns.

To arrive at the cost to the end-customer requires some additional calculations. The DISCOs costs of owning, operating, maintaining its distribution network and the commercial costs of meter reading, billing and collection of revenues should be added to the generation and transmission costs presented in the above sections. The average DISCOs costs were 1.18 US ¢/kWh in 2010. For calculating the end cost to the customer, the losses in the DISCOs also need to be taken into account.

Table 9-12 presents a summary of the costs of supply to the DISCOs and the final cost of supply to the end customer. This is compared to the existing tariffs both with and without subsidy and escalated at 2% over the forecast period.

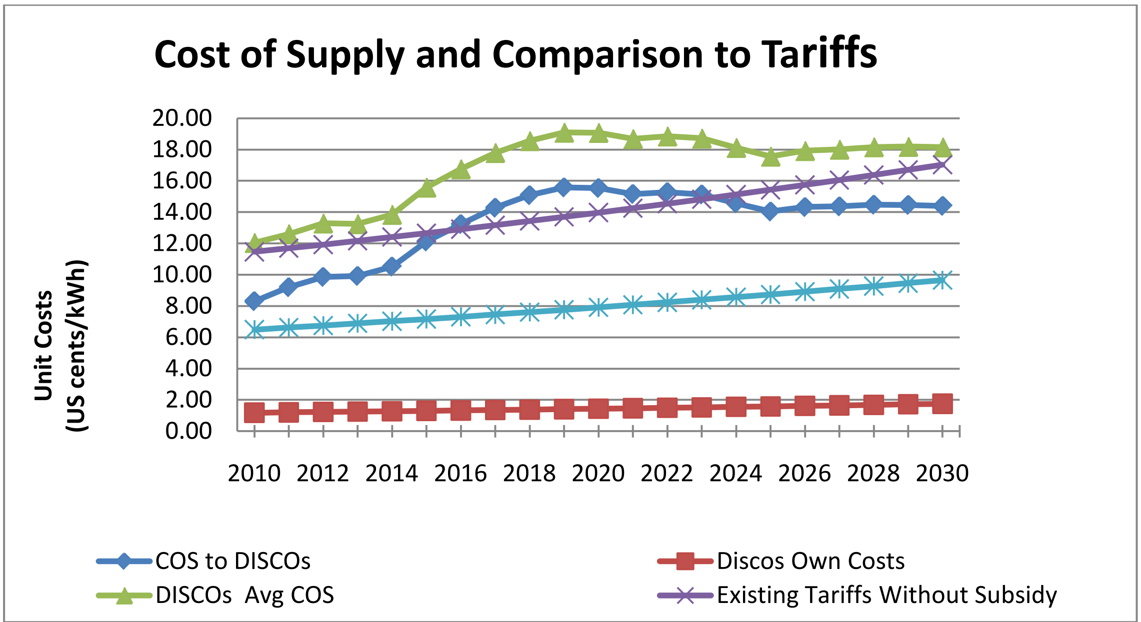
Table 9-11 Total Cost of Supply from the DISCOs and Comparison to the Existing Tariffs Escalated at 2 % (¢/kWh)

	2010	2015	2020	2025	2030
Purchase Power	8.3	12.1	15.5	14.0	14.4
DISCOs Cost	1.2	1.3	1.4	1.6	1.8
Total Costs (1)	9.5	13.4	17.0	15.6	16.2
Total Costs (2)	12.0	15.6	19.1	17.6	18.2
Tariff with subsidy	6.5	7.2	7.9	8.7	9.7
Tariffs with no subsidy	11.5	12.7	14.0	15.4	17.0

Notes: *The total cost of supply (1) represents the cost of purchased power plus the DISCOs own costs for its operations. The total cost of supply (2) represents the cost of supply based on the sales to customers, that is after losses (both technical and non technical) in the distribution system.*

The costs of the generation, transmission and distribution over the forecast period and the cost of supply to the customer and the escalated current tariffs are also shown in Figure 9-4.

Table 9-12 Comparison of Unit Cost of Supply and End Tariffs



With respect to tariffs, there can be two possible outcomes i.e., the first outcome is the existing tariff that includes a subsidy of about 50%. The tariff is escalated over the forecast period at 2%. The second outcome is without any subsidy. Both these outcomes are shown in the Table 9-12 above. As can be seen from the information provided in the above table, the cost of supply in every year is higher than the current tariff with no subsidy. This indicates that the future cost of supply is going to be significantly high as compared to current values and will have a significant impact on the end-consumer tariffs. This implies that in order to recover the power supply costs, the tariffs have to be increased significantly and should be higher than the total supply costs of electricity. For supporting the necessary investment in the power sector for its viable operation, it would be inevitable to have tariffs that should make it possible to recover the cost of electricity supply with the necessary margins so that the necessary development of the power sector in the future can be sustained on a continuous basis to meet the increasing demand of power.

9.8 Analyses of Results and Concluding Remarks

The above sections have presented the results of the total generation and transmission costs as well as the annual investment outlays over the planning period. In addition, the total supply costs for DISCOS and the implications on end-consumer tariff are also provided in the section.

The results regarding the generation and transmission investment outlays indicate that the total generation costs over the planning period would be over 647 billion USD, while the total expenditure on the transmission system is expected to be over 36 billion USD. In Present Value terms with a discount rate of 10%, these values are 248 billion USD and 15 billion USD respectively.

As regards the annual investment requirements in the generation and transmission, it ranges from minimum of 306 million USD in 2011 to the maximum of 17,602 million USD in the year 2016. The investment requirements are low in the year 2011 due to the reason that generation capacity would not be added during this year and the investments will be made in transmission network only. The high investments in 2016 are due to the massive investment requirements in the generation capacity. The average annual investment outlay is assessed to be over 11 billion USD. Considering that the GDP of the country was little over 170 billion USD in 2010, these investment requirements will be about 6.4% of the 2010 GDP of the country.

The review of results presented in the above paragraphs manifests that the cost of generation from thermal projects throughout the planning period is significantly higher as compared to the cost of hydro generation. The average cost of generation for the hydro plants is estimated to 6.8 cents/kWh over the planning horizon, while thermal generation costs is computed as 13.1 cents/kWh. The main reason of high thermal generation cost is the inclusion of fuel costs, which constitute a substantial portion in the total thermal generation cost. For hydro plants the production cost is extremely low due to the absence of any fuel requirements thus making the unit cost of generation form hydro plants significantly less as compared to the thermal plants. This implies that allocating capital investment to the hydro plants on a priority basis and putting emphasis on the development of hydro generation would be a prudent strategy in order to keep the cost of generation low. This would also facilitate in keeping the end-consumer tariff low. In addition, according high priority to hydro generation would have a long-term positive impact on the tariffs as these would not be subjected to the uncertainty of changing fuel prices thus keeping the tariffs relatively more stable.

The financial implications of investment in hydro generation would also be beneficial in the sense that foreign exchange requirements would be relatively lower in the long-term. Considering that a substantial investment for hydro projects is required in civil works, for which indigenous resources can be used, a large portion of financing can be arranged in domestic currency.

The cost results presented previously also indicates that the unit costs of generation during the period 2015 to 2025 would be relatively high, i.e., in the range of 11.5 to 11.8 cents/kWh. This is due to higher investment in the generation capacity during this period as well as due to high production costs from the thermal units. The average cost of generation over the planning period is evaluated as 11.1 cents/kWh.

The transmission investment shows a sharp increase from the period 2010-2015 to the period 2015-2020 due to the large transmission capacity requirements in order to evacuate the power from the generation capacity to be built during this period.

As regards the comparison of cost of supply with tariffs, it was observed that the cost of supply for each of the year during the planning horizon is higher than the current tariff with no subsidy. This implies that the cost of energy supply in the future is going to be considerably high as compared to current values. This will have major implications on the electricity tariffs for all the consumer sectors. However, in order to have a sustainable and viable operation and development of the power sector in order to meet the rising demand of electric energy, the implementation of tariffs so that the cost of power supply can be recovered with some margin would be imperative.

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