Indicative Generation Capacity Expansion Plan 2018-40

Power System Planning
National Transmission and Dispatch Company (NTDC)
February 2019

NATIONAL TRANSMISSION & DESPATCH CO. LTD

Company Secretary

No. NTDC/CS/ 155-57 Dated: 26-02-2019

NOTIFICATION

Approval for Authorization for Managing Director NTDC to submit Indicative Generation Capacity Expansion Plan (IGCEP) 2018-2040 to NEPRA in order to comply with NEPRA Grid Code PC 4 regulatory obligation.

The Board of Directors National Transmission & Despatch Company Limited (NTDC) in its 150th meeting held on 25.02.2019 against agenda item No.14 has unanimously resolved applauding the performance of the team associated with subject plan and authorized Managing Director NTDC to submit Indicative Generation Capacity Expansion Plan (IGCEP) 2018-2040 to NEPRA in order to comply with NEPRA Grid Code PC 4 obligation.

Ijaz Ahmad
Company Secretary

Copy to:

1. Managing Director
2. Dy. Managing Directors (P&E)
3. Chief Financial Officer

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Acronyms

Abbreviation	Description
$/kW	Dollar per kilo Watt
$/MWh	Dollar per Mega Watt hour
ACGR	Annual Compound Growth Rate
ADB	Asian Development Bank
Agr	Agriculture
AJKPPC	Azad Jammu Kashmir Private Power Cell
BCF	Billion Cubic Feet
c/Gcal	cent per Giga calorie
c/kWh	cents per kilo Watt hour
CASA	Central Asia South Asia
CCGT	Combined Cycle Gas Turbine
CFPP	Coal Fired Power Project
COD	Commercial Operation Date
Com	Commercial
CONGEN	Configuration Generator
CPEC	China Pakistan Economic Corridor
CPI	Consumer Price Index
CPPA	Central Power Purchasing Agency – Guarantee
Cumm.	Cumulative
Cus.	Customer
DISCO	Distribution Company
DSM	Demand Side Management
DYNPRO	Dynamic Programming and Optimization
EOI	Expression of Interest
EPA	Energy Purchase Agreement
FC	Financial Close
FESCO	Faisalabad Electric Supply Company
FIXSYS	Fixed System

Abbreviation	Description
FS	Feasibility Studies
FY	Fiscal Year
G.R.	Growth Rate
GDP	Gross Domestic Product
GENCOs	Generation Companies
GEPCO	Gujranwala Electric Power Company
GoP	Government of Pakistan
GT	Gas Turbine
GWh	Giga Watt-hour
HCPC	Habibullah Coastal Power Company
HESCO	Hyderabad Electric Supply Company
HPP	Hydro Power Projects
HR&A	Human Resource and Administration
HSD	High Speed Diesel
IAEA	International Atomic Energy Agency
IDC	Interest During Construction
IEP	Integrated Energy Plan
IESCO	Islamabad Electric Supply Company
IGCEP	Indicative Generation Capacity Expansion Plan
IIEP	International Institute of Electric Power Ltd.
IMF	International Monetary Fund
Imp.	Imported
IPP	Independent Power Producer
JICA	Japan International Corporation Agency
kcal/kWh	kilo calorie per kilo Watt hour
KE	K-Electric
kV	kilo volts
LDC	Load Duration Curve
LESCO	Lahore Electric Supply Company

Abbreviation	Description
LF&GP-PSP Team	Load Forecast and Generation Planning Section of Power System Planning, NTDC
LNG	Liquid Natural Gas
LOADSY	Load System
LOI	Letter of Intent
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LOS	Letter of Support
MEPCO	Multan Electric Power Company
MERSIM	Merge and Simulate
Mnf	Manufacturing
MW	Mega Watt
NEPRA	National Electric Power Regulatory Authority
NPCC	National Power Control Center
NPP	National Power Plan
NPSEP	National Power System Expansion Plan
NTDC	National Transmission and Despatch Company
O&M	Operation and Maintenance
OLS	Ordinary Least Squares
PAEC	Pakistan Atomic Energy Commission
PC	Planning Code
PEDO	Pakhtunkhwa Energy Development Board
PESCO	Peshawar Electric Supply Company
PP	Project Planning
PPA	Power Purchase Agreement
PPDB	Punjab Power Development Board
PPIB	Private Power Infrastructure Board
PSP	Power System Planning, NTDC
QESCO	Quetta Electric Supply Company
RE	Renewable Energy

Abbreviation	Description
REPROBAT	Report Writer of WASP in Batched Environment
RFO	Residual Furnace Oil
RLNG	Re-gasified Liquid Natural Gas
ROR	Run of the river
RP	Resource Planning
Rs./kWh	Rupees per kilo Watt hour
RTPSS	Real Time Power System Simulator
SEPCO	Sukkur Electric Power Company
SS	System Studies
TESCO	Tribal Electric Supply Company
Tot.	Total
TRA	Traction
TRP	Transmission Planning
TSEP	Transmission System Expansion Plan
TWh	Tera-Watt hour
USA	United States of America
VARSYS	Variable System
WAPDA	Water and Power Development Authority
WASP	Wien Automatic System Planning
WPP	Wind Power Project

Useful Links of Stakeholder Entities

Stakeholder Entity	Cyber Link
Alternate Energy Development Board (AEDB)	http://www.aedb.org/
Azad Jammu Kashmir Power Development Organization (AJKPDO)	http://ajkpdo.com/
Central Power Purchasing Agency (CPPA)	http://www.cppa.gov.pk/
Energy Department, Government of Punjab	http://www.energy.punjab.gov.pk/
Energy Department, Government of Sindh	http://sindhenergy.gov.pk/
Faisalabad Electric Supply Company (FESCO)	http://www.fesco.com.pk/
Federal Ministry of Energy	http://www.mowp.gov.pk/
Federal Ministry of Finance	http://www.finance.gov.pk/
Federal Ministry of Planning, Development & Reforms	https://www.pc.gov.pk/
Government of Azad Jammu and Kashmir	http://www.ajk.gov.pk/
Government of Baluchistan	http://www.balochistan.gov.pk/
Government of Gilgit Baltistan	http://www.gilgitbaltistan.gov.pk/
Government of Khyber Pakhtunkhwa	http://kp.gov.pk/
Government of Pakistan	http://pakistan.gov.pk/
Government of Punjab	https://www.punjab.gov.pk/
Government of Sindh	http://www.sindh.gov.pk/
Gujranwala Electric Power Company (GEPCO)	http://www.gepco.com.pk/
Hyderabad Electric Supply Company (HESCO)	http://www.hesco.gov.pk/
Islamabad Electric Supply Company (IESCO)	http://www.iesco.com.pk/
K-Electric (KE)	https://www.ke.com.pk/
Lahore Electric Supply Company (LESCO)	http://www.lesco.gov.pk/
Multan Electric Power Company (MEPCO)	http://www.mepco.com.pk/

Stakeholder Entity	Cyber Link
National Electric Power Regulatory Authority (NEPRA)	http://www.nepra.org.pk/
National Transmission and Despatch Company (NTDC)	http://www.ntdc.com.pk/
Pakhtunkhwa Energy Development Organization (PEDO)	http://www.pedo.pk/
Pakistan Atomic Energy Commission (PAEC)	http://www.paec.gov.pk/
Pakistan Bureau of Statistics	http://www.pbs.gov.pk/
Peshawar Electric Supply Company (PESCO)	http://www.pesco.gov.pk/
Private Power Infrastructure Board (PPIB)	http://www.ppib.gov.pk/
Quetta Electric Supply Company (QESCO)	http://www.qesco.com.pk/
Sukkur Electric Power Company (SEPCO)	http://www.sepco.com.pk/
Tribal Areas Electric Supply Company (TESCO)	http://www.tesco.gov.pk/
Water and Power Development Authority (WAPDA)	http://www.wapda.gov.pk/

Foreword

The Report on ‘Indicative Generation Capacity Expansion Plan (IGCEP) 2018-40’ presents the results of the latest expansion planning studies conducted by the Load Forecast and Generation Planning (LF&GP) of Power System Planning (PSP), National Transmission and Despatch Company (NTDC) as per the criteria specified in the Grid Code.

This report gives a comprehensive view of the existing generating system, future electricity demand forecast and future power generation options in addition to the expansion study results. It is pertinent to highlight that annual updating of this plan is also a regulatory obligation on the part of the NTDC.

In a bid to manage higher level of transparency as well as to make this report comprehensive, various aspects have been included such as stakeholder entities who have shared the input data, currency of input data for the IGCEP, software tools used along with their specifications and limitations, generation planning process, etc. However, the LF&GP-PSP Team would certainly welcome suggestions and comments for adding further value to this important regulatory obligation of NTDC.

Acknowledgements

Commissioning of a study and preparation of a country vide power generation plan, such as the IGCEP, naturally relies extensively on the input data provided by multiple stakeholders namely Pakistan Atomic Energy Commission (PAEC), Alternate Energy Development Board (AEDB), National Electric Power Regulatory Authority (NEPRA), Private Power Infrastructure Board (PPIB), Pakhtunkhwa Electric Development Organization (PEDO), Punjab Power Development Board (PPDB), Sindh Energy Board, Azad Jammu & Kashmir Private Power Cell (AJKPPC) and Water and Power Development Authority (WAPDA); this output could have been materialized without the contribution by these stakeholders.

This intervention was hugely complemented by Central Power Purchasing Agency (Guarantee) who engaged and placed the services of two senior consultants at the disposal of PSP-NTDC focused on load forecast and generation planning.

The IGCEP also benefited from advice, suggestions, and value addition from various entities including CPPA, senior power sector professionals and colleagues from PSP-NTDC.

The LF&GP-PSP Team is highly grateful for Prime Minister's Task Force headed by Mr. Nadeem Babar for Energy Reforms for their kind and concerned review of the IGCEP. Further guidance by Mr. Shahzad Qaisar, Special Advisor to Prime Minister on Power is also appreciated.

The LF&GP-PSP Team is, therefore, highly grateful to all those who contributed in preparation of the IGCEP. Nevertheless, the Team is responsible for any errors and omissions available in this report.

1. Power System Planning – Gateway to NTDC

Pursuant to the NTDC Transmission License and Grid Code, NTDC is responsible for power system planning of the whole country. PSP is the gateway to NTDC and is mandated to undertake power system planning of the whole country except for Karachi which is being governed by K-Electric for all facets of the power system i.e. generation, transmission and distribution.

Vision

PSP as the spearhead component of NTDC is equipped with all it takes to confront the challenges pertaining to Pakistan power system planning; be it intellect, procedures and processes, and tools.

Mission

PSP endeavors becoming and sustaining a smart department of NTDC that offers optimized solutions at the most competitive cost through a highly upbeat and competent human resource equipped with modern tools, formalized systems and above all the performing culture aiming to achieve the objectives of NTDC in the most competitive, efficient and timely manner.

Strategic Goal

PSP to contribute proactively in the efforts for NTDC be acknowledged as a trusted, professional and efficient utility owing to its competent and committed work force internationally accepted working procedures, and excellent performance standards.

Approach

PSP believes in participatory approach: *seek commitment through involvement at all levels.*

Slogan

Driven by future

Core Responsibility

PSP is primarily responsible for development of power transmission investment plan that encompasses demand forecast, generation expansion and associated transmission development plan and the consolidated NTDC Investment Plan.

A Snapshot of Major Functions

Following are the core functions of the PSP mandated to manage power system planning of the NTDC network:

a. Development of Medium Term and Long Term Load Forecast and Indicative Generation Capacity Expansion Plan (IGCEP)

b. Preparation of Transmission Development Plan

c. Development of Power Transmission Investment Plan

Major Challenges

a. Rapidly increasing load growth and corresponding size of the grid vis-à-vis governments policy to restrict public sector investment in the power sector

b. Optimal quantum of renewable energy in the national energy mix owing to various factors such as i) intermittent nature of renewable energy; ii) lack of a robust electricity grid; iii) extreme local temperature in the wind corridor; iv) Harmonic distortion due to the presence of inverters in the generation mechanism of solar power plants and the newer technology wind power plants; and v) lack of reliable weather forecast effecting efficient dispatch

c. Brain drain, a tough challenge for the PSP for around three decades or so i.e. migration of professionals to other departments, companies and / or countries for better opportunities, has adversely affected the intellectual strength of the PSP.

PSP Organogram

PSP is comprised of three different sections, each one is headed by a Chief Engineer, which include i) Load Forecast and Generation Planning, ii) Transmission Planning and iii) Resource Planning. Figure 1-1 provides the broad organogram of the PSP:

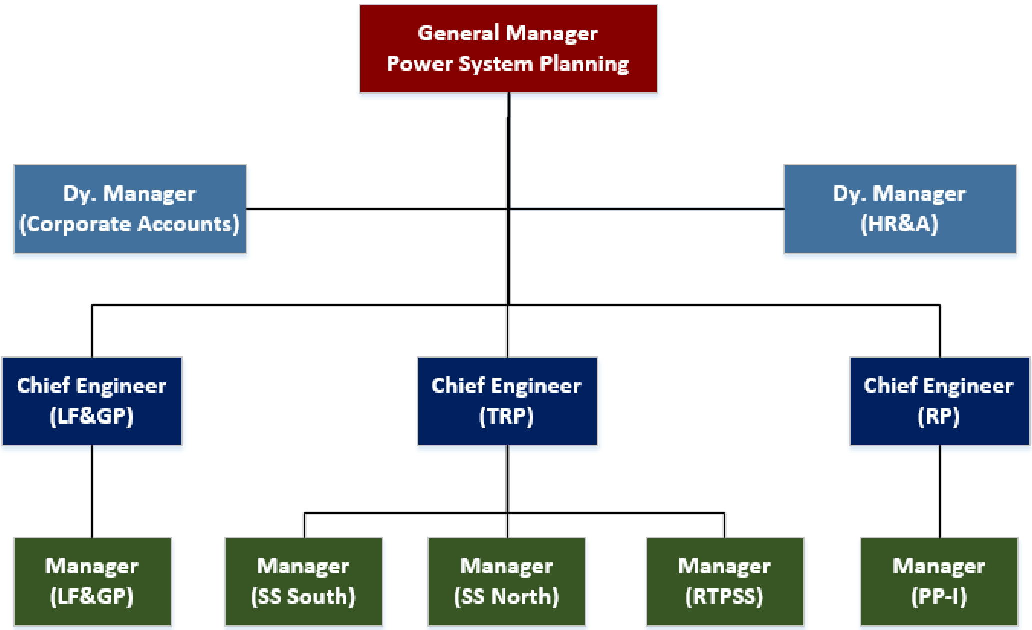


Figure 1-1: Organogram of the Power System Planning, NTDC

PSP Key Performance Indicators (KPI)

Following are the six KPIs to evaluate its success at reaching targets in the most optimal manner:

a. Regulatory Compliance

Regulatory obligations / submissions are managed in the most comprehensive and timely manner.

b. Relevance

Right person for the right job including task assignment, nominations for the trainings and meeting attendance.

c. Coherence

All three sections coordinating with each other in true sense.

d. Quality and Effectiveness

At par with the local market and best utility practices.

e. Sustainability

Impact of previous investments and efforts are reflected in the knowledge creation and outcome in an optimal manner.

f. Participation

Following participatory approach by involving all stakeholders including internal and external, where applicable.

2. Setting the Perspective

This section is provided to facilitate an introduction to the IGCEP – the plan.

2.1. Generation Planning – A Subset of Power System Planning

Power system planning is a subset of the integrated energy planning. Its objective is, therefore, to determine a minimum cost strategy for long-range expansion of the power generation, transmission and distribution systems adequate to supply the load forecast within a set of prevailing technical, economic and political constraints. Traditionally, power system planning is predominantly related to generation expansion planning; it is due to the fact that investment in transmission system is relatively a small fraction of the investment corresponding to the construction of power stations.

Generation expansion planning concerns decisions for investment pertaining to development of different types of power plants over a multi-decade horizon, in case of the IGCEP 2018 it remains 22 years, under various uncertainties. The goal of this study is to improve decision-making under various long term uncertainties while assuring a robust generation expansion plan with low cost and risk over all possible future scenarios.

As depicted in the Figure 2-1, generation planning is at the heart of Planning Cycle. In an idealistic scenario, the Integrated Energy Plan (IEP) being prepared by Ministry of Planning, Development and Reforms is meant to provide the fuel mix targets for all sectors of the economy including the power sector and such targets are adopted under the electricity policy. The IGCEP is prepared to ensure its maximum contribution in energy security, sustainability and affordability while considering policy inputs and broader macroeconomic perspectives. Under Section 32 of NEPRA Act, such integration should be ensured that brings the full dividends of the integrated planning.

However, in absence of the IEP output, the IGCEP optimizes the generation costs to ensure that adequate generation is added at least-cost to meet the load of the future with its given load shape, which also brings tremendous benefits over back of the envelop based plans, leading to higher costs, shortages or surpluses.

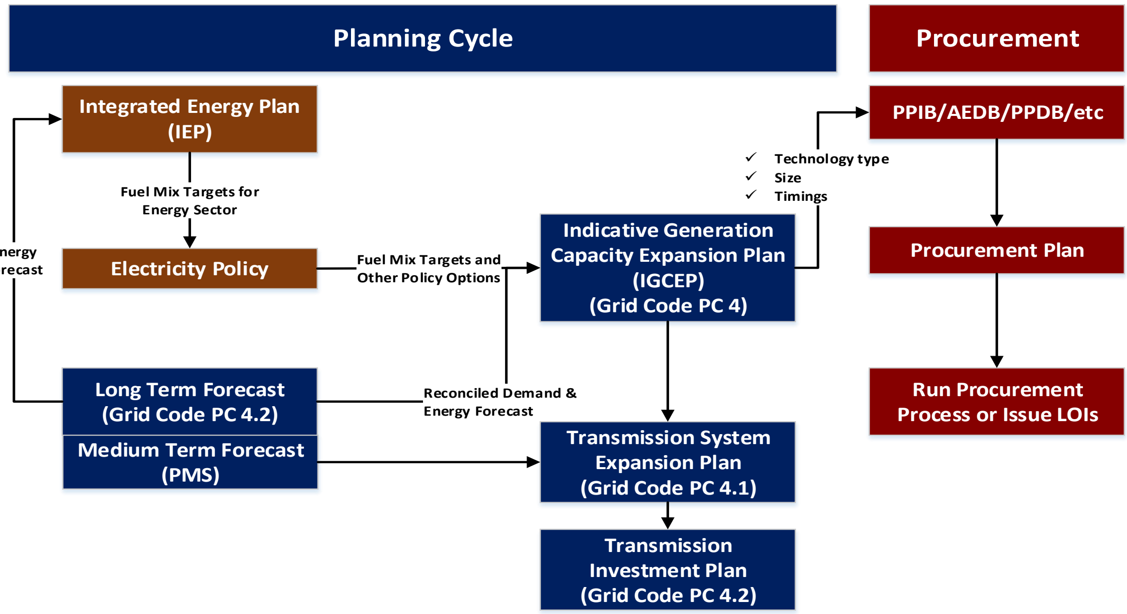


Figure 2-1: Planning Cycle Leading to Procurement

It is pertinent to mention here that the new procurements for the consumers done by any agency or by DISCOs shall be informed by the results of IGCEP or in other words shall be in-line with the IGCEP inputs.

2.2. Preamble

Looking back at the previous practices, following three (03) major plans have been formulated by the then WAPDA and now NTDC with the assistance of foreign consultants:

a. National Power Plan (NPP 1994-2018) developed by Canadian Consultant, M/s ACRES International Limited;

b. National Power System Expansion Plan (NPSEP 2011-2030) developed by Canadian Consultant, M/s SNC Lavalin; and

c. Least Cost Plan (LCP 2016-2035) developed by Japanese Consultant, M/s International Institute of Electric Power, Ltd. (IIEP)

However, due to multiple reasons, NTDC has not been consistent in preparation of the IGCEP and its submission to the NEPRA for approval. In order to ensure regulatory compliance and sustain it on annual basis, as required by the Grid Code, NTDC in collaboration with CPPA, has formulated the IGCEP (2018-2040) by considering all the existing as well as firm future power plants.

2.3. Introduction

In view of its rapidly increasing utilization and demand for enhanced access thereof, electricity is today recognized as the most critical pre-requisite for improving the lives of people of a country; Pakistan is not an exception. Therefore, certain electricity indices such as per capita consumption of electricity and access to electricity are used to express the strength of a country's economy. Electricity is a unique kind of commodity since it is economically not viable to store its large quantum and it has to be consumed instantaneously. Further, certain ground realities such as seasonal variations, consumers' varying choices make the demand forecast process quite difficult. On the other hand, insufficient as well as surplus capacity adversely affects the economy. Careful planning of the power sector is, therefore, quite complex while carrying great importance since the decisions to be taken involve the commitment of large resources, with potentially serious economic risks for the electrical utility and the economy as a whole.

The function of an electric power system is to provide a 24/7 reliable and continuous source of electricity. In order to make it happen, each of the three main components of an electric power system — generation, transmission and distribution — must perform as planned. The generation system consists of physical facilities that convert energy resources e.g. coal, oil, uranium, hydro, renewable into electricity. The transmission system then transports the generated electricity to the load centers. The distribution system ultimately provides the actual connection to each customer, and enables the customer to consume electricity upon demand. An electric power system is thus a dynamic system, which is a balance of supply and demand of electricity.

The power sector of Pakistan during the last few years displayed resolute efforts to get rid of the menace of load shedding which had adversely affected entire socio-economic balance of the Country. From being in state of scarcity to achieving the demand-supply balance, moving forward, it now has become essential to prepare and implement integrated plans in timely manner across the entire value chain of the electricity sector.

The integrated power planning calls for a well-coordinated planning not only within the electricity sector but also its integration with overall energy planning at the country level. In Pakistan, the generation capacity additions in past five years have been remarkable. However, planning remained fragmented all-across the energy value chain of which electricity is a subset. The sector recognizes the importance of integrated planning as it will not only enhance investor's confidence by basing investments' decisions on transparent and predictable planning process but will also be a key factor in ensuring affordable and secure supply for the sector.

The best utility practices pertaining to planning methodologies are there for all three main components of a power system, and each one is in itself a major subject of study. Least cost generation planning is one of the most important element of overall integrated planning of electricity sector. Therefore, and further in compliance to NERPA's approved Grid Code clause PC-4 (Forecasts and Generation Expansion Plan) and PC-4.1 (Generation Capacity Additions), this long-term least cost generation plan or Indicative Generation Capacity Expansion Plan (IGCEP) is prepared for review and approval by NEPRA, the Regulator.

The IGCEP is prepared based on long-term electricity demand forecast prepared by NTDC, updated generation commitment schedule and other parameters updated as of June 30, 2018.

Figure 2-2: IGCEP Objectives

2.4. Objectives of the IGCEP

The IGCEP is envisioned to meet the following objectives, as highlighted in the Figure 2-2:

a. **Identify** new generation requirements by capacity, technology and commissioning dates on year-by-year basis;

b. **Satisfy** the Loss of Load Probability (LOLP) not more than 1% year to year, as initially set under the Grid Code: PC - 4.1;

c. **Cater** for the long-term load growth forecast and reserve margins pursuant to the Grid Code; and

d. **Provide** a least cost generation expansion plan for development of hydroelectric, thermal, thermal nuclear and renewable energy resources to meet the expected load up to the year 2040

2.5. Scope and Planning Horizon

The IGCEP covers the whole country except for Karachi. K-Electric, a vertically integrated power utility, managing all three key stages – generation, transmission and distribution – of producing and delivering electrical energy to consumers within the geographical jurisdiction of the city of Karachi. However, the IGCEP, for the purpose of load forecast and indicative generation plan includes a fixed export of 650 MW from NTDC system to K-Electric. The planning horizon of the IGCEP is 2018 – 2040.

2.6. Nature of the IGCEP

Overall purpose of the IGCEP is the fulfillment of outlines, actions, and strategies as stipulated in the relevant policies of Government of Pakistan, latest generation technologies, constraints and relevant regulatory obligations. The focus of this plan is to identify generation additions, by capacity and fuel type along with commissioning dates, for a certain plan period, through optimal use of all available generation resources. The system's optimum expansion is determined by the IGCEP considering various limitations and factors such as investment costs, operation costs, fuels, reserves, maintenance allowance, etc. For this purpose, WASP-IV tool has been used to elaborate projected electric power demand 2018-40 and various other characteristics such as hydrology of existing and future hydro power projects, fuel costs estimations and all technical and financial data pertaining to existing and potential generation options i.e. feasible hydro power, thermal and renewables future projects potential generation options, simulation of different scenarios and optimization of all options. The IGCEP is developed as a suggested starting point for the preparation of a determinative Transmission Expansion Plan as a part of the overall PSP process.

However, the IGCEP is meant to be considered as an indicative generation expansion plan, since it will be updated on yearly basis to account for any change in generation technologies trends, governmental policies, progress/priorities of different project execution entities and project sponsors in developing the generation facilities, etc.

2.7. Rationale for Preparation of the IGCEP

Pursuant to the provisions of the Grid Code i.e. Planning Code (PC) - 4 and PC - 4.1, NTDC is mandated for preparation of the IGCEP on annual basis for review and approval of NEPRA. This plan shall take-into account the objectives/criteria as mentioned under sub-section 1.1 above and shall be used as an input for NTDC's Transmission System Expansion Plan (TSEP) as stated in the PC 4.2. Relevant excerpts from the PC 4 of the Grid Code are as follows:

PC 4: "Each year, the NTDC shall prepare and deliver to NEPRA a Ten-Year "Indicative Generation Capacity Expansion Plan (IGCEP)" covering 0-10 Year timeframe. NTDC shall provide this IGCEP of NTDC Plan.**"**

PC 4: “The Plan shall be subject to review and approval by NEPRA.”

PC 4.1: “The NTDC Plan shall be based on a twenty-year Load Demand and Energy Forecast and shall be prepared according to a Loss of Load Probability (LOLP) methodology established under this Grid Code, and NEPRA Transmission Performance Standard Rules.”

PC 4.1: “The NTDC Plan shall be submitted to NEPRA on or before April 15 for the next financial year.”

2.8. Report Structure

An illustration of the structure of IGCEP report through a mind map is provided for quick understanding and reference in the Figure 2-3.

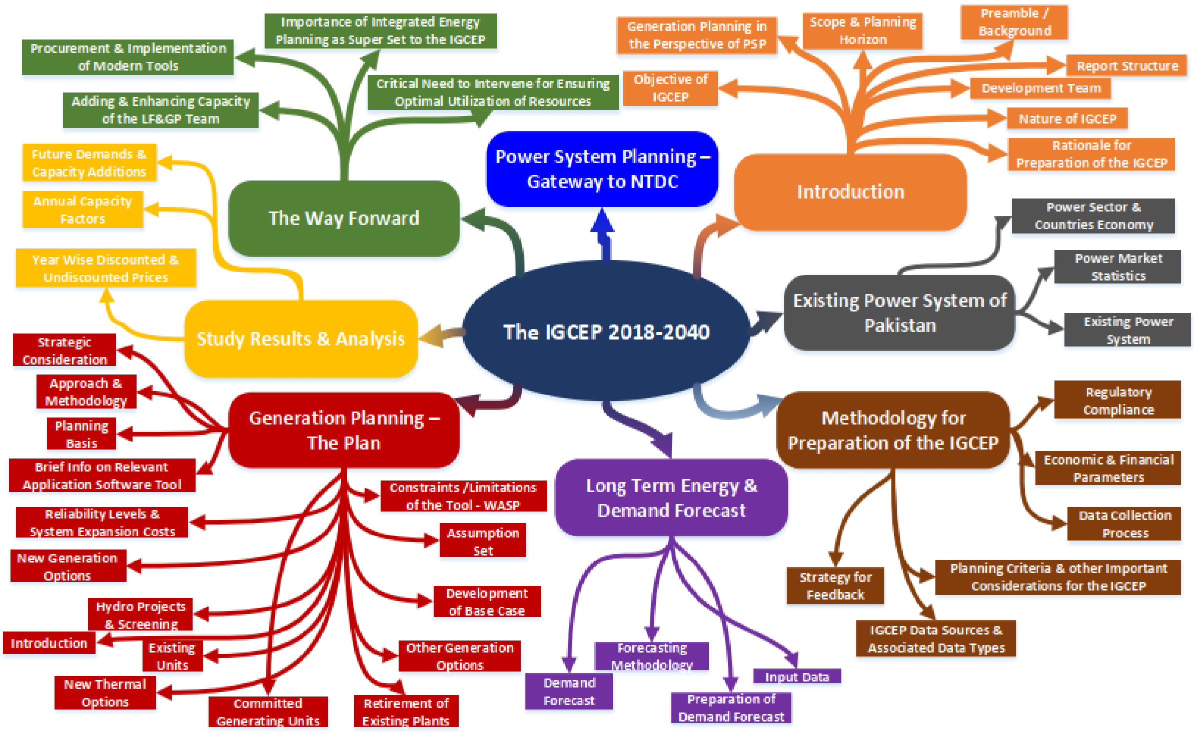


Figure 2-3: IGCEP Mind map

2.9. IGCEP Development Team

Following team members have contributed towards the preparation of the IGCEP:

a. Engr. Abdul Razzaq, Consultant, Generation Planning, engaged by CPPA and dedicated for preparing the IGCEP
b. Engr. Bilal Ahmed, Consultant, Load Forecast, engaged by CPPA and dedicated for preparing the IGCEP
c. Engr. Dr. Khawaja Riffat Hassan, General Manager, Power System Planning
d. Engr. Salis Usman, Chief Engineer, Load Forecast and Generation Planning
e. Engr. Tauseef ur Rehman Khan, Deputy Manager, Load Forecast
f. Engr. Ahmad Miraj Butt, Deputy Manager, Generation Planning and Optimization
g. Engr. Irfan Saqib, Assistant Manager, Generation Planning and Optimization
h. Mr. Shahid Abbas, Staff Economist
i. Engr. Yasoon Aslam, Assistant Manager, Generation Planning and Optimization

3. Power System of Pakistan: Existing Scenario

3.1. Power Sector and Country's Economy

Energy is a critical input for economic development and correspondingly power sector comprises an indispensable infrastructure in any economy. Providing adequate and affordable electric power is essential for economic development, human welfare and better living standards. The growth of economy along with its global competitiveness hinges on the availability of reliable and quality power at competitive rates to all consumers throughout the country. Electricity is central to achieving economic, social and environmental objectives of sustainable human development. Development of different sectors of economy is impossible without matching development of the power sector.

The demand for power in a developing country like Pakistan is enormous and is further growing steadily. In spite of massive generation capacity additions over the last five years, after witnessing acute electricity shortages since 2006, electricity demand, at certain times during the year, still exceeds the generation capacity. However, the difference is relatively quite small and demand-supply projections ensure that there will be sufficient capacity to meet the demand in the coming years.

In order to meet the electricity demand requirements of the country, for the FY 2017-18, 120, 783 GWh energy was generated from all power plants. In our distribution system, the electricity consumers are segregated in six different categories i.e. domestic, commercial, small industries, medium and large industries, agriculture and public lights. Each category is subjected to different electricity tariff. By 2017-18 the total number of electricity consumers has reached to 26,871,660 out of which 23,173,856 belongs to domestic category, 3,028,054 belongs to commercial category, 339,853 consumers fall under industries, there are 315,021 agriculture consumers, Bulk Supply consumers are 4,450 and public lighting consumers have been recorded as 10,426.

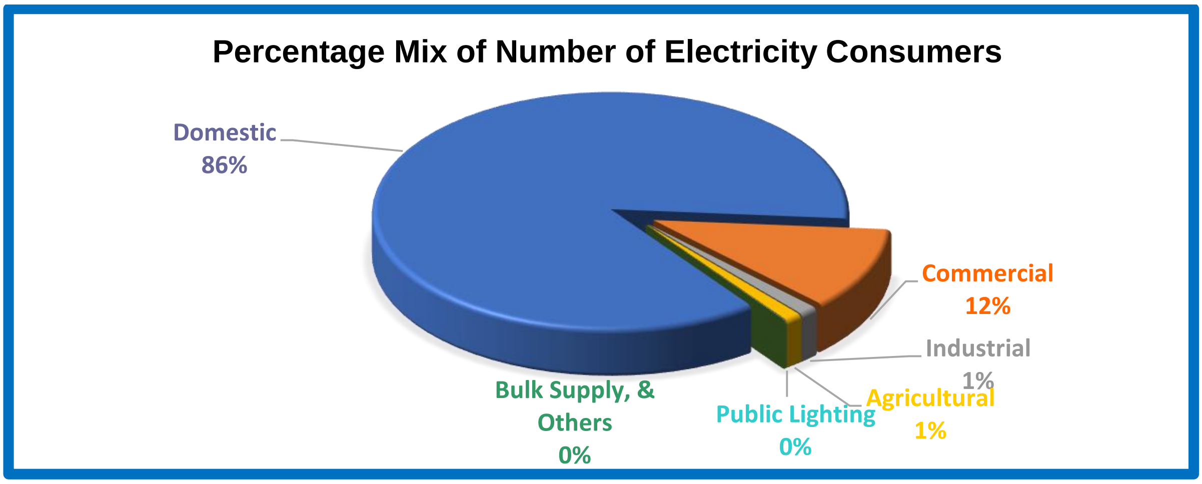


Chart 3-1: Percentage Mix of Number of Electricity Consumers

During the FY 2017-18, domestic consumers had a share of 46,114 GWh, commercial consumers used 6,753 GWh, industrial consumption was 23,274 GWh, agriculture consumers had a share of 9,978 GWh, 319 GWh have been consumed by public lighting, and Bulk supply was catered with 5,631 GWh.

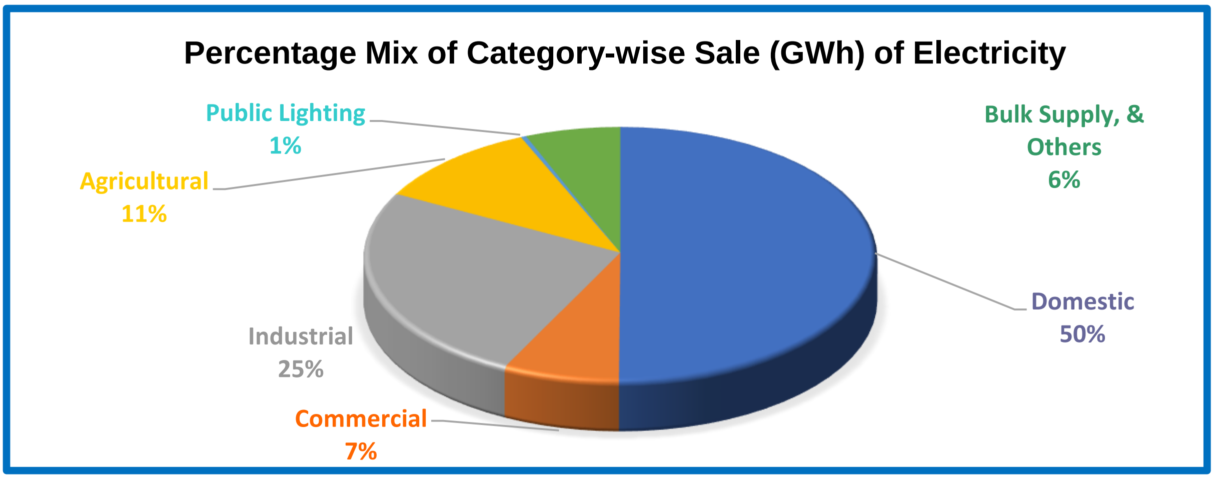


Chart 3-2: Percentage Mix of Category-wise Sale (GWh) of Electricity

The availability of electricity has a very direct impact on the country's GDP as shown in the Chart 3-3. As declared by Economic Survey of Pakistan, in the fiscal year 2017-18, the country has seen 5.79% growth rate in total GDP. The sector-wise components of GDP are agriculture, industrial and commercial/services sector. A growth rate of 3.81%, 5.80% and 6.43% was observed in agriculture, industrial and commercial/services sector, respectively.

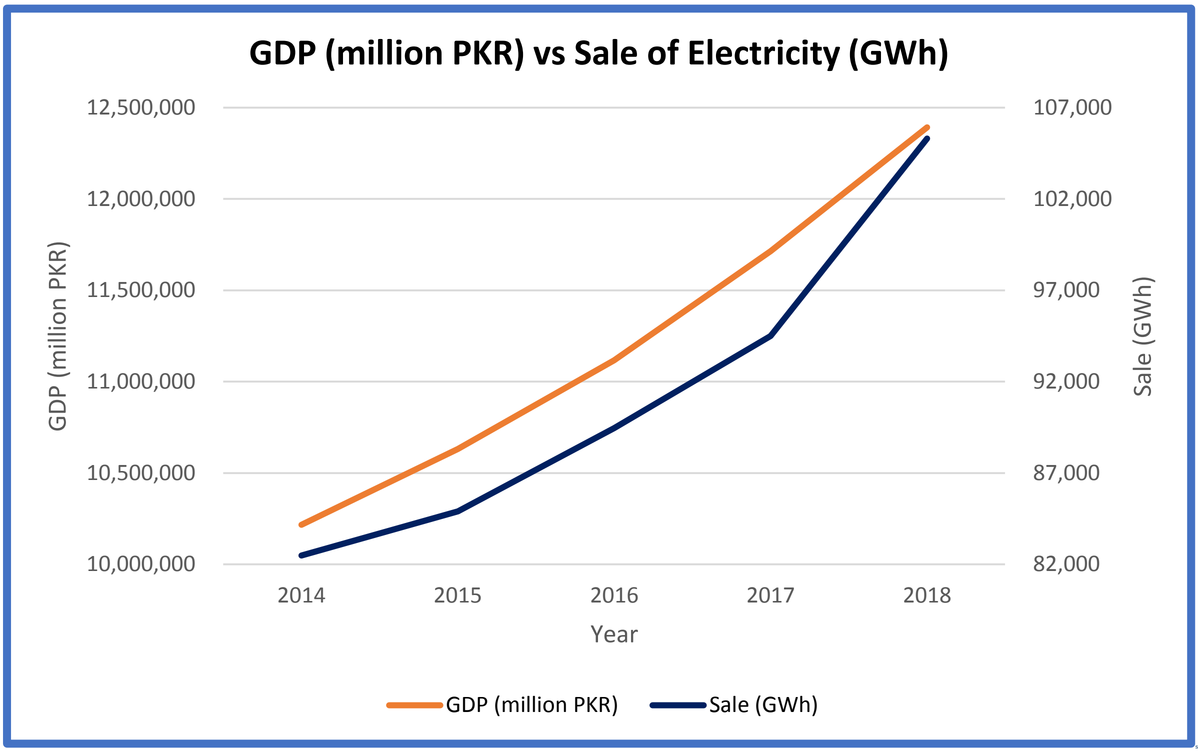


Chart 3-3: GDP (million PKR) vs Sale of Electricity (GWh)

The electricity demand of Pakistan is met through different sources of energy e.g. hydro, gas, coal, furnace oil, solar power and wind power. In 2017-18, 28,562 GWh was generated through hydro power, 8,800 GWh from the nuclear energy, 80,609 GWh through Gas, High Speed Diesel (HSD), Residual Furnace Oil (RFO) and coal power, 664 GWh by solar power and 2,117 GWh by the wind power plants.

3.2. Power Market Statistics

Currently, Pakistan's electricity sector has a flexible generation mix with 69% share of thermal and 26% share of hydro generation and its turnover now exceeds 100 TWh threshold. It comprises of 18 Nos. 500 kV, 42 Nos. 220 kV and about 1,000 Nos. 132 kV substations.

There has been an increasing trend in the electricity generation statistics for the period 2012-13 to 2017-18 as shown in the Chart 3-4.

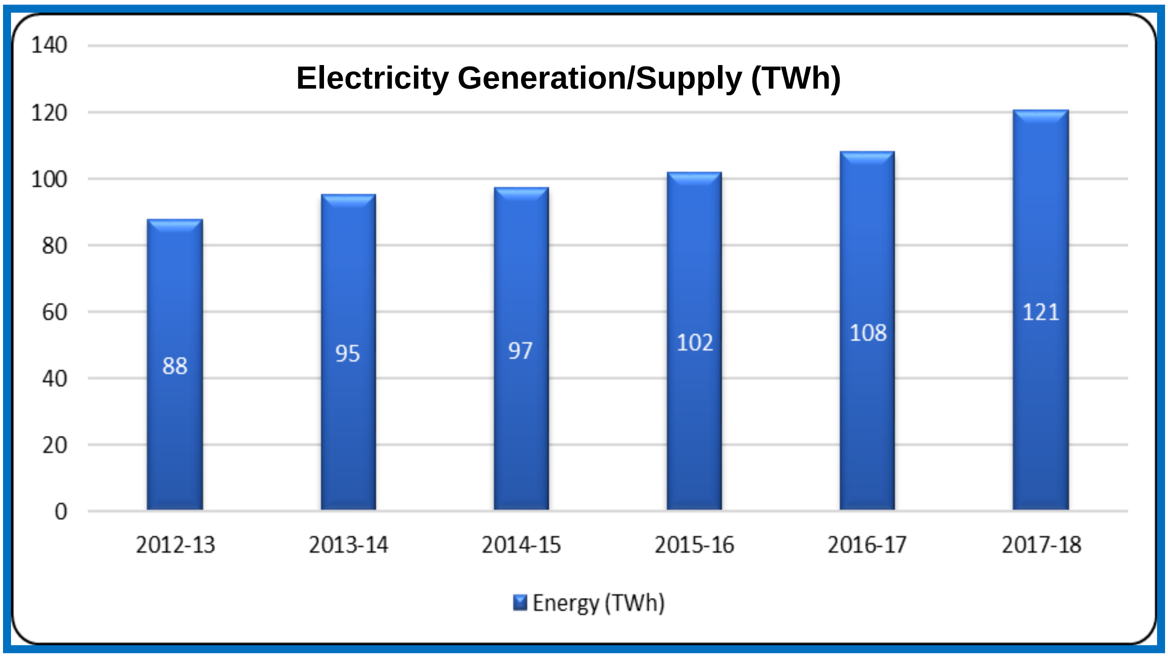


Chart 3-4: Electricity Generation/Supply (TWh)

Though electricity generation has increased significantly in the past few years, the demand has also been growing steadily with improved electricity supply; it is evident from the electricity demand trend over the past five years as shown in the Chart 3-5.

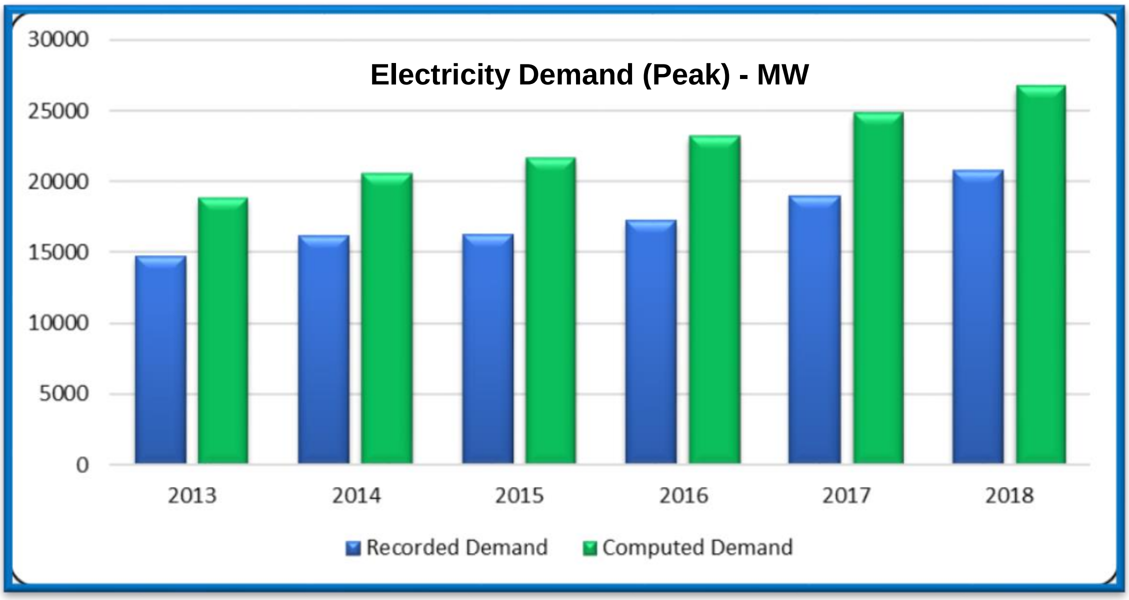


Chart 3-5: Electricity Demand (Peak) - MW

Electricity consumption in Pakistan is dominated by domestic sector followed by industrial and agricultural sector. The trend of electricity consumption in different categories is highlighted in the Chart 3-6.

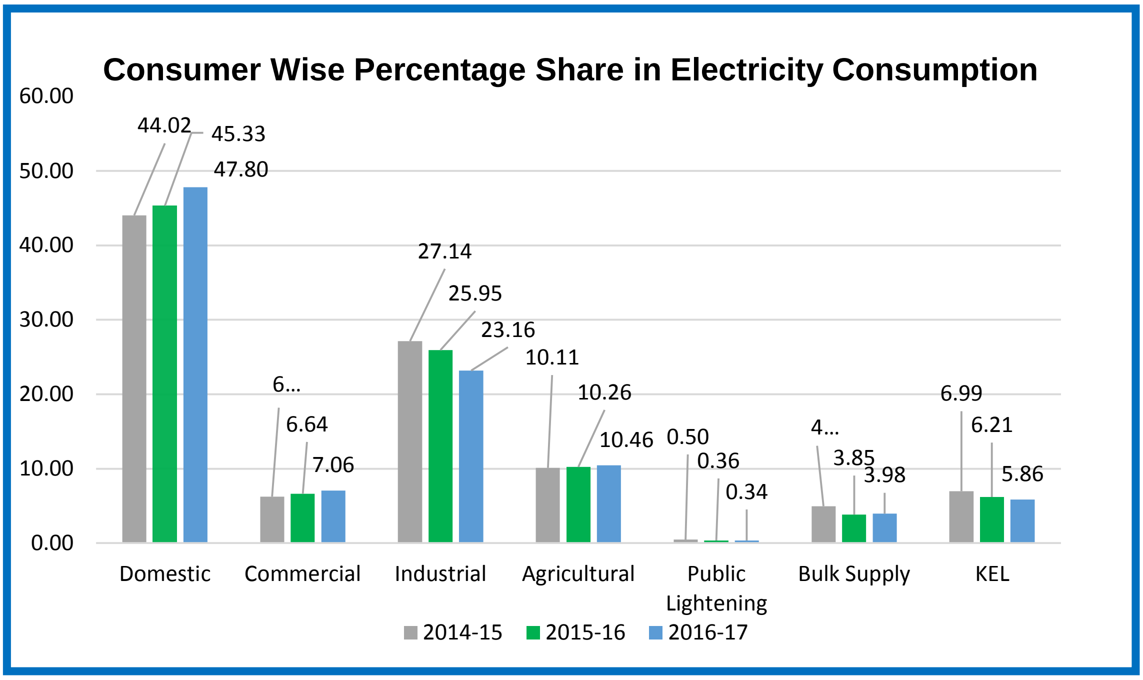


Chart 3-6: Consumer Wise Percentage Share in Electricity Consumption

3.3. Existing Power System

The existing generation capacity of NTDC system is illustrated below in Chart 3-7. It comprises of 29% share of hydro generation in terms of installed capacity whereas thermal share is 61%. Wind, Solar, Bagasse and Nuclear contribution stand at 3%, 1%, 1% and 4% respectively[1].

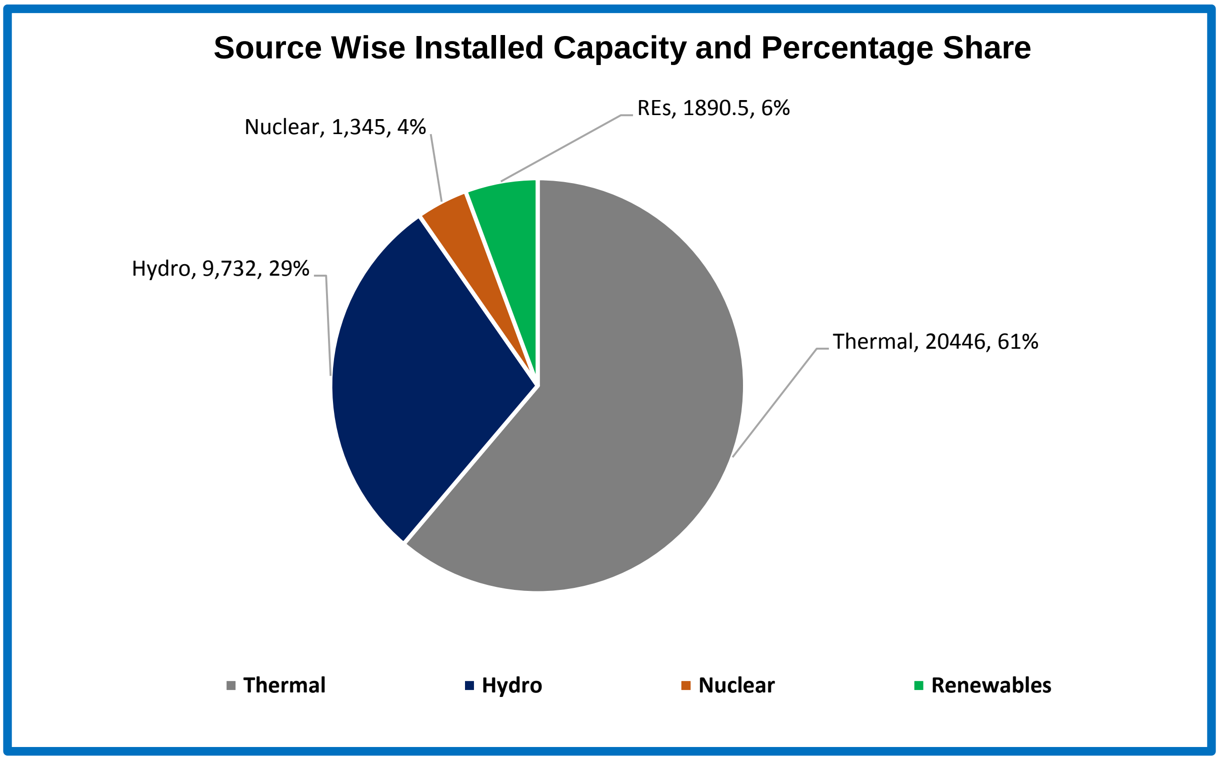


Chart 3-7: Source Wise Installed Capacity and Percentage Share

In terms of energy share, the generation mix of Pakistan, as in the year 2017-18, is depicted through the Chart 3-8:

[1] As on 30th December 2018

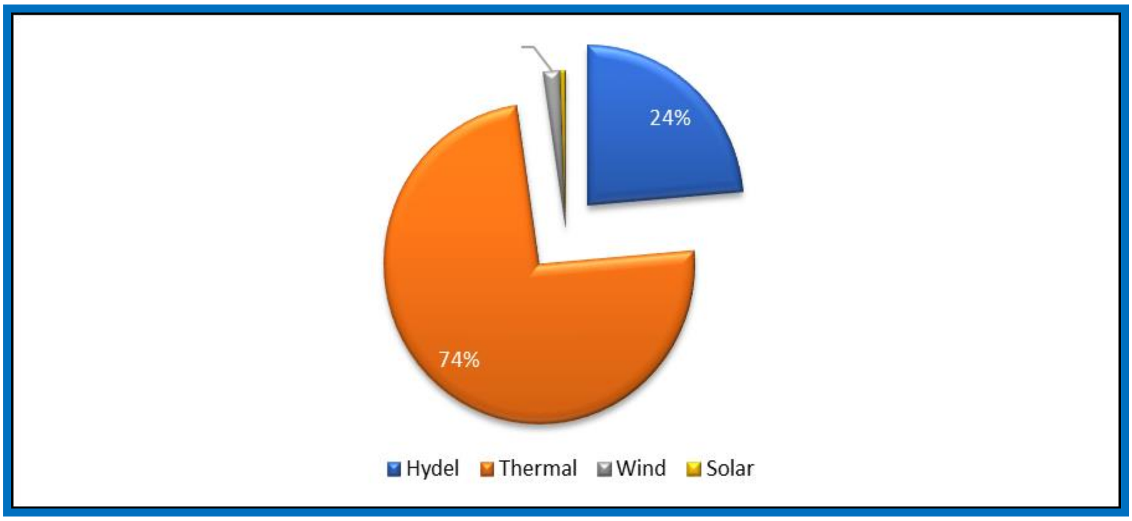


Chart 3-8: Share in Energy Generation (2017-18)

Figure 3-1 is provided to illustrate the geographical layout of existing power generation sources in the NTDC system.

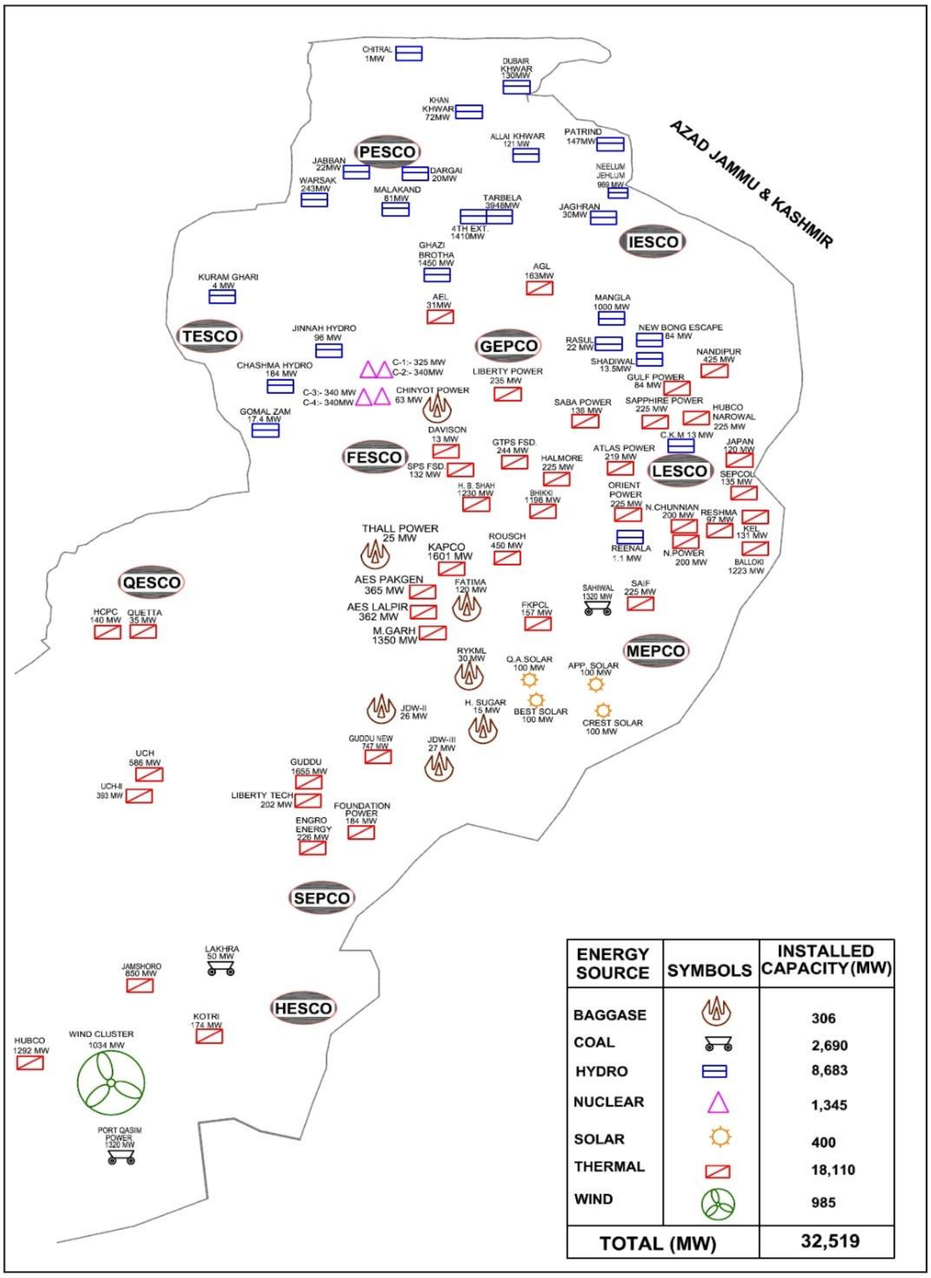


Figure 3-1: Geographical Layout of Existing Power Generation Sources

The Government of Pakistan has been pursuing broad objectives for the economically viable power generation development including renewable energy, focusing on environment friendly resources and reduced dependence on the imported fuels. Also, diversification of fuel resources and security of fuel supply have been remained among its priorities. The addition of different new generation technologies in the past few years have changed the power mix of the sector largely dominating from Furnace Oil to Coal, Re-Gasified Liquefied Natural Gas (RLNG) and Renewables as no major addition on furnace oil has been made so far and even planned in the future. Chart 3-9 shows fuel wise, installed capacity mix of Pakistan as on 30 December 2018.

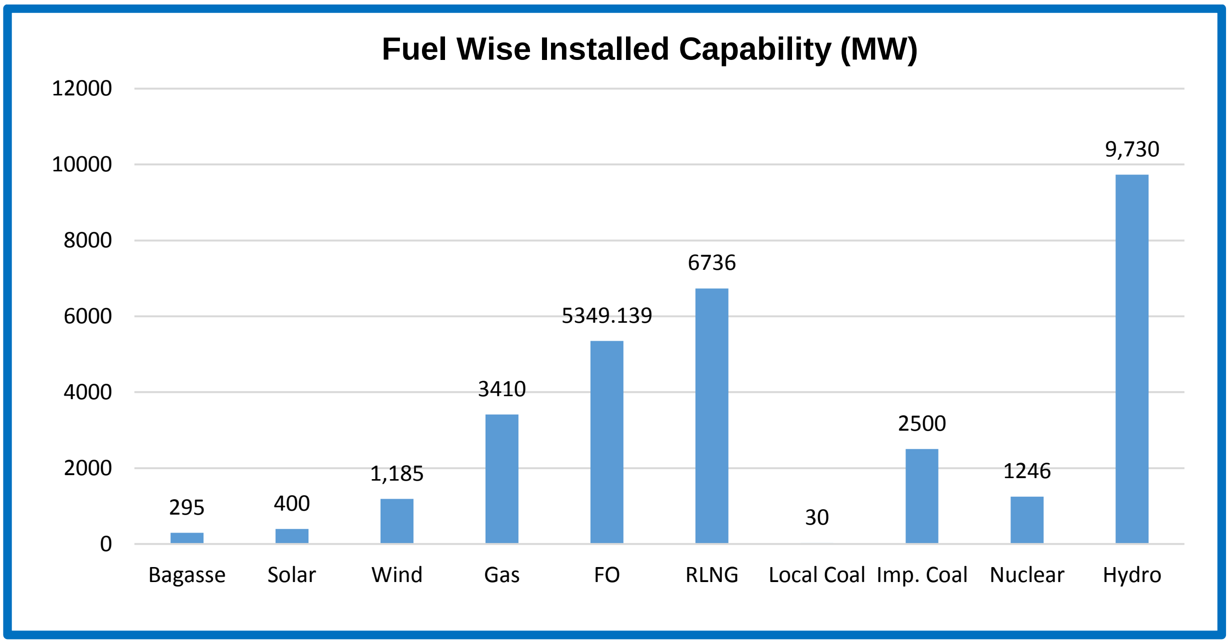


Chart 3-9: Fuel Wise Installed Capability (MW)

The IGCEP also follows the policy of reduced dependence on imported fuel; increasing the capacity of renewable and indigenous fuel-based plants. Following these guidelines, the results of least cost generation capacity expansion plan are presented in the following chapters.

4. Methodology Customized for the IGCEP

This section details methodology adopted for the preparation of the IGCEP.

4.1 Regulatory Compliance

The IGCEP covers the development of hydroelectric, thermal, nuclear and renewable energy resources to meet the expected load up to the year 2040. It identifies new capacity requirements by capacity, technology and commissioning dates on year by year basis by complying with the various regulatory requirements as set out in the Grid Code including Loss of Load Probability (LOLP) not more than 1% year to year, the long-term load growth forecast and reserve margins.

4.2 Data Currency Log

For reference of IGCEP users, Table 4-1 provides the currency of various input data used for preparing the IGCEP.

Table 4-1: IGCEP Input Data Currency Log

Sr. No.	Data Aspect	Currency Date
1	Load Duration Curves	30th June 2018
2	Electricity Consumers (Numbers)	30th June 2017
3	Energy Sale (GWh)	30th June 2017
4	Gross Domestic Product (GDP) Pak Rupees	30th June 2017
5	Existing Installed Capacity (MW)	31st December 2018
6	Load Forecast - Regression Based (MW and GWh)	Base year 2016-17
7	Country Peak Demand (MW)	2017-18
8	Monthly Demand Factors	2017-18
9	Fuel Pricing (US $)	Real Prices as of December 2018
10	Hydro Power Plant Cost Data (US $)	Indexed to December 2018 (NEPRA)
11	Committed Plants CODs (Date)	December 2018
12	US $ Rate (Pak Rupees)	December 2018

4.3 Data Collection Process

The data gathering process was quite rigorous; all concerned project executing agencies were approached to provide the requisite data on the prescribed format. However, after repeated reminders and active follow-up, data collection was finalized. The following process was followed for the collection of different types of data from multiple sources:

a. Specific data input formats were customized, involving suitable conversions, as per requirements of the modelling tool.

b. Concerned entities were approached to share required data on the customized data input formats. Multiple reminders were dispatched to ensure timely provision of requisite data.

c. The data obtained was critically analyzed for accuracy and completeness, and gaps were identified.

d. Suitable assumptions were proposed, discussed and finalized to address the data gaps.

e. Besides seeking data from the concerned entities, most of the data, specifically the prices data, was obtained from tariff determinations of the plants available on NEPRA website.

f. The data was formulated as per requirement of the tool.

4.3.1 IGCEP Data Sources and Associated Data Types

Following entities shown in Figure 4-1 have contributed (directly / indirectly) for the preparation of input data to be used in IGCEP:

a. Water and Power Development Authority (WAPDA)

- Future hydro power plants to be developed by WAPDA

b. Private Power Infrastructure Board (PPIB)

- Future hydro and thermal power plants under the IPP mode

c. Pakhtunkhwa Energy Development Organization (PEDO)

- Future hydro power plants under the jurisdiction of KPK

Figure 4-1: IGCEP Input Data Sources

d. Azad Jammu Kashmir Private Power Cell (AJKPPC)

- Future hydro power plants under the jurisdiction of AJ&K

e. Punjab Power Development Board (PPDB)

- Future hydro, thermal and renewables power plants under the jurisdiction of the Punjab province

f. GENCOs

- Existing and future thermal power plants in public sector

g. Alternate Energy Development Board (AEDB)

- Future renewable projects

h. National Power Control Centre (NPCC):

- Load Duration Curve points (extracted from NPCCs shared hourly load data) as shown in Annexure B-1.
- Monthly energy and MWs for existing hydro, thermal, wind and solar

i. Central Power Purchasing Agency Guarantee Limited (CPPA):

- Fuel prices and existing system merit order
- Updating the cost of hydro plants, the indexation values

j. National Electric Power Regulatory Authority (NEPRA):

Different types of data were collected from NEPRA publications / website:

- For updating the cost to December 2018, latest values from NEPRA quarterly indexation were used for those plants for which NEPRA has published the indexation values.
- For the plants for which NEPRA has not yet determined the quarterly indexation, the final values for the indexation of Local and Foreign Consumer Price Index (CPI) and exchange rate were obtained from NEPRA website and these values were updated accordingly.
- For updating the cost of hydro plants, the indexation values were also obtained from NEPRA website.

k. Pakistan Atomic Energy Commission (PAEC)

- Future nuclear power plants

l. Pakistan Electric Power Company (PEPCO)

- Category-wise sale, generation, number of consumers and losses etc.

m. Pakistan Bureau of Statistics

- Input data for long term forecast such as GDP and its components, Population, etc.

4.4 Economic and Financial Parameters

For existing system, cost data was taken from the latest merit order provided by CPPA whereas for the future power plants, cost data shared by concerned project-executing agencies, after indexation, have been considered. For future candidate thermal power plants, the cost data from the respective Power Purchase Agreements (PPAs)/Energy Purchase Agreements (EPAs) of same technology have been considered/assumed.

4.5 IGCEP Process Map

The IGCEP is prepared after following the process given in Figure 4-2; and is being submitted to NEPRA for review and approval, following an internal consultative process.

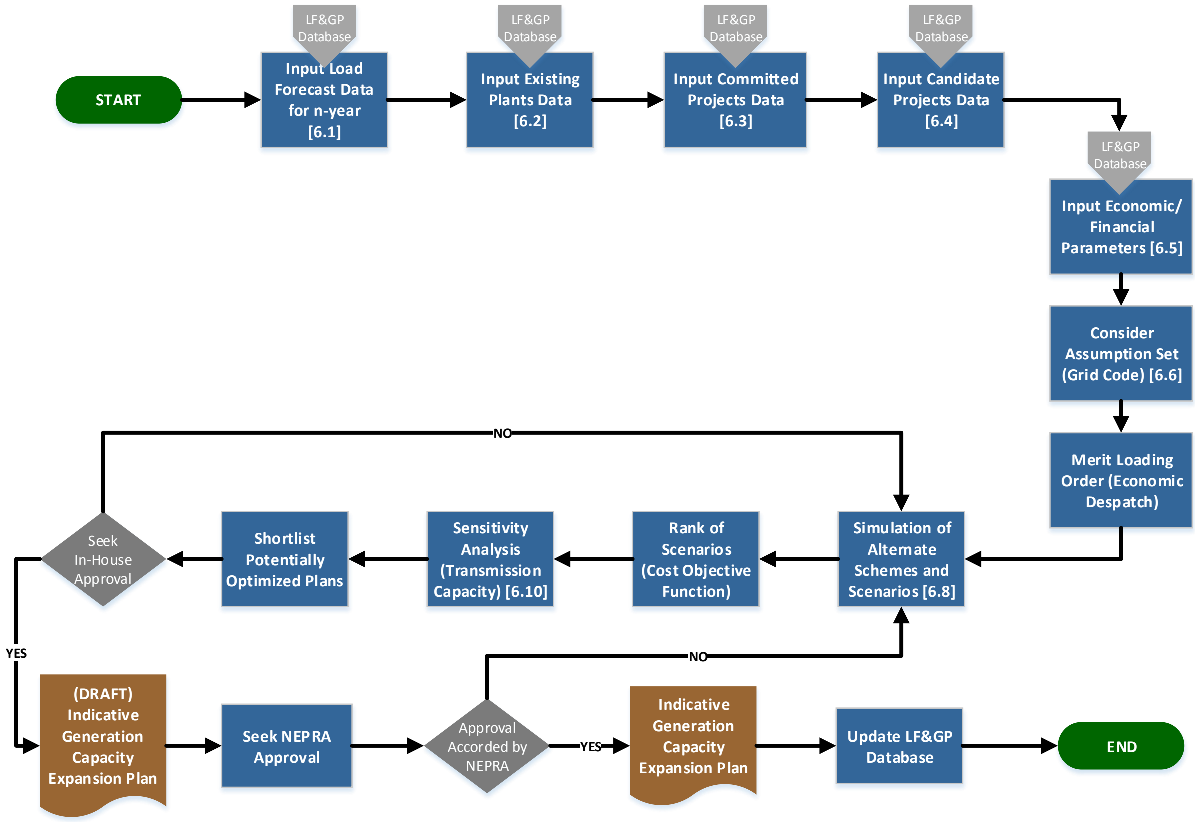


Figure 4-2: IGCEP Preparation Process

4.6 Different Criteria and Other Important Considerations for the IGCEP

4.6.1 Planning Timeframe

An overall framework encompassing technical and economic criteria provides a consistent set of parameters for use in the comparison of different expansion sequences. In this study, the WASP generation planning application software was used to develop least-cost sequences consistent with the overall framework. The planning period taken for this study is from July 1, 2018 to June 30, 2040.

4.6.2 Economic Parameters

The governing economic parameters are presented in Annexure B-3 and B-4. The reference date for costs is December 2018 and the discount rate is 10% per year.

4.6.3 Generation System Reliability

The capability of the generating system to meet the forecast peak demand remains an important factor in generation planning. In this perspective, the IGCEP takes into account the scheduled maintenance and forced outages allowance of all generating units as well as the seasonal and year-to-year variability of the energy and capacity of the hydroelectric plants.

Loss of Load Expectation (LOLE) or equivalently Loss of Load Probability (LOLP) is commonly considered as generating system reliability; for the purpose of preparation of IGCEP, an LOLP value of 1% (i.e. LOLE value of 3.65 days/year) has been adopted.

4.6.4 Hydrological Risk

Pakistan power system includes a substantial hydroelectric component. Hydroelectric projects usually exhibit significant seasonality of energy as well as capacity corresponding to the annual hydrological cycle. The relevant effect on system reliability and operating costs may be significant. For the IGCEP, average monthly values of energy and capacity are used to capture the seasonality for the hydroelectric plants.

4.6.5 Renewable Energy (RE) Generation

Pakistan power system has had a significant quantum of RE generation added in the generation mix in the past few years. As of 31st December 2018, 400 MW of solar and approximately 1,185 MW wind power, on grid projects have already been commissioned. Various wind projects are at different stages of completion and will be added into national grid in the next few years. However, these two energy resources due to their intermittency cannot be considered as a firm available capacity, at all points in time or all around the clock.

Analyzing the generation dispatch/trend of solar and wind generation reveals that although they can provide a significant quantum of generation at certain times, yet the corresponding generation also drops to zero at different times; this is evident from the dispatch record of last few years.

Further, forecast of wind availability and hence its corresponding generation has not matured enough to estimate the generation for long duration. Therefore, projection of historical trend of wind power has been carried out to estimate their future generation.

4.6.6 Spinning Reserve

The spinning reserve of a generating system is a measure of the system's ability to respond to rapid increases of load or the loss of generating unit(s). Practically speaking, spinning reserve is an operational concern and is often achieved by taking a suitable amount of reserve from the existing running plants. The stochastic method used to model the operation of the system in WASP allows for the unplanned outages of the generating units. As such, when the system reliability has a LOLP of 1%, it is expected that there will be sufficient reserve in the system. However, spinning reserve equal to one large thermal unit running in the system has been considered during the course of study period.

4.6.7 Scheduled Maintenance of the Generation Projects

Scheduled maintenance plays an important role in retaining the desired efficiency and reliability while at the same time preserving the useful life of a generating unit. It is assumed, for the preparation of the IGCEP, that all generating units will undergo an annual maintenance program.

4.6.8 System Load Characteristics

From planning perspective, the system load to be met by the generating system is represented by the system's load duration curves for each calendar month. The load forecast provides the annual peak demands and associated energy demands. Normal scenario of the load forecast has been adopted in the base case of this study. The load forecast developed by the LF&GP-PSP Team is presented in Table 5-2; it may be observed that the forecast peak demand increases about three-fold over the planning period i.e. 2018-2040.

In order to establish characteristics of the load in NTDC system, the hourly load data for the year 2017-18 was obtained and analyzed. Monthly normalized load duration curves were prepared for use in preparing the IGCEP (Annexure B-1). The distribution of monthly peak loads as a proportion of the annual peak demand were also prepared.

4.7 Strategy for Feedback

The IGCEP has been prepared after taking inputs from all relevant agencies and the LF&GP-PSP Team is more than willing to discuss and incorporate further suggestions from the stakeholders to shape it into a meaningful outcome. As per PC4 of the Grid Code, NEPRA will review and approve the IGCEP. However, any suggestions or concerns received, after the anticipated approval by NEPRA, will be duly considered and incorporated in the next version of IGCEP i.e. for the year 2019. All kind of suggestions, comments and concerns are most welcome at ce.glfp@ntdc.com.pk; 042-99202612. For wider dissemination of the IGCEP and seeking sufficient feedback, the IGCEP would be published on the NTDC Website after its approval from NEPRA.

5 Long-term Energy and Demand Forecast

Energy and demand forecast provides the basis for all planning activities in the power sector. It is one of the decisive inputs for the generation planning. Planning Code (PC4) of the Grid Code states that three levels of load forecasts should be employed for a time horizon of at least next twenty years for the long term. These three levels are i) High Growth ii) Medium Growth and iii) Low Growth projections. Factors that are to be taken into account while preparing the load forecasts include economic activity, population trends, industrialization, weather, distribution companies forecasts, demand side management and load shedding etc.

The long-term forecast prepared by LF&GP-PSP Team has been used for this Study pursuant to the provision PC4.

The methodology employed to assess the energy and demand forecast fulfills the criteria specified in the Gird Code. The methodology and its results are explained in the following sections.

5.1. Forecasting Methodology

The long-term forecast is carried out by multiple regression analysis techniques. Electricity consumption (GWh) is regressed on electricity price, GDP, population and number of consumers using historical data for the period 1970-2017. The process of forecast is illustrated in the process flow map in Figure 5-1.

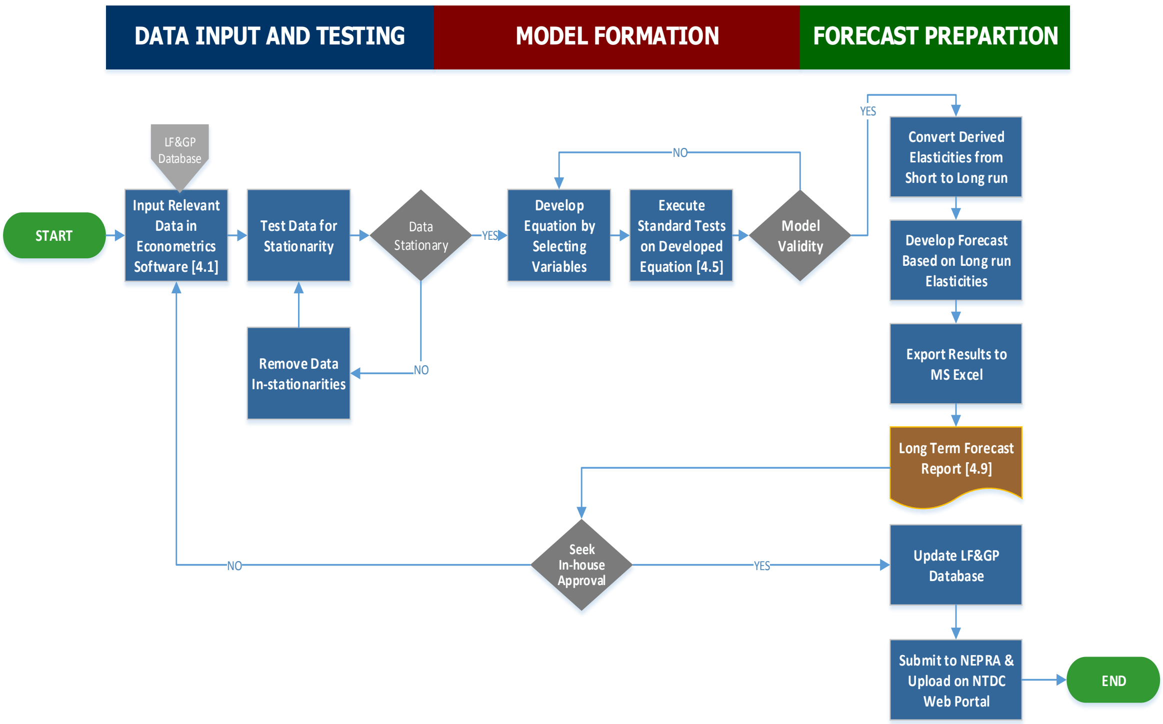


Figure 5-1: Process Flow of Methodology of Long Term Forecast

A detailed regression analysis involves the review of fundamental quantitative relationships between the electricity demand and the independent variables of the equation like electricity price, sector’s GDP, and population of Pakistan etc.

For this model, the impact of historical load management i.e. load shedding is included in the data base, so the resulting equations estimate the actual energy demand.

5.2. Input Data

LF&GP-PSP Team is maintaining a huge database encompassing data regarding electricity sector and economics variables. The database includes, but not limited to, the following important parameters:

a. Country's low projection of GDP growth rates by sectors, i.e. agriculture, industrial and commercial available as Annexure A-1

b. Country's normal projection of GDP growth rates by sectors, i.e. agriculture, manufacturing, trade, services etc. available as Annexure A-2

c. Country's high projection of GDP growth rates by sectors, i.e. agriculture, manufacturing, trade, services etc. available as Annexure A-3

d. Total GDP factor cost and sectorial GDP factor cost in millions with base year 2005-06 and Consumer Price Index (CPI) and it growth rate, available as Annexure A-4

e. Nominal category-wise Average Tariff of NTDC and KE, available as Annexure A-5

f. Real Price of Average Tariff of NTDC and KE with base year 2005-06, available as Annexure A-6

g. Weighted Average of Real Price, available as Annexure A-7

h. Electricity Consumption by Category (GWh) – NTDC, available as Annexure A-8

i. Category-wise Load Shedding (GWh) - NTDC, available as Annexure A-9

j. Electricity Consumption by Category (GWh) - KE, available as Annexure A-10

k. Load shedding by Category (GWh) - KE, available as Annexure A-11

l. Category Wise Number of Customers – NTDC, available as Annexure A-12

m. Category Wise Number of Customers – KE, available as Annexure A-13

n. Category-Wise Total Number of Customers & Population, available as Annexure A-14

o. Category-Wise Consumption per Customer – NTDC, available as Annexure A-15

p. Category-Wise Consumption per Customer – KE, available as Annexure A-16

q. Average Consumption per Customer (kWh) – Country, available as Annexure A-17

In a bid to consider the effect of load shedding, prevailing in the country, the electricity consumption data includes an estimate of the unserved energy to reflect the total demand. The above stated data has been collected from Economic Survey of Pakistan, Power System Statistics and various other sources from the year 1970 up to 2017.

5.3. Preparation of Demand Forecast

The electricity consumption of Pakistan is segregated into the following four different sectors:

- Domestic;
- Commercial;
- Industrial; and
- Agriculture

These four sectors have different patterns of consumption during the year. Hence, they are forecasted separately. The forecast of the four sectors are then combined to form the forecast of total electrical energy demand. In order to forecast the annual consumption of electricity up to 2040, a multiple regression model is used. Electricity energy sale of the respective category is the dependent variable in the regression model, whereas, the independent variables for each category are as follows:

a. Annual GDP and its components i.e. agriculture sector, industrial sector and services sector;
b. Tariff-wise electricity prices i.e. domestic, commercial, agriculture and industrial;
c. Number of consumers;
d. Population trend;
e. Lag of dependent variables;
f. Consumer Price Index; and
g. Dummy variables

Four equations are proposed for each category of electricity consumption. For statistical analysis, popular statistical software namely EViews is used. EViews (http://www.eviews.com/general/about_us.html) is a well-known econometrics tool widely used for forecasting. It is a "canned" regression package for econometric analysis. EViews has an object-oriented design. Each type of object has specific 'views' and procedures that are used in EViews. It provides sophisticated data analysis, regression, and forecasting tools on Windows based computers. With EViews one can quickly develop a statistical relation from the available data and then use the relation to forecast future values of the data. Areas where EViews has proven to be useful include scientific data analysis and evaluation, financial analysis, macroeconomic forecasting, simulation, sales forecasting, and cost analysis. In addition to the menu driven object oriented user interface, it is also possible to write simple programs in EViews programming language, without having to invest too much effort in the programming. NTDC Power System Planning office has been using this software since 1992.

Ordinary Least Square (OLS) technique is selected for the estimation of regression equation. Log on both sides of the equation is used to get elasticity in the percentage form, in order to get easy to interpret and standardized results. Various statistical tests were performed to establish the significance of the relationship between the dependent variable and the independent variables.

After thorough statistical analysis using EViews, the appropriate elasticity coefficients were selected for all the four equations. These elasticities were then converted into long term elasticities. On the other hand, growth rates for independent variables such as total GDP, electricity price were projected based on the past data. The long term elasticities and the projected independent variables were subsequently used in the equation to develop the long term energy forecast of each category using the equation below.

$$\mathbf{Y_{T} = Y_{T-1} * (1+GR\ of\ G)^{b} * (1+GR\ of\ R)^{C} * (1+GR\ of\ L)^{d}}$$

Table 5-1 provides the description of all the variables used in this equation:

Table 5-1: Description of Variables used in the Regression Equation

Variable	Description
Y_T	Electricity Demand of current year (Sales GWh)
Y_{T-1}	Electricity Demand of previous year (Sales GWh)
GR	Growth Rate
G, R, L	Independent variable (GDP, Real Price, Lag)
b, c, d	Elasticities of independent variables (GDP, Real Price and Lag respectively)

The forecast results of the four categories were combined to calculate the sale forecast at the country level. Required generation (GWh) was calculated after adding projected distribution losses at 11 kV and Transmission Losses at 132 kV and 500/220 kV according to the loss reduction plan of respective DISCOs and NTDC. In order to convert the energy in peak demand, load factor was calculated from energy generated and peak demand of the base year. That load factor was then projected for future years. The projected load factor was then used along with projected energy generation to forecast the peak demand.

5.4. Demand Forecast Numbers

Based on the variables and methodology explained above, the Table 5-2 highlights forecast prepared for the Low, Normal and High growth scenarios. Moreover, the comparison of different demand growth scenarios is graphically illustrated in Chart 5-1.

Table 5-2: Annual Long-Term Energy and Peak Demand Forecast

Fiscal Year	Low GDP 4.5%		Normal GDP 5.5%		High GDP 7.0%	
	Generation	Peak Demand	Generation	Peak Demand	Generation	Peak Demand
	GWh	MW	GWh	MW	GWh	MW
2017-18*	120,791	26,741	120,791	26,741	120,791	26,741
2018-19	144,665	27,072	145,674	27,261	147,188	27,545
2019-20	151,062	27,814	152,914	28,155	155,718	28,671
2020-21	158,842	28,782	161,841	29,325	166,429	30,157
2021-22	166,267	30,127	170,645	30,921	177,416	32,147
ACGR (2019-22)	**8.32%**	**3.03%**	**9.02%**	**3.70%**	**10.09%**	**4.71%**
2022-23	173,178	30,889	179,142	31,953	188,476	33,618
2023-24	181,051	32,294	188,914	33,696	201,374	35,919
2024-25	188,749	33,640	198,744	35,422	214,788	38,281

Fiscal Year	Low GDP 4.5%		Normal GDP 5.5%		High GDP 7.0%	
	Generation	Peak Demand	Generation	Peak Demand	Generation	Peak Demand
	GWh	MW	GWh	MW	GWh	MW
2025-26	193,948	34,062	206,155	36,206	226,011	39,693
2026-27	202,763	35,610	217,664	38,227	242,228	42,541
ACGR (2023-27)	**4.02%**	**3.62%**	**4.99%**	**4.58%**	**6.47%**	**6.06%**
2027-28	211,718	37,183	229,603	40,324	259,492	45,573
2028-29	220,940	38,802	242,104	42,519	277,960	48,816
2029-30	231,142	40,594	255,989	44,958	298,670	52,453
2030-31	241,889	42,481	270,792	47,557	321,130	56,398
2031-32	253,101	44,451	286,441	50,306	345,315	60,645
ACGR (2028-32)	**4.56%**	**4.56%**	**5.69%**	**5.69%**	**7.40%**	**7.40%**
2032-33	265,289	46,591	303,554	53,311	372,070	65,344
2033-34	278,069	48,835	321,710	56,500	400,940	70,414
2034-35	291,403	51,177	340,888	59,868	431,973	75,865
2035-36	305,685	53,686	361,590	63,504	465,916	81,826
2036-37	320,652	56,314	383,529	67,357	502,479	88,247
ACGR (2033-37)	**4.85%**	**4.85%**	**6.02%**	**6.02%**	**7.80%**	**7.80%**
2037-38	336,293	59,061	406,719	71,429	541,779	95,149
2038-39	352,917	61980	431,584	75,796	584,509	102,653
2039-40	370,348	65,042	457,939	80,425	630,529	110,736
ACGR (2038-40)	**4.94%**	**4.94%**	**6.11%**	**6.11%**	**7.88%**	**7.88%**
ACGR (2018-40)	**5.22%**	**4.12%**	**6.24%**	**5.13%**	**7.80%**	**6.67%**

*For 2017-18, actual Demand (MW) & Energy generation (GWh) is considered.

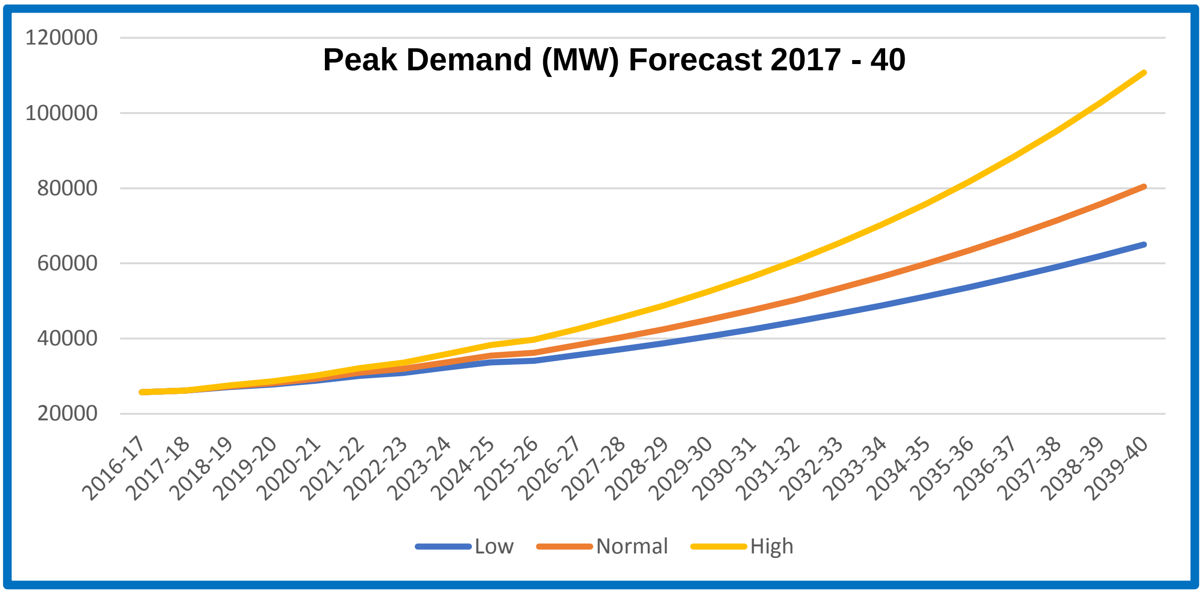


Chart 5-1: Peak Demand (MW) Forecast 2017 - 40

The annual peak demand forecast was converted into monthly peak demand forecast using appropriate monthly factors worked out based on the historical data. The monthly factors were expressed as the percentage of annual peak demand. The monthly demand factors are shown in Table 5-3 along with graphical representation of the same in Chart 5-2.

Table 5-3: Monthly Demand Factors

Months	Demand Factor
July	0.902
August	0.965
September	0.823
October	0.770
November	0.614
December	0.601
January	0.599
February	0.582
March	0.682
April	0.786
May	0.947
June	1.000

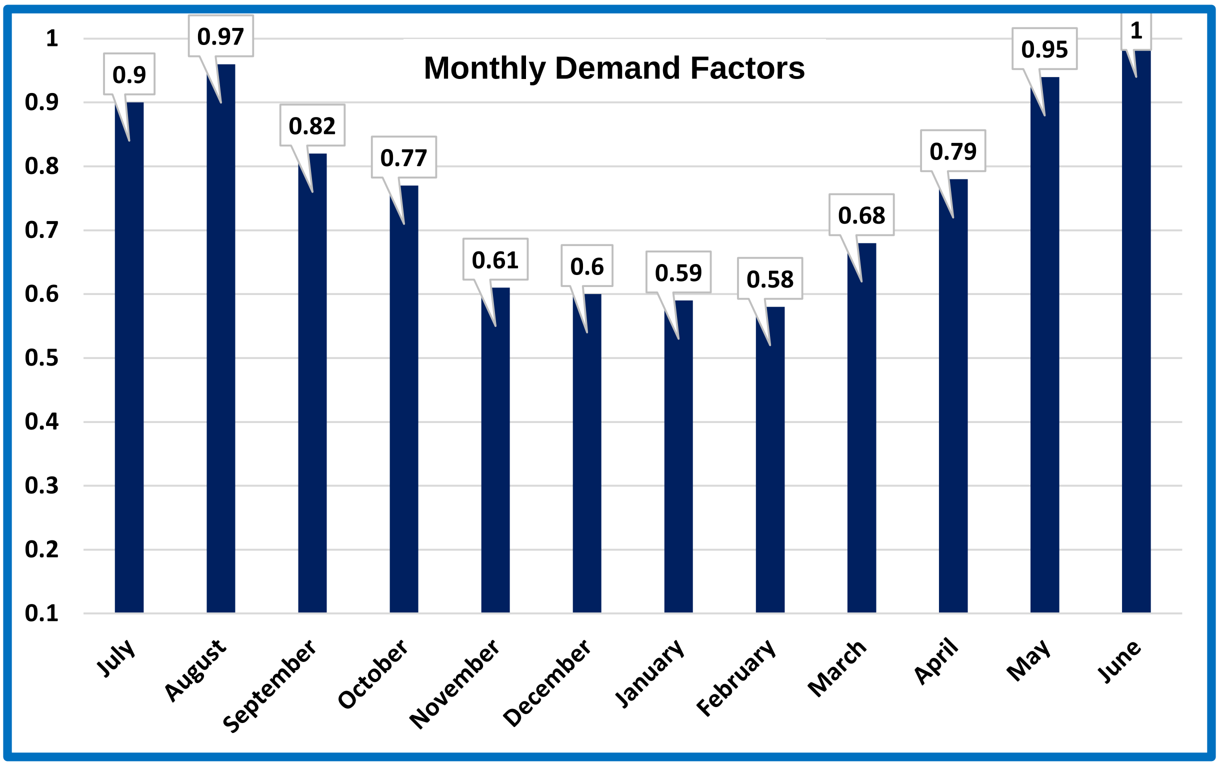


Chart 5-2: Monthly Demand Factors

Consequently, based on the annual long-term forecast and utilizing the monthly factors, a monthly peak demand forecast for the long term was worked out and utilized in the generation plan. The energy requirements are automatically worked out in the WASP tool by utilizing the Load Duration Curve (LDC). For the IGCEP, the load duration curve for the year 2017-18 has been utilized.

6. Inside the IGCEP – the Plan

6.1. Introduction

The key objective of the generation expansion planning activity is to develop an Indicative Generation Capacity Expansion Plan for Pakistan for the period 2018-19 to 2039-40 to meet the maximum load demand and energy consumption whilst taking into account the regulatory requirements as stipulated under Planning Code 4 of the Grid Code and identified constraints. The following section describes the key parameters and results of the generation planning study.

6.2. Strategic Considerations

In order to develop an effective least cost generation capacity expansion plan that will meet the power needs of the country, both the strategic considerations and constraints faced by Pakistan's power sector are somewhat considered. These constraints include the take or pay energy constraints on RLNG. For the RLNG projects, 66% energy is on take or pay basis. All strategic projects have been considered in the study. In the long term, it is assumed that the GoP's policy will continue to focus on harnessing of indigenous resources, particularly Thar coal and REs in South and hydro potential in North. However, the IGCEP has been prepared only considering least cost generation options and the study output depicts the same.

6.3. Approach and Methodology

The development of the least cost generation capacity expansion plan is the process of optimizing i) existing generation facilities and ii) additions of generation supply options in order to determine the least cost development sequence, which would meet the projected demand and would also satisfy the specified reliability criteria. For the purpose of the IGCEP, following methodology has been adopted:

a. **First Step:** Review the existing generation facilities, committed power projects and the corresponding existing system and committed system, and to review the range of generation addition options available to meet the future demand.

b. **Second Step:** Determine the economically attractive/viable generation options and generation mix.

c. **Third Step:** Define the Base Case subsequent to identification of the economically attractive options.

d. **Fourth Step:** Develop the least cost plan under the already defined Base Case using the Wien Automatic System Planning (WASP-IV) tool.

6.4. Planning Basis

In order to ensure that the base case scenario meet the requirements in terms of performance, the generation planning criteria tabulated in the Table 6-1 was defined, discussed and thus adopted:

Table 6-1: Generation Planning Criteria

Parameter	Value
Discount Rate	10% real

Parameter	Value
Construction Period:	
- Nuclear Plants	7 years
- Coal Fired Steam Turbines	4 years
- Combined Cycle Plants	3 years
- Combustion Turbines	2 years
- Wind Power Plants	2 years
- Solar Power Plants	2 years
Life of Plant:	
- Hydroelectric	50 years
- Steam Turbines	30 years
- Combined Cycle Plants	25 years
- Combustion Turbines	20 years
- Wind Power Plants	25 years
- Solar Power Plants	25 years
Reference date for costs	December 2018
Fuel Pricing	Real Prices of December 2018
Cost of unserved energy	US $ 0.80/kWh
Loss of Load Probability	1.00%

6.5. Assumption Set

Based on the existing data and information available, the IGCEP study has been conducted using the following important assumptions:

a. A project is considered as committed one provided the project is already under construction or has achieved financial close or has strategic importance i.e. China-Pakistan Economic Corridor (CPEC) Project or Public Sector Committed Projects.

b. CODs for committed and candidate power projects conveyed by project executing agencies and further rationalized by the Prime Minister's Task Force for Energy Reforms have been considered.

c. All the costs have been updated as of December 2018.

d. All future hydropower projects of 30 MW or greater have been considered for the IGCEP.

e. Plants without requisite data on the prescribed format have not been considered.

f. RLNG, imported coal and some local gas based projects have been given a minimum dispatch but not less than their contractual obligations/bindings (Take or Pay energy constraints).

g. All strategic projects have been considered in the study i.e. CPEC projects, CASA-1,000 and Gwadar Coal Fired power Project (CFPP).

h. Candidate Wind and Solar Power projects are modelled as Hydro in blocks of 500 MW and 400 MW respectively, from the year 2021-22 and onwards.

i. Spinning reserve equal to the biggest unit of thermal power plant has been assumed.

j. Due to high-annualized cost, projects like Chiniot, Kaigah, Tungas, Yalbo and Basho have not been included for this study.

k. 1,320 MW Oracle Thar Based CFPP, though being a CPEC project, has not been considered as a committed one; the project has been emerging with different plant characteristics and frequently changing COD over a prolonged time period. Consequently, under the current scenario, evacuation arrangements for this project are not part of the current transmission expansion plan. However, this project may be considered or out rightly removed from the next IGCEP run depending on the decision of the relevant forum.

l. Hydrology and other WASP related data for Dasu has been obtained from previous studies i.e. NPSEP 2011-30 and JICA's Least Cost Plan.

m. Fixed System

- Existing System Fuel cost and Variable O&M cost were obtained from Merit Order as of December 2018.
- Fixed O&M cost figures were obtained from NEPRA's quarterly indexation of December 2018, available on NEPRA's website.
- Moreover, the Fixed O&M costs of power plants built under 1994 policy were not available on NEPRA's website, so these costs were obtained from previous data available with this office.
- Fixed O&M cost for hydro and renewable plants has been assumed as 0.83 cents/kW/months.

n. Variable System

- For local coal, the reference cost and operational data of Sino Sindh Resources (Private) Limited (SSRL) is considered.
- For Imported coal, the reference cost operational data of Port Qasim is considered.
- For RLNG, the reference cost operational data of Balloki is considered.
- For Wind PPs costs, tariff determination of 50 MW Act 2 has been considered.

- For Solar PPs costs, tariff determination of 100 MW Siachen Solar has been considered.
- For HPPs, the cost data shared by concerned project executing agencies has been indexed to December 2018 (Annexure B-4). The values for indexation were obtained from NEPRA's website.

6.6. Existing Units

The total installed capacity of existing NTDC system is about 33,414 MW as of 31st December 2018 and the de-rated capacity is equivalent to 30,881 MW. The percentage wise share of hydro, thermal, nuclear and REs in existing NTDC generation mix is about 29%, 61%, 4% and 6% respectively. This technology wise break-up down is shown in Chart 6-1.

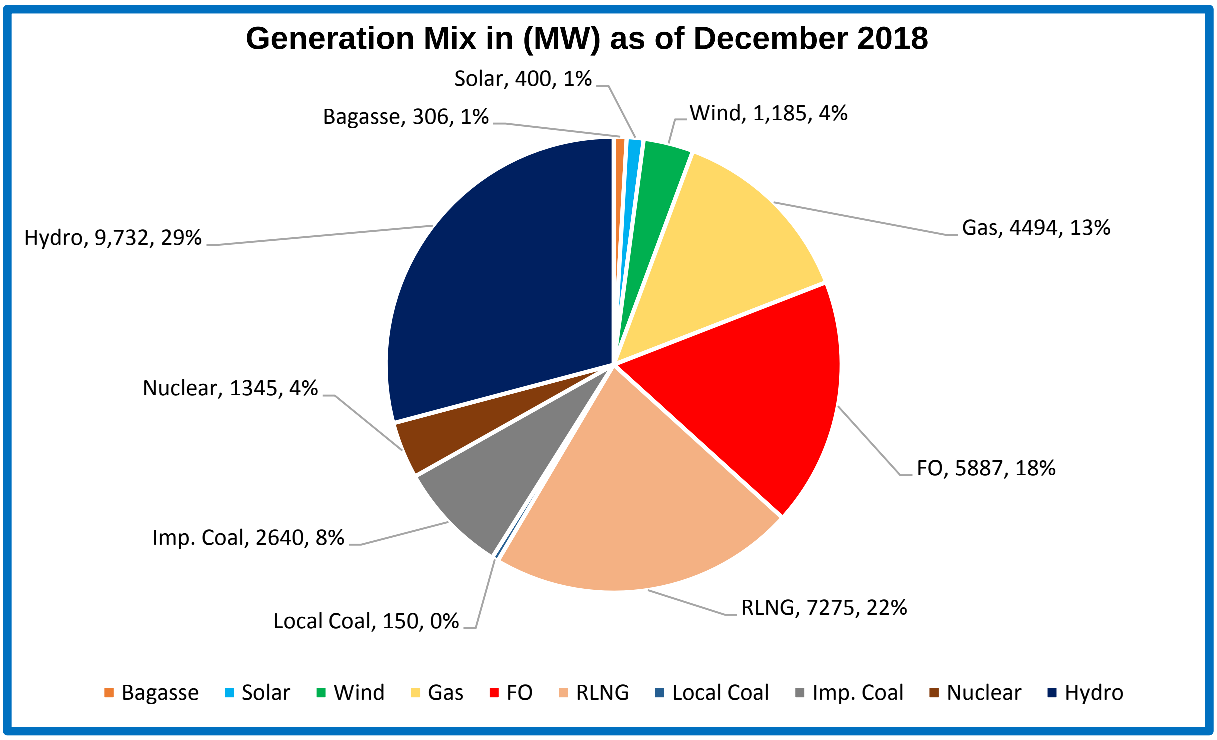


Chart 6-1: Generation Mix in (MW) as of December 2018

6.7. Retirement of Existing Plants

Quite a few power plants are going to be retired during the planning horizon of the IGCEP. A plant is supposed to be declared as retired upon completing its useful/economic life. The retirement schedule for the IGCEP is provided in the Table 6-2.

Table 6-2: Retirement Schedule of Existing Power System

Name of the Power Station	No. of Units / Block	Unit Cap. MW	Year											
			2020	22	23	25	26	27	28	29	30	31	32	2040
Jamshoro	1	200			-1									
	3	170			-3									
Kotri C.C.	1	107				-1								

Name of the Power Station	No. of Units / Block	Unit Cap. MW	Year											
			2020	22	23	25	26	27	28	29	30	31	32	2040
Guddu Steam	2	60			-2									
	2	140			-2									
Guddu C.C.	2	280			-2									
	1	360				-1								
Muzaffargarh Steam	5	177						-5						
	1	245							-1					
Faisalabad Steam	2	50	-2											
Faisalabad G.T.	4	19	-4											
Faisalabad C.C.	1	134				-1								
Lakhra	2	30					-2							
Kot Addu	1	251		-1										
	3	247				-3								
	1	336							-1					
Hubco	4	300						-3	-1					
Kohinoor	9	13.8							-9					
AES	2	350							-1	-1				
Habibullah Coastal	1	126									-1			
Uch	1	551										-1		
Rousch	1	395									-1			
Fauji Kabirwala	1	150										-1		
Saba Power	1	123									-1			
Altern Energy Ltd.	3	10											-3	
Liberty Power	1	212											-1	

Name of the Power Station	No. of Units / Block	Unit Cap. MW	Year											
			2020	22	23	25	26	27	28	29	30	31	32	2040
Attock Gen Ltd(AGL	1	156												-1
Atlas Power	1	214												-1

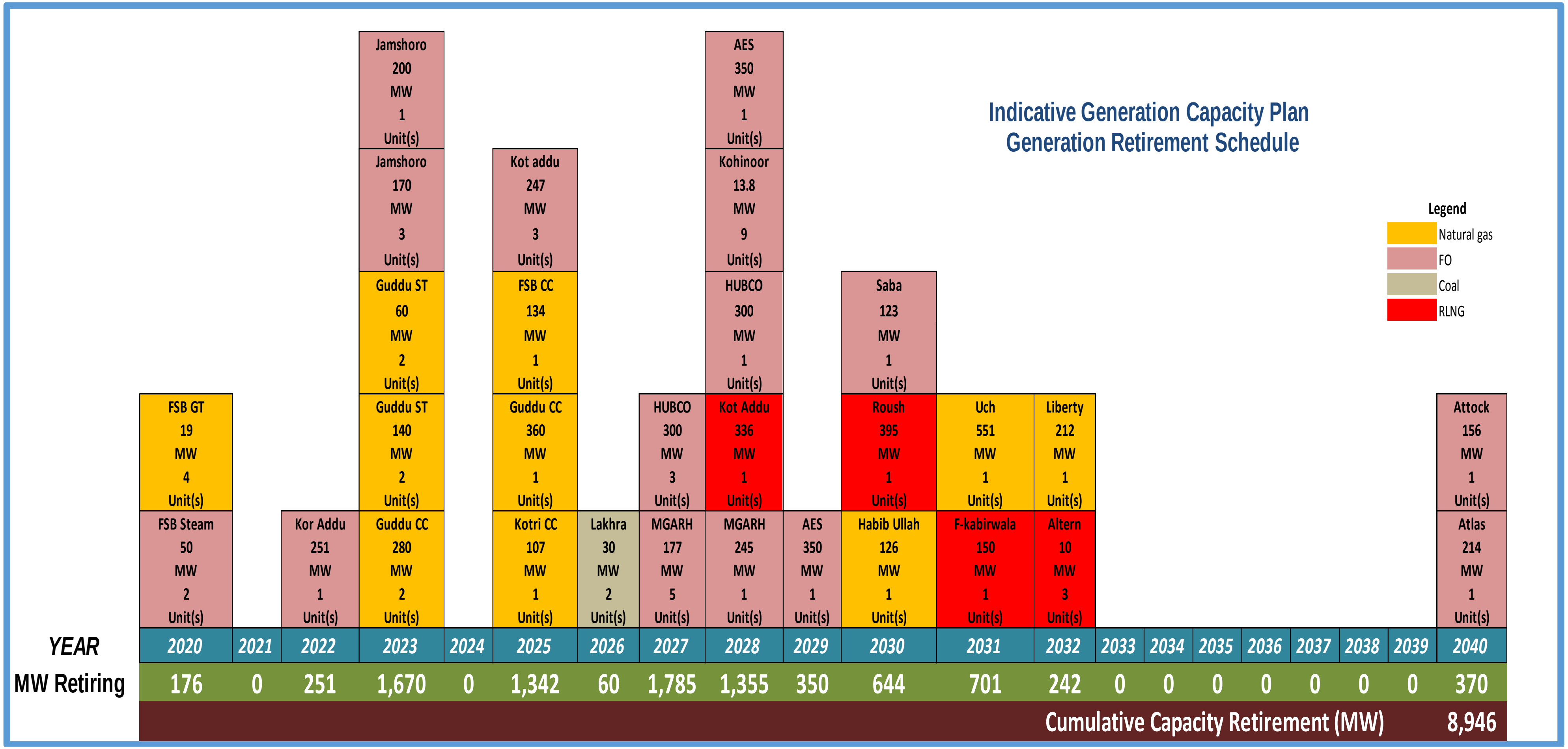


Figure 6-1: IGCEP Retirement Schedule

6.8. Committed Generating Units

Various plants have been considered in the IGCEP as committed projects, based on the criterion that the projects are under construction or have achieved financial close or have strategic importance i.e. CPEC Projects and Public Sector Committed Projects.

6.8.1. Public Sector Committed Projects

Committed projects in the public sector are listed in the Table 6-3:

Table 6-3: Public Sector Committed Projects

Sr. No.	Name of Project	Fuel Type	Installed Capacity (MW)	Schedule of Commissioning
1	Daral Khwar	Hydro	37	2019
2	Golen Gol	Hydro	106	2019
3	Koto HPP	Hydro	40	2020
4	Karachi Coastal (Unit-I)	Nuclear	1,100	2021
5	Keyal Khwar	Hydro	122	2022
6	Karachi Coastal (Unit-II)	Nuclear	1,100	2022
7	Jamshoro CFPP	Imp. Coal	1,320	2023
8	CASA 1000 Project	Import	1,000	2025
9	Chashma Nuclear (C-V)	Nuclear	1,100	2025
Total Public Sector Committed Projects (MW)			**5,925**	

6.8.2. Private Sector Committed Projects

Private sector, upcoming projects considered as committed projects for the purpose of the IGCEP study are listed in the Table 6-4:

Table 6-4: List of Committed Projects in the Private Sector

Sr. No.	Name of Committed Project	Fuel Type	Installed Capacity (MW)	Expected Schedule of Commissioning
1	TGS	Wind	49.5	2019

Sr. No.	Name of Committed Project	Fuel Type	Installed Capacity (MW)	Expected Schedule of Commissioning
2	Tricon Boston A	Wind	49.6	2019
3	Tricon Boston B	Wind	49.6	2019
4	Tricon Boston C	Wind	49.6	2019
5	Zephyr	Wind	48.3	2019
6	Port Qasim Power Project (Unit-II)	Imp. Coal	660	2019
7	Almoiz Industries Limited	Bagasse	36	2020
8	Etihad Power Generation Limited.	Bagasse	74.4	2020
9	Chanar Energy Limited	Bagasse	22	2020
10	Gulpur	Hydro	100	2020
11	Zorlu Solar	Solar	100	2020
12	LNG Based Plant at Trimmun	Imp. LNG	1,243	2020
13	Engro Powergen Project	Local Coal	660	2020
14	HUB Power Company Ltd.	Imp. Coal	1,320	2020
15	Shahtaj Sugar Mills Ltd.	Bagasse	32	2021
16	Hunza Power (Pvt.) Ltd.	Bagasse	49.8	2021
17	Ittefaq Power (Pvt.) Ltd.	Bagasse	31.2	2021
18	Kashmir Power Private Ltd	Bagasse	40	2021
19	Indus Energy Limited.	Bagasse	31	2021
20	Bahawalpur Energy Ltd.	Bagasse	31.2	2021
21	Alliance Sugar Mills Ltd.	Bagasse	30	2021
22	RYK Energy Limited.	Bagasse	25	2021
23	Mirpurkhas Energy Ltd.	Bagasse	26	2021

Sr. No.	Name of Committed Project	Fuel Type	Installed Capacity (MW)	Expected Schedule of Commissioning
24	Two Star Industries Pvt Ltd.	Bagasse	49.8	2021
25	TAY	Bagasse	30	2021
26	Sheikhoo Power Ltd.	Bagasse	30	2021
27	Hamza Sugar Mills Ltd.	Bagasse	30	2021
28	Faran Power Ltd.	Bagasse	26.5	2021
29	Mehran Energy Ltd.	Bagasse	26.5	2021
30	Habib Sugar Mills Ltd.	Bagasse	26.5	2021
31	Sadiqabad Power Pvt Ltd.	Bagasse	45	2021
32	Alman	Bagasse	34.5	2021
33	Thal Indus	Bagasse	20	2021
34	Ranipur	Bagasse	60	2021
35	Digri Gen	Bagasse	25	2021
36	Popular	Bagasse	30	2021
37	Hamza	Bagasse	15	2021
38	Darya Khan	Bagasse	40	2021
39	Al- Mughnee	Bagasse	40	2021
40	Gotki Power Pvt Ltd.	Bagasse	45	2021
41	Karot HPP	Hydro	720	2021
42	Lucky Electric Power Company Ltd.	Local Coal	660	2022
43	TEL Mine Mouth Lignite Fired Project at Thar	Local Coal	330	2022
44	Sukki Kinari HPP	Hydro	870	2023

Sr. No.	Name of Committed Project	Fuel Type	Installed Capacity (MW)	Expected Schedule of Commissioning
45	Imported Coal based Power Plant at Gawadar	Imp. Coal	300	2023
46	Thal Nova Mine Mouth Lignite Fired Project at Thar	Local Coal	330	2023
47	SSRL Mine Mouth Project at Thar	Local Coal	1,320	2024
48	Siddiqsons Limited	Local Coal	330	2024
49	Kohala HPP	Hydro	1,124	2027
	Total (MW):	**11,316**		

6.9. New Generation Options

Following are the basic supply options available for the expansion of the future generation system:

a. Imported Coal;

b. Local Coal (Thar);

c. Oil;

d. RLNG;

e. Nuclear;

f. Hydro;

g. Solar;

h. Wind; and

i. Bagasse

6.10. Hydro Projects and Screening

The data for hydro projects was obtained from the relevant project executing agencies. Table 6-5 shows the costs of candidate hydro plants.

Table 6-5: Annualized Cost of Candidate Hydro Power Project

Sr. No.	Power Plant	Capacity (MW)	Earliest Availability	Installed Cost** ($/KW)	Annual Energy (GWh)	Annualized Cost of Energy (c/kWh)	Annualized Cost of Energy (Rs./kWh)
1	Pattan	2,400	2030	1,908	12,544	3.87	4.81

Sr. No.	Power Plant	Capacity (MW)	Earliest Availability	Installed Cost** ($/KW)	Annual Energy (GWh)	Annualized Cost of Energy (c/kWh)	(Rs./kWh)
2	Dasu Hydel	2,160	2025	1,888	11,176	3.87	4.81
3	Mahl	640	2029	2,378	3,720	4.30	5.34
4	Phander	80	2024	1,923	365	4.47	5.56
5	Shyok HPP	640	2030	2,753	3,740	4.92	6.12
6	Jagran-III	35	2022	2,059	154	4.95	6.15
7	Azad Pattan	700	2026	2,149	3,192	4.97	6.18
8	Diamer Basha *	4,500	2028	1,881	18,049	4.98	6.19
9	Harigel	40	2022	2,657	223	4.99	6.20
10	Lower Palas	665	2028	1,883	2,568	5.18	6.44
11	Ashkot HPP	300	2026	2,287	1,376	5.25	6.52
12	Lower Spat Gah	496	2028	2,173	2,084	5.45	6.78
13	Chakothi	500	2028	2,719	2,440	5.82	7.24
14	Harpo	34.5	2024	2,938	173	6.11	7.59
15	Bunji Hydel	3,600	2030	1,973	12,078	6.23	7.74
16	Mohmand Dam *	800	2024	2,148	2,859	6.34	7.88
17	Taunsa	135	2024	2,961	651	6.40	7.95
18	Lawi	69	2021	2,766	311	6.41	7.97
19	Matiltan	84	2020	2,582	339	6.69	8.32
20	Thakot HPP	4,000	2030	3,246	19,947	6.77	8.41
21	Tarbela5	1,410	2025	586	1,401	6.95	8.64
22	Gumat Nar HPP	49.5	2023	3,165	218	7.48	9.29
23	Luat HPP	49	2021	3,202	205	7.96	9.89
24	Basho HPP	40	2030	2,930	149	8.20	10.20

Sr. No.	Power Plant	Capacity (MW)	Earliest Availability	Installed Cost** ($/KW)	Annual Energy (GWh)	Annualized Cost of Energy (c/kWh)	(Rs./kWh)
25	Kaigah HPP	548	2030	2,882	2,009	8.20	10.20
26	Yalbo HPP	2,800	2030	3,372	11,357	8.63	10.73
27	Tangas HPP	2,200	2030	3,433	8,622	9.09	11.30
28	Chiniot HPP	80	2030	7,063	241	24.01	29.84

*These are multi-purpose projects and only 65% of full project costs have been charged to the power sector.
**Includes Interest during Construction (IDC)

It is pertinent to mention here that the relevant project execution agencies did not provide cost data updated as of June 2018. In order to use the uniform prices for the IGCEP, cost data was used after updating to December 2018 by applying appropriate indexation.

It has been observed with respect to the candidate hydro plants that due to the limitation of the WASP software package, whole group of the hydro plants is selected based on the average cost of that group. Due to this limitation, some expensive generation plant(s) followed by an economical one in the same group is also selected. In order to overcome this constraint, the projects list was screened for those expensive plants and these were put in a separate group and were tested. It was observed that due to their higher cost, these plants were not selected in the separated group. The expensive plants thus excluded from the IGCEP, due to their higher cost, are Basho HPP, Kaigah HPP, Yulbo HPP, Tungus HPP & Chiniot HPP.

6.11. New Thermal Options

New thermal options include Gas Turbines (GTs), Combined Cycle Gas Turbines (CCGTs) using RLNG and Steam Turbines using Imported Coal, Thar Coal and Nuclear Fuel. In order 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. Table 6-6 shows the technical characteristics of the thermal candidate plants:

Table 6-6: Performance Characteristics of Generic Thermal Power Plants

Performance Characteristics		Coal Fired Steam Imported 660 MW	Coal Fired Steam Thar 660 MW	Combined Cycle on RLNG 1,223 MW	Combustion Turbine on RLNG 400 MW	Nuclear 1100 MW
A	Net Capacity (MW)	607	601	1,199	396	1,012
B	Station Service (%)	8	9	2	1	8
C	Minimum Load (%)	25	25	50	50	100

	Performance Characteristics	Coal Fired Steam Imported 660 MW	Coal Fired Steam Thar 660 MW	Combined Cycle on RLNG 1,223 MW	Combustion Turbine on RLNG 400 MW	Nuclear 1100 MW
D	Lifetime Average Net Heat Rate (kcal/kWh)					
	- At Minimum Load	2,388	2,388	1,633	2,960	2,341
	- At Maximum Load	2,204	2,204	1,545	2,502	2,341
E	Scheduled Outage (d/year)	30	30	40	30	60
F	Forced Outage (%)	7	7	5	5	5
G	Economic Life (years)	30	30	25	20	50
H	O & M Cost					
	- Fixed ($/kW/Month)	2.13	14.44	1.43	1.6	5.98
	- Variable ($/MWh)	3.69	7.53	3.56	1.9	0.00

The economic parameters of the thermal candidate plants are highlighted through the Table 6-7:

Table 6-7: Economic Parameters of Generic Thermal Power Units

Technology	Capital Cost with IDC ($/kW)	Plant Life Years	Discount Rate	Fuel Price (Cent/Gcals)
Nuclear (1,100 MW)	4,342	50	10%	305.0
C.T. (400 MW)	534	20	10%	5,044
C.C. (1,223 MW)	694	25	10%	5,044
Imp. Coal (660 MW)	1,556	30	10%	1,884

Technology	Capital Cost with IDC ($/kW)	Plant Life Years	Discount Rate	Fuel Price (Cent/Gcals)
Thar Coal (660 MW)	1,556	30	10%	403

6.12. Other Generation Options

Other generation options include Wind, Solar, Bagasse, Municipals Solid Waste, Geo-thermal and Tidal Energy. For the bagasse-based power plants, most of the projects are taken as committed projects and there seems to be no additional capacity in the near future. In respect of Municipal Solid Waste, Geo-thermal and Tidal Energy, the technologies are not currently mature enough in Pakistan to be considered as candidates and there is no data available. Therefore, only solar and wind projects are currently the viable options and are taken as candidate plants for the IGCEP study. These plants are considered on block basis. Table 6-8 shows the economic parameters of the candidate Wind and Solar projects:

Table 6-8: Economic Parameters of Candidate Wind and Solar Blocks

Sr. No.	Power Plants	Block Capacity (MW)	Earliest Availability Year	Installed Cost ($/KW)	Annual Energy (GWh)	Annualized Cost of Energy (Cents/kWh)
1	Solar	400	2022	752	663	5.62
2	Wind	500	2022	1,259	1,435	5.18

6.13. Development of the Base Case

After finalization of the input data and technical due diligence, the base case was finalized adopting the following criteria:

a. The study period will be from 2018 up to 2040.

b. Regression base Forecast for the base year 2016-17 is used.

c. All hydro plants above 30 MW, with data available on the prescribed format have been considered in the study.

d. The updated cost data as of December 2018 has been used.

e. All Wind, Solar, Thermal and Nuclear candidate plants have been included in the study.

f. Wind and solar power plants have been modelled as hydro in a separate group.

g. Fixed Dispatch has been ensured for RLNG based power plants up to 2032.

h. Hydro timelines have been optimized by WASP.

6.14. Reliability Levels and System Expansion Costs

The system reliability is directly proportional to the cost of the system; higher the reliability, higher the costs. For the current study, the results satisfy the LOLP up to 1% criteria as specified in the Grid Code. As the base case satisfies the reliability criterion prescribed in the Grid Code, therefore, no additional sensitivity analysis has been conducted for different reliability levels.

6.15 Brief Info on Relevant Application Software Tools

As mentioned earlier, for preparation of the IGCEP, WASP IV package has been utilized. The tool has been developed by International Atomic Energy Agency (IAEA) and Version IV of the package remains the latest.

WASP was originally developed in 1972 by the Tennessee Valley Authority and the Oak Ridge National Laboratory in the USA to meet the IAEA's needs to analyze the economic competitiveness of nuclear power in comparison to other generation expansion alternatives for supplying the future electricity requirements of a country or region. Experience gained from its application allowed development of WASP into a very comprehensive planning tool for electric power system expansion analysis. The tool has global footprints and is widely used in generation capacity expansion plants. The model developed under WASP is illustrated through Figure 6-2 and its dimensions are given in Table 6-9.

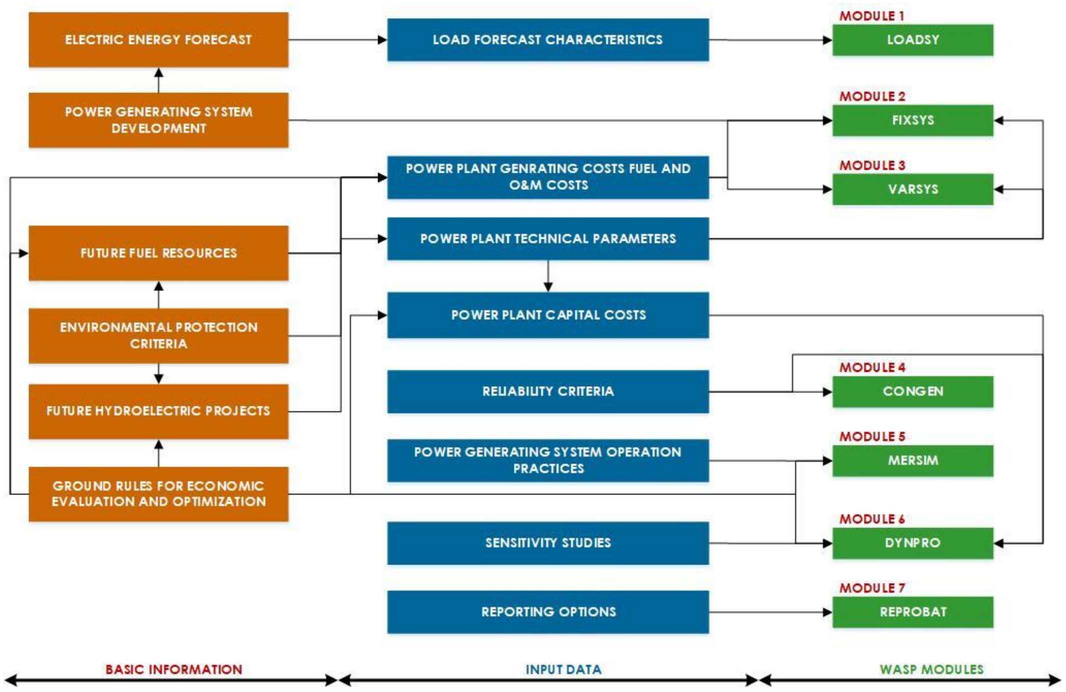


Figure 6-2: IGCEP WASP Input Data Model

Table 6-9: Dimensions of the WASP-IV Computer Model

Parameters	Maximum Limit
Years of study period	30
Periods per year	12
Load duration curves (one for each period and for each year)	360
Cosine terms in the Fourier representation of the inverted load duration curve of each period	100
Types of plants grouped by "fuel" types of which: 10 types of thermal plants; and 2 composite hydroelectric plants and one pumped storage plants	12
Thermal plants of multiple units. This limit corresponds to the total number of plants in the Fixed System plus those thermal plants considered for system expansion which are described in the Variable System (87 if P-S is used)	88
Types of plants candidates for system expansion, of which: 12 types of thermal plants (11 if P-S is used); 2 hydroelectric plant types, each one composed of up to 30 projects; and1 pumped storage plant type with up to 30 composed projects	15
Environmental pollutants (materials)	2
Group limitations	5
Hydrological conditions (hydrological years)	5
System configurations in all the study period (in one single iteration involving sequential runs of modules 4 to 6)	5,000

6.16. Limitations of the Modelling Tool - WASP

With all its comprehensive modelling capabilities, the WASP-IV model still has some limitations to comprehensively model the existing complex system of Pakistan. These limitations and the proposed methodology to address these, where possible, are discussed below:

a. There is a provision of up to two groups for hydro power plants whereas 30 plants can be handled in each of the two groups. For the purpose of the IGCEP, one group is reserved for hydro plants and the other group is reserved for renewables since the software does not recognize renewables. The disadvantage of this approach is that the hydro projects in a group are only compared with the thermal and hydro projects of other group but there is no comparison among the hydro projects within a group.

b. Maximum 30 projects can be handled in each hydro group; only 30 new hydro projects and 30 new Wind and Solar blocks can be handled in one study.

c. The current Take or Pay Energy contracts can't be exactly modeled in the software. These contracts are 66% energy for RLNG, 50% imported coal and 50% local gas plants of 2002 policy. In order to apply this constraint, the merit order list was manually adjusted only for RLNG based plants up to the year 2032 i.e. for the period for which the constraint is there. The limitation of this approach is that the plants can't be dispatched at exactly the same percentage as required. In the current study, the merit order is adjusted in such a way that the dispatch is above the minimum value.

d. The hydro projects are selected in sequence within a group. If a project after an expensive project is cheaper, it will not be selected until the expensive project is selected. In a bid to overcome this limitation, the expensive projects were screened first and then excluded from the groups.

e. Bagasse based plants have been modelled as hydro due to seasonal variation.

6.17. Do-ables for the Future Generation Plans

LF&GP-PSP Team considers it appropriate to list certain aspects to be discussed and resolved to improve the future editions of the IGCEP which are as follows:

a. Potential power projects of less than 30 MW capacity have not been included in the study.

b. Having no clue of any ongoing or planned interventions pertaining to demand side management (DSM), the Team has been compelled to simply ignore any offset to load growth in terms of megawatts. It is expected that the Team will be able to secure DSM relevant data for the future editions of the IGCEP.

c. Similarly, the Team has no access to the targets set by AEDB pertaining to off-grid solar installations including those under Net Metering; any impact thereof would not be reflected in the study outcome.

d. Limitations of the software tool WASP, as discussed in the previous section, may also be included as another area of improvement for the IGCEP since such limitations are likely to have an impact on the study outcome.

e. In certain cases, retirement schedules were not communicated by the concerned project executing agencies, hence the term of each plant's PPA was considered as retirement. Relevant entities will be approached again for providing précised/updated data.

f. Due to already signed agreements, certain power plants require fixed dispatch. Such bindings need to be addressed for the upcoming power procurements.

7. IGCEP Study Outcome

Based on the input data and assumptions, the base case scenario was simulated in the WASP tool. After detailed processing and analysis, the WASP tool produced the optimal least cost results which are discussed in the following sections:

7.1. Future Demand and Capacity Additions

Chart 7-1 depicts the relationship between future capacity additions, in terms of different types of energy sources, and the projected peak demand of the system. It is evident that the trend of the demand is similar to the capacity additions as both are increasing in the positive direction and there is gradual increment during the plan horizon. In the year 2018, the nominal capacity and demand match quite closely as the nominal/de-rated capacity from all generation sources hovers around 27,715 MW whereas the demand is close to 26,700 MW. From year 2019, the gap between nominal capacity and the demand is steadily widening, and the same starts surpassing the peak load of the system. Let us take the snapshot of two random years i.e. 2032 and 2040 to closely assess the demand and capacity situation. In the year 2032, the cumulative nominal capacity is approximately 62,979 MW whereas the peak load is projected at 50,306 MW, thus a wide disparity of around 13,000 MW exists between the two parameters and the capacity is in surplus as compared to demand. Let us take another example of year 2040, which is the last projected year for the IGCEP. As per the study outcome, in the year 2040, the total nominal capacity in the system stands at 98, 091 MW against a peak load projected as 80, 425 MW. Therefore, it can be observed that a significant surplus of around 17,600 MW persists between the projected demand and the installed capacity. Consequently, from the Chart 7-1, it is evident that sufficient generation has been added to satisfy the 1% LOLP criteria and sufficient reserves are added to the system.

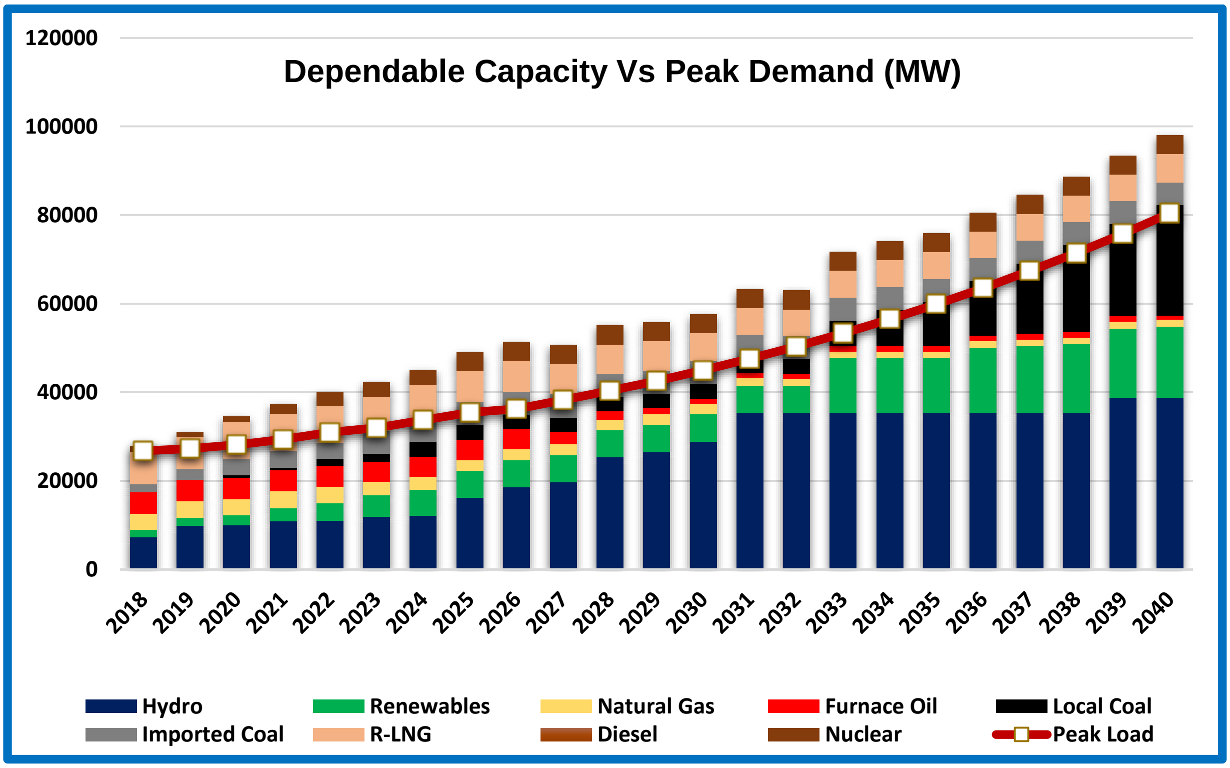


Chart 7-1: Dependable Capacity Vs Peak Demand (MW)

The WASP model selects hydro capacity up to the year 2039 (Bunji Stage-II) and it remains constant up to 2040 since the last hydro project (Thakot), made available to software, is not being selected by the it due to its high cost. In order to meet the demand after 2033, thermal generation is also added by the model; all the thermal generation being added is based on Thar Coal except for one (01) small unit of Gas Turbine of 400 MW, in 2040. The Table 7-1 demonstrates the detailed analysis of the year-wise future generation capacity additions in terms of generation technologies. The candidates for the generation plants fed into the model were as follows:

a. Steam PP on Imported Coal (660 MW)

b. Steam PP on Thar Coal (660 MW)

c. Combined Cycle PP on Imported Gas / LNG (1,223 MW)

d. Gas Turbines on Imported Gas / LNG (400 MW)

e. Nuclear Steam PP on Uranium (1,100 MW)

f. Wind Turbines (Block of 500 MW)

g. Solar Panels (Block of 400 MW)

Referring to the hydropower projects (HPP), it is observed that no HPP is selected in the first two years, 2018 and 2019. The first HPP selected by the model is Matiltan which is an 84 MW Run-of-the-River (ROR) hydropower plant envisaged to be commissioned in the year 2020. Various other ROR HPPs follow it, among which the commissioning of 2,160 MW Dasu Stage-I HPP in the year 2025 is worth mentioning. Moving forward, the first reservoir based HPP i.e. Mohmand Dam is proposed to be commissioned in the year 2025. Similarly, the year 2028 will see another reservoir based mega project, Diamer Bhasha HPP with a capacity of 4,500 MW. By the year 2040, the total share of “Candidate Hydro” in the up-coming generation additions will be approximately equivalent to 25,047 MW. The optimized Hydro schedule by WASP-IV is shown in Table 7-3

As far as Thar coal power plants are concerned, the model selects no power plant until the year 2032. However, after the year 2032 a series of Thar coal power plants are selected and by the year 2040, a total of 36 units on Thar coal would have been brought into the system with a cumulative capacity of 23,760 MW.

In addition to the above-mentioned technologies, only one (01) Gas Turbine of 400 MW on imported gas/LNG, having a capacity of 400 MW is selected by the model in the year 2040. It is pertinent to mention that neither any Combined Cycle Power Plant on imported gas/LNG nor any Nuclear Power Plant is selected by the model during the whole course of study period i.e. 2018-2040. (Please see Annexure B-5, Screening Curve, for cost comparison of technologies.)

As far as renewables are concerned, total capacity of 6,000 MW and 7,000 MW would be available from solar and wind power plants respectively. First block of 500 MW of wind and 400 MW solar power plants will hit the ground in year 2022, followed by 13 more blocks of wind and 14 blocks of solar, respectively, till 2040.

Hence, by the year 2040 there will be an overall additional capacity of 63,307 MW from the candidate power projects made available to the WASP model.

Moreover, a graph showing energy generation by different sources i.e. fuel types is shown below in Chart 7-2. Both the graphs clearly show that the capacity selected by WASP after considering / satisfying all reliability criterion (LOLP, reserves) is sufficient enough to meet both the power (MW) and energy demand (Gwh) of NTDC system. It can be seen from Chart 7-1 that although the system do have FO based capacity available but its share in dispatch from 2019 and onwards declines almost drastically, being low in merit order it is being replaced by cheaper fuels.

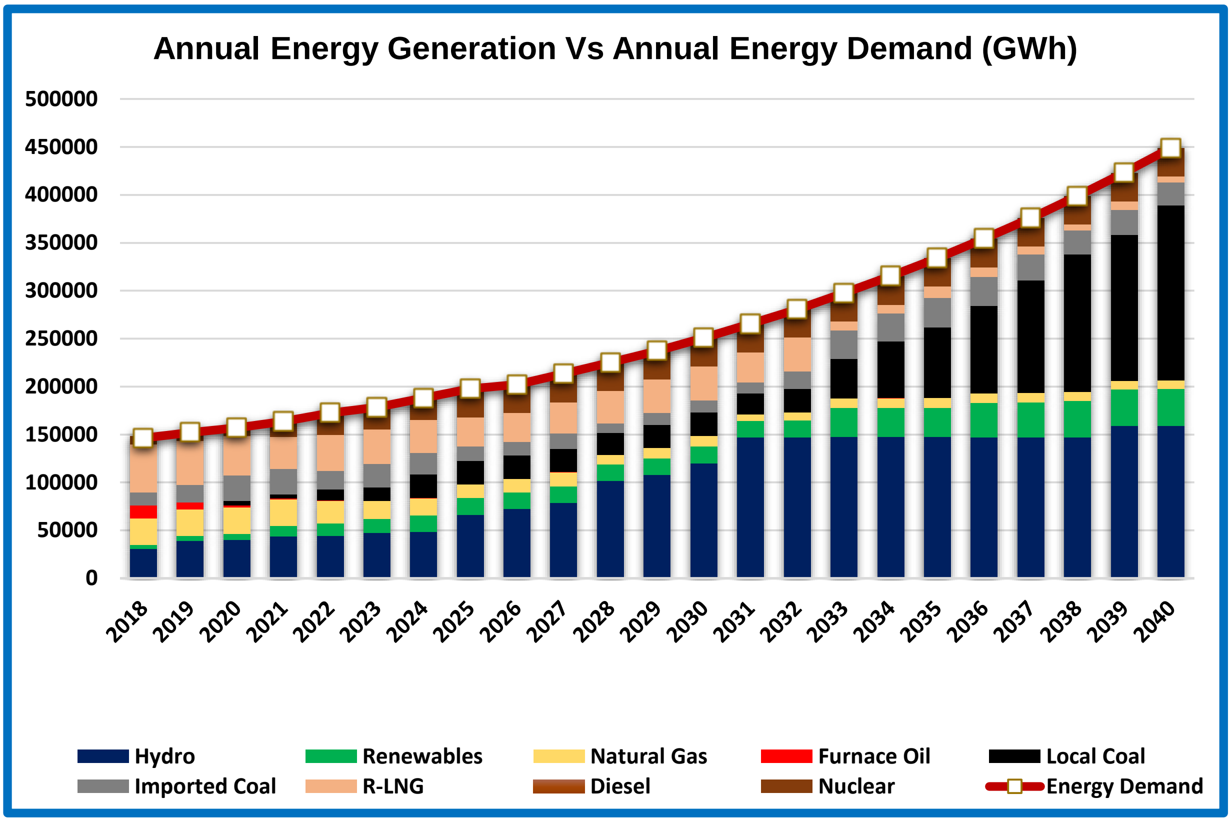
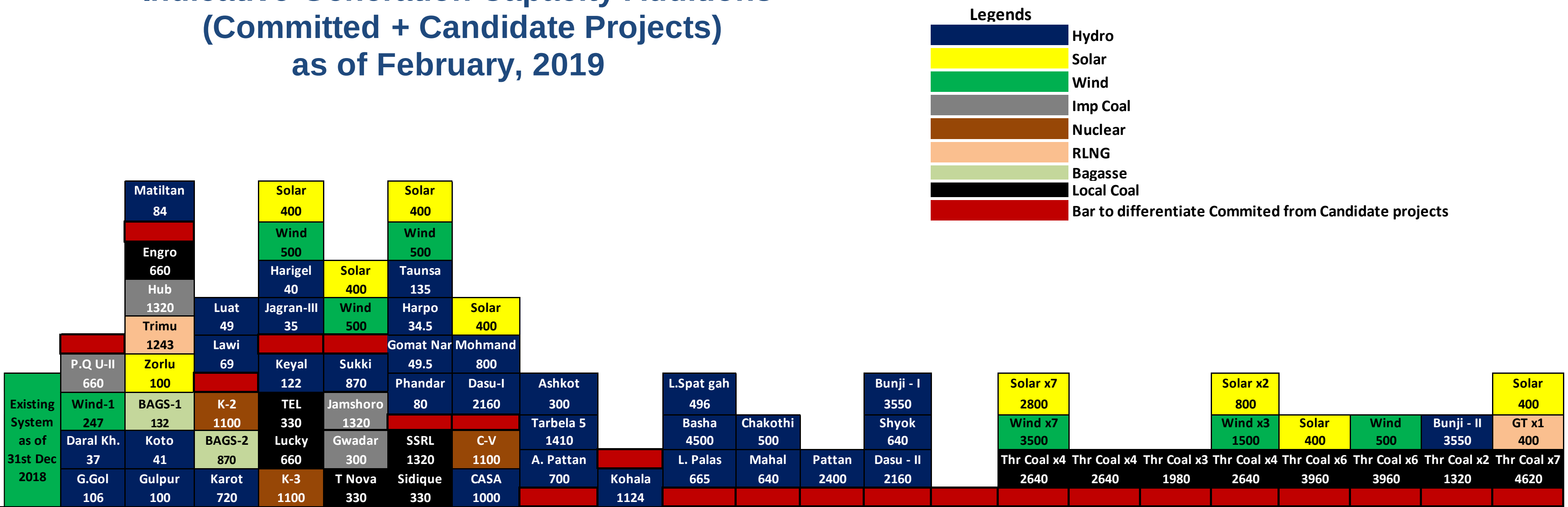


Chart 7-2: Annual Energy Generation Vs Annual Energy Demand (GWh)

Table 7-1: Future Generation Capacity Additions

Fiscal Year	660 MW Steam on Imported COAL		660 MW Steam on Thar COAL		1200 MW Comb. Cycle on Imported Gas/LNG		400 MW Gas Turbines on Imported Gas/LNG		1100 MW Nuclear Steam on Uranium		Renewable		Hydroelectric Projects		Per Year Capacity Addition	Cumulative Capacity Addition	LOLP
											Wind	Solar					
	# Units	MW	# Units	MW	# Units	MW	# Units	MW	# Units	MW	MW	MW	Plant Name	MW	MW	MW	%
2018	-	-	-	-	-	-	-	-	-	-	-	-			-		5.802
2019	-	-	-	-	-	-	-	-	-	-	-	-			-	-	1.833
2020	-	-	-	-	-	-	-	-	-	-	-	-	Matiltan HPP	84	84	84	0.170
2021	-	-	-	-	-	-	-	-	-	-	-	-	Lawi & Luat HPP	118	118	202	0.027
2022	-	-	-	-	-	-	-	-	-	-	500	400	Harigel & Jagran-3 HPP	75	975	1,177	0.014
2023	-	-	-	-	-	-	-	-	-	-	500	400			900	2,077	0.005
2024	-	-	-	-	-	-	-	-	-	-	500	400	Gummat, Taunsa, Harpo & Phander HPP	299	1,199	3,276	0.003
2025	-	-	-	-	-	-	-	-	1	1,100	-	400	Mohmand Dam & Dasu stage-I HPP	2,960	4,460	7,736	0.000
2026	-	-	-	-	-	-	-	-	-	-	-	-	Tarbela 5th Extension, Azad Pattan & Ashkot HPP	2,410	2,410	10,146	0.000
2027	-	-	-	-	-	-	-	-	-	-	-	-			-	10,146	0.023
2028	-	-	-	-	-	-	-	-	-	-	-	-	Palas, Spat Gah & Diamer Basha	5,661	5,661	15,807	0.001
2029	-	-	-	-	-	-	-	-	-	-	-	-	Chakothi & Mahal HPP	1,140	1,140	16,947	0.014
2030	-	-	-	-	-	-	-	-	-	-	-	-	Pattan,HPP	2,400	2,400	19,347	0.073
2031	-	-	-	-	-	-	-	-	-	-	-	-	Bunji Stage-I, Shyok & Dasu stage-II	6,350	6,350	25,697	0.001
2032	-	-	-	-	-	-	-	-	-	-	-	-			-	25,697	0.110
2033	-	-	4	2,640	-	-	-	-	-	-	3,500	2,800			8,940	34,637	0.014
2034	-	-	4	2,640	-	-	-	-	-	-	-	-			2,640	37,277	0.048
2035	-	-	3	1,980	-	-	-	-	-	-	-	-			1,980	39,257	0.227
2036	-	-	4	2,640	-	-	-	-	-	-	1,500	800			4,940	44,197	0.292
2037	-	-	6	3,960	-	-	-	-	-	-	-	400			4,360	48,557	0.333
2038	-	-	6	3,960	-	-	-	-	-	-	500	-			4,460	53,017	0.381
2039	-	-	2	1,320	-	-	-	-	-	-	-	-	Bunji Stage-II	3,550	4,870	57,887	0.293
2040	-	-	7	4,620	-	-	1	400	-	-	-	400			5,420	63,307	0.356
Total	**-**	**-**	**36**	**23,760**	**-**	**-**	**1**	**400**	**1**	**1,100**	**7,000**	**6,000**		**25,047**	**63,307**	**63,307**	

Indicative Generation Capacity Additions
(Committed + Candidate Projects)
as of February, 2019



Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Commited MW	0	1,050	3,596	2,690	2,212	2,820	1,650	2,100	0	1,124	0	0	0	0	0	0	0	0	0	0	0	0	0
Candidate MW	0	0	84	118	975	900	1,199	3,360	2,410	0	5,661	1,140	2,400	6,350	0	8,940	2,640	1,980	4,940	4,360	4,460	4,870	5,420
Total MW		1,050	3,680	2,808	3,187	3,720	2,849	5,460	2,410	1,124	5,661	1,140	2,400	6,350	0	8,940	2,640	1,980	4,940	4,360	4,460	4,870	5,420
Cummulative Total (MW)																				79,449			

O/o General Manager(PSP)

Note: The Projects below the red bar are Commited Projects and above the red line are candidate projects.

Figure 7-1: IGCEP: Generation Sequence

The break-up of RE projects lumped as blocks in above IGCEP Generation Sequence Figure 7-1 is given below in Table 7-2:

Table-7-2: Name of Blocks for Wind and Bagasse Power Plants

Sr. No.	Year	Block Name	Name of Project	Installed Capacity (MW)
1	2019	Wind-1	TGS	49.5
2			T Boston A	49.5
3			T Boston B	49.5
4			T Boston C	49.5
5			Zephyr	48.3
6	2020	BAGS-1	Al-moiz	36
7			Chanar	22
8			Etihad	74.4
9	2021	BAGS-2	Thal Indus	20
10			Alman	34.5
11			Shahtaj	32
12			Hunza	49.8
13			Ittefaq	31.2
14			Kashmir	40
15			Indus	31
16			Bahawalpur	31.2
17			Alliance	30
18			RYK Energy	25
19			Gotki	45
20			Ranipur	60
21			Digri Gen	25
22			Mirpur	26
23			Two Star	49.8
24			TAY	30
25			Sheikhoo	30
26			Hamza	30

Sr. No.	Year	Block Name	Name of Project	Installed Capacity (MW)
27			Faran	26.5
28			Mehran	26.5
29			HSM	26.5
30			Sadiqabad	45
31			Al-Mughnee	40
32			Darya Khan	40
33			Hamza	15
34			Popular	30

The following table depicts the CODs of Candidate Hydro power projects optimized by WASP (software).

Table-7-3: Hydel Projects Optimized by WASP

Sr. No.	Name of Project	Installed Capacity (MW)	CODs given to WASP	CODs Optimized by WASP
1	Matilatan HPP	84	2020	2020
2	Lawi	69	2021	2021
3	Luat	49	2021	2021
4	Harigel	40.32	2022	2022
5	Jagran-III	35	2022	2022
6	Gaumat Nar	49.5	2023	2024
7	Taunsa	135	2024	2024
8	Harpo	34.5	2024	2024
9	Phander	80	2024	2024
10	Mohmand Dam	800	2024	2025
11	Dasu (Stage-I)	2,160	2025	2025
12	Tarbela 5th Ext.	1,410	2025	2026

Sr. No.	Name of Project	Installed Capacity (MW)	CODs given to WASP	CODs Optimized by WASP
13	Azad Pattan	700	2026	2026
14	Ashkot	300	2026	2026
15	Lower Pallas Valley	665	2028	2028
16	Lower Spat Gah	496	2028	2028
17	Diamer Basha	4,500	2028	2028
18	Chakothi Hattian	500	2028	2029
19	Mahal	640	2029	2029
20	Pattan	2,400	2030	2030
21	Bunji (Stage-I)	3,550	2030	2031
22	Shyok	640	2030	2031
23	Dasu (Stage-II)	2,160	2031	2031
24	Bunji (Stage-II)	3,550	2032	2039
25	Thakot	4,000	2032	Not Selected

WASP final output compromising of year-wise addition of all committed and candidate power plants is given below in Table 7-4:

Table-7-4: List of Projects uptill 2040 (Committed + Candidate)

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
2019						
1	Daral Khwar	Hydro	37	Public / PEDO	Committed	2019
2	Golen Gol	Hydro	106	Public / WAPDA	Committed	2019
3	TGS	Wind	49.5	Private / AEDB	Committed	2019
4	Tricon Boston A	Wind	49.6	Private / AEDB	Committed	2019
5	Tricon Boston B	Wind	49.6	Private / AEDB	Committed	2019
6	Tricon Boston C	Wind	49.6	Private / AEDB	Committed	2019
7	Zephyr	Wind	48.3	Private / AEDB	Committed	2019
8	Port Qasim Power Project (Unit-II)	Imp. Coal	660	Private / PPIB	Committed (CPEC)	2019
Generation Additions in 2019			**1,049.6 MW**			
2020						
9	Matilatan HPP	Hydro	84	Public / PEDO	Optimized	2020
10	Almoiz Industries Limited	Bagasse	36	Private / AEDB	Committed	2020
11	Etihad Power Generation Limited.	Bagasse	74.4	Private / AEDB	Committed	2020
12	Chanar Energy Limited	Bagasse	22	Private / AEDB	Committed	2020
13	Koto HPP	Hydro	40	Public / PEDO	Committed	2020

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
14	Gulpur	Hydro	100	Private / PPIB	Committed	2020
15	Zorlu Solar	Solar	100	Public / PPDB	Committed	2020
16	LNG Based Plant at Trimmun	Imp. LNG	1,243	Private / PPIB	Committed	2020
17	Engro Powergen Project	Local Coal	660	Private / PPIB	Committed (CPEC)	2020
18	HUB Power Company Ltd.	Imp. Coal	1,320	Private / PPIB	Committed (CPEC)	2020
Generation Additions in 2020			**3,679.4 MW**			
2021						
19	Karachi Coastal (Unit-I)	Nuclear	1,100	Public / PAEC	Committed	2021
20	Shahtaj Sugar Mills Ltd.	Bagasse	32	Private / AEDB	Committed	2021
21	Hunza Power (Pvt.) Ltd.	Bagasse	49.8	Private / AEDB	Committed	2021
22	Ittefaq Power (Pvt.) Ltd.	Bagasse	31.2	Private / AEDB	Committed	2021
23	Kashmir Power Private Ltd	Bagasse	40	Private / AEDB	Committed	2021
24	Indus Energy Limited.	Bagasse	31	Private / AEDB	Committed	2021
25	Bahawalpur Energy Ltd.	Bagasse	31.2	Private / AEDB	Committed	2021
26	Alliance Sugar Mills Ltd.	Bagasse	30	Private / AEDB	Committed	2021
27	RYK Energy Limited.	Bagasse	25	Private / AEDB	Committed	2021
28	Mirpurkhas Energy Ltd.	Bagasse	26	Private / AEDB	Committed	2021

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
29	Two Star Industries Pvt Ltd.	Bagasse	49.8	Private / AEDB	Committed	2021
30	TAY	Bagasse	30	Private / AEDB	Committed	2021
31	Sheikhoo Power Ltd.	Bagasse	30	Private / AEDB	Committed	2021
32	Hamza Sugar Mills Ltd.	Bagasse	30	Private / AEDB	Committed	2021
33	Faran Power Ltd.	Bagasse	26.5	Private / AEDB	Committed	2021
34	Mehran Energy Ltd.	Bagasse	26.5	Private / AEDB	Committed	2021
35	Habib Sugar Mills Ltd.	Bagasse	26.5	Private / AEDB	Committed	2021
36	Sadiqabad Power Pvt Ltd.	Bagasse	45	Private / AEDB	Committed	2021
37	Alman	Bagasse	34.5	Private / AEDB	Committed	2021
38	Thal Indus	Bagasse	20	Private / AEDB	Committed	2021
39	Ranipur	Bagasse	60	Private / AEDB	Committed	2021
40	Digri Gen	Bagasse	25	Private / AEDB	Committed	2021
41	Popular	Bagasse	30	Private / AEDB	Committed	2021
42	Hamza	Bagasse	15	Private / AEDB	Committed	2021
43	Darya Khan	Bagasse	40	Private / AEDB	Committed	2021
44	Al- Mughnee	Bagasse	40	Private / AEDB	Committed	2021

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
45	Gotki Power Pvt Ltd.	Bagasse	45	Private / AEDB	Committed	2021
46	Lawi	Hydro	69	Public / PEDO	Optimized	2021
47	Luat	Hydro	49	Private / AJKPPC	Optimized	2021
48	Karot HPP	Hydro	720	Private / PPIB	Committed (CPEC)	2021
Generation Additions in 2021			**2,808 MW**			
2022						
49	Keyal Khwar	Hydro	122	Public / WAPDA	Committed	2022
50	Karachi Coastal (Unit-II)	Nuclear	1,100	Public / PAEC	Committed	2022
51	Lucky Electric Power Company Ltd.	Local Coal	660	Private / PPIB	Committed	2022
52	Jagran-III	Hydro	35	Private / AJKPPC	Optimized	2022
53	Harigel	Hydro	40.32	Private / AJKPPC	Optimized	2022
54	Candidate Wind Block-I	Wind	500	Yet to be decided	Optimized	2022
55	Candidate Solar Block-I	Solar	400	Yet to be decided	Optimized	2022
56	TEL Mine Mouth Lignite Fired Project at Thar	Local Coal	330	Private / PPIB	Committed (CPEC)	2022
Generation Additions in 2022			**3,187 MW**			
2023						
57	Sukki Kinari HPP	Hydro	870	Private / PPIB	Committed (CPEC)	2023

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
58	Jamshoro CFPP	Imp. Coal	1320	Public / GENCOs	Committed	2023
59	Imported Coal based Power Plant at Gawadar	Imp. Coal	300	Private / PPIB	Committed (Strategic)	2023
60	Candidate Wind Block-II	Wind	500	Yet to be decided	Optimized	2023
61	Candidate Solar Block-II	Solar	400	Yet to be decided	Optimized	2023
62	Thal Nova Mine Mouth Lignite Fired Project at Thar	Local Coal	330	Private / PPIB	Committed (CPEC)	2023
Generation Additions in 2023			**3,720 MW**			
2024						
63	SSRL Mine Mouth Project at Thar	Local Coal	1,320	Private / PPIB	Committed (CPEC)	2024
64	Siddiqsons Limited	Local Coal	330	Private / PPIB	Committed	2024
65	Gaumat Nar	Hydro	49.5	Private / AJKPPC	Optimized	2024
66	Taunsa	Hydro	135	Private / PPDB	Optimized	2024
67	Harpo	Hydro	34.5	Public / WAPDA	Optimized	2024
68	Phander	Hydro	80	Public / WAPDA	Optimized	2024
69	Candidate Wind Block-III	Wind	500	Yet to be decided	Optimized	2024
70	Candidate Solar Block-III	Solar	400	Yet to be decided	Optimized	2024
Generation Additions in 2024			**2,849 MW**			
2025						

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
71	Mohmand Dam	Hydro	800	Public / WAPDA	Optimized	2025
72	Dasu (Stage-I)	Hydro	2160	Public / WAPDA	Optimized	2025
73	Candidate Solar Block-IV	Solar	400	Yet to be decided	Optimized	2025
74	CASA 1000 Project	Import	1,000	GoP	Committed	2025
75	Chahma Nuclear (C-V)	Nuclear	1,100	Public / PAEC	Optimized	2025
Generation Additions in 2025			**5,460 MW**			
2026						
76	Tarbela 5th Ext.	Hydro	1,410	Public / WAPDA	Optimized	2026
77	Azad Pattan	Hydro	700	Private / PPIB	Optimized	2026
78	Ashkot	Hydro	300	Private / AJKPPC	Optimized	2026
Generation Additions in 2026			**2,410 MW**			
2027						
79	Kohala HPP	Hydro	1,124	Private / PPIB	Committed (CPEC)	2027
Generation Additions in 2027			**1,124 MW**			
2028						
80	Lower Spat Gah	Hydro	496	Public / WAPDA	Optimized	2028
81	Lower Pallas Valley	Hydro	665	Public / WAPDA	Optimized	2028
82	Diamer Basha	Hydro	4,500	Public / WAPDA	Optimized	2028

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
Generation Additions in 2028			**5,661 MW**			
2029						
83	Chakothi Hattian	Hydro	500	Private / PPIB	Optimized	2029
84	Mahal	Hydro	640	Private / PPIB	Optimized	2029
Generation Additions in 2029			**1,140 MW**			
2030						
85	Pattan	Hydro	2,400	Public / WAPDA	Optimized	2030
Generation Additions in 2030			**2,400 MW**			
2031						
86	Bunji (Stage-I)	Hydro	3,550	Public / WAPDA	Optimized	2031
87	Shyok	Hydro	640	Public / WAPDA	Optimized	2031
88	Dasu (Stage-II)	Hydro	2,160	Public / WAPDA	Optimized	2031
Generation Additions in 2031			**6,350 MW**			
2032						
Generation Additions in 2032			**0 MW**			
2033						
89	Candidate Wind Block-IV	Wind	500	Yet to be decided	Optimized	2033
90	Candidate Wind Block-V	Wind	500	Yet to be decided	Optimized	2033
91	Candidate Wind Block-VI	Wind	500	Yet to be decided	Optimized	2033

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
92	Candidate Wind Block-VII	Wind	500	Yet to be decided	Optimized	2033
93	Candidate Wind Block-VIII	Wind	500	Yet to be decided	Optimized	2033
94	Candidate Wind Block-IX	Wind	500	Yet to be decided	Optimized	2033
95	Candidate Wind Block-X	Wind	500	Yet to be decided	Optimized	2033
96	Candidate Solar Block-V	Solar	400	Yet to be decided	Optimized	2033
97	Candidate Solar Block-VI	Solar	400	Yet to be decided	Optimized	2033
98	Candidate Solar Block-VII	Solar	400	Yet to be decided	Optimized	2033
99	Candidate Solar Block-VIII	Solar	400	Yet to be decided	Optimized	2033
100	Candidate Solar Block-IX	Solar	400	Yet to be decided	Optimized	2033
101	Candidate Solar Block-X	Solar	400	Yet to be decided	Optimized	2033
102	Candidate Solar Block-XI	Solar	400	Yet to be decided	Optimized	2033
103	Candidate Thar CFPP (04 Units*660MW)	Local Coal	2,640	Yet to be decided	Optimized	2033
Generation Additions in 2033			**8,940 MW**			
2034						
104	Candidate Thar CFPP (04 Units*660MW)	Local Coal	2,640	Yet to be decided	Optimized	2034
Generation Additions in 2034			**2,640 MW**			
2035						

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
105	Candidate Thar CFPP (03 Units*660MW)	Local Coal	1,980	Yet to be decided	Optimized	2035
Generation Additions in 2035			**1,980 MW**			
2036						
106	Candidate Thar CFPP (04 Units*660MW)	Local Coal	2,640	Yet to be decided	Optimized	2036
107	Candidate Wind Block-XI	Wind	500	Yet to be decided	Optimized	2036
108	Candidate Wind Block-XII	Wind	500	Yet to be decided	Optimized	2036
109	Candidate Wind Block-XIII	Wind	500	Yet to be decided	Optimized	2036
110	Candidate Solar Block-XII	Solar	400	Yet to be decided	Optimized	2036
111	Candidate Solar Block-XIII	Solar	400	Yet to be decided	Optimized	2036
Generation Additions in 2036			**4,940 MW**			
2037						
112	Candidate Thar CFPP (06 Unit*660MW)	Local Coal	3,960	Yet to be decided	Optimized	2037
113	Candidate Solar Block-XIV	Solar	400	Yet to be decided	Optimized	2037
Generation Additions in 2037			**4,360 MW**			
2038						
114	Candidate Wind Block-XIV	Wind	500	Yet to be decided	Optimized	2038
115	Candidate Thar CFPP (06 Units*660MW)	Local Coal	3,960	Yet to be decided	Optimized	2038
Generation Additions in 2038			**4,460 MW**			

Sr #	Name of Project	Fuel Type	Installed Capacity (MW)	Agency	Status	Schedule of Commissioning
2039						
116	Bunji (Stage-II)	Hydro	3,550	Public / WAPDA	Optimized	2039
117	Candidate Thar CFPP (02 Units*660MW)	Local Coal	1,320	Yet to be decided	Optimized	2039
Generation Additions in 2039			**4,870 MW**			
2040						
118	Candidate Solar Block-XV	Solar	400	Yet to be decided	Optimized	2040
119	Candidate Thar CFPP (07 Units*660MW)	Local Coal	4,620	Yet to be decided	Optimized	2040
120	Candidate Gas Turbine (01 Unit*400MW)	LNG	400	Yet to be decided	Optimized	2040
Generation Additions in 2040			**5,420 MW**			
Total Generation Addition till 2040 (MW)			**79,448 MW**			

7.2. Annual Capacity Factors

The annual capacity factors information, as shown in the Table 7-5 is one of the most important output of the WASP tool. The drastic change in capacity factor of some plants between the years 2028 to 2032 is due to certain rationale: up to the year 2032, the power purchaser is obliged to utilize 66% of the RLNG fueled plants under contractual obligations. Beyond 2032, these take or pay fuel contracts of 4 x RLNG plants will expire and the results of capacity factors are thus different. Due to this reason, the capacity factors of coal-based plants, imported as well as Thar coal, are lower in the period from 2028 to 2032 and then onwards, there is a rising trend.

In order to honor the contracts of RLNG plants, the model has been developed in a way, that up to 2032, the capacity factors of RLNG plants are higher than 66%. If the contract of these plants are not modeled in the tool, these plants are dispatched way below the guaranteed dispatches of 66%, that will result in additional burden to the electricity customer as the sector will end up paying for fuel not utilized below these capacity factors.

Due to this onstraint, the Thar coal-based projects are dispatched at lower capacity factor. As these constraints are released in 2032, the capacity factors of the RLNG plants, being a costly option, reduce and those of Thar Coal based projects increase substantially which means that Thar coal is a cheaper option in the future.

The gradual decrease in the capacity factors of other older plants is result of efficient and cheap generation addition in the system. However, the sudden drop of capacity factors of certain economical plants from high utilization factors to zero is because of the expiry of respective PPAs; particularly, HCPC, Uch and Liberty Power fall in this category. These are indigenous gas based economical plants which are expected to be dispatched at high capacity factors till the expiry of their corresponding PPAs.

Table 7-5: Annual Capacity Factors (%age)

PLANT NAME	Fuel	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
HYDEL PLANTS	Hydro	45.5	45.7	46.0	45.9	45.3	45.5	46.8	44.4	45.7	45.7	46.4	47.5	47.7	47.7	47.7	47.7	47.7	47.7	47.7	47.7	46.9	46.9
RENEWABLES	RE	31.6	33.0	41.5	37.5	35.0	33.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	32.3	28.1	28.1	28.1	27.6	27.4	27.4	27.4	27.2
THERMAL:																							
Jamshoro Steam unit 1	FO	6.7	1.4	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jamshoro Steam units 2 - 4	FO	8.8	1.9	0.6	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kotri Combined Cycle	Gas	82.5	82.5	80.9	52.0	41.8	35.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Guddu Steam (3 , 4)	Gas	83.4	83.3	81.5	51.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Guddu C.C. units 1-6	Gas	83.4	83.4	82.0	53.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Guddu C.C. units 7-9	Gas	83.4	83.4	83.3	74.0	63.2	57.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Guddu C.C. 747 MW	Gas	84.3	84.3	84.3	84.3	84.3	83.9	83.7	83.8	83.8	54.4	61.5	64.3	50.6	70.9	76.1	76.6	78.4	77.6	75.9	74.3	73.5	71.4
Muzaffargarh ST(1-3 & 5-6)	FO	2.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Muzaffargarh Steam unit 4	FO	2.9	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Faisalabad Combined Cycle	Gas	77.9	77.9	76.7	54.5	40.2	33.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lakhra Fluidized Bed Coal	Local Coal	55.0	55.0	55.0	55.0	54.9	54.7	54.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nandipur Combined Cycle	RLNG	86.5	49.7	31.7	19.7	13.3	6.2	2.7	2.1	3.7	0.1	5.5	5.8	0.0	12.6	0.2	0.3	6.2	1.0	1.0	1.1	0.8	0.9
Kot Addu C.C. (1-4 & 9-10)	RLNG	76.3	30.8	16.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kot Addu C.C. (5-8 & 11-12)	RLNG	56.6	14.3	6.1	4.3	1.9	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kot Addu C.C. units 13-15	RLNG	24.4	4.9	2.3	1.5	0.5	0.4	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hub Power Project (HUBCO)	FO	4.7	0.9	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kohinoor Energy Ltd.	FO	28.4	5.5	2.6	1.8	0.6	0.4	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AES (Lalpir & PakGen)	FO	15.4	3.0	1.3	0.8	0.2	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Habibullah Coastal	Gas	88.0	88.0	87.3	60.5	48.8	42.1	26.3	20.3	27.2	12.9	14.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uch Power Project	Gas	88.0	88.0	88.0	88.0	88.0	88.0	87.9	87.8	87.9	67.1	75.6	76.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rousch(Pakistan) Power Ltd.	RLNG	66.2	18.8	9.9	6.2	3.1	2.0	0.4	0.4	0.7	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fauji Kabirwala	RLNG	74.1	24.0	15.1	11.2	4.5	2.9	0.7	0.6	1.2	0.0	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Saba Power	FO	22.3	3.9	1.7	1.1	0.3	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Liberty Power Project	Gas	88.0	87.9	85.6	54.6	44.4	37.0	19.9	17.3	22.2	9.3	12.9	15.8	5.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Altern Energy Ltd. (AEL)	RLNG	7.8	1.7	0.5	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

PLANT NAME	Fuel	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Davis Energen	RLNG	20.4	3.8	1.6	1.1	0.3	0.2	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.2	0.2	0.3	0.3	0.2	0.4
Attock Generation PP	FO	74.7	23.4	13.4	8.4	4.0	2.5	0.6	0.6	1.0	0.0	0.1	0.2	0.0	0.3	0.0	0.1	0.4	0.5	0.5	0.6	0.4	0.0
ATLAS Power	FO	42.5	8.2	3.6	2.7	1.0	0.7	0.2	0.2	0.4	0.0	0.0	0.1	0.0	0.2	0.0	0.1	0.3	0.4	0.4	0.5	0.3	0.0
Engro P.P. Daharki, Sindh	Gas	88.0	88.0	86.8	62.2	46.0	42.4	21.2	19.9	18.3	12.3	13.3	10.7	13.2	25.6	51.9	62.5	69.3	62.2	47.3	49.3	44.2	47.4
Saif P.P. Sahiwal, Punjab	RLNG	79.0	36.9	21.4	12.7	6.2	3.8	1.0	1.0	1.8	0.1	0.2	0.4	0.0	4.0	0.1	0.2	0.6	0.6	0.7	0.7	0.5	0.6
Orient P.P. Balloki, Punjab	RLNG	81.7	44.5	26.2	16.0	10.3	5.3	1.6	1.6	2.8	0.1	1.7	4.1	0.0	4.2	0.1	0.2	0.7	0.8	0.8	0.9	0.7	0.7
Nishat P.P. Near Lahore	FO	38.4	7.5	3.3	2.4	0.9	0.6	0.2	0.2	0.3	0.0	0.0	0.1	0.0	0.1	0.0	0.1	0.3	0.3	0.4	0.4	0.3	0.5
Nishat Chunian Proj. Lahore	FO	35.5	6.5	3.0	2.0	0.8	0.5	0.1	0.1	0.3	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.2	0.3	0.3	0.4	0.3	0.4
Foundation Power	Gas	88.0	88.0	88.0	78.3	68.7	63.9	45.7	39.8	44.3	33.8	50.1	52.9	38.7	56.2	75.3	75.7	78.0	76.7	77.6	70.7	71.3	67.3
Saphire Muridke	Gas	80.4	39.7	23.8	14.3	9.0	4.5	1.3	1.3	2.3	0.1	0.2	0.4	0.0	4.1	0.1	0.2	0.6	0.7	0.8	0.8	0.6	0.7
Liberty Tech	FO	48.0	9.9	4.5	3.3	1.3	0.9	0.3	0.3	0.6	0.0	0.0	0.2	0.0	0.2	0.0	0.1	0.4	0.5	0.5	0.5	0.4	0.5
Hubco Narowal	FO	21.1	4.4	1.9	1.3	0.4	0.3	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.2	0.3	0.3	0.3	0.3	0.4
Halmore Bhikki	Gas	76.1	32.3	19.7	13.1	5.3	3.3	0.9	0.8	1.4	0.0	0.1	0.3	0.0	3.1	0.1	0.1	0.5	0.6	0.6	0.6	0.5	0.6
Uch-II	Gas	88.0	88.0	88.0	87.9	87.7	87.0	87.1	86.7	87.0	49.4	62.3	60.6	57.2	78.4	78.4	78.9	80.9	80.0	78.0	76.2	75.5	73.1
Reshma Power	FO	11.5	2.4	0.9	0.5	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.2	0.2	0.3	0.3	0.2	0.3
Gulf Power	FO	86.0	53.6	35.0	26.0	11.3	10.1	3.3	3.1	4.6	0.2	5.7	6.0	0.0	18.3	0.2	1.4	6.3	3.0	5.1	1.2	0.9	0.9
Chashma Nuclear (PAEC)-I	Uranium	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2
Chashma Nuclear (PAEC)-II	Uranium	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2
Chashma Nuclear (PAEC)-III	Uranium	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	79.7	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5
Chashma Nuclear (PAEC)-IV	Uranium	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	77.8	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5	81.5
Sahiwal Coal	Imp. Coal	85.3	84.9	82.1	49.3	38.8	32.0	14.3	14.1	16.6	7.3	9.6	9.0	3.1	18.0	48.6	46.8	54.3	50.7	40.2	32.5	40.2	34.9
Bhikki C.C.	RLNG	87.1	73.2	57.2	79.9	77.8	74.8	59.0	56.6	63.4	75.5	78.1	79.0	68.2	78.8	4.7	6.1	11.1	10.1	5.8	3.1	5.8	1.6
Haveli Bahadur Shah C.C.	RLNG	87.6	85.5	80.0	87.1	86.5	85.6	84.3	84.5	85.4	87.4	87.6	87.5	80.4	84.6	42.7	39.6	43.9	39.6	32.6	26.1	33.6	26.7
Balloki C.C.	RLNG	87.5	79.1	67.3	83.5	82.2	79.4	66.9	66.7	76.1	79.4	81.4	81.8	75.9	80.9	15.9	16.0	18.1	19.0	14.0	10.8	14.8	7.2
Trimmun C.C.	RLNG	0.0	82.9	74.4	85.6	85.0	83.2	78.7	77.7	81.7	82.2	86.3	85.8	78.3	83.0	27.4	26.5	33.4	28.6	21.6	17.5	26.0	20.5
Port Qasim Power Project	Imp. Coal	85.3	85.3	85.1	72.2	58.5	53.1	37.6	34.9	39.1	24.2	34.2	38.2	31.7	50.0	71.4	71.7	73.9	72.5	69.4	65.9	66.7	61.3
HUB Power Company Ltd.	Imp. Coal	0.0	85.2	84.6	62.7	50.7	45.1	28.4	26.8	31.5	12.5	17.7	21.8	18.1	38.9	66.6	65.0	70.6	68.6	63.0	51.1	60.2	48.4
Coal Based Power Plant at Gawadar	Imp. Coal	0.0	0.0	0.0	0.0	45.9	39.9	22.5	19.1	23.2	10.7	12.7	15.8	17.7	32.8	59.3	58.5	70.2	65.8	54.7	45.3	49.5	43.1
Engro Powergen Project at Thar	Local Coal	0.0	85.3	85.3	85.3	85.3	85.3	85.2	85.2	85.2	85.3	85.3	85.3	81.4	85.3	81.2	81.7	82.6	82.3	79.9	78.9	77.7	76.6

PLANT NAME	Fuel	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thar Energy Limited (HUBCO Ltd.)	Local Coal	0.0	0.0	0.0	85.3	85.3	85.3	85.2	85.2	85.2	85.3	85.3	85.2	80.6	84.0	80.3	80.6	82.4	81.3	79.2	78.2	77.0	75.7
Thal NOVA Thar Coal	Local Coal	0.0	0.0	0.0	0.0	85.2	85.2	85.2	85.2	85.2	85.3	85.3	85.2	80.3	82.5	80.0	80.3	82.2	81.0	78.8	77.6	76.5	75.0
Shanghai Electric Power Project	Local Coal	0.0	0.0	0.0	0.0	0.0	85.3	85.2	85.3	85.3	85.3	85.3	85.3	80.6	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3
Lucky Electric Power Company Ltd.	Local Coal	0.0	0.0	0.0	85.2	85.2	85.1	85.0	84.9	85.0	62.4	70.5	71.0	59.6	73.3	78.1	78.6	80.6	79.5	78.0	76.6	75.7	73.9
Siddiqsons Limited	Local Coal	0.0	0.0	0.0	0.0	0.0	85.3	85.3	85.3	85.3	85.3	85.3	85.3	82.8	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3	85.3
Karachi Coastal Nuclear Power Plant	Uranium	0.0	0.0	79.8	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2
Jamshoro Coal Power Plant	Imp. Coal	0.0	0.0	0.0	0.0	75.0	71.1	52.2	50.0	56.9	43.1	51.0	51.0	47.1	61.8	74.3	74.8	76.9	75.9	73.6	71.0	71.0	67.9
CHASHNUPP-V	Uranium	0.0	0.0	0.0	0.0	0.0	0.0	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2	79.2
Future Gas Turbines	RLNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Future Combined Cycle Power Plant	RLNG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Imported Coal Fired Plant	Imp. Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Future Thar Coal Fired Plant	Local Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	83.2	84.4	85.2	85.0	84.8	84.7	84.3	84.2

7.3. Annual Energy Generation

The annual energy generation figures during the plan period as calculated by the WASP tool are shown in Table 7-6.

Table 7-6: Annual Energy Generation 2018-40 (GWh)

PANT NAME	Fuel	2019	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	2040
HYDEL ENERGY	Hydro	38,947	39,982	43,657	44,378	47,202	48,608	66,272	72,241	78,849	101,550	107,710	120,254	147,248	147,248	147,248	147,248	147,248	147,248	147,248	147,248	159,326	159,326
RENEWABLE ENERGY	RE	5,372	6,268	11,060	12,950	14,840	16,730	17,395	17,395	17,395	17,395	17,395	17,395	17,395	17,395	30,625	30,625	30,625	35,630	36,295	37,520	37,520	38,185
THERMAL:																							
Jamshoro Steam unit 1	FO	118	25	8	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Jamshoro Steam units 2 - 4	FO	394	83	29	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kotri Combined Cycle	Gas	773	773	758	488	392	335	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Guddu Steam (3 , 4)	Gas	1,023	1,022	999	635	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Guddu C.C. units 1-6	Gas	4,092	4,091	4,022	2,617	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Guddu C.C. units 7-9	Gas	2,631	2,631	2,628	2,333	1,994	1,809	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Guddu C.C. 747 MW	Gas	5,519	5,519	5,518	5,516	5,514	5,492	5,480	5,482	5,486	3,560	4,027	4,205	3,313	4,640	4,980	5,014	5,128	5,077	4,964	4,860	4,810	4,670
Muzaffargarh ST(1-3 & 5-6)	FO	166	18	3	1	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Muzaffargarh Steam unit 4	FO	63	9	2	1	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-
Faisalabad Combined Cycle	Gas	915	914	900	640	471	397	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lakhra Fluidized Bed Coal	Local Coal	145	145	145	144	144	144	143	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nandipur Combined Cycle	RLNG	3,410	1,960	1,250	777	524	244	105	83	145	5	218	230	1	495	6	13	243	41	40	41	32	33
Kot Addu C.C. (1-4 & 9-10)	RLNG	1,678	677	357	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kot Addu C.C. (5-8 & 11-12)	RLNG	3,677	925	393	281	121	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Kot Addu C.C. units 13-15	RLNG	718	144	67	45	15	10	2	2	5	-	-	-	-	-	-	-	-	-	-	-	-	-
Hub Power Project (HUBCO)	FO	498	94	24	13	6	3	0	0	1	-	-	-	-	-	-	-	-	-	-	-	-	-
Kohinoor Energy Ltd.	FO	314	61	28	20	7	5	1	1	3	-	-	-	-	-	-	-	-	-	-	-	-	-
AES (Lalpir & PakGen)	FO	947	186	76	48	13	8	1	1	4	0	-	-	-	-	-	-	-	-	-	-	-	-
Habibullah Coastal	Gas	971	971	963	668	539	465	291	224	300	143	163	-	-	-	-	-	-	-	-	-	-	-

PANT NAME	Fuel	2019	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	2040
Uch Power Project	Gas	4,248	4,248	4,247	4,247	4,247	4,247	4,241	4,239	4,242	3,240	3,650	3,669	-	-	-	-	-	-	-	-	-	-
Rousch(Pakistan) Power Ltd.	RLNG	2,289	651	343	215	108	69	14	13	25	0	2	-	-	-	-	-	-	-	-	-	-	-
Fauji Kabirwala	RLNG	973	315	198	147	59	38	9	7	16	0	1	3	-	-	-	-	-	-	-	-	-	-
Saba Power	FO	240	42	18	12	4	2	0	0	1	0	0	-	-	-	-	-	-	-	-	-	-	-
Liberty Power Project	Gas	1,634	1,632	1,590	1,014	824	686	370	321	412	172	240	293	110	-	-	-	-	-	-	-	-	-
Altern Energy Ltd. (AEL)	RLNG	21	4	1	1	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
Davis Energen	RLNG	18	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Attock Generation PP	FO	1,020	320	184	114	55	34	8	8	14	0	1	3	0	3	0	1	6	7	7	8	6	-
ATLAS Power	FO	796	153	68	50	19	13	4	3	8	0	1	2	0	3	0	1	5	7	8	8	6	-
Engro P.P. Daharki, Sindh	Gas	1,673	1,672	1,650	1,182	873	806	403	378	348	233	252	204	251	487	987	1,187	1,317	1,183	900	937	841	900
Saif P.P. Sahiwal, Punjab	RLNG	1,447	676	392	232	113	70	19	18	33	1	3	6	0	72	1	3	10	12	12	13	10	11
Orient P.P. Balloki, Punjab	RLNG	1,495	815	480	292	189	97	30	30	51	2	32	75	0	77	2	4	14	15	15	16	12	13
Nishat P.P. Near Lahore	FO	656	128	57	41	16	11	3	3	6	0	0	2	0	2	0	1	5	6	6	7	5	8
Nishat Chunian Proj. Lahore	FO	587	108	50	33	13	9	2	2	5	0	0	1	0	2	0	1	4	5	5	6	5	7
Foundation Power	Gas	1,403	1,403	1,402	1,248	1,096	1,019	729	635	706	539	799	844	617	895	1,200	1,206	1,244	1,223	1,237	1,127	1,136	1,073
Saphire Muridke	Gas	1,472	726	435	261	164	82	24	23	41	1	4	8	0	75	1	3	12	13	14	14	11	12
Liberty Tech	FO	757	156	71	51	21	14	4	4	9	0	1	2	0	3	0	1	6	7	8	8	6	8
Hubco Narowal	FO	375	77	34	23	7	5	1	1	2	0	0	1	0	1	0	1	3	4	5	6	4	7
Halmore Bhikki	Gas	1,379	586	358	238	96	61	16	15	25	1	3	5	0	56	1	2	9	10	11	11	9	10
Uch-II	Gas	2,891	2,891	2,890	2,886	2,881	2,857	2,863	2,846	2,859	1,624	2,045	1,991	1,878	2,575	2,574	2,593	2,657	2,629	2,563	2,505	2,479	2,401
Reshma Power	FO	91	19	7	4	1	1	0	0	0	0	0	0	0	1	0	0	1	2	2	2	2	2
Gulf Power	FO	467	291	190	141	62	55	18	17	25	1	31	33	0	99	1	7	34	16	28	6	5	5
Chashma Nuclear (PAEC)-I	Uranium	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087
Chashma Nuclear (PAEC)-II	Uranium	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087	2,087
Chashma Nuclear (PAEC)-III	Uranium	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,199	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250
Chashma Nuclear (PAEC)-IV	Uranium	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,146	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250

PANT NAME	Fuel	2019	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	2040
Sahiwal Coal	Imp. Coal	9,066	9,025	8,732	5,239	4,128	3,401	1,520	1,500	1,765	777	1,018	958	332	1,913	5,171	4,979	5,778	5,391	4,276	3,452	4,272	3,715
Bhikki C.C.	RLNG	8,823	7,409	5,793	8,090	7,883	7,577	5,976	5,732	6,423	7,643	7,913	7,998	6,907	7,976	475	619	1,120	1,019	583	309	585	157
Haveli Bahadur Shah C.C.	RLNG	8,872	8,655	8,099	8,817	8,755	8,672	8,534	8,552	8,643	8,848	8,871	8,864	8,144	8,563	4,327	4,006	4,446	4,008	3,300	2,641	3,400	2,703
Balloki C.C.	RLNG	9,192	8,308	7,072	8,766	8,638	8,340	7,030	7,000	7,991	8,336	8,551	8,595	7,971	8,497	1,672	1,675	1,897	2,000	1,473	1,135	1,550	757
Trimmun C.C.	RLNG	-	9,027	8,106	9,317	9,250	9,055	8,567	8,460	8,890	8,946	9,401	9,341	8,521	9,041	2,984	2,880	3,641	3,110	2,354	1,901	2,830	2,236
Port Qasim Power Project	Imp. Coal	9,066	9,066	9,045	7,681	6,223	5,647	4,003	3,710	4,155	2,576	3,641	4,062	3,366	5,322	7,590	7,621	7,854	7,705	7,376	7,004	7,096	6,522
HUB Power Company Ltd.	Imp. Coal	-	9,065	8,997	6,665	5,395	4,797	3,017	2,848	3,349	1,328	1,884	2,315	1,929	4,140	7,087	6,913	7,505	7,290	6,696	5,431	6,401	5,147
Coal Based Power Plant at Gawadar	Imp. Coal	-	-	-	-	1,223	1,063	598	507	618	286	338	420	470	874	1,579	1,558	1,870	1,752	1,458	1,206	1,319	1,149
Engro Powergen Project at Thar	Local Coal	-	4,481	4,481	4,481	4,481	4,481	4,480	4,480	4,480	4,481	4,481	4,481	4,277	4,481	4,270	4,294	4,344	4,324	4,199	4,149	4,085	4,026
Thar Energy Limited (HUBCO Ltd.)	Local Coal	-	-	-	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,119	2,207	2,110	2,119	2,164	2,137	2,082	2,054	2,023	1,989
Thal NOVA Thar Coal	Local Coal	-	-	-	-	2,240	2,240	2,239	2,240	2,240	2,240	2,240	2,240	2,111	2,167	2,102	2,111	2,159	2,130	2,070	2,039	2,010	1,972
Shanghai Electric Power Project	Local Coal	-	-	-	-	-	8,976	8,976	8,976	8,976	8,976	8,976	8,976	8,490	8,976	8,976	8,976	8,976	8,976	8,976	8,976	8,976	8,976
Lucky Electric Power Company Ltd.	Local Coal	-	-	-	4,488	4,487	4,480	4,475	4,471	4,474	3,286	3,709	3,737	3,138	3,856	4,113	4,138	4,242	4,188	4,104	4,034	3,984	3,892
Siddiqsons Limited	Local Coal	-	-	-	-	-	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,175	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240	2,240
Karachi Coastal Nuclear Power Plant	Uranium	-	-	7,110	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106	14,106
Jamshoro Coal Power Plant	Imp. Coal	-	-	-	-	7,976	7,558	5,551	5,321	6,049	4,578	5,421	5,420	5,009	6,575	7,900	7,958	8,173	8,068	7,827	7,553	7,551	7,225
CHASHNUPP-V	Uranium	-	-	-	-	-	-	7,018	7,018	7,018	7,018	7,018	7,018	7,018	7,018	7,018	7,018	7,018	7,018	7,018	7,018	7,018	7,018
Future Gas Turbines	RLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11
Future Combined Cycle Power Plant	RLNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Imported Coal Fired Plant	Imp. Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Future Thar Coal Fired Plant	Local Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	17,510	35,530	49,337	67,142	93,721	120,351	128,654	159,633
THERMAL ENERGY		107,676	110,878	108,947	115,244	116,290	122,721	114,026	112,433	117,103	106,107	112,197	113,263	100,776	116,115	119,660	137,456	156,243	171,536	192,358	213,851	226,155	251,314
TOTAL ENERGY GENERATION		**151,995**	**157,128**	**163,664**	**172,572**	**178,332**	**188,060**	**197,693**	**202,068**	**213,347**	**225,051**	**237,301**	**250,911**	**265,419**	**280,758**	**297,532**	**315,329**	**334,116**	**354,414**	**375,900**	**398,618**	**423,001**	**448,825**
ENERGY DEMAND		**152,146**	**157,135**	**163,665**	**172,572**	**178,332**	**188,060**	**197,693**	**202,068**	**213,348**	**225,051**	**237,301**	**250,914**	**265,419**	**280,761**	**297,532**	**315,330**	**334,127**	**354,431**	**375,924**	**398,650**	**423,023**	**448,857**
Energy Not Served (ENS)		150.860	6.850	0.590	0.190	-0.070	-0.110	-0.200	-0.130	0.500	-0.110	0.170	2.290	-0.130	3.650	-0.060	1.410	11.530	17.500	23.810	31.770	21.980	32.510

7.4. Year-wise Discounted and Un-Discounted Prices

The year wise cost breakup (Discounted prices) and un-Discounted Prices are shown in Table 7-7 and Table 7-8 respectively and their comparison is given in Annexure B-7.

Table 7-7: Year wise Cost Breakup-Discounted Prices

Year	Present Worth Cost of the Year (k$)					
	Construction	Salvage Value	Operation	Energy Not Served	Total	Objective Function (Cumulative)
2018	-	-	8,648,783	418,452	9,067,235	9,067,235
2019	-	-	6,933,536	104,644	7,038,180	16,105,415
2020	179,246	14,048	5,764,374	4,397	5,933,969	22,039,384
2021	261,308	23,305	4,756,825	422	4,995,250	27,034,634
2022	757,773	37,339	4,372,421	172	5,093,026	32,127,660
2023	577,643	29,090	3,901,278	49	4,449,880	36,577,540
2024	983,259	93,067	3,634,506	25	4,524,724	41,102,264
2025	5,383,741	785,977	2,915,065	-	7,512,828	48,615,092
2026	1,407,295	235,829	2,617,278	-	3,788,744	52,403,836
2027	-	-	2,484,238	185	2,484,424	54,888,260
2028	4,161,750	892,078	2,104,868	4	5,374,544	60,262,804
2029	1,009,921	244,560	2,016,187	61	2,781,608	63,044,412
2030	1,459,075	398,888	1,851,122	591	2,911,900	65,956,312
2031	3,720,494	1,147,532	1,532,792	6	4,105,760	70,062,072
2032	-	(3)	1,592,256	693	1,592,952	71,655,024
2033	2,454,422	800,881	1,281,182	30	2,934,752	74,589,776
2034	814,069	320,273	1,307,791	213	1,801,800	76,391,576
2035	555,047	250,651	1,350,374	1,734	1,656,504	78,048,080
2036	1,120,651	570,597	1,325,699	2,399	1,878,152	79,926,232
2037	966,617	571,287	1,315,082	2,940	1,713,352	81,639,584
2038	927,602	625,826	1,303,784	3,600	1,609,160	83,248,744

Year	Present Worth Cost of the Year (k$)					
	Construction	Salvage Value	Operation	Energy Not Served	Total	Objective Function (Cumulative)
2039	1,199,212	945,870	1,270,883	2,255	1,526,480	84,775,224
2040	867,091	761,374	1,258,983	3,052	1,367,752	86,142,976

Table 7-8: Year wise Cost Breakup-Un-Discounted Prices (k$)

Year	Un-Discounted Cost of the Year (k$)					
	Construction	Salvage Value	Operation	Energy Not Served	Total	Objective Function (Cumulative)
2018	-	-	9,070,920	438,876	9,509,796	9,509,796
2019	-	-	7,999,149	120,727	8,119,876	17,629,672
2020	227,474	17,828	7,315,329	5,580	7,530,555	25,160,227
2021	364,777	32,533	6,640,359	589	6,973,192	32,133,419
2022	1,163,607	57,336	6,714,119	264	7,820,652	39,954,072
2023	975,707	49,136	6,589,716	83	7,516,369	47,470,440
2024	1,826,924	172,921	6,753,017	46	8,407,068	55,877,508
2025	11,003,461	1,606,405	5,957,902	-	15,354,956	71,232,464
2026	3,163,902	530,194	5,884,203	-	8,517,911	79,750,375
2027	-	-	6,143,611	458	6,144,071	85,894,446
2028	11,321,375	2,426,756	5,725,957	11	14,620,587	100,515,033
2029	3,022,061	731,815	6,033,186	183	8,323,612	108,838,645
2030	4,802,708	1,312,984	6,093,174	1,945	9,584,843	118,423,488
2031	13,471,063	4,154,952	5,549,891	22	14,866,023	133,289,512
2032	-	(12)	6,341,717	2,760	6,344,489	139,634,000
2033	10,753,154	3,508,768	5,613,031	131	12,857,544	152,491,544
2034	3,923,201	1,543,475	6,302,570	1,026	8,683,322	161,174,866
2035	2,942,400	1,328,744	7,158,566	9,192	8,781,415	169,956,281

Year	Un-Discounted Cost of the Year (k$)					
	Construction	Salvage Value	Operation	Energy Not Served	Total	Objective Function (Cumulative)
2036	6,534,842	3,327,317	7,730,536	13,989	10,952,050	180,908,330
2037	6,200,287	3,664,474	8,435,488	18,858	10,990,159	191,898,489
2038	6,545,031	4,415,742	9,199,319	25,401	11,354,010	203,252,499
2039	9,307,621	7,341,320	9,863,892	17,502	11,847,695	215,100,194
2040	7,402,870	6,500,301	10,748,684	26,057	11,677,309	226,777,503

7.5. Salient Features of the IGCEP

In order to balance a projected peak load of 80,000 plus MW by the year 2040, the WASP model gives a target of managing around 95,000 MW as the nominal generation capacity; salient features of the study are as follows:

a. Massive utilization of indigenous coal based power
b. Balancing the overall basket price with increased share of hydro power
c. Less reliance on imported fuel i.e. coal, R-LNG, RFO
d. Renewable accounts for a share of 16% of the overall capacity

Meanwhile, by the year 2040, a capacity of around 9, 000 MW is meant to be retired. In order to provide a quick understanding of the generation mix over the plan period i.e. 2018 – 40, the report includes the Table 7-9 which highlights addition of different types of generation capacities. Moreover, fuel-wise, capacity in megawatts, energy in GWh and their monthly share in the total generated energy respectively, over the plan period, are further illustrated by the Chart 7-3 through 7-7, Chart 7-8 through 7-12 and Chart 7-13 through 7-16.

Table 7-9: Year wise Nominal Capacity Addition (MW)

Year	Local Coal	Capacity Addition Over the Plan Period (2018-40) - MW							
		Hydro	RLNG	Nuclear	Imported Coal	RE	Natural Gas	Furnace Oil	Total (MW)
2018	30	7,244	7,218	1,232	1,821	1,691	3,711	4,768	27,715
2020	600	2,747	1,243	-	1,821	479	-	-	6,890
2025	2,703	6,164	(1,502)	3,046	1,518	3,970	(1,301)	(200)	14,398
2030	(30)	12,735	(731)	-	-	-	(126)	(3,279)	8,569

Year	Local Coal	Capacity Addition Over the Plan Period (2018-40) - MW							
		Hydro	RLNG	Nuclear	Imported Coal	RE	Natural Gas	Furnace Oil	Total (MW)
2035	6,611	6,350	(180)	-	-	6,300	(763)	-	18,318
2040	15,025	3,550	396	-	-	3,600	-	(370)	22,201
Total:	**24,939**	**38,790**	**6,444**	**4,278**	**5,160**	**16,040**	**1,521**	**919**	**98,091**

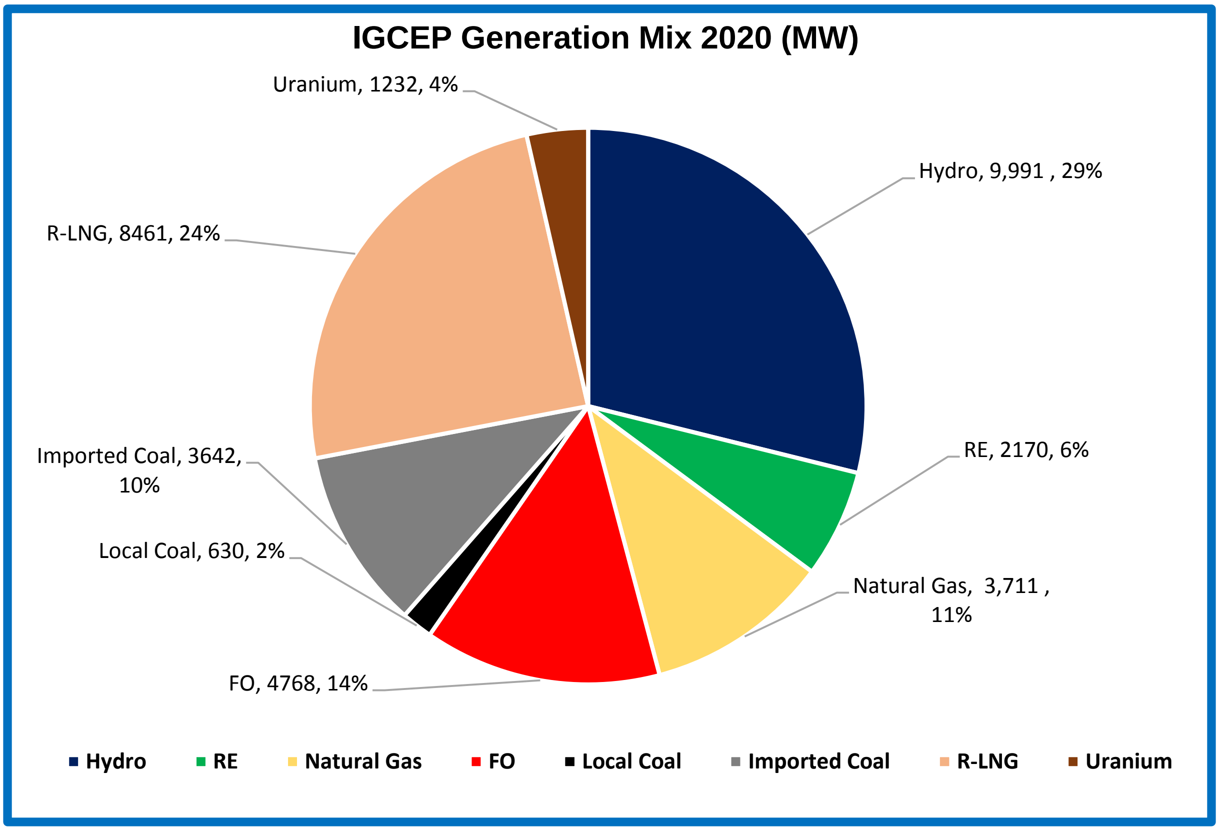


Chart 7-3: IGCEP Generation Mix 2020 (MW)

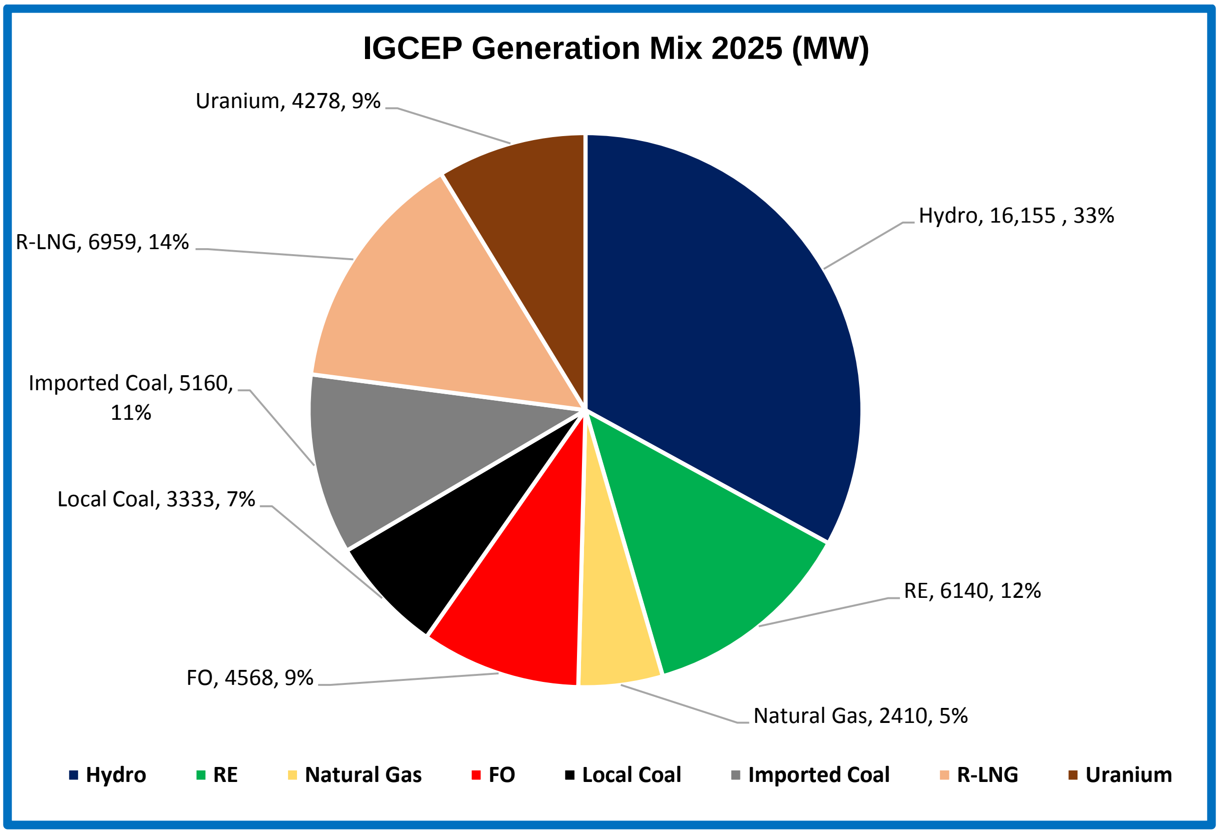


Chart 7-4: IGCEP Generation Mix 2025 (MW)

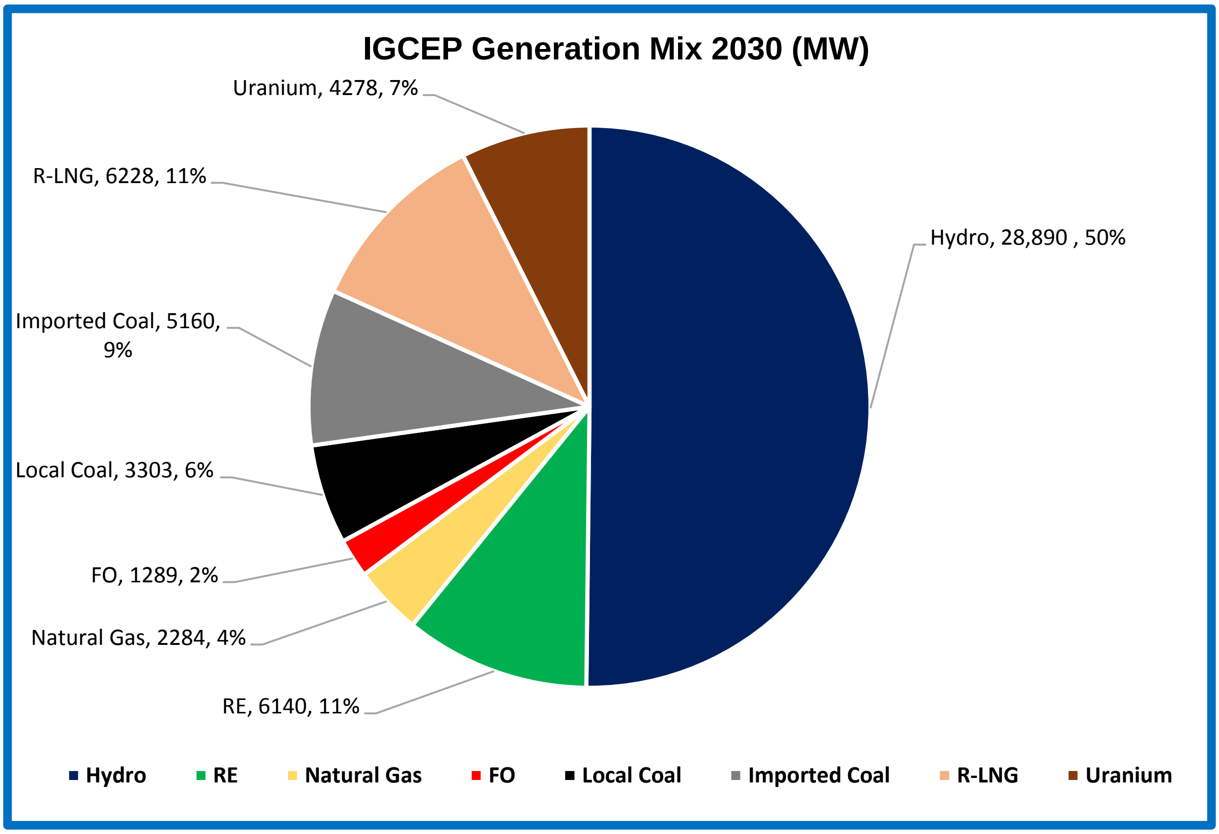


Chart 7-5: IGCEP Generation Mix 2030 (MW)

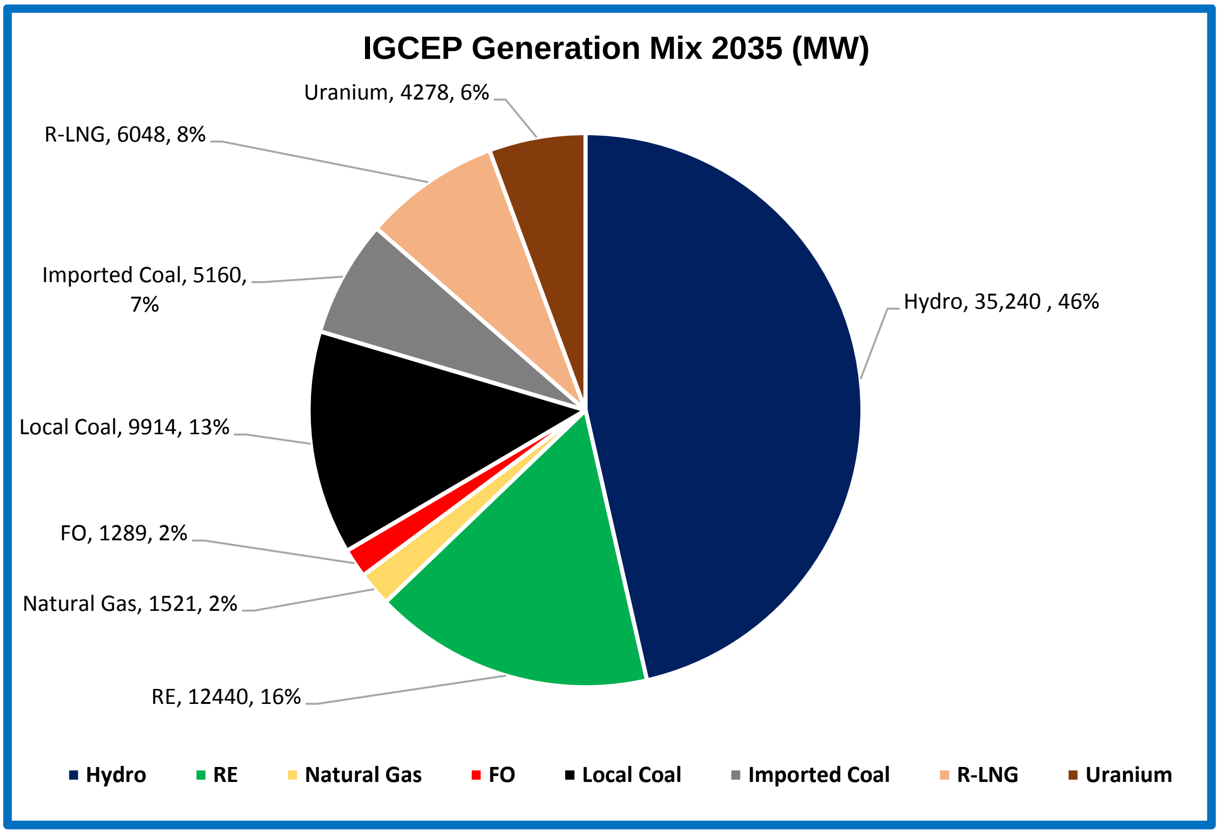


Chart 7-6: IGCEP Generation Mix 2035 (MW)

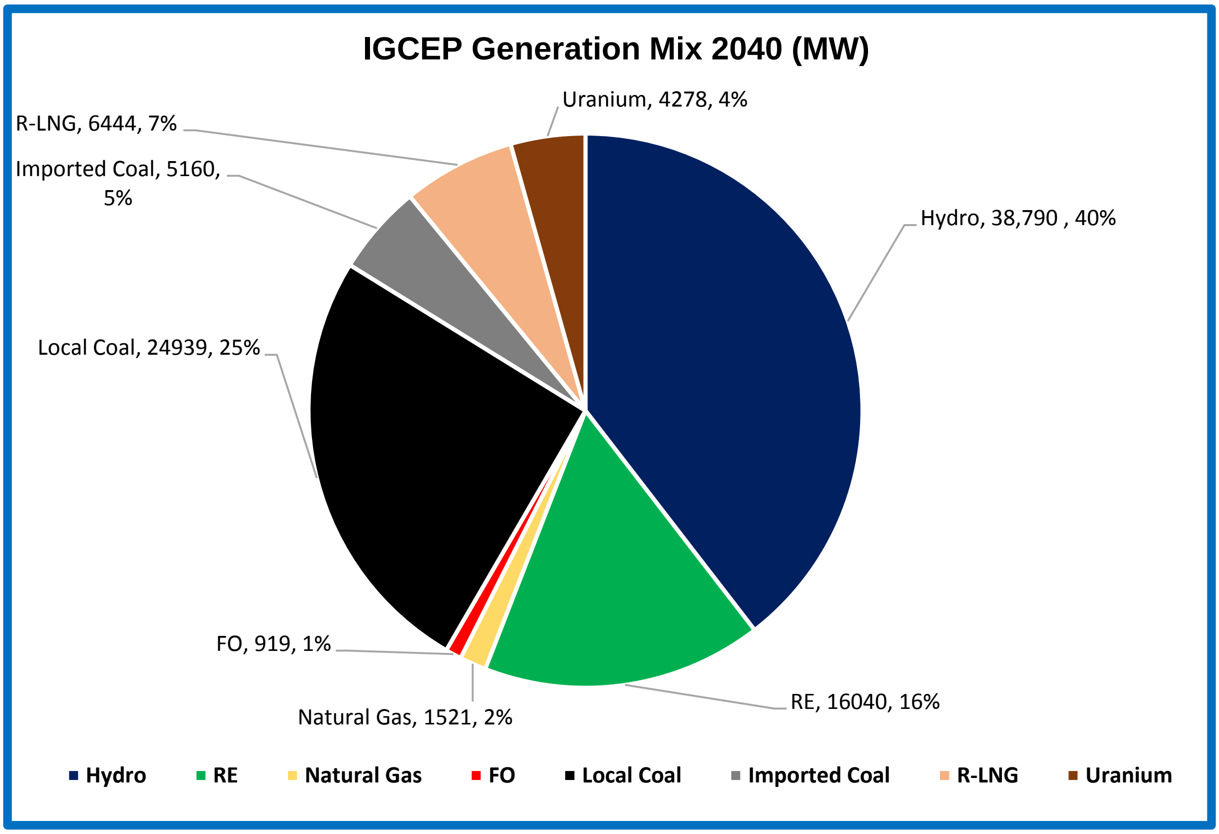


Chart 7-7: IGCEP Generation Mix 2040 (MW)

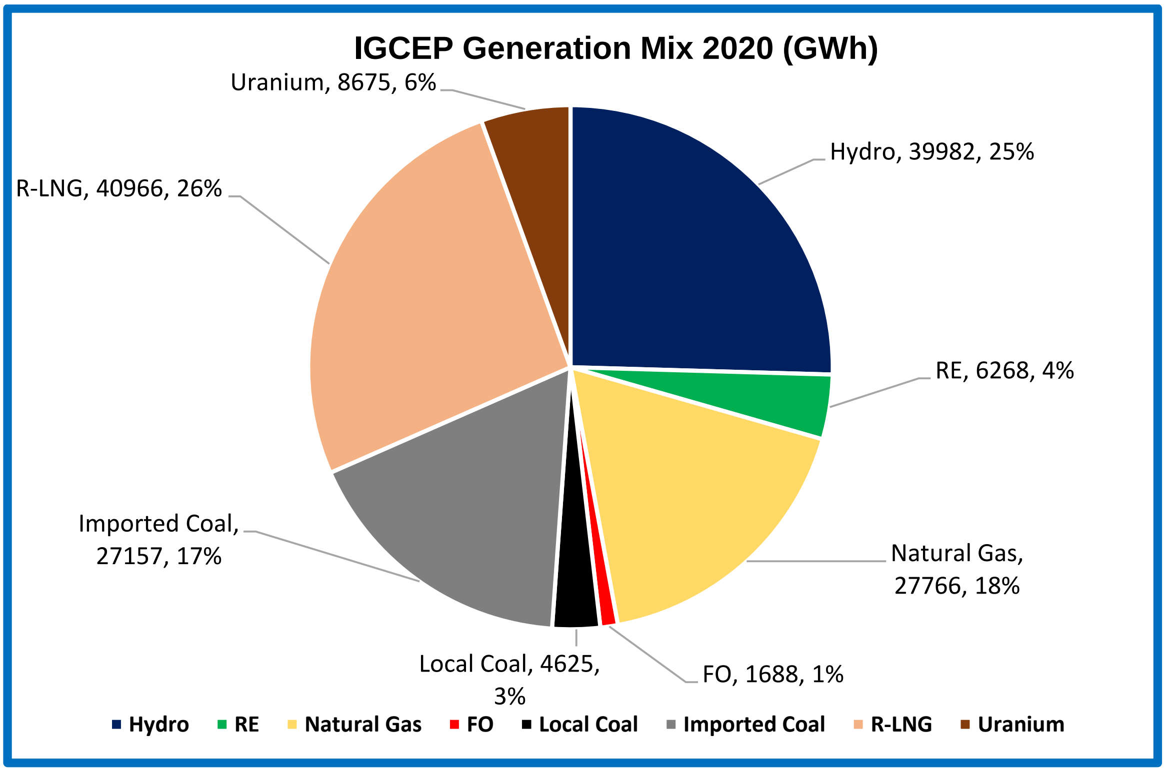


Chart 7-8: IGCEP Generation Mix 2020 (GWh)

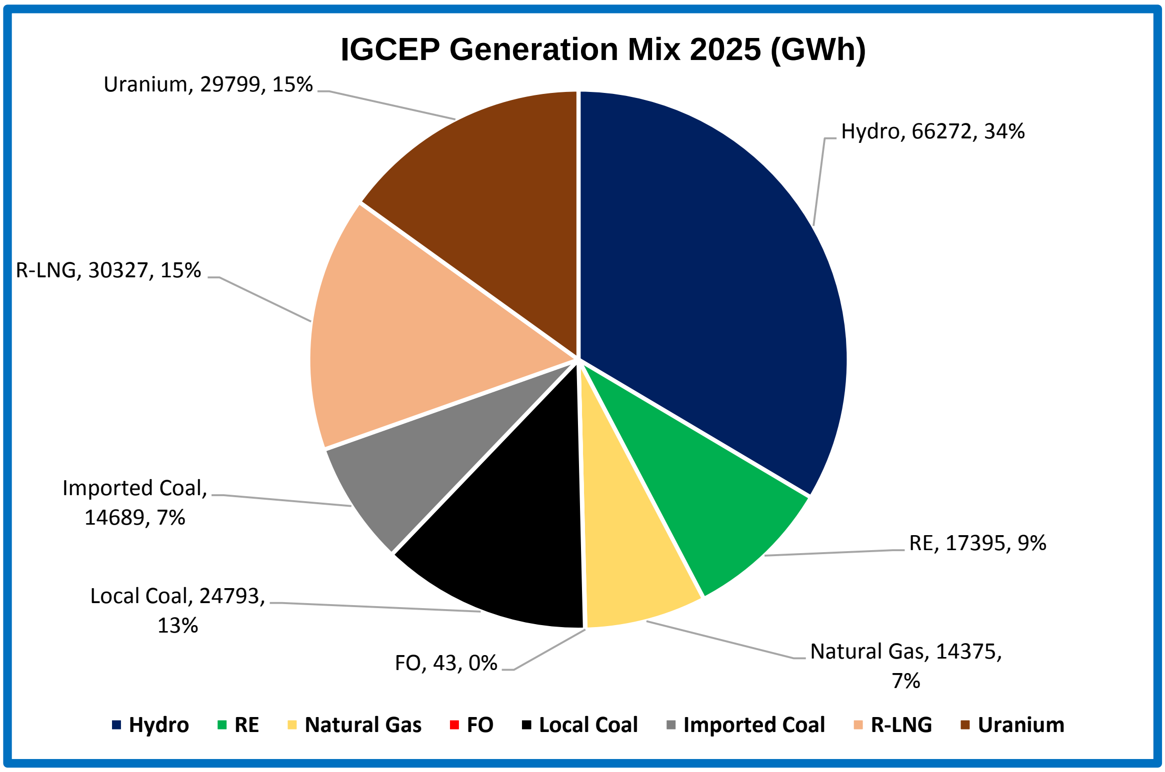


Chart 7-9: IGCEP Generation Mix 2025 (GWh)

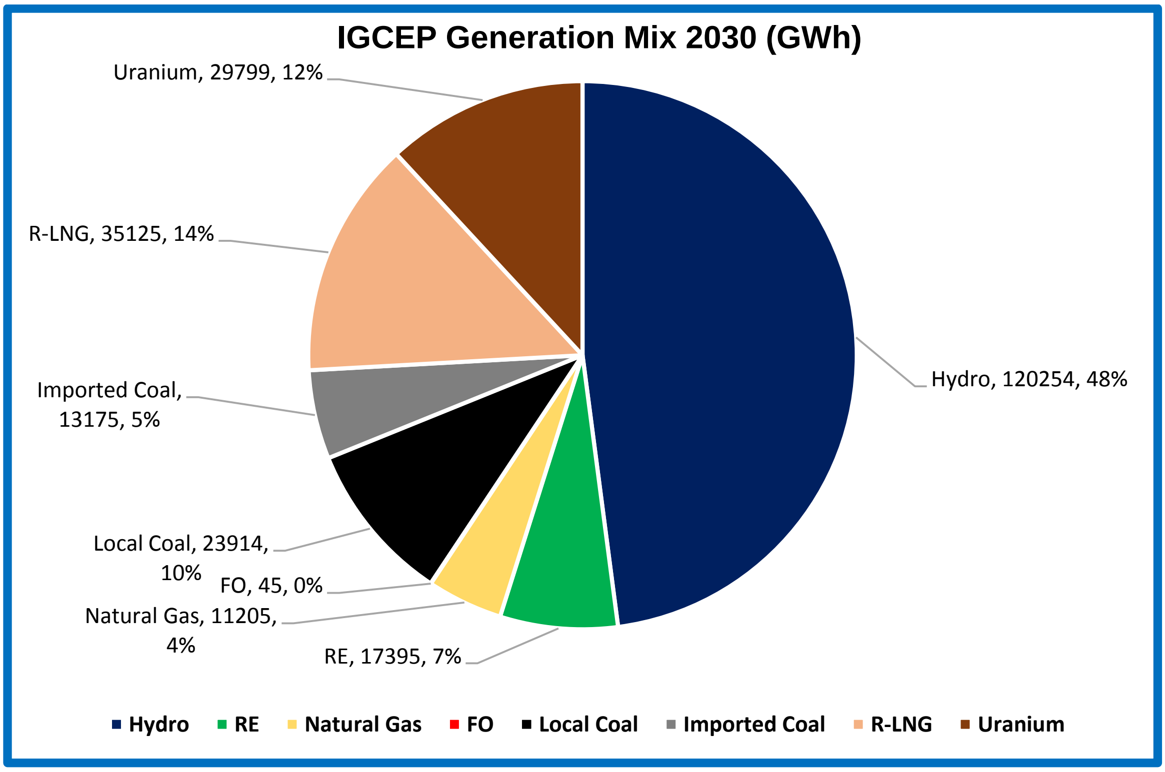


Chart 7-10: IGCEP Generation Mix 2030 (GWh)

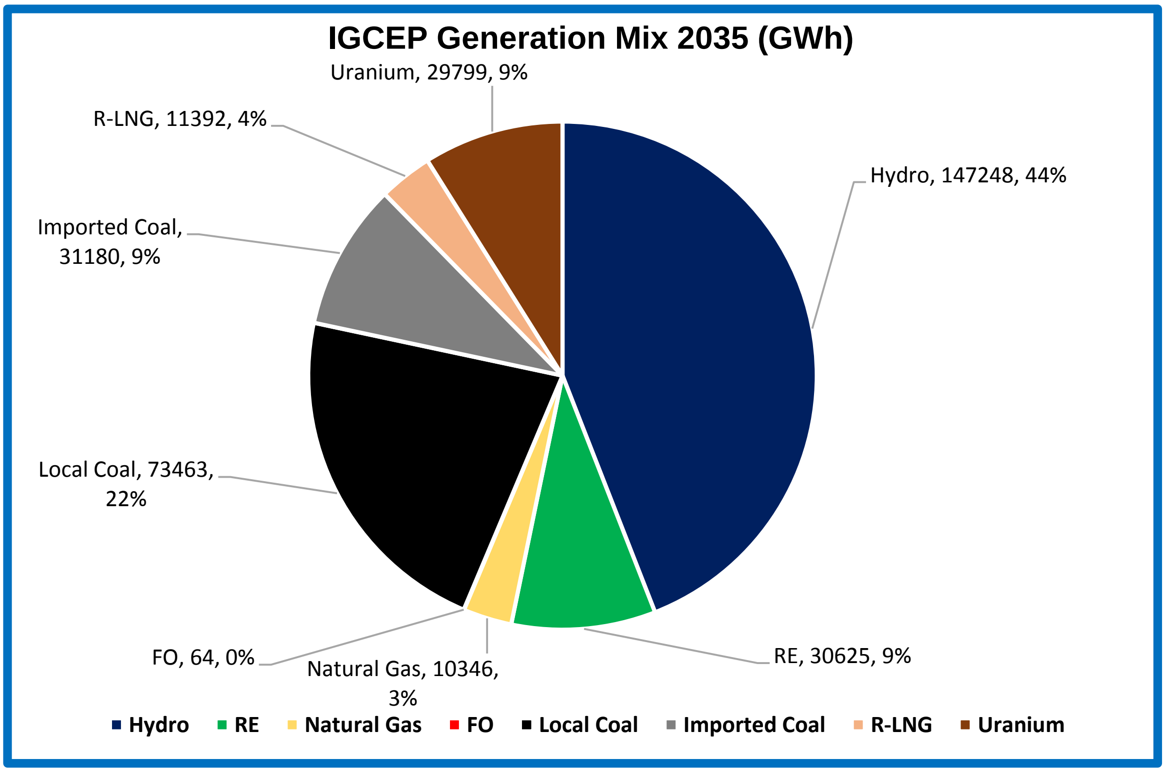


Chart 7-11: IGCEP Generation Mix 2035 (GWh)

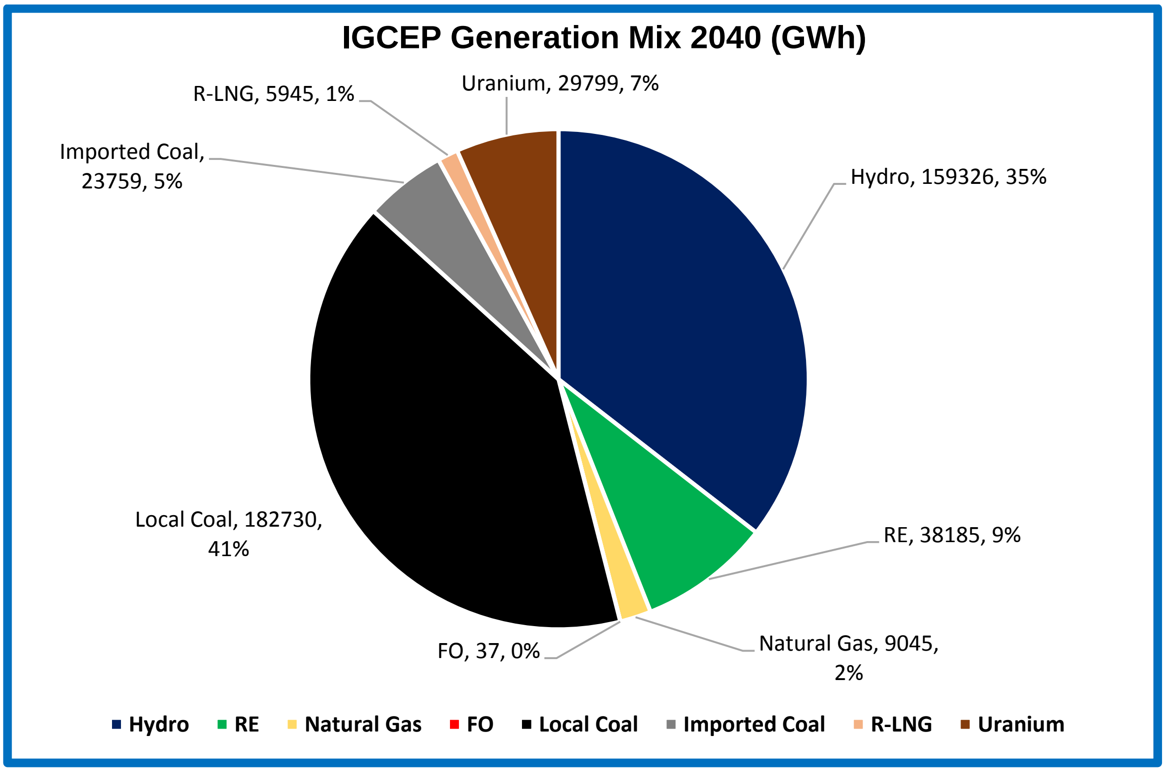


Chart 7-12: IGCEP Generation Mix 2040 (GWh)

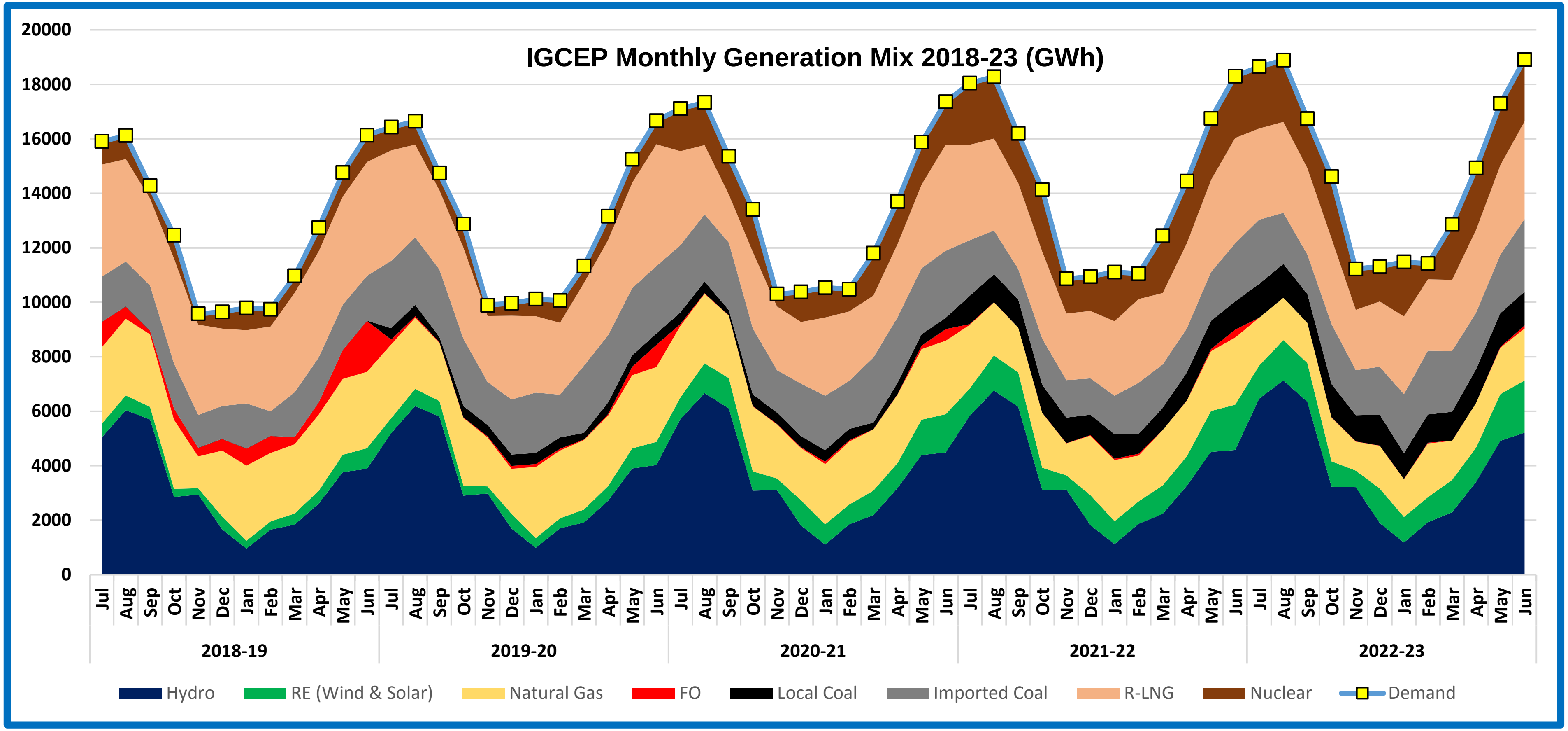


Chart 7-13: IGCEP Monthly Generation Mix 2018-23 (GWh)

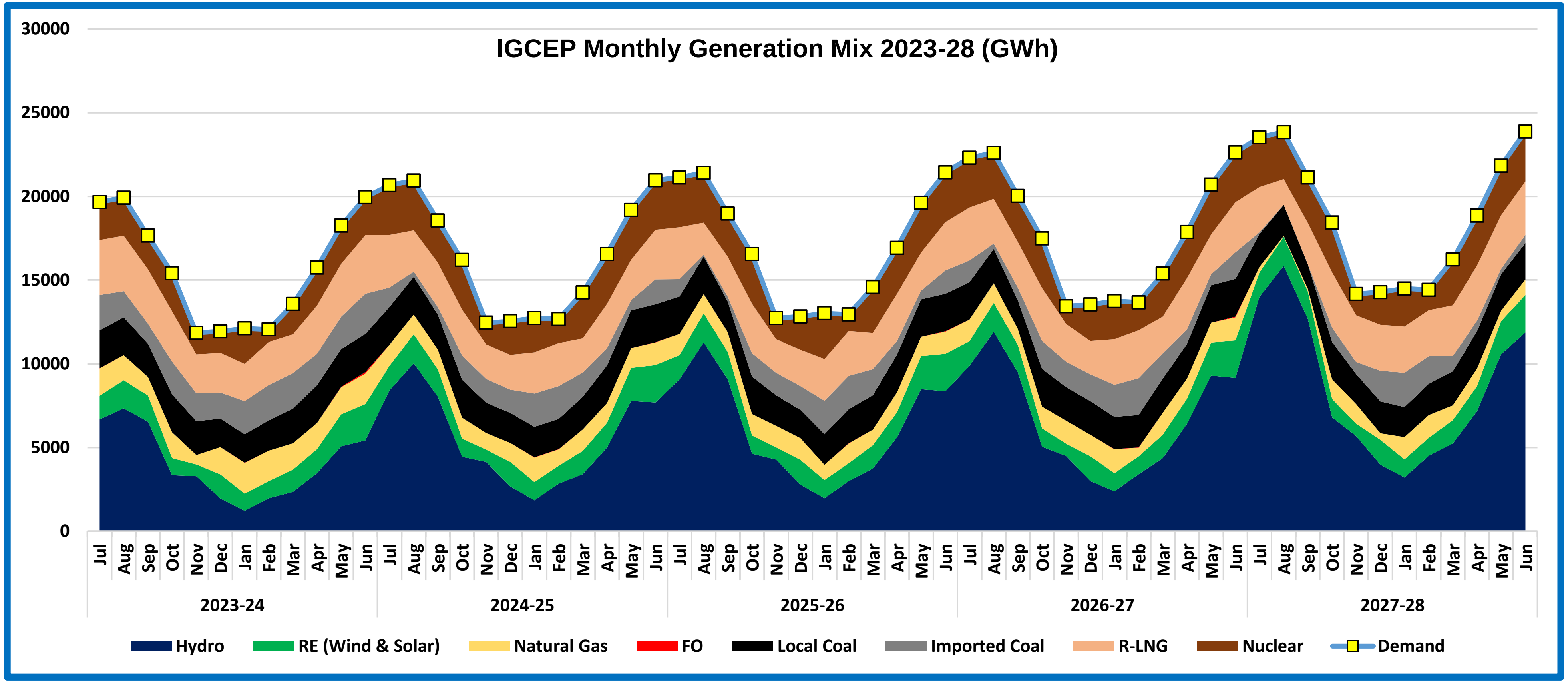


Chart 7-14: IGCEP Monthly Generation Mix 2023-28 (GWh)

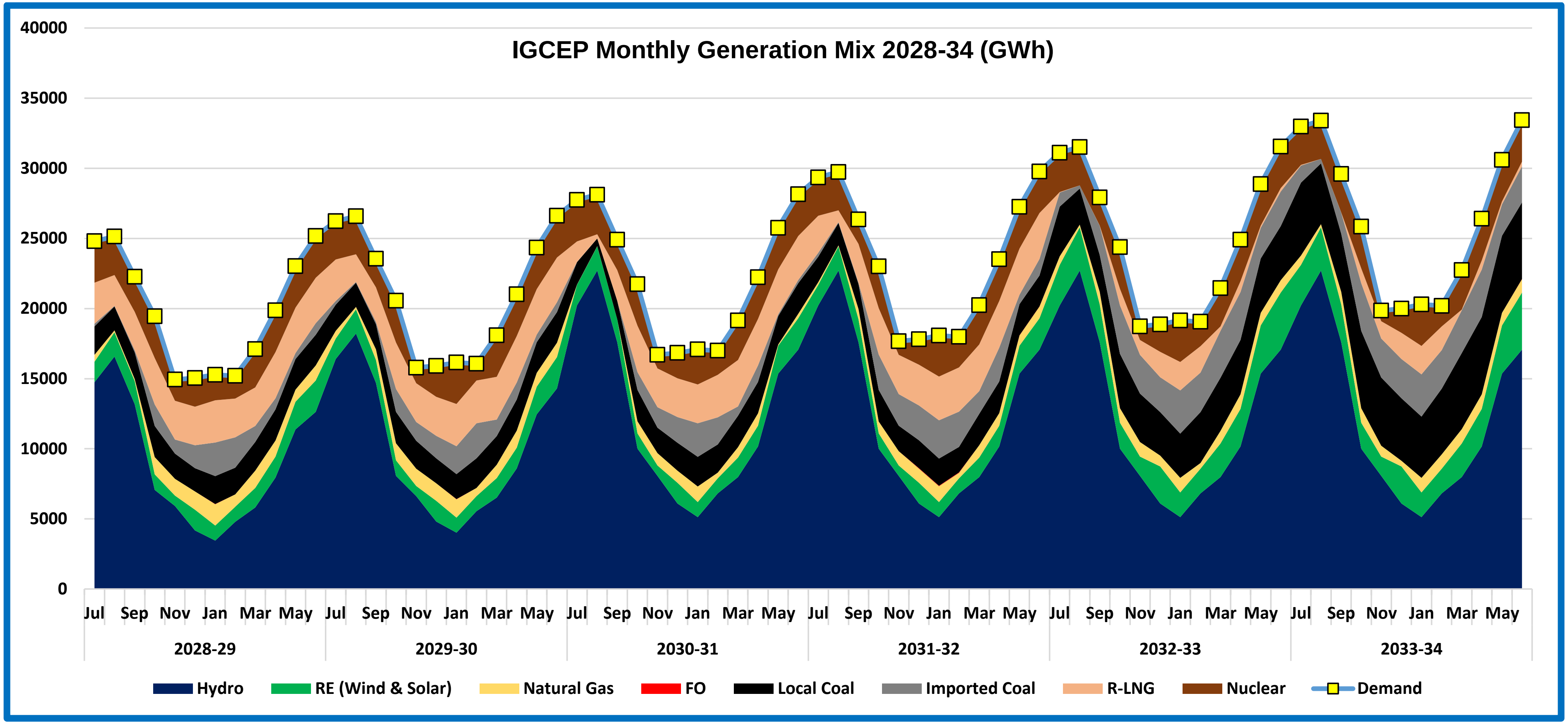


Chart 7-15: IGCEP Monthly Generation Mix 2028-34 (GWh)

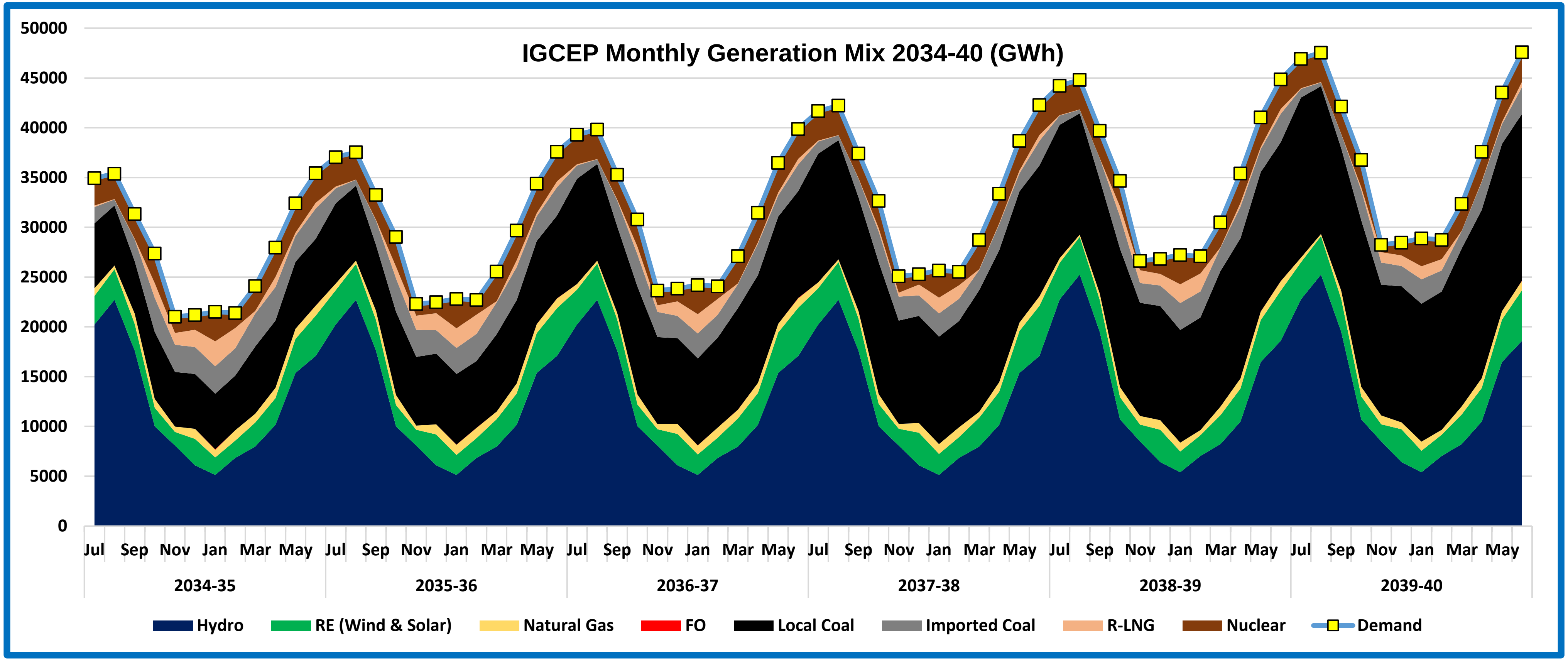


Chart 7-16: IGCEP Monthly Generation Mix 2034-40 (GWh)

8. The Way Forward

The IGCEP 2018-40 represents the first complete iteration of an integrated planning exercise for the power sector of Pakistan. The results of this study are inevitability based on the input parameters and the constraints imposed in the modeling exercise. A policy decision which is not based on analytics may not yield the most optimal results just like analysis without policy direction would lack qualitative factors necessary in decision making. Keeping in view a few important factors i.e. i) NTDC will be migrating to more modern software tools for preparation of next versions of IGCEP; ii) from now on this exercise will be conducted on yearly basis to ensure regulatory compliance; and IGCEP is meant to be considered as an important indicative reference, the Team would like to highlight a few items for further improving the output of this exercise.

The current modeling runs show that with the current costs of renewable energy, as well as the increase in costs for imported fuels given the decline in value of Pak Rupee, the least cost generation plan utilizes large quantities of Hydro capacity, Thar Coal based generation and Renewable Energy. This trend is in line with the general policy view to reduce dependence on imported fuels from the perspective of energy security, sustainability and affordability ultimately yielding significant reduction in foreign reserve requirements pertaining to imported fuels.

The ideal process would entail a feedback loop between policy makers and the Team so that the policy and the IGCEP process feed each other to add value. In order to do so for the future, the Team endorses the view of using higher percentage of RE capacity coupled with increased used of hydro and domestic coal. Meanwhile, based on the learning and outcome of this study and the challenges faced in the formulation of an all-inclusive generation expansion plan that accurately captures the power market realities while being aligned with the policy directives, the Team seeks more clarity from the policy makers to address the following aspects whilst aiming to ensure sustainable, affordable, reliable and secure supply of energy.

a. The impact of Demand Side Management (DSM) and Net-Metering has not been incorporated for the purpose of IGCEP 2018-40. There is a dire need of the policy directives on DSM and Net-Metering for the subsequent iterations of IGCEP.

b. Existing iteration of IGCEP has been formulated taking into account the contractual commitments of RLNG imports under term contracts. Although cheaper plants are available for dispatch but their generation has been curtailed to account for RLNG contractual obligations. There is a need to ponder, ascertain and establish how the fuel contracts will be negotiated in the renewal phase of these projects with respect to minimum take-or-pay fuel requirements? Moreover, the Net Proceed Differential (NPD) arising due to diversion of RLNG to the other sectors needs to be captured under the respective policy and/or regulatory tools for incorporating its cost impact into the IGCEP.

c. The future capacity expansion plan is premised on the assumptions that the projects in pipe line will be completed as per the timelines provided by the respective project execution entities. Any deviation from the stipulated time lines may change the overall optimization matrix. Accordingly, the same requires due consideration under the applicable regulatory framework.

d. As already envisaged in Section 14 A ("National Electricity Policy and Plan") of the amended NEPRA Act 2018, the National Electricity Policy and National Electricity Plan needs to be finalized to assist formulation of subsequent iterations of IGCEP especially with regards to utilization of local resources, energy and fuel mix, imported fuels targets, distributed generation, micro grids, etc.

e. Study based gradual targets of renewables integration into the system needs to be informed into the subsequent iterations of IGCEP through the respective policy directive.

f. IGCEP can only optimize the Long Run Marginal Cost (LRMC) based on the matrix of parameters for the Power Sector. In order to ensure global optimization of the entire energy sector, it is imperative for IGCEP to be infeed from the sector specific targets derived from Integrated Energy Plan (IEP). This will not only ensure optimization of cost on the basis of the top-tier consolidated plan but would also facilitate impetus for the alignment of sector specific initiatives with the overall objective functions of energy and economy.

g. Consideration of shadow prices for the imported fuels and carbon, if any, needs to be incorporated in the National Electricity Policy and Plan to eventually inform the next iterations of the IGCEP. This can be done by imposing a national carbon tax for thermal fuels and an exchange rate penalty for imported fuels, in order to account for other social and economic costs for such fuels.

h. There is a dire need for alignment of initiatives and roles of the federal and provincial project execution entities, responsible for power generation business, with the policy and regulatory stipulations for the Generation Expansion Plan, thus yielding optimized fuel mix based on indigenous resources.

i. For induction of REs, GoP needs to develop/revamp and implement relevant policies and plans, develop projects, promote local manufacturing leading to indigenization of technologies, create awareness, channeling international expertise for enhancing the share of RE in the national generation mix. Should there be a benefit given to locally produced items in the future analysis of IGCEP?

j. RE induction needs to be carried out whilst accounting for the following pre-conditions:

- New SCADA system with Automatic Governor Control (AGC)
- Grid reinforcement to guarantee steady-state and transient stability
- High Accuracy Operational Demand Forecasting System
- Provision of short term reliable weather forecast mechanism
- Rapid processing and procurement
- Enhancement of current planning skills and professionals
- Building up a competitive power market
- Reserve requirements (specific to RE integration)

In order to proceed aggressively for REs one shall keep in mind factors like; how much finances will be required, how much time will be needed and the know how to expedite and successfully carry out the whole process stated above in addition to manage optimal dispatch.

k. It is high time for the power sector of Pakistan to consider, discuss and plan a shift from capacity based regime to energy regime. However, this requires some major changes in the regulatory framework as well as ensuring that the entities operating the sector are financially viable and bankable. Pakistan power sector needs to start moving in this direction.

l. Competitive bidding for all the fuels starting from REs may be considered except for Hydro and Nuclear. This will yield true "current market prices" every year to modify the generation plan on annual basis.

A n n e x u r e s

Annexure A-1: Projected GDP Growth by Sector (Country) – Low

GDP Growth Rate (%)				
Year	Gross Domestic Product (%)			
	Total	Agriculture	Industrial	Commercial
2016-17	5.2	3.7	6.4	5.7
2017-18	4.5	2.96	5.74	4.95
2018-19	4.5	2.96	5.74	4.95
2019-20	4.5	2.96	5.74	4.95
2020-21	4.5	2.96	5.74	4.95
2021-22	4.5	2.96	5.74	4.95
2022-23	4.5	2.96	5.74	4.95
2023-24	4.5	2.96	5.74	4.95
2024-25	4.5	2.96	5.74	4.95
2025-26	4.5	2.96	5.74	4.95
2026-27	4.5	2.96	5.74	4.95
2027-28	4.5	2.96	5.74	4.95
2028-29	4.5	2.96	5.74	4.95
2029-30	4.5	2.96	5.74	4.95
2030-31	4.5	2.96	5.74	4.95
2031-32	4.5	2.96	5.74	4.95
2032-33	4.5	2.96	5.74	4.95
2033-34	4.5	2.96	5.74	4.95
2034-35	4.5	2.96	5.74	4.95
2035-36	4.5	2.96	5.74	4.95
2036-37	4.5	2.96	5.74	4.95
2037-38	4.5	2.96	5.74	4.95
2038-39	4.5	2.96	5.74	4.95
2039-40	4.5	2.96	5.74	4.95

Annexure A-2: Projected GDP Growth by Sector (Country) – Normal

GDP Growth Rate (%)				
Year	Gross Domestic Product (%)			
	Total	Agriculture	Industrial	Commercial
2016-17	5.2	3.7	6.4	5.7
2017-18	5.5	3.96	6.74	5.95
2018-19	5.5	3.96	6.74	5.95
2019-20	5.5	3.96	6.74	5.95
2020-21	5.5	3.96	6.74	5.95
2021-22	5.5	3.96	6.74	5.95
2022-23	5.5	3.96	6.74	5.95
2023-24	5.5	3.96	6.74	5.95
2024-25	5.5	3.96	6.74	5.95
2025-26	5.5	3.96	6.74	5.95
2026-27	5.5	3.96	6.74	5.95
2027-28	5.5	3.96	6.74	5.95
2028-29	5.5	3.96	6.74	5.95
2029-30	5.5	3.96	6.74	5.95
2030-31	5.5	3.96	6.74	5.95
2031-32	5.5	3.96	6.74	5.95
2032-33	5.5	3.96	6.74	5.95
2033-34	5.5	3.96	6.74	5.95
2034-35	5.5	3.96	6.74	5.95
2035-36	5.5	3.96	6.74	5.95
2036-37	5.5	3.96	6.74	5.95
2037-38	5.5	3.96	6.74	5.95
2038-39	5.5	3.96	6.74	5.95
2039-40	5.5	3.96	6.74	5.95

Annexure A-3: Projected GDP Growth by Sector (Country) - High

GDP Growth Rate (%)				
Year	Gross Domestic Product (%)			
	Total	Agriculture	Industrial	Commercial
2016-17	5.2	3.7	6.4	5.7
2017-18	7.0	5.46	8.24	7.45
2018-19	7.0	5.46	8.24	7.45
2019-20	7.0	5.46	8.24	7.45
2020-21	7.0	5.46	8.24	7.45
2021-22	7.0	5.46	8.24	7.45
2022-23	7.0	5.46	8.24	7.45
2023-24	7.0	5.46	8.24	7.45
2024-25	7.0	5.46	8.24	7.45
2025-26	7.0	5.46	8.24	7.45
2026-27	7.0	5.46	8.24	7.45
2027-28	7.0	5.46	8.24	7.45
2028-29	7.0	5.46	8.24	7.45
2029-30	7.0	5.46	8.24	7.45
2030-31	7.0	5.46	8.24	7.45
2031-32	7.0	5.46	8.24	7.45
2032-33	7.0	5.46	8.24	7.45
2033-34	7.0	5.46	8.24	7.45
2034-35	7.0	5.46	8.24	7.45
2035-36	7.0	5.46	8.24	7.45
2036-37	7.0	5.46	8.24	7.45
2037-38	7.0	5.46	8.24	7.45
2038-39	7.0	5.46	8.24	7.45
2039-40	7.0	5.46	8.24	7.45

Annexure A-4: GDP (Factor Cost) Constant 2005-06, Consumer Price Index

Year	GDP Total (Rs. Million)	GDP Agr. (Rs. Million)	GDP Mnf. (Rs. Million)	GDP Comm. (Rs. Million)	CPI	CPI G. R.
1970	1,255,525	521,097	140,766	332,819	4.57	-
1971	1,271,055	505,100	144,217	339,116	4.83	5.7%
1972	1,300,486	522,630	139,343	348,996	5.06	4.8%
1973	1,388,932	531,333	153,833	389,676	5.55	9.7%
1974	1,492,443	553,546	165,478	444,940	7.21	29.9%
1975	1,550,333	541,818	166,426	527,385	9.15	26.9%
1976	1,600,768	566,062	168,771	523,730	10.22	11.7%
1977	1,646,272	580,277	172,723	546,494	11.42	11.7%
1978	1,773,545	595,445	189,900	609,106	12.30	7.7%
1979	1,871,581	615,586	204,918	644,718	13.12	6.7%
1980	2,008,716	656,282	226,047	683,480	14.52	10.7%
1981	2,137,308	680,567	250,153	740,445	16.32	12.4%
1982	2,298,923	712,716	284,357	796,070	18.13	11.1%
1983	2,454,984	744,108	303,804	688,336	18.96	4.6%
1984	2,552,522	708,209	327,274	925,421	20.34	7.3%
1985	2,774,798	785,576	346,325	995,318	21.50	5.7%
1986	2,951,359	832,307	382,303	1,056,035	22.43	4.3%
1987	3,122,857	859,388	411,081	1,114,621	23.24	3.6%
1988	3,323,849	882,860	452,568	1,192,592	24.71	6.3%
1989	3,483,670	943,516	470,242	1,263,559	27.28	10.4%
1990	3,643,525	972,110	497,675	1,311,332	28.91	6.0%
1991	3,846,372	1,020,348	529,384	1,375,436	32.58	12.7%
1992	4,141,564	1,117,294	571,073	1,457,115	36.03	10.6%
1993	4,266,967	1,058,234	601,235	1,514,280	39.57	9.8%

Year	GDP Total	GDP Agr.	GDP Mnf.	GDP Comm.	CPI	CPI G. R.
	(Rs. Million)					
1994	4,429,617	1,113,553	633,515	1,577,341	44.03	11.3%
1995	4,661,543	1,186,688	655,445	1,655,302	49.76	13.0%
1996	4,976,770	1,325,805	687,270	1,757,952	55.14	10.8%
1997	5,072,592	1,327,444	696,269	1,815,828	61.64	11.8%
1998	5,175,511	1,387,413	684,444	1,805,402	66.45	7.8%
1999	5,392,044	1,414,449	712,130	1,893,817	70.24	5.7%
2000	5,602,669	1,501,445	723,911	1,972,165	72.77	3.6%
2001	5,705,503	1,468,754	784,416	2,018,527	75.97	4.4%
2002	5,882,653	1,470,272	821,112	2,139,702	78.63	3.5%
2003	6,167,179	1,531,248	883,770	2,260,994	81.06	3.1%
2004	6,692,079	1,568,493	1,063,236	2,413,069	84.79	4.6%
2005	7,291,537	1,670,176	1,220,333	2,663,013	92.68	9.3%
2006	7,715,777	1,775,346	1,319,668	2,860,032	100.00	7.9%
2007	8,142,969	1,836,125	1,434,583	3,015,136	107.80	7.8%
2008	8,549,148	1,869,310	1,514,065	3,162,836	120.74	12.0%
2009	8,579,987	1,934,691	1,455,674	3,150,102	141.30	17.0%
2010	8,801,394	1,939,132	1,479,432	3,249,367	155.57	10.1%
2011	9,120,336	1,977,178	1,496,889	3,394,780	176.88	13.7%
2012	9,470,255	2,084,794	1,536,397	3,544,016	196.34	11.0%
2013	9,819,055	2,103,600	1,608,092	3,747,009	210.87	7.4%
2014	10,217,056	2,156,117	1,686,412	3,924,500	229.01	8.6%
2015	10,629,661	2,210,647	1,752,394	4,088,731	239.31	4.5%
2016	11,130,035	2,206,357	1,845,605	4,358,062	246.01	2.8%
2017	11,696,961	2,284,561	1,912,695	4,641,330	256.07	4.1%

Annexure A-5: Nominal Category-Wise Average Tariff of NTDC and KE System

Year	Average Tariff (Paisas/kWh) NTDC				Average Tariff (Paisas/kWh) KE			
	Dom	Com	Ind	Agr	Dom	Com	Ind	Agr
1970	19.50	23.90	12.30	8.40	16.70	17.63	11.70	13.83
1971	19.90	25.10	13.00	7.70	17.00	17.27	11.80	12.99
1972	20.20	26.0	13.80	9.00	16.30	17.93	12.30	12.82
1973	19.70	26.60	14.30	10.00	16.70	20.80	15.50	14.76
1974	19.90	31.80	17.60	10.70	16.70	27.35	25.50	15.06
1975	20.90	36.20	21.20	12.00	16.60	29.96	29.50	14.27
1976	23.00	46.50	28.10	15.50	16.50	30.08	30.60	15.26
1977	25.00	53.40	33.50	15.70	18.40	36.14	32.30	13.52
1978	24.20	59.60	37.40	14.40	24.40	45.26	34.20	16.82
1979	28.50	71.70	46.20	21.00	28.50	52.13	40.30	23.33
1980	34.60	94.60	57.10	28.50	33.90	75.14	54.60	26.91
1981	39.60	100.10	63.10	32.20	38.90	95.94	68.90	46.31
1982	41.70	107.80	67.70	35.90	43.70	121.38	95.90	73.75
1983	43.30	118.00	75.50	38.40	43.80	148.38	126.90	67.98
1984	43.80	121.20	76.50	42.60	44.60	147.39	125.30	66.90
1985	43.90	122.70	78.50	38.40	43.80	145.19	123.80	67.67
1986	49.50	142.90	92.00	43.30	47.90	147.59	122.00	65.24
1987	47.60	139.60	89.10	36.90	48.20	141.89	118.30	64.12
1988	52.20	171.20	111.10	39.90	57.30	158.39	135.80	59.08
1989	62.20	213.40	133.00	45.70	73.40	218.60	135.90	70.68
1990	66.00	245.90	150.30	54.50	82.10	246.11	150.10	80.29
1991	76.10	276.30	165.50	56.50	91.90	281.64	168.60	94.74
1992	80.60	315.50	188.80	63.20	99.80	311.71	188.30	105.11
1993	84.10	331.00	198.90	66.20	101.50	309.04	188.40	106.25

Year	Average Tariff (Paisas/kWh) NTDC				Average Tariff (Paisas/kWh) KE			
	Dom	Com	Ind	Agr	Dom	Com	Ind	Agr
1994	96.00	385.50	229.00	73.70	133.30	355.89	230.20	125.07
1995	110.30	427.40	268.20	93.60	136.20	420.95	278.50	135.50
1996	136.10	537.00	336.30	130.70	125.10	365.65	288.30	112.82
1997	155.70	565.50	374.50	163	178.10	510.02	341.50	94.76
1998	185.10	655.00	410.90	187	244.80	621.82	382	159.46
1999	234.70	718.20	448.40	233.40	287.40	644.30	422.80	205.48
2000	233.20	703.50	416.30	231	297.00	715.26	425.60	272.77
2001	259	703.70	415.70	257.70	312.80	736.31	434.80	312.06
2002	318.40	708.40	418.70	292.90	344.10	744.10	451.60	346.67
2003	334	703	442	333	357.60	746.90	468.80	375.70
2004	434	685	446	351	375.70	759.92	495.50	254.29
2005	340	660	425	349	362	721	476	173
2006	345	1,003	425	340	366	721	472	137
2007	376	821	517	364	381	751.50	476.80	125.78
2008	464	946	568	429	422	779	514	124
2009	540	1,154	748	502	494	974	631	133
2010	656	1,324	894	615	579	1,107	711	115
2011	731	1,490	960	799	697	1,310	821	137
2012	841	1,664	1,090	935	765	1,324	1,029	173
2013	873	1,793	1,220	1,003	893	1,682	1,178	178
2014	948	2,127	1,583	1,202	895	1,722	1,484	180
2015	1,022	2,224	1,539	1,400	881	1,759	1,475	174
2016	1,048	2,017	1,375	1,266	1,159	1,786	1,349	183
2017	1,065	2,022	1,412	1,064	1,199	1,788	1,202	619

Annexure A-6: Real Price of Average Tariff of NTDC and KE, Base year 2005-06

Year	Avg. Tariff/kWh 2005-06 Rs. (Real Price) NTDC				Avg. Tariff/kWh 2005-06 Rs. (Real Price) KE			
	Dom	Com	Ind	Agr	Dom	Com	Ind	Agr
1970	427	522	269	184	364	386	255	303
1971	412	520	269	160	352	358	243	269
1972	399	513	273	179	322	354	244	253
1973	355	479	258	179	301	375	278	266
1974	276	442	245	149	231	379	354	209
1975	229	395	232	131	181	327	322	156
1976	225	455	275	152	161	294	300	149
1977	219	468	294	138	161	316	283	118
1978	197	485	304	117	199	368	278	137
1979	218	546	352	160	217	397	307	178
1980	238	652	393	196	234	517	376	185
1981	243	613	387	197	238	588	422	284
1982	230	595	373	198	241	669	529	407
1983	228	622	398	203	231	783	670	359
1984	215	596	376	209	219	725	616	329
1985	204	571	365	178	204	675	576	315
1986	221	637	410	193	213	658	544	291
1987	205	601	383	159	207	611	509	276
1988	211	693	450	161	232	641	549	239
1989	228	782	488	168	269	801	498	259
1990	228	851	520	189	284	851	519	278
1991	234	848	508	173	282	864	518	291
1992	224	876	524	175	277	865	523	292

Year	Avg. Tariff/kWh 2005-06 Rs. (Real Price) NTDC				Avg. Tariff/kWh 2005-06 Rs. (Real Price) KE			
	Dom	Com	Ind	Agr	Dom	Com	Ind	Agr
1993	213	836	503	167	256	781	476	269
1994	218	876	520	167	303	808	523	284
1995	222	859	539	188	274	846	560	272
1996	247	974	610	237	227	663	523	205
1997	253	917	608	264	289	827	554	154
1998	279	986	618	281	368	936	575	240
1999	334	1,022	638	332	409	917	602	293
2000	320	967	572	317	408	983	585	375
2001	341	926	547	339	412	969	572	411
2002	405	901	532	373	438	946	574	441
2003	412	867	545	411	441	921	578	463
2004	512	808	526	414	443	896	584	300
2005	367	712	459	377	391	778	514	187
2006	345	1,003	425	340	366	721	472	137
2007	349	762	480	338	353	697	442	117
2008	384	784	470	355	350	645	426	103
2009	382	817	529	355	350	689	447	94
2010	422	851	575	395	372	712	457	74
2011	413	842	543	452	394	741	464	77
2012	428	848	555	476	390	674	524	88
2013	414	850	579	476	423	798	559	84
2014	414	929	691	525	391	752	648	349
2015	427	929	643	585	368	735	616	449
2016	426	820	559	515	471	726	548	440
2017	416	790	551	416	468	698	469	242

Annexure A-7: Country (Real Price) Weighted Average

Years	Country (NTDC and KE)							
	Real Price Weighted Average				Price Weighted Average			
	Dom	Com	Ind	Agr	Dom	Com	Ind	Agr
1970	406.2	436.2	265.2	184.7	18.6	19.9	12.1	8.4
1971	392.2	422.8	261.1	160.5	18.9	20.4	12.6	7.8
1972	371.6	416.5	265.7	179.3	18.8	21.1	13.4	9.1
1973	336	416.4	263.4	180	18.7	23.1	14.6	10
1974	259.6	404.5	273.8	148.9	18.7	29.2	19.7	10.7
1975	210.5	354.1	256.1	131.2	19.3	32.4	23.4	12
1976	201.2	359.4	281.7	151.9	20.6	36.7	28.8	15.5
1977	196.3	377.2	291.2	137.4	22.4	43.1	33.3	15.7
1978	197.5	419.2	298.1	116.9	24.3	51.6	36.7	14.4
1979	217.4	489.8	346	160.3	28.5	64.3	45.4	21
1980	237.2	605.3	389.6	195.9	34.4	87.9	56.6	28.4
1981	241.3	600.9	394.3	197.4	39.4	98.1	64.4	32.2
1982	232.8	627.9	405.8	198.7	42.2	113.8	73.6	36
1983	228.8	692.9	449.8	203.4	43.4	131.4	85.3	38.6
1984	216.4	651.4	424.3	210.1	44	132.5	86.3	42.7
1985	204.2	614.6	406.9	179	43.9	132.1	87.5	38.5
1986	219	646	435.7	193.5	49.1	144.9	97.7	43.4
1987	205.2	604.9	407.9	159.2	47.7	140.6	94.8	37
1988	215.6	670.3	468.8	161.8	53.3	165.6	115.8	40
1989	236.3	790.7	489.7	168.1	64.5	215.7	133.6	45.9
1990	238.8	850.8	519.8	189	69	246	150.3	54.6
1991	241.9	855.3	509.7	173.9	78.8	278.7	166.1	56.7
1992	231.9	873	523.8	175.9	83.6	314.5	188.7	63.4
1993	219.1	823	498.3	167.8	86.7	325.7	197.2	66.4
1994	231	857.5	520.6	168	101.7	377.6	229.2	74
1995	228.8	855.9	542.2	188.5	113.8	425.9	269.8	93.8
1996	244.1	899.1	596.7	236.8	134.6	495.8	329	130.6

Years	Country (NTDC and KE)							
	Real Price Weighted Average				Price Weighted Average			
	Dom	Com	Ind	Agr	Dom	Com	Ind	Agr
1997	257	898	599.2	263.4	158.4	553.5	369.4	162.4
1998	289.9	974	611.1	281.1	192.6	646.9	406.1	186.8
1999	343.2	997.9	631.6	332	241	700.9	443.7	233.2
2000	330.5	970.2	574.4	317.8	240.5	706	418	231.3
2001	349.3	936.4	551.8	339.6	265.4	711.4	419.2	258
2002	408.6	911.2	539.4	372.8	321.3	716.4	424.1	293.1
2003	415.4	879.1	550.8	411.1	336.7	712.6	446.5	333.2
2004	503.5	827.1	535.7	413.2	426.9	701.3	454.2	350.4
2005	369.9	727	467.5	374.8	342.8	673.3	433.3	347.3
2006	347.6	945.6	432.6	338.1	347.6	945.6	432.6	338.1
2007	349.3	749.5	473.3	335.5	376.6	808	510.3	361.7
2008	379.8	754.6	463.1	352.5	458.6	911.1	559.1	425.6
2009	378.1	792.1	515.5	352.3	534.2	1,119	728.4	497.8
2010	415.5	823.7	554.5	391.9	646.5	1,281	862.6	609.6
2011	410.9	823.8	529.9	446.5	726.9	1,457	937.3	789.8
2012	423.3	813.2	550.4	470.1	831.1	1,596	1,080	923.1
2013	415.4	836.9	575.4	468.1	875.9	1,765	1,213	987
2014	410.7	886.5	684.9	516.3	940.5	2,030	1,568	1,182
2015	418.2	881.4	639	574.4	1,000.70	2,109	1,529	1,375
2016	432.8	797.6	557.3	506.2	1,064.70	1,962	1,371	1,245
2017	423.1	770.2	538.1	412.5	1,083.50	1,972	1,378	1,056

Annexure A-8: Electricity Consumption by Category (GWh) System

Year	Dom	Com	Ind	Agr	Str Light	Bulk	Tra/Others	Exp to KESC	Total
1970	367	125	1,646	956	20	487	0	0	3,600
1971	382	152	1,689	1,080	24	638	0	0	3,966
1972	392	142	2,109	997	75	422	0	0	4,137
1973	462	165	2,236	1,184	22	530	0	0	4,599
1974	523	179	2,267	1,142	20	569	42	0	4,742
1975	566	184	2,245	1,531	20	604	63	0	5,212
1976	678	222	2,262	1,386	26	697	45	0	5,315
1977	780	246	2,357	1,400	29	597	43	0	5,452
1978	1,004	305	2,596	1,718	42	784	42	0	6,490
1979	1,240	336	2,770	1,666	70	856	43	0	6,981
1980	1,564	389	3,154	2,057	50	900	46	0	8,160
1981	1,858	445	3,482	2,125	58	1,056	44	0	9,068
1982	2,408	574	3,960	2,357	74	873	42	0	10,288
1983	2,866	634	4,427	2,546	78	992	44	0	11,587
1984	3,470	739	4,708	2,663	75	1,069	38	0	12,762
1985	3,887	796	5,061	2,783	77	1,115	37	0	13,756
1986	4,513	875	5,894	2,880	90	1,215	36	0	15,504
1987	5,357	991	6,436	3,452	110	1,361	38	0	17,745
1988	6,290	1,054	7,236	4,394	117	1,571	40	0	20,702
1989	6,939	1,068	7,578	4,356	127	1,795	35	82	21,982
1990	7,647	1,106	8,360	5,004	148	1,646	38	171	24,121
1991	8,617	1,152	9,115	5,596	178	1,700	33	194	26,585
1992	9,691	1,192	10,213	5,823	229	1,799	29	292	29,267
1993	11,220	1,303	10,913	5,595	195	1,925	27	94	31,272
1994	11,963	1,318	10,532	5,743	216	1,964	27	368	32,131
1995	13,448	1,490	10,604	6,220	252	2,112	22	884	35,032
1996	14,792	1,648	10,335	6,657	301	2,377	20	795	36,925

Year	Dom	Com	Ind	Agr	Str Light	Bulk	Tra/Others	Exp to KESC	Total
1997	15,594	1,757	10,115	7,018	308	2,485	19	1,233	38,529
1998	16,367	1,768	10,238	6,888	307	2,694	16	1,145	39,422
1999	16,927	1,825	9,945	5,575	159	2,646	15	1,808	38,900
2000	18,942	2,003	10,773	4,512	150	2,676	15	1,840	40,910
2001	20,019	2,120	11,744	4,896	146	2,634	14	1,811	43,384
2002	20,549	2,285	12,637	5,582	149	2,662	12	1,329	45,204
2003	20,855	2,516	13,462	5,986	166	2,626	10	1,801	47,421
2004	22,668	2,884	14,476	6,624	192	2,796	9	1,843	51,492
2005	24,049	3,192	15,568	6,921	227	2,892	12	2,416	55,278
2006	27,009	3,768	16,596	7,873	279	3,031	13	3,836	62,405
2007	28,944	4,289	17,603	8,097	316	3,252	13	4,905	67,419
2008	28,711	4,358	17,299	8,380	340	3,319	11	4,072	66,489
2009	27,755	4,203	16,035	8,695	347	3,188	10	5,014	65,248
2010	29,479	4,465	16,372	9,585	371	3,357	10	5,208	68,847
2011	30,972	4,683	17,700	8,847	374	3,607	10	5,449	71,642
2012	30,365	4,563	18,403	8,414	360	3,509	43	5,684	71,341
2013	30,329	4,435	18,636	7,548	351	3,659	60	5,463	70,481
2014	33,325	4,795	20,550	8,130	351	3,872	32	5,441	76,496
2015	34,567	4,853	21,086	7,866	330	3,909	33	5,427	78,071
2016	37,123	5,417	21,150	8,364	295	4,239	34	5,059	81,682
2017	41,412	6,114	20,067	9,063	298	4,566	31	5,077	86,628

Annexure A-9: Electricity Consumption by Category (GWh) KE System

Years	Electricity Consumption by Category KE System (GWh)						
	Dom	Com	Ind	Agr	Street Light	Bulk	Total
1970	179	213	653	9	9	74	1,137
1971	190	227	710	9	10	115	1,261
1972	217	221	701	9	12	122	1,282
1973	257	247	834	8	14	138	1,498
1974	302	264	826	7	17	196	1,612
1975	351	284	812	8	19	142	1,616
1976	413	325	809	9	23	35	1,614
1977	498	367	727	10	36	43	1,681
1978	612	390	784	10	36	25	1,857
1979	314	206	439	5	15	13	992
1980	448	206	902	11	29	43	1,639
1981	748	416	932	9	18	11	2,134
1982	881	460	1,042	10	28	63	2,485
1983	929	501	1,036	13	30	70	2,579
1984	1,096	559	1,190	13	28	129	3,015
1985	1,204	579	1,256	13	31	770	3,852
1986	1,361	651	1,402	20	41	569	4,043
1987	1,482	723	1,560	19	36	310	4,130
1988	1,649	816	1,718	21	51	303	4,558
1989	1,743	853	1,863	22	60	225	4,765
1990	1,755	858	1,973	23	71	394	5,338
1991	1,782	914	2,002	24	84	163	5,011
1992	1,768	407	2,075	25	82	1,136	5,955
1993	1,985	419	2,118	26	92	1,240	6,397
1994	2,170	482	2,096	29	82	1,228	6,438
1995	2,135	451	1,924	32	73	1,016	5,839
1996	2,324	522	1,854	38	77	1,206	6,319
1997	2,145	484	1,863	67	82	998	5,730
1998	2,357	566	2,059	48	81	1,273	6,546
1999	2,311	556	2,254	43	66	901	6,146

Years	Electricity Consumption by Category KE System (GWh)						
	Dom	Com	Ind	Agr	Street Light	Bulk	Total
2000	2,457	541	2,431	28	89	885	6,443
2001	2,683	653	2,604	28	66	889	6,945
2002	2,623	665	2,504	26	62	839	6,738
2003	2,726	702	2,719	30	78	720	7,155
2004	3,135	804	2,890	44	70	874	7,992
2005	3,508	888	3,023	66	78	853	8,416
2006	3,760	962	3,206	76	74	982	9,298
2007	3,864	986	3,544	79	65	829	9,367
2008	4,263	1,153	3,398	95	74	1,069	10,052
2009	3,989	1,004	3,226	100	83	994	9,396
2010	4,168	1,091	3,387	104	87	1,068	9,905
2011	4,257	1,043	3,447	125	82	1,117	10,071
2012	4,564	1,128	3,342	134	118	991	10,277
2013	5,083	1,507	3,445	149	111	647	10,942
2014	5,488	1,507	3,568	160	106	624	11,453
2015	6,161	1,589	3,843	166	110	426	12,295
2016	6,596	1,685	3,830	163	163	428	12,865
2017	6,643	1,655	3,885	159	167	452	12,981

Annexure A-10: Load Shedding (GWh) NTDC System

Year	Load Shedding – NTDC System (GWh)				
	Dom	Com	Ind	Agr	Total
2004	219	28	140	64	451
2005	112	15	72	32	231
2006	517	72	318	151	1,057
2007	884	131	537	247	1,798
2008	5,367	814	3,229	1,564	10,974
2009	7,840	1,186	4,524	2,453	16,003
2010	9,519	1,441	5,281	3,092	19,333
2011	9,174	1,387	5,243	2,621	18,425
2012	11,943	1,793	7,232	3,306	24,274
2013	12,269	1,793	7,532	3,051	24,645
2014	12,243	1,760	7,542	2,984	24,530
2015	13,497	1,893	8,225	3,069	26,683
2016	11,993	1,750	6,833	2,702	23,278
2017	13,310	1,965	6,450	2,913	24,638

Annexure A-11: Load Shedding by Category (GWh) KE System

Years	Load Shedding KE (GWh)				
	Dom Shed	Com Shed	Ind	Agr Shed	Total Shed
1970	-	-	-	-	-
1971	-	-	-	-	-
1972	-	-	-	-	-
1973	-	-	-	-	-
1974	-	-	-	-	-
1975	-	-	-	-	-
1976	-	-	-	-	-
1977	-	-	-	-	-
1978	-	-	-	-	-
1979	-	-	-	-	-
1980	-	-	-	-	-
1981	-	-	-	-	-
1982	-	-	-	-	-
1983	-	-	-	-	-
1984	-	-	-	-	-
1985	-	-	-	-	-
1986	-	-	-	-	-
1987	-	-	-	-	-
1988	-	-	-	-	-
1989	-	-	-	-	-
1990	-	-	-	-	-
1991	-	-	-	-	-
1992	-	-	-	-	-
1993	-	-	-	-	-
1994	-	-	-	-	-
1995	-	-	-	-	-
1996	-	-	-	-	-
1997	-	-	-	-	-
1998	-	-	-	-	-
1999	-	-	-	-	-
2000	-	-	-	-	-

Years	Load Shedding KE (GWh)				
	Dom Shed	Com Shed	Ind	Agr Shed	Total Shed
2001	-	-	-	-	-
2002	-	-	-	-	-
2003	-	-	-	-	-
2004	24	6	22	-	53
2005	13	3	11	-	28
2006	59	15	50	1	126
2007	95	24	87	2	208
2008	664	180	529	15	1,387
2009	856	215	692	21	1,785
2010	1,005	263	816	25	2,109
2011	512	126	415	15	1,068
2012	641	159	470	19	1,288
2013	644	191	437	19	1,291
2014	763	209	496	22	1,490
2015	756	195	472	20	1,443
2016	793	203	461	20	1,476
2017	1,171	292	685	28	2,175

Annexure A-12: Number of Consumers (Category Wise) NTDC System

Year	Consumers (NTDC System)						
	Dom	Com	Ind	Agr	Street Light	Bulk+ Tract.	Total
1971	930,350	238,147	64,494	50,212	587	434	1,284,224
1972	998,922	258,328	67,056	52,343	663	477	1,377,789
1973	1,070,192	275,273	72,158	58,472	684	530	1,477,309
1974	1,137,676	300,219	78,277	63,730	718	534	1,581,154
1975	1,232,621	322,252	80,730	69,687	740	560	1,706,590
1976	1,347,122	347,167	85,250	76,508	801	524	1,857,372
1977	1,498,747	376,284	91,365	81,813	926	722	2,049,857
1978	1,670,213	422,901	95,036	90,341	1,018	832	2,280,341
1979	1,866,550	462,950	100,946	95,666	1,315	787	2,528,214
1980	2,049,728	471,757	101,228	98,268	1,477	821	2,723,279
1981	2,479,453	571,800	111,484	104,108	2,090	1,010	3,269,945
1982	2,732,903	624,900	115,890	111,278	2,161	1,118	3,588,250
1983	2,989,397	674,600	119,417	114,390	2,390	1,225	3,901,419
1984	3,261,362	724,462	123,508	118,265	2,511	1,428	4,231,536
1985	3,500,171	770,465	128,441	120,905	2,447	1,541	4,523,970
1986	3,779,838	834,127	133,573	124,918	2,647	1,684	4,876,787
1987	4,106,424	898,118	139,537	130,034	2,801	1,772	5,278,686
1988	4,525,987	964,377	147,439	136,860	3,017	1,943	5,779,623
1989	5,077,686	1,039,033	153,042	143,869	3,462	2,075	6,419,167
1990	5,467,690	1,088,932	158,800	149,554	3,453	2,250	6,870,679
1991	5,805,382	1,134,754	162,624	152,169	3,531	2,261	7,260,721
1992	6,219,656	1,185,723	169,436	155,305	3,759	2,362	7,736,241
1993	6,622,977	1,221,223	172,145	153,088	3,829	2,488	8,175,750
1994	6,995,561	1,257,887	174,577	157,710	3,730	2,577	8,592,042
1995	7,376,032	1,342,946	179,392	162,303	3,954	2,649	9,067,276
1996	7,783,832	1,344,975	181,092	165,114	3,990	2,728	9,481,731
1997	8,154,894	1,354,940	184,301	167,245	4,064	3,168	9,868,612
1998	8,455,442	1,396,973	186,539	170,562	4,645	2,911	10,217,072
1999	8,911,587	1,517,199	190,084	173,078	4,708	2,979	10,799,635
2000	9,553,828	1,653,870	194,566	174,456	4,892	3,045	11,584,657

Year	Consumers (NTDC System)						
	Dom	Com	Ind	Agr	Street Light	Bulk+ Tract.	Total
2001	10,045,035	1,737,199	195,511	180,411	4,993	3,195	12,166,344
2002	10,482,804	1,803,132	199,839	184,032	4,854	3,361	12,678,022
2003	11,043,530	1,867,226	206,336	191,961	5,441	3,739	13,318,233
2004	11,737,078	1,935,462	210,296	198,829	5,800	3,873	14,091,338
2005	12,490,189	1,983,216	212,233	200,756	6,171	3,677	14,896,242
2006	13,389,762	2,068,312	222,283	220,501	6,550	3,753	15,911,161
2007	14,354,365	2,151,971	233,162	236,255	6,990	3,811	16,986,554
2008	15,226,711	2,229,403	242,401	245,640	7,337	3,874	17,955,366
2009	15,859,373	2,291,628	253,089	258,368	7,680	3,976	18,674,114
2010	16,673,015	2,362,312	263,507	271,268	8,034	4,088	19,582,224
2011	17,322,140	2,421,221	273,067	280,603	8,386	4,066	20,309,483
2012	17,978,395	2,482,702	286,401	286,287	8,698	4,128	21,046,611
2013	18,713,537	2,550,808	296,849	301,115	9,107	4,184	21,875,600
2014	19,323,307	2,635,086	305,294	310,578	9,369	4,236	22,587,870
2015	20,148,495	2,723,708	315,116	318,081	9,554	4,293	23,519,247
2016	21,040,707	2,814,234	325,816	321,055	9,857	5,030	24,516,699
2017	21,991,479	2,905,517	336,045	323,524	10,124	5,114	25,571,803

Annexure A-13: Number of Consumers (Category Wise) KE System

Year	Consumers (KE System)						
	Dom	Com	Ind	Agr	Street Light	Bulk	Total
1971	148,770	61,548	11,192	516	353	2,843	225,222
1972	169,778	62,110	12,298	540	372	2,855	247,953
1973	188,543	62,216	6,855	535	36	40	258,225
1974	220,868	62,816	7,610	528	36	40	291,898
1975	243,764	65,656	9,044	562	36	40	319,102
1976	267,129	73,959	10,788	609	46	396	352,927
1977	293,910	79,125	11,524	611	47	397	385,614
1978	318,129	84,587	12,155	620	49	396	415,936
1979	325,859	86,553	12,243	627	49	396	425,727
1980	358,758	64,143	12,585	630	51	396	436,563
1981	403,307	102,037	13,021	637	50	396	519,448
1982	442,230	112,059	13,543	626	51	396	568,905
1983	472,698	122,322	14,335	742	53	396	610,546
1984	502,563	130,985	14,986	783	53	396	649,766
1985	541,671	142,575	15,964	792	53	396	701,451
1986	586,918	160,016	16,835	931	53	398	765,151
1987	627,154	176,865	17,927	972	56	402	823,376
1988	664,730	193,912	19,185	1,001	56	402	879,286
1989	699,564	205,199	20,180	1,051	60	402	926,456
1990	745,375	219,052	20,731	1,066	68	406	986,698
1991	794,998	236,342	21,825	1,062	70	407	1,054,704
1992	834,177	250,196	22,849	1,156	78	407	1,108,863
1993	875,827	263,807	24,404	1,212	80	908	1,166,238
1994	948,107	282,524	26,268	1,253	80	931	1,259,163
1995	948,107	282,524	26,268	1,253	80	931	1,259,163
1996	972,105	286,154	26,221	1,251	137	666	1,286,534
1997	1,010,123	297,544	27,272	1,276	153	965	1,337,333

Year	Consumers (KE System)						
	Dom	Com	Ind	Agr	Street Light	Bulk	Total
1998	1,046,423	311,284	28,046	1,341	153	976	1,388,223
1999	1,093,765	323,135	29,041	1,398	152	1,014	1,448,505
2000	1,229,532	346,648	29,777	1,548	159	1,055	1,608,719
2001	1,269,912	366,611	30,339	1,594	157	1,107	1,669,720
2002	1,294,002	355,080	30,623	1,650	157	1,137	1,682,649
2003	1,306,748	355,581	20,071	1,526	158	959	1,685,043
2004	1,349,375	377,235	20,112	1,589	163	999	1,749,473
2005	1,398,576	395,719	21,220	1,775	123	823	1,818,236
2006	1,447,728	409,452	21,871	1,893	138	887	1,881,969
2007	1,494,669	425,001	21,920	2,007	69	1,408	1,945,074
2008	1,518,644	433,416	21,453	2,038	140	1,415	1,977,106
2009	1,531,971	437,463	20,751	2,073	112	1,376	1,993,746
2010	1,582,426	445,442	20,703	2,157	71	1,484	2,052,283
2011	1,632,604	452,667	20,595	2,233	57	1,467	2,109,623
2012	1,659,766	456,537	20,537	2,536	67	426	2,139,869
2013	1,660,768	452,329	20,462	2,616	66	368	2,136,609
2014	1,650,034	438,150	20,464	2,410	74	204	2,111,336
2015	1,694,779	438,683	20,609	2,484	77	199	2,156,831
2016	1,758,467	444,687	20,625	2,623	72	203	2,226,677
2017	1,945,091	456,087	20,852	2,615	74	201	2,424,920

Annexure A-14: Number of Consumers (Category wise) Country

Year	Dom	Com	Ind	Agr	Street Light	Bulk + Trac.	Total	Population
1970	1,001,355	276,044	71,731	46,949	902	3,130	1,400,111	58,090,759
1971	1,079,120	299,695	75,686	50,728	940	3,277	1,509,446	59,687,140
1972	1,168,700	320,438	79,354	52,883	1,035	3,332	1,625,742	61,338,261
1973	1,258,735	337,489	79,013	59,007	720	570	1,735,534	63,059,481
1974	1,358,544	363,035	85,887	64,258	754	574	1,873,052	64,870,833
1975	1,476,385	387,908	89,774	70,249	776	600	2,025,692	66,787,901
1976	1,614,251	421,126	96,038	77,117	847	920	2,210,299	68,813,220
1977	1,792,657	455,409	102,889	82,424	973	1,119	2,435,471	70,946,231
1978	1,988,342	507,488	107,191	90,961	1,067	1,228	2,696,277	73,194,937
1979	2,192,409	549,503	113,189	96,293	1,364	1,183	2,953,941	75,567,682
1980	2,408,486	535,900	113,813	98,898	1,528	1,217	3,159,842	78,068,144
1981	2,882,760	673,837	124,505	104,745	2,140	1,406	3,789,393	80,696,945
1982	3,175,133	736,959	129,433	111,904	2,212	1,514	4,157,155	83,445,863
1983	3,462,095	796,922	133,752	115,132	2,443	1,621	4,511,965	86,297,640
1984	3,763,925	855,447	138,494	119,048	2,564	1,824	4,881,302	89,228,949
1985	4,041,842	913,040	144,405	121,697	2,500	1,937	5,225,421	92,219,488
1986	4,366,756	994,143	150,408	125,849	2,700	2,082	5,641,938	95,264,460
1987	4,733,578	1,074,983	157,464	131,006	2,857	2,174	6,102,062	98,357,473
1988	5,190,717	1,158,289	166,624	137,861	3,073	2,345	6,658,909	101,474,835
1989	5,777,250	1,244,232	173,222	144,920	3,522	2,477	7,345,623	104,588,490
1990	6,213,065	1,307,984	179,531	150,620	3,521	2,656	7,857,377	107,678,614
1991	6,600,380	1,371,096	184,449	153,231	3,601	2,668	8,315,425	110,730,420
1992	7,053,833	1,435,919	192,285	156,461	3,837	2,769	8,845,104	113,747,135
1993	7,498,804	1,485,030	196,549	154,300	3,909	3,396	9,341,988	116,749,560
1994	7,943,668	1,540,411	200,845	158,963	3,810	3,508	9,851,205	119,769,556
1995	8,324,139	1,625,470	205,660	163,556	4,034	3,580	10,326,439	122,829,148
1996	8,755,937	1,631,129	207,313	166,365	4,127	3,394	10,768,265	125,938,339
1997	9,165,017	1,652,484	211,573	168,521	4,217	4,133	11,205,945	129,086,987

Year	Dom	Com	Ind	Agr	Street Light	Bulk + Trac.	Total	Population
1998	9,501,865	1,708,257	214,585	171,903	4,798	3,887	11,605,295	132,253,264
1999	10,005,352	1,840,334	219,125	174,476	4,860	3,993	12,248,140	135,405,584
2000	10,783,360	2,000,518	224,343	176,004	5,051	4,100	13,193,376	138,523,285
2001	11,314,947	2,103,810	225,850	182,005	5,150	4,302	13,836,064	141,601,437
2002	11,776,806	2,158,212	230,462	185,682	5,011	4,498	14,360,671	144,654,143
2003	12,350,278	2,222,807	226,407	193,487	5,599	4,698	15,003,276	147,703,401
2004	13,086,453	2,312,697	230,408	200,418	5,963	4,872	15,840,811	150,780,300
2005	13,888,765	2,378,935	233,453	202,531	6,294	4,500	16,714,478	153,909,667
2006	14,837,490	2,477,764	244,154	222,394	6,688	4,640	17,793,130	157,093,993
2007	15,849,034	2,576,972	255,082	238,262	7,059	5,219	18,931,628	160,332,974
2008	16,745,355	2,662,819	263,854	247,678	7,477	5,289	19,932,472	163,644,603
2009	17,391,344	2,729,091	273,840	260,441	7,792	5,352	20,667,860	167,049,580
2010	18,255,441	2,807,754	284,210	273,425	8,105	5,572	21,634,507	170,560,182
2011	18,954,744	2,873,888	293,662	282,836	8,443	5,533	22,419,106	174,184,265
2012	19,638,161	2,939,239	306,938	288,823	8,765	4,554	23,186,480	177,911,533
2013	20,374,305	3,003,137	317,311	303,731	9,173	4,552	24,012,209	181,712,595
2014	20,973,341	3,073,236	325,758	312,988	9,443	4,440	24,699,206	185,546,257
2015	21,843,274	3,162,391	335,725	320,565	9,631	4,492	25,676,078	189,380,513
2016	22,799,174	3,258,921	346,441	323,678	9,929	5,233	26,743,376	193,203,476
2017	23,936,570	3,361,604	356,897	326,139	10,198	5,315	27,996,723	207,774,520

Annexure A-15: Consumption per Customer (Category wise) NTDC System

Years	Dom	Com	Ind	Agr	Total
	kWh				
1971	411	638	26,194	21,518	48,761
1972	393	551	31,444	19,050	51,438
1973	431	600	30,992	20,244	52,267
1974	459	596	28,965	17,918	47,938
1975	459	572	27,803	21,972	50,806
1976	503	639	26,528	18,117	45,788
1977	520	654	25,803	17,108	44,085
1978	601	721	27,314	19,012	47,648
1979	664	725	27,442	17,419	46,250
1980	763	824	31,158	20,936	53,681
1981	749	779	31,234	20,408	53,170
1982	881	918	34,174	21,177	57,150
1983	959	940	37,069	22,257	61,226
1984	1,064	1,020	38,119	22,520	62,723
1985	1,111	1,033	39,406	23,018	64,568
1986	1,194	1,049	44,129	23,056	69,429
1987	1,304	1,103	46,122	26,551	75,080
1988	1,390	1,093	49,077	32,109	83,669
1989	1,367	1,028	49,519	30,280	82,194
1990	1,399	1,016	52,642	33,461	88,518
1991	1,484	1,015	56,047	36,773	95,319
1992	1,558	1,005	60,277	37,491	100,331
1993	1,694	1,067	63,392	36,548	102,701
1994	1,710	1,048	60,328	36,412	99,498
1995	1,823	1,110	59,108	38,323	100,364
1996	1,900	1,225	57,070	40,320	100,516
1997	1,912	1,297	54,883	41,962	100,054

Years	Dom	Com	Ind	Agr	Total
	kWh				
1998	1,936	1,265	54,884	40,383	98,468
1999	1,899	1,203	52,317	32,213	87,632
2000	1,983	1,211	55,368	25,861	84,422
2001	1,993	1,220	60,068	27,137	90,418
2002	1,960	1,267	63,235	30,329	96,792
2003	1,888	1,347	65,244	31,181	99,660
2004	1,931	1,490	68,837	33,317	105,575
2005	1,925	1,609	73,354	34,476	111,366
2006	2,017	1,822	74,663	35,705	114,207
2007	2,020	1,993	75,498	34,274	113,781
2008	1,888	1,955	71,364	34,116	109,320
2009	1,752	1,834	63,357	33,653	100,595
2010	1,770	1,891	62,127	35,334	101,123
2011	1,788	1,934	64,819	31,529	100,070
2012	1,690	1,838	64,253	29,390	97,173
2013	1,622	1,739	62,780	25,067	91,207
2014	1,726	1,820	67,309	26,177	97,033
2015	1,717	1,782	66,912	24,731	95,142
2016	1,764	1,925	64,914	26,052	94,656
2017	1,883	2,104	59,715	28,013	91,716

Annexure A-16: Consumption per Customer (Category wise) KE System

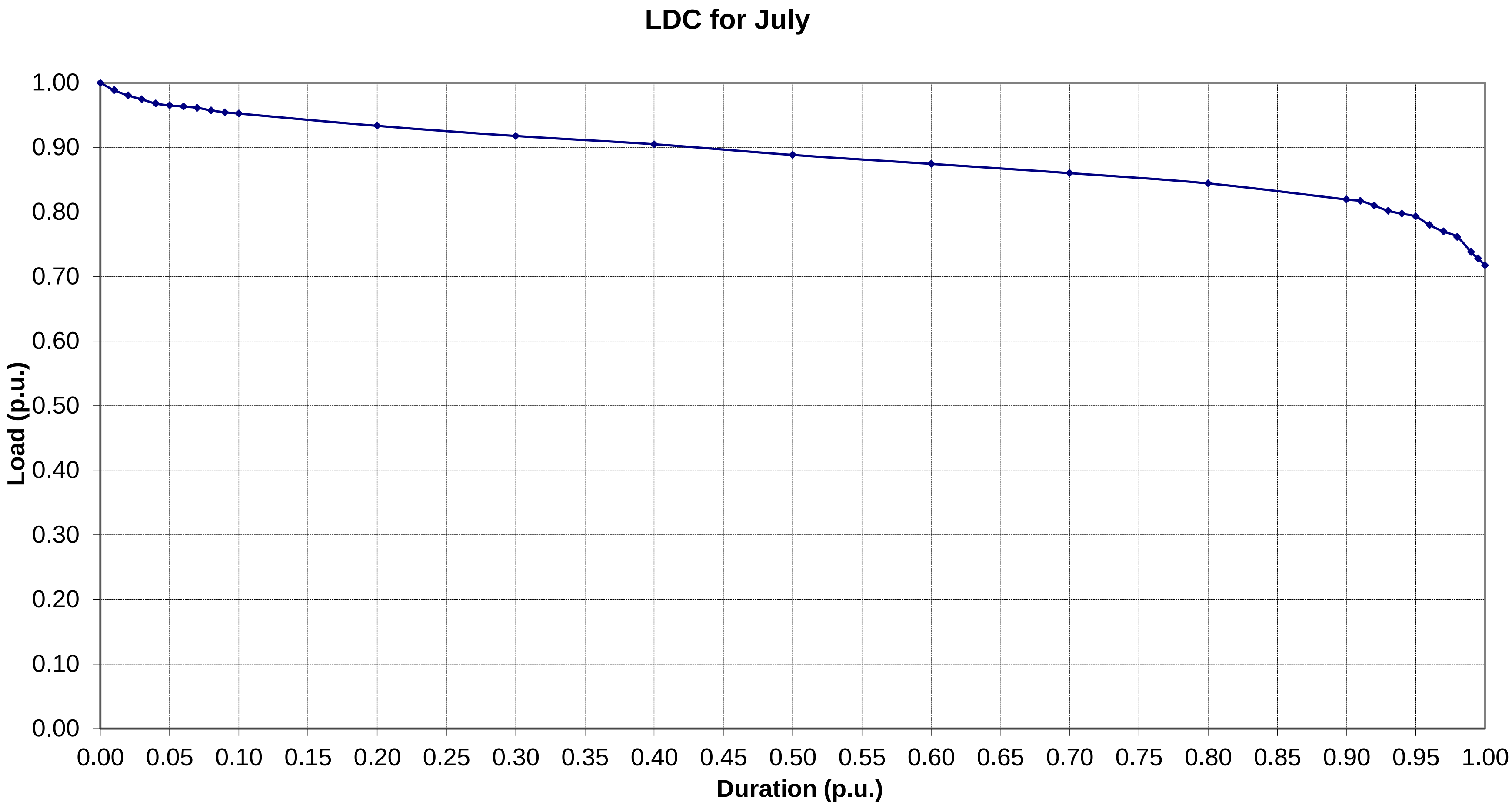
Years	Dom	Com	Ind	Agr	Total
	kWh				
1971	1,277	3,688	63,438	17,442	85,845
1972	1,278	3,558	57,001	16,667	78,504
1973	1,363	3,970	121,663	14,953	141,949
1974	1,367	4,203	108,541	13,258	127,369
1975	1,440	4,326	89,783	14,235	109,784
1976	1,546	4,394	74,991	14,778	95,709
1977	1,694	4,638	63,086	16,367	85,785
1978	1,924	4,611	64,500	16,129	87,164
1979	964	2,380	35,857	7,974	47,175
1980	1,248	3,212	71,708	17,048	93,215
1981	1,854	4,075	71,591	14,239	91,758
1982	1,993	4,106	76,936	15,942	98,977
1983	1,966	4,098	72,251	17,466	95,781
1984	2,182	4,266	79,397	16,743	102,589
1985	2,222	4,059	78,684	16,578	101,543
1986	2,319	4,067	83,272	21,149	110,807
1987	2,364	4,086	87,026	19,444	112,920
1988	2,481	4,210	89,545	21,019	117,255
1989	2,492	4,159	92,305	20,628	119,584
1990	2,354	3,916	95,159	21,895	123,325
1991	2,242	3,867	91,730	22,599	120,437
1992	2,119	1,625	90,834	21,557	116,135
1993	2,267	1,588	86,773	21,766	112,393
1994	2,289	1,706	79,793	23,144	106,932
1995	2,252	1,596	73,263	25,451	102,562
1996	2,391	1,824	70,693	30,616	105,523
1997	2,124	1,626	68,322	52,774	124,846

Years	Dom	Com	Ind	Agr	Total
	kWh				
1998	2,253	1,819	73,428	36,115	113,615
1999	2,112	1,720	77,604	31,059	112,495
2000	1,998	1,561	81,627	18,127	103,313
2001	2,113	1,782	85,839	17,491	107,224
2002	2,027	1,874	81,769	15,479	101,148
2003	2,086	1,975	135,491	19,954	159,506
2004	2,324	2,133	143,697	27,923	176,077
2005	2,508	2,244	142,460	37,183	184,395
2006	2,597	2,350	146,606	40,085	191,638
2007	2,585	2,320	161,679	39,362	205,946
2008	2,807	2,660	158,393	46,614	210,474
2009	2,604	2,295	155,462	48,239	208,601
2010	2,634	2,449	163,599	48,215	216,898
2011	2,607	2,304	167,371	55,979	228,261
2012	2,750	2,471	162,731	52,839	220,790
2013	3,061	3,332	168,361	56,957	231,710
2014	3,326	3,439	174,355	66,390	247,510
2015	3,635	3,622	186,472	66,828	260,557
2016	3,751	3,789	185,697	62,143	255,380
2017	3,415	3,629	186,313	60,803	254,160

Annexure A-17: Average Consumption per Customer (Country)

Year	Dom	Com	Ind	Agr	Total
	kWh				
1970	545	1,223	32,049	20,557	54,374
1971	530	1,264	31,702	21,477	54,972
1972	521	1,134	35,405	19,026	56,086
1973	571	1,221	38,858	20,196	60,846
1974	607	1,220	36,016	17,879	55,722
1975	621	1,208	34,047	21,910	57,785
1976	676	1,298	31,972	18,091	52,037
1977	713	1,346	29,979	17,103	49,140
1978	813	1,369	31,531	18,992	52,705
1979	709	986	28,352	17,358	47,404
1980	835	1,110	35,642	20,912	58,498
1981	904	1,278	35,455	20,370	58,006
1982	1,036	1,403	38,648	21,148	62,235
1983	1,096	1,425	40,840	22,226	65,588
1984	1,213	1,517	42,586	22,482	67,798
1985	1,260	1,506	43,749	22,976	69,490
1986	1,345	1,535	48,510	23,042	74,433
1987	1,445	1,594	50,779	26,498	80,315
1988	1,530	1,615	53,737	32,028	88,909
1989	1,503	1,544	54,503	30,210	87,761
1990	1,513	1,502	57,552	33,379	93,946
1991	1,576	1,507	60,269	36,675	100,026
1992	1,624	1,113	63,908	37,373	104,019
1993	1,761	1,160	66,295	36,431	105,647
1994	1,779	1,169	62,874	36,308	102,129
1995	1,872	1,194	60,916	38,225	102,207
1996	1,955	1,330	58,793	40,247	102,326
1997	1,936	1,356	56,615	42,044	101,951
1998	1,971	1,366	57,308	40,349	100,994
1999	1,923	1,294	55,668	32,204	91,088
2000	1,984	1,272	58,853	25,793	87,902

Year	Dom	Com	Ind	Agr	Total
	kWh				
2001	2,006	1,318	63,530	27,053	93,907
2002	1,968	1,367	65,698	30,197	99,230
2003	1,909	1,448	71,471	31,092	105,921
2004	1,972	1,595	75,372	33,274	112,212
2005	1,984	1,715	79,636	34,500	117,835
2006	2,074	1,909	81,108	35,742	120,832
2007	2,073	2,047	82,904	34,317	121,337
2008	1,972	2,070	78,440	34,219	116,698
2009	1,827	1,908	70,336	33,770	107,840
2010	1,845	1,979	69,519	35,436	108,780
2011	1,859	1,992	72,011	31,722	107,584
2012	1,780	1,936	70,842	29,596	104,156
2013	1,739	1,979	69,589	25,342	98,647
2014	1,852	2,051	74,033	26,487	104,424
2015	1,866	2,037	74,252	25,057	103,212
2016	1,918	2,179	72,105	26,344	102,547
2017	2,008	2,311	67,112	28,276	99,707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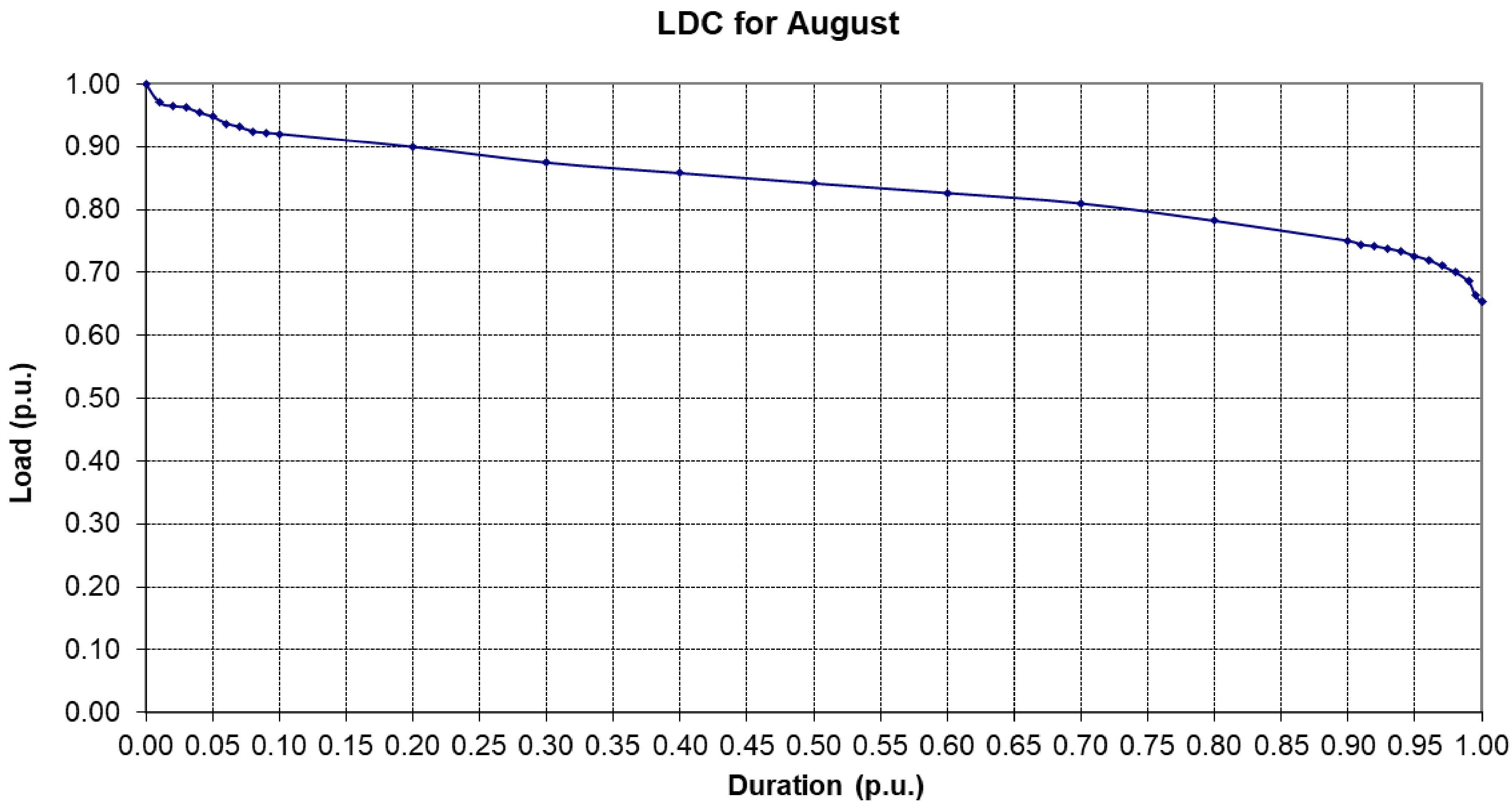
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Load (p.u.)
0.00 0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45 0.50 0.55 0.60 0.65 0.70 0.75 0.80 0.85 0.90 0.95 1.00
Duration (p.u.)


LDC for August
Load (p.u.)
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45 0.50 0.55 0.60 0.65 0.70 0.75 0.80 0.85 0.90 0.95 1.00
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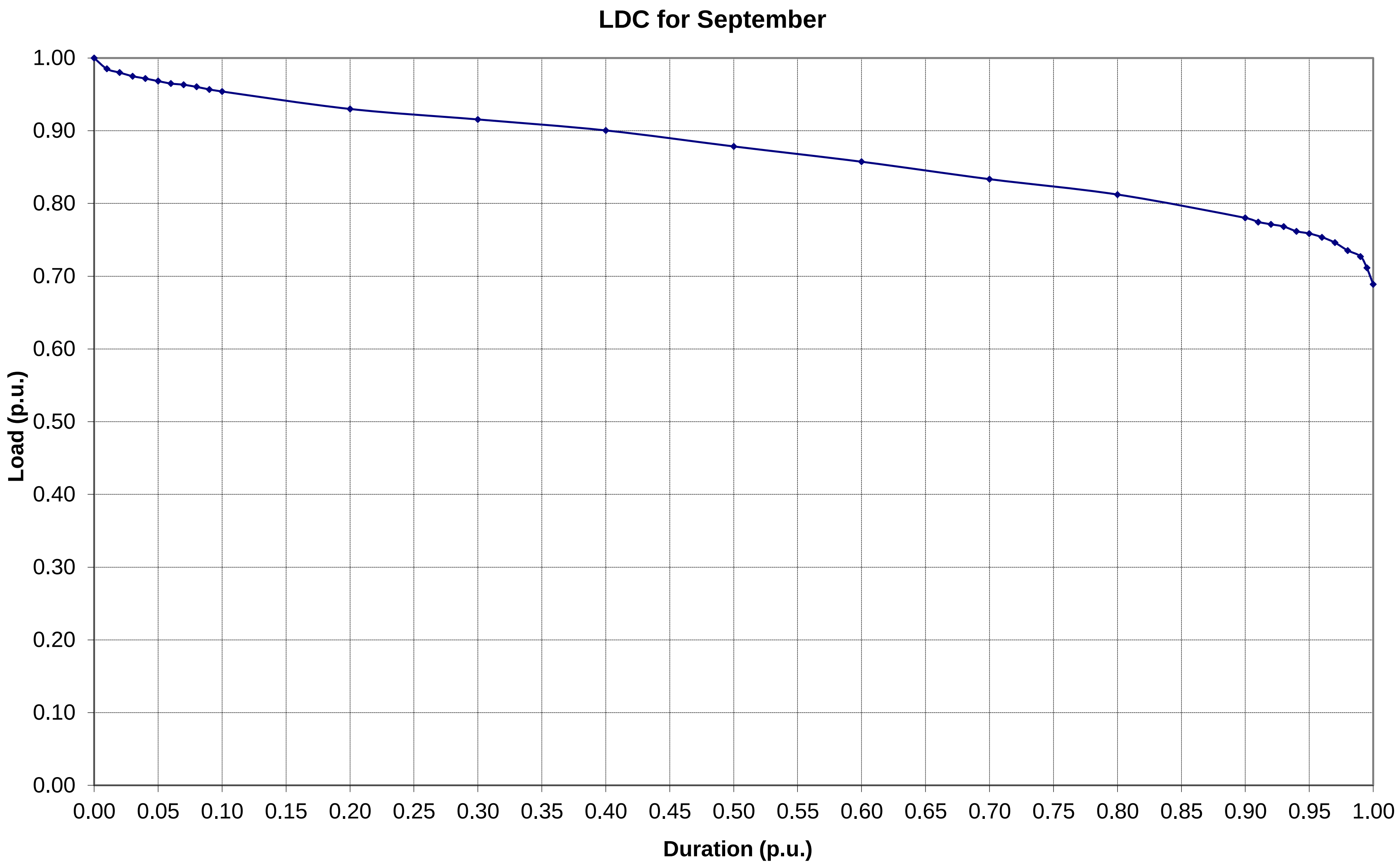
LDC for September
Load (p.u.)
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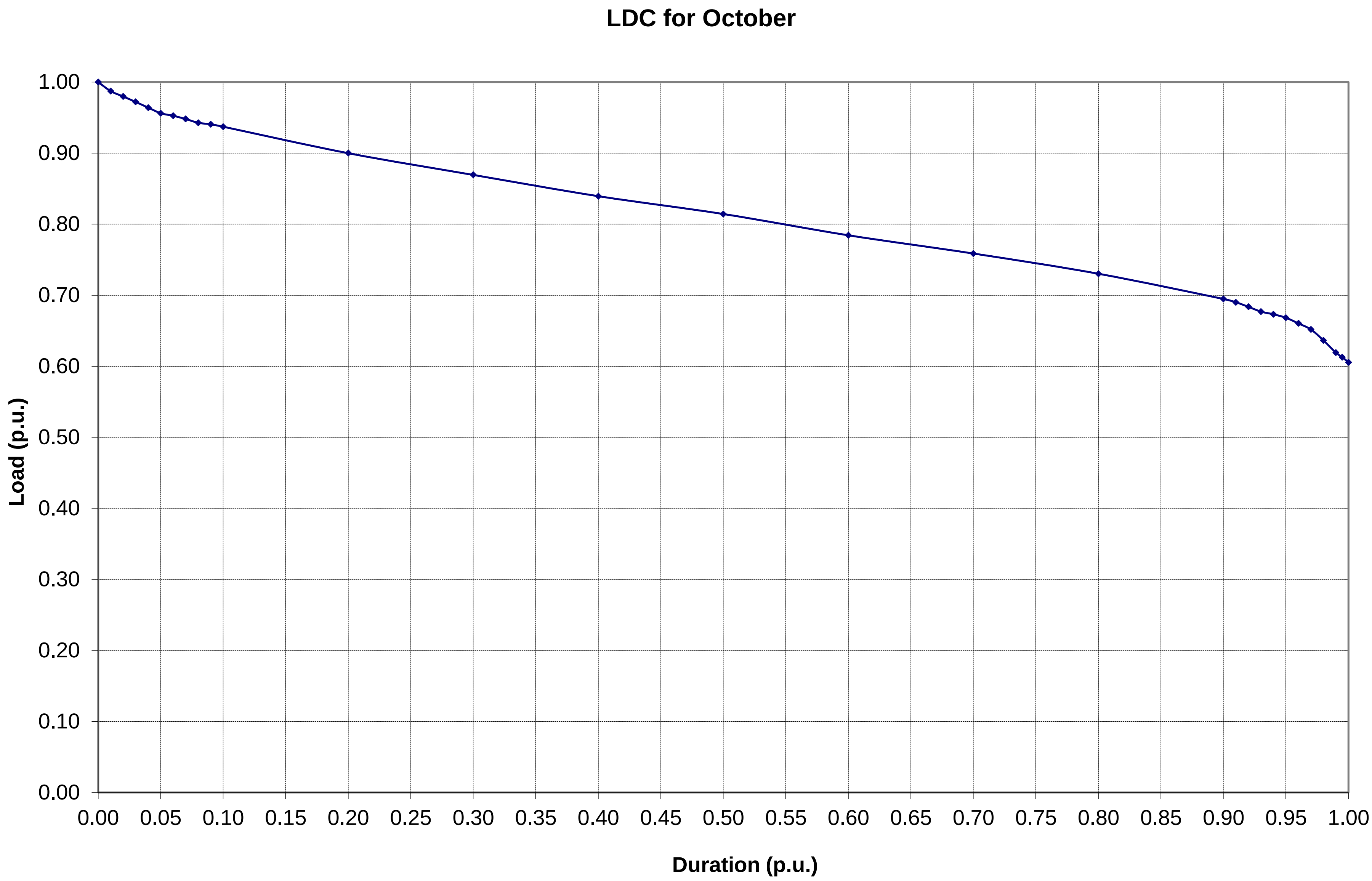
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45 0.50 0.55 0.60 0.65 0.70 0.75 0.80 0.85 0.90 0.95 1.00
Duration (p.u.)


LDC for October
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0.60
0.50
0.40
0.30
0.20
0.10
0.00
Load (p.u.)
0.00
0.05
0.10
0.15
0.20
0.25
0.30
0.35
0.40
0.45
0.50
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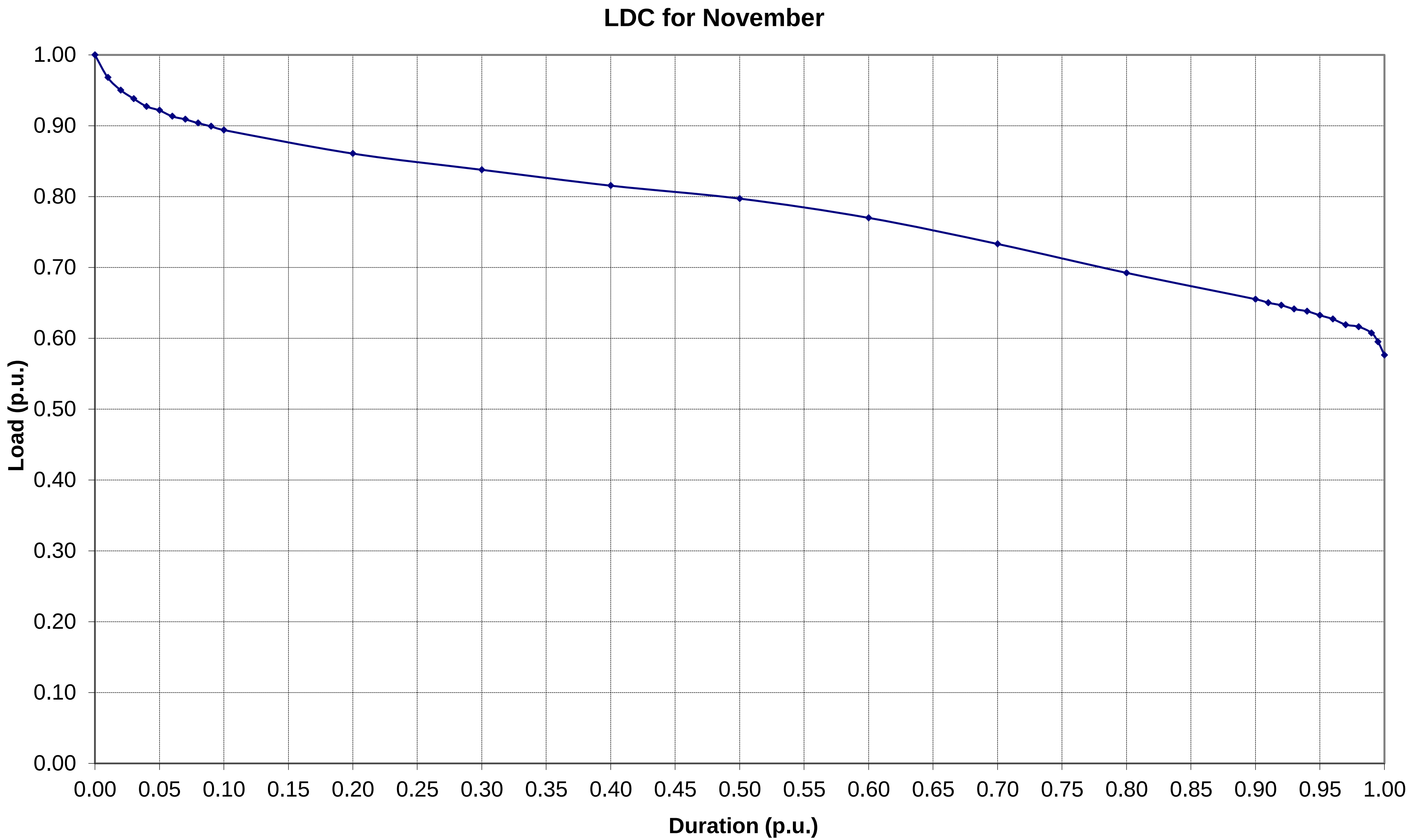
1.00
Duration (p.u.)



LDC for November
Load (p.u.)
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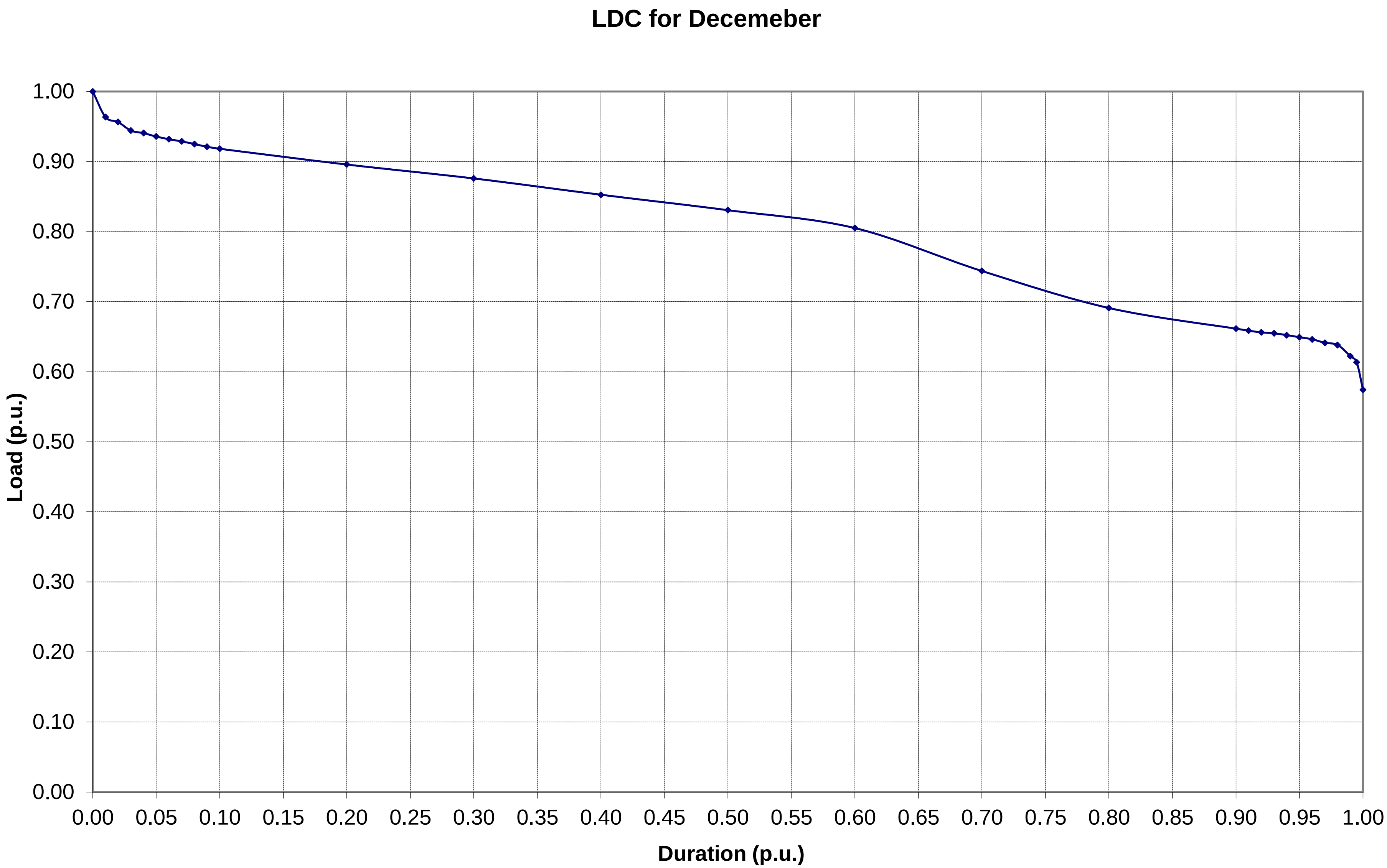
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45 0.50 0.55 0.60 0.65 0.70 0.75 0.80 0.85 0.90 0.95 1.00
Duration (p.u.)


LDC for Decemeber
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0.40
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0.20
0.10
0.00
0.00
0.05
0.10
0.15
0.20
0.25
0.30
0.35
0.40
0.45
0.50
0.55
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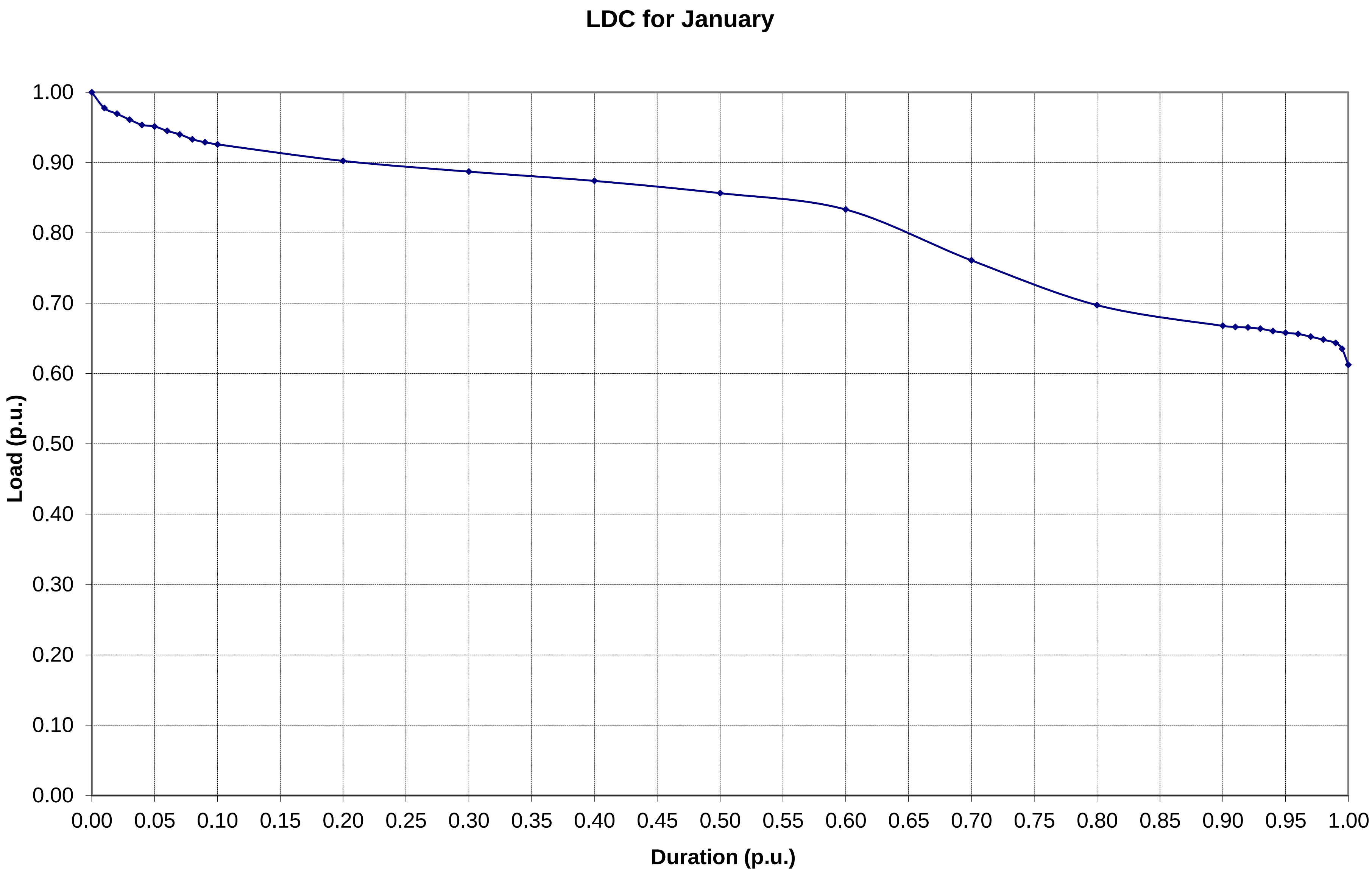
0.65
0.70
0.75
0.80
0.85
0.90
0.95
1.00
Duration (p.u.)



LDC for January
Load (p.u.)
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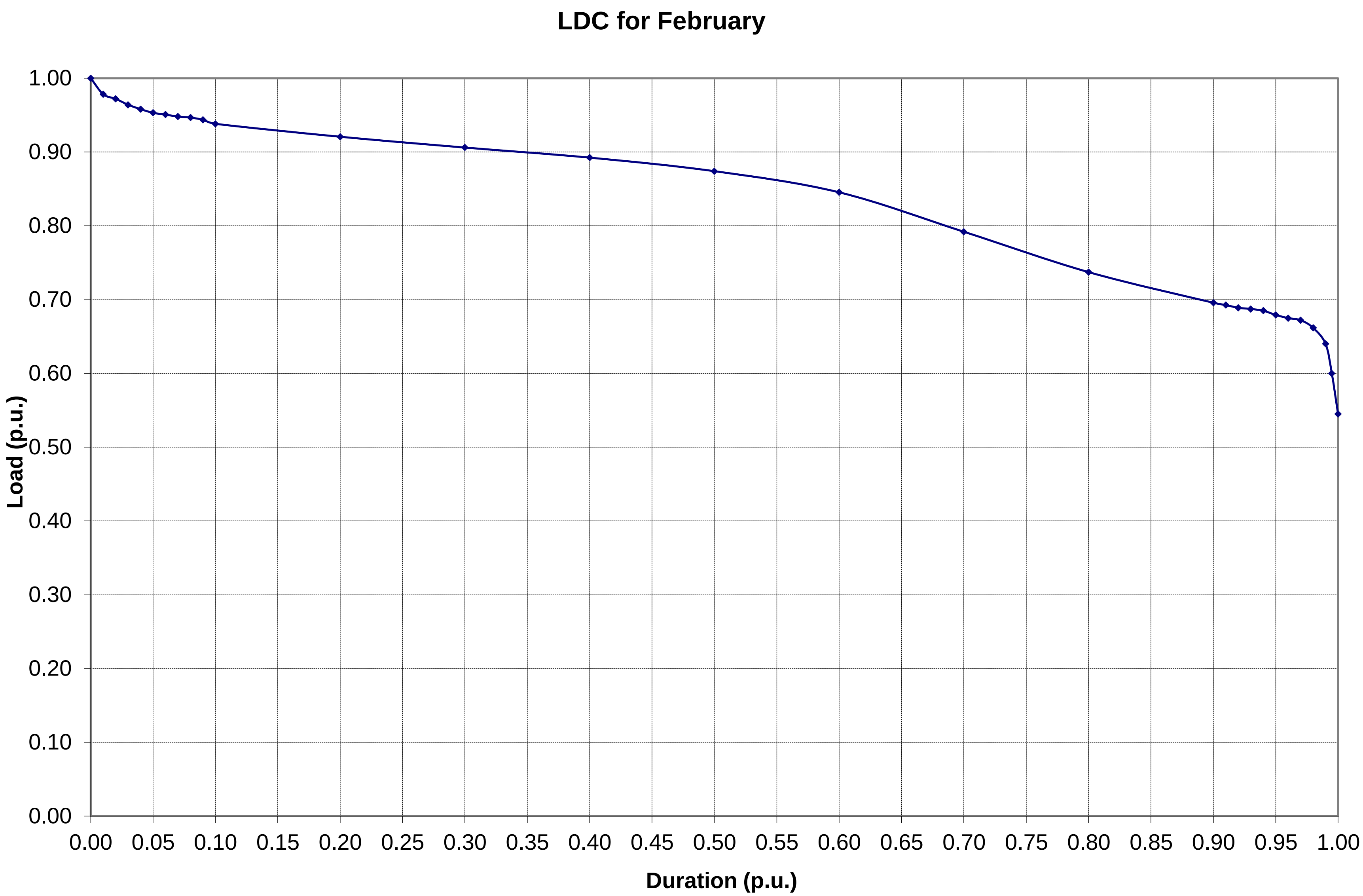
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00
0.05
0.10
0.15
0.20
0.25
0.30
0.35
0.40
0.45
0.50
0.55
0.60
0.65
0.70
0.75
0.80
0.85
0.90
0.95
1.00
Duration (p.u.)


LDC for February
Load (p.u.)
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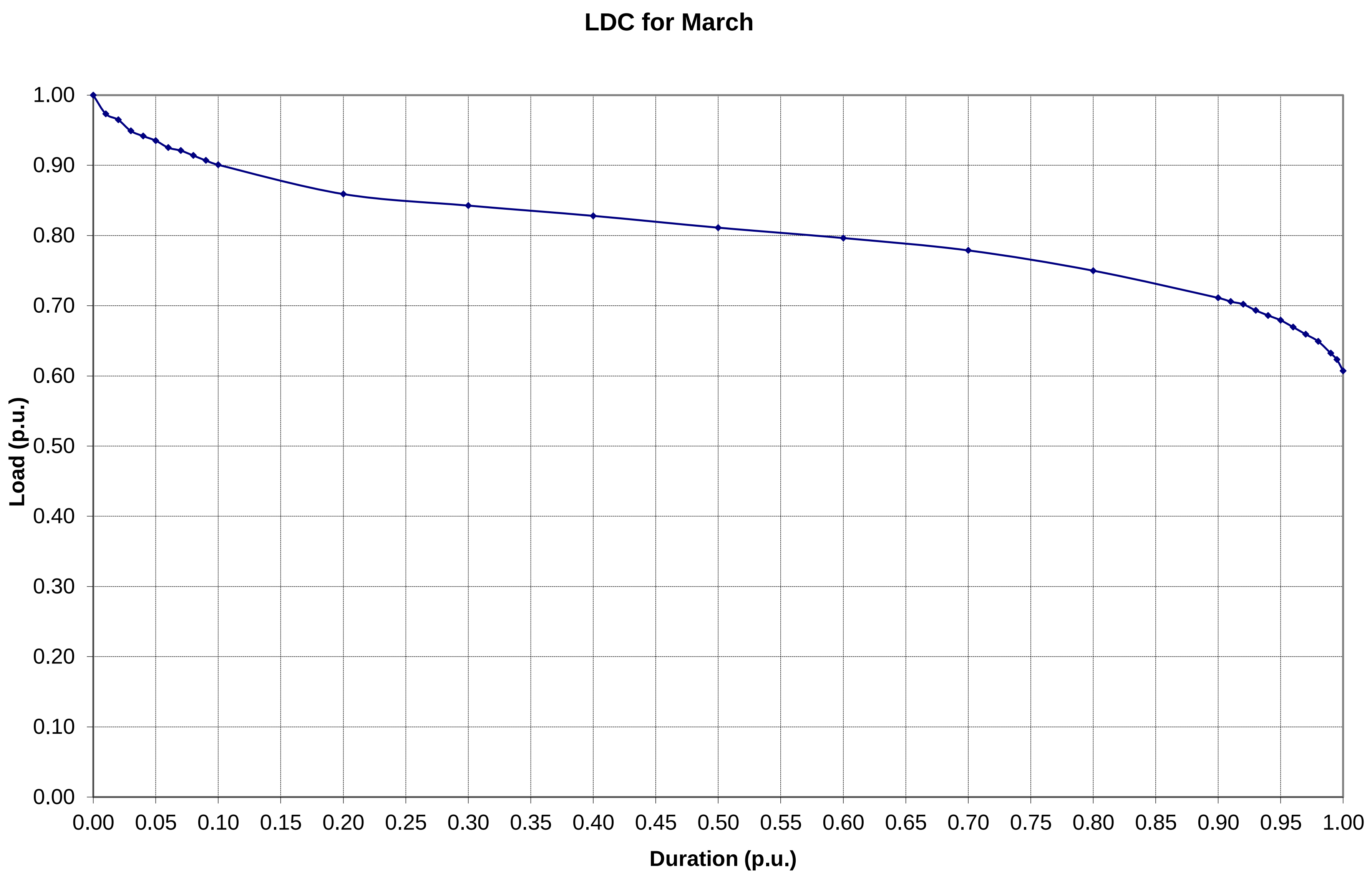
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45 0.50 0.55 0.60 0.65 0.70 0.75 0.80 0.85 0.90 0.95 1.00
Duration (p.u.)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Load (p.u.)
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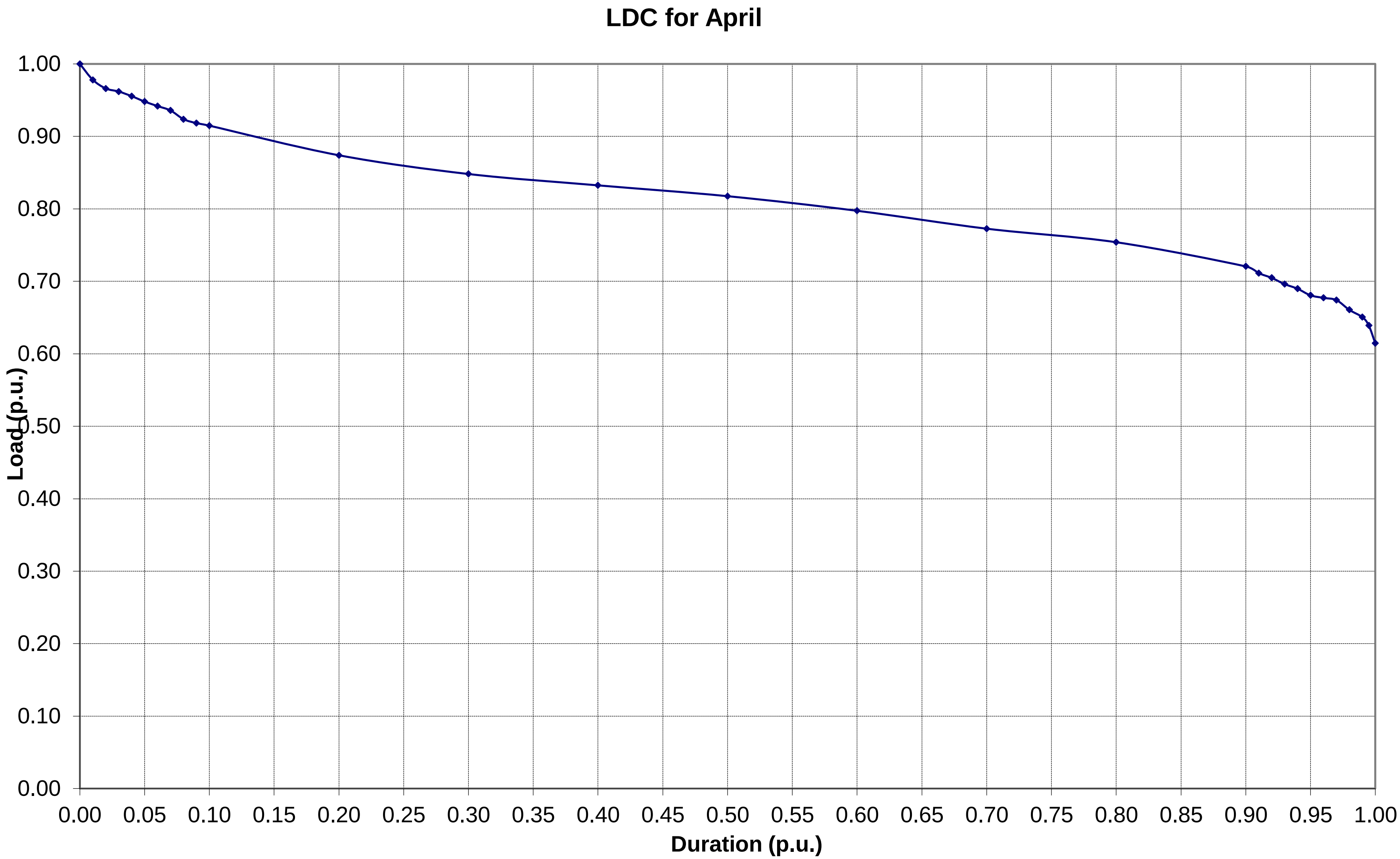
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45 0.50 0.55 0.60 0.65 0.70 0.75 0.80 0.85 0.90 0.95 1.00
Duration (p.u.)


LDC for April
Load (p.u.)
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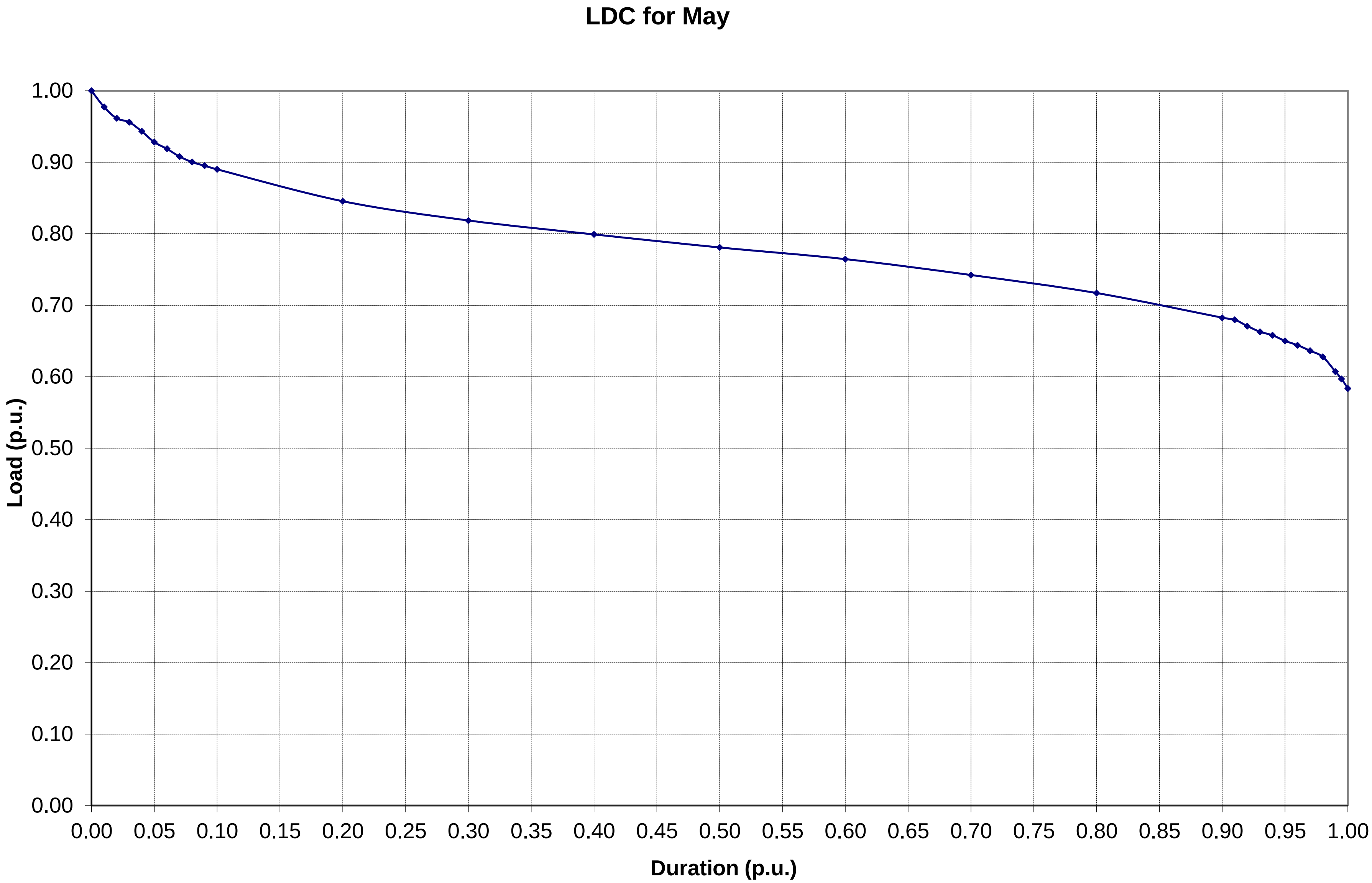
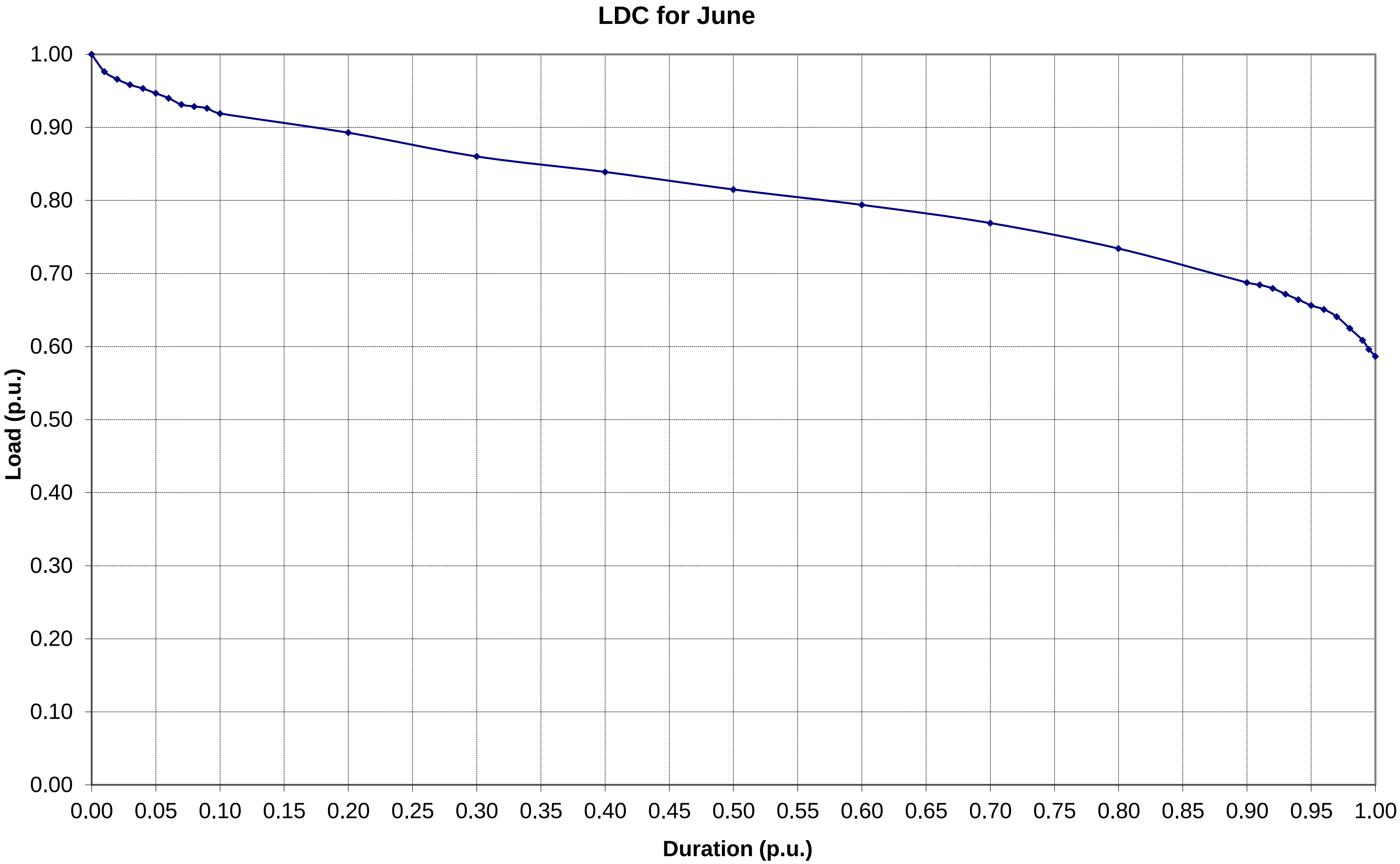
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45 0.50 0.55 0.60 0.65 0.70 0.75 0.80 0.85 0.90 0.95 1.00
Duration (p.u.)


LDC for May
Load (p.u.)
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00
0.05
0.10
0.15
0.20
0.25
0.30
0.35
0.40
0.45
0.50
0.55
0.60
0.65
0.70
0.75
0.80
0.85
0.90
0.95
1.00
Duration (p.u.)


LDC for June
Load (p.u.)
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0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.00 0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45 0.50 0.55 0.60 0.65 0.70 0.75 0.80 0.85 0.90 0.95 1.00
Duration (p.u.)

Annexure B-2: Existing Installed Capacity (As of December 2018)

Sr. No.	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
Public Sector				
WAPDA Hydro				
1	Tarbela	Hydro	3,478	3,478
2	Tarbela Ext. 04	Hydro	1,410	1,410
3	Mangla	Hydro	1,000	1,000
4	Ghazi Brotha	Hydro	1,450	1,450
5	Warsak	Hydro	243	243
6	Chashma Hydro	Hydro	184	184
7	Jinnah Hydel	Hydro	96	96
8	Allai Khwar	Hydro	121	121
9	Khan Khwar	Hydro	72	72
10	Dubair Khwar	Hydro	130	130
11	Nelum Jehlum	Hydro	969	969
12	Golen Gol	Hydro	106	106
13	Small Hydel	Hydro	128.4	128.4
Sub Total: WAPDA Hydro			**9,387**	**9,387**
GENCOs				
14	Jamshoro	RFO/RLNG	850	710
15	Kotri	Gas	174	120

Sr. No.	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
16	Lakhra	Dom. Coal	150	30
		Sub Total: GENCOs – I	**1,174**	**860**
17	Guddu 1-4	Gas	640	150
18	Guddu 5-13	Gas	1,035	630
19	Guddu 747	Gas	747	747
		Sub Total: GENCOs – II	**2,422**	**1,527**
20	Muzzafar Garh	FO/RLNG	1,350	1,130
21	GTPS Faisalabad	Gas	144	110
22	Nandi Pur	RLNG	425	425
		Sub Total: GENCOs – III	**1,919**	**1,665**
		Total GENCOs (Public Sector)	**5,515**	**4,052**
		Private Sector		
		Nuclear		
23	Chashnupp - I	Nuclear	325	301
24	Chashnupp - II	Nuclear	340	315
25	Chashnupp - III	Nuclear	340	315
26	Chashnupp - IV	Nuclear	340	315
		Sub Total: Nuclear	**1,345**	**1,246**
		Hydel IPPs		
27	Jagran	Hydro	30	30.4

Sr. No.	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
28	Malakand - III	Hydro	81	81
29	New Bong Escape	Hydro	84	84
30	Patrind	Hydro	150	147
Sub Total: IPPs Hydro			**345**	**342.4**
Thermal IPPs				
31	Kapco	RLNG	1,601	1,345
32	Hubco	FO	1,292	1,207
33	Kel	FO	131	124
34	AES Lalpir	FO	362	350
35	AES Pakgen	FO	365	350
36	HCPC	Gas	140	129
37	Uch	Gas	586	549
38	Rousch	RLNG	450	395
39	FKPCL	RLNG	172	151
40	Saba	FO	136	126
41	Liberty Power	Gas	225	213
42	Ael	RLNG	31	27
43	Davis	RLNG	13	10
44	Agl	FO	163	156
45	Atlas	FO	219	214

Sr. No.	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
46	Engro	Gas	226	213
47	Saif	RLNG	225	204
48	Oreint	RLNG	225	204
49	Nishat Power	FO	202	195
50	Nishat Chunian	FO	209	196
51	Foundation	Gas	184	174
52	Sapphire	RLNG	225	207
53	Liberty Tech.	FO	202	196.139
54	Hubco Narowal	FO	225	214
55	Halmore	RLNG	225	207
56	Uch - II	Gas	393	375
57	Bhiki (Qatpl)	RLNG	1,230	1,156
58	Sahiwal (Coal) (HSR)	Imp. Coal	1,320	1,250
59	H-B-Shah	RLNG	1,230	1,207
60	Reshma Power	FO	97	97
61	Gulf Power	FO	84	84
62	Balloki	RLNG	1,223	1,198
63	Port Qasim Coal	Imp. Coal	1,320	1,250
		Sub Total (IPPs Fossil Fuels)	**14,931**	**13,973**
		Bagasse Based Power Projects		

Sr. No.	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
64	JDW - II (Sadiq Abad)	Bagasse	26	24
65	JDW - III (Ghotki)	Bagasse	27	24
66	RYKML	Bagasse	30	24
67	Chiniot Power	Bagasse	63	63
68	Fatima Energy (FEL)	Bagasse	120	120
69	Hamza Sugar	Bagasse	15	15
70	Thall Power (Layyah)	Bagasse	25	25
Sub Total Bagasse			**306**	**295**
Wind Power Projects				
71	FFCEL Wind	Wind	50	50
72	ZEPL Wind	Wind	56	56
73	TGF Wind	Wind	50	50
74	FWEL - I Wind	Wind	50	50
75	FWEL - II Wind	Wind	50	50
76	Sapphire Wind	Wind	49.5	50
77	Metro Wind (MPCL)	Wind	50	50
78	Younis Wind	Wind	50	50
79	Tapal Wind(TWEPL)	Wind	30	30
80	Master Wind (MWEL)	Wind	50	50
81	Tenaga Wind	Wind	50	50

Sr. No.	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
82	Gul Ahmed Wind	Wind	50	50
83	Dawood Wind	Wind	50	50
84	Sachal Wind	Wind	50	50
85	UEP Wind Power	Wind	99	99
86	Artistic Wind	Wind	50	50
87	Jhimpir Power	Wind	50	50
88	Hawa Wind (HEPL)	Wind	50	50
89	TGT Wind	Wind	50	50
90	TGS Energy	Wind	50	50
91	Tricon Boston (A)	Wind	50	50
92	Tricon Boston (B)	Wind	50	50
93	Tricon Boston (C)	Wind	50	50
Sub Total Wind Power Plants			**1,185**	**1,185**
Solar Power Projects				
94	Quaid e Azam Solar	Solar	100	100
95	Appolo Solar	Solar	100	100
96	Best Green Solar	Solar	100	100
97	Crest Energy Solar	Solar	100	100
Sub Total Solar Power Plants			**400**	**400**
Total Public Sector			**14,902**	**13,439**

Sr. No.	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
Total Private Sector			18,512	17,442
Total Installed Capacity / Capability			33,414	30,881

Annexure B-3: Cost Related Data in Respect of Existing and Committed Thermal Plants

Sr.#	Plant Name	Fuel	Fixed O&M ($/Kw/Month)	Variable O&M ($/MWh)	Fuel Cost (cents/Gcal)
Existing Power Plants					
GENCOs					
1	TPS Jamshoro #1	RFO	4.6	0.74	5,389
2	TPS Jamshoro #2-4	RLNG	4.6	0.74	4,867
3	GTPS Kotri #1-7	Gas	10.7	0.74	2,008
4	TPS Guddu Steam/CC #1-13	Gas	1.50	0.55	2,008
5	Guddu 747 CC	Gas	1.50	2.41	2,008
6	TPS Muzaffargarh #1-6	RFO	3	1.1	5,396
7	GTPS Faisalabad #5-9	Gas/HSD	3	1.1	2,008
8	Nandipur	RLNG	1.4	3.91	5,044
9	FBC Lakhra	Coal	25.4	1.57	1,023
IPPs					
10	KAPCO (B-I)	RLNG	1.80	2.44	5,044
11	KAPCO (B-II)	RLNG	1.80	2.85	5,044
12	KAPCO (B-III)	RLNG	1.80	5.49	5,044
13	HUBCO	RFO	1.80	1.56	6,051
14	KEL	RFO	1.50	5.49	5,402
15	LALPIR (Pvt) Ltd	RFO	1.80	1.57	5,407
16	PAKGEN Power Ltd.	RFO	1.80	1.57	5,407
17	HCPC	Gas	1.80	4.66	2,008
18	UCH	Gas	1.80	2.19	1,556
19	ROUSCH	RLNG	1.90	2.27	5,044

Sr.#	Plant Name	Fuel	Fixed O&M ($/Kw/Month)	Variable O&M ($/MWh)	Fuel Cost (cents/Gcal)
20	FKPCL	RLNG	1.80	6.90	4,862
21	SABA	RFO	1.80	1.57	5,277
22	LIBERTY	Gas	1.80	3.04	3,279
23	ALTERN ENERGY LTD.	RLNG	1.80	6.29	5,206
24	Davis Energen	RLNG	1.80	4.72	5,206
25	Attock Gen	RFO	2.34	9.10	4,879
26	Atlas Power	RFO	1.97	8.96	5,357
27	Engro PowerGen	Gas	1.66	3.25	2,227
28	Saif Power	RLNG	1.71	3.65	5,587
29	Orient Power Company Ltd	RLNG	2.31	2.15	5,587
30	Nishat Chunian Power Ltd	RFO	2.04	8.94	5,490
31	Nishat Power Ltd	RFO	2.04	8.96	5,498
32	Foundation Power	Gas	2.17	3.68	2,224
33	Sapphire Electric Co	RLNG	1.65	3.61	5,587
34	Liberty Power Tech Limited	RFO	2.01	9.93	5,270
35	HUBCO Narowal	RFO	1.92	8.32	6,067
36	Halmore Power	RLNG	1.67	3.67	5,587
37	UCH-II	Gas	2.20	1.12	1,988
38	Reshma PowerGen	RFO	2.10	8.08	5,626
39	GULF PowerGen	RFO	2.10	7.62	4,064
40	Sahiwal Power	Imp. Coal	2.13	3.67	2,764
41	QATPL - Bhikki (CC)	RLNG	1.50	3.59	5,044
42	NPPMC - HBS (CC)	RLNG	1.42	3.56	5,044

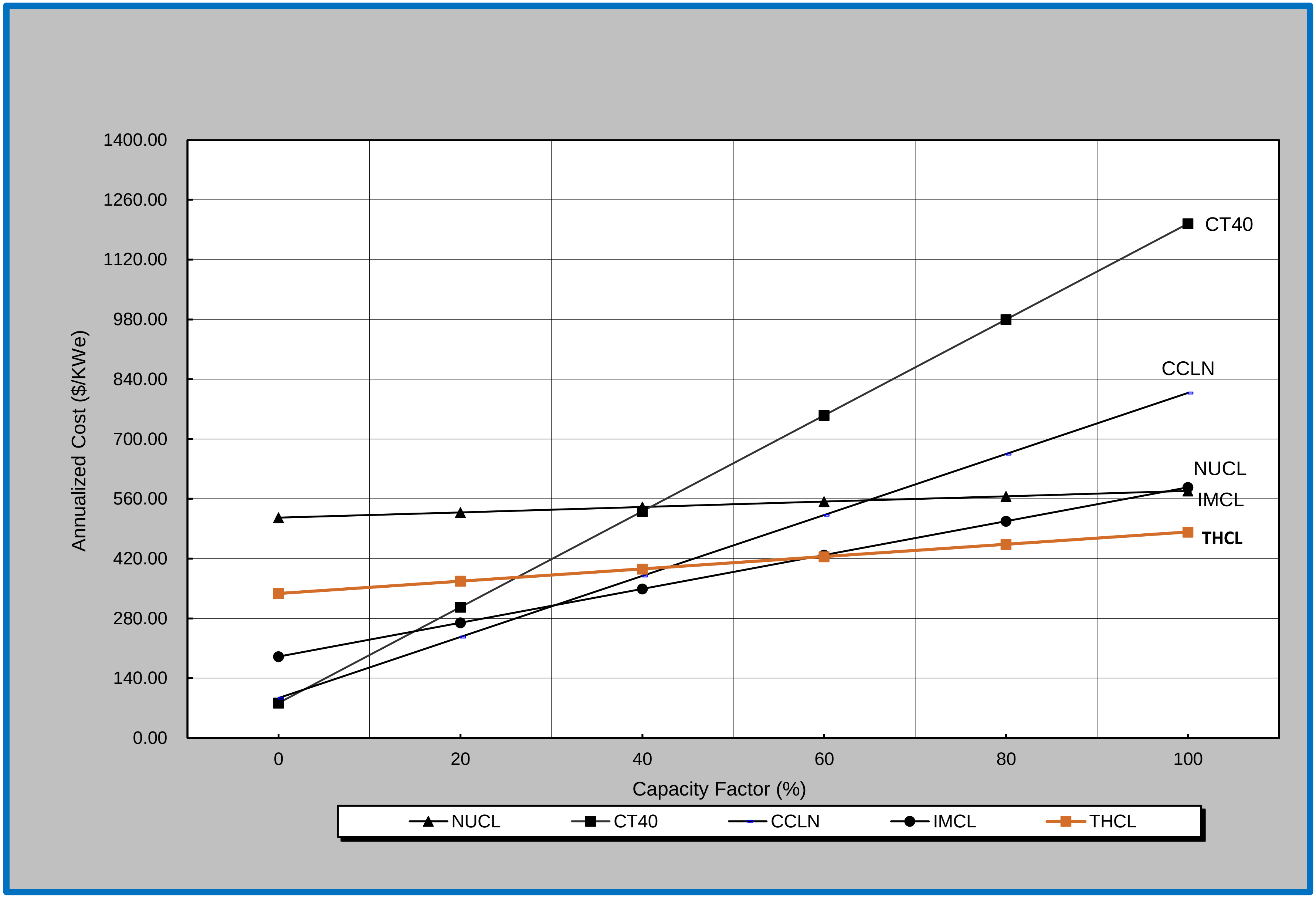
Sr.#	Plant Name	Fuel	Fixed O&M ($/Kw/Month)	Variable O&M ($/MWh)	Fuel Cost (cents/Gcal)
43	NPPMC - Baloki (CC)	RLNG	1.43	3.56	5,044
44	PORT QASIM	Imp. Coal	2.13	3.69	1,884
45	Chashma-I	Nuclear	11.33	0.00	377
46	Chashma-II	Nuclear	11.33	0.00	377
47	Chashma-III	Nuclear	11.33	0.00	430
48	Chashma-IV	Nuclear	11.33	0.00	430
Committed Power Plants					
49	Trimu Jhang	RLNG	1.11	2.89	5,044
50	Hub Imported Coal	Imp. Coal	2.18	3.7	1,884
51	Gawadar Coal Fired PP	Imp. Coal	2.13	3.69	1,884
52	Jamshoro Imported Coal	Imp. Coal	2.13	1.9	1,884
53	Engro Power	Local Coal	15.25	7.53	403
54	Thar Energy (TEL)-HUBCO	Local Coal	15.25	7.53	403
55	Thal Nova	Local Coal	15.25	7.53	403
56	SSRL	Local Coal	14.44	7.53	403
57	Lucky	Local Coal	2.18	3.7	1,442
58	Siddique Sons	Local Coal	15.69	7.16	403
59	Karachi Coastal	Nuclear	5.2	0	305
60	Chashma Nuclear	Nuclear	5.98	0	305

Note: All plant names with red color font indicate that basic data for these plants was not available hence; the data available in the previous planning studies has been utilized.

Annexure B-4: Revised Capital Cost Calculations of Candidate Hydro Power Plants

No.	Name of Project	Installed Capacity (MW)	Energy Generation (GWh)	Construction Period (Years)	Plant Life	Availability Year	Capital Cost without IDC (Million US$)			Capital Cost with IDC (Million US$)			Rev. Dec'18 Capital Cost with IDC (Million US$)		
							Local	Foreign	Total	Local	Foreign	Total	Local	Foreign	Total
1	Matiltan	84	346	4	50	2020	122	65	187	141	65	206	147	70	217
2	Lawi	69	306	5	50	2021	138	41	179	152	45	197	143	48	191
3	Luat HPP	49	214	4	50	2021	21	120	141	47	108	155	44	113	157
4	Harighel HPP	40	231	4	50	2022	57	31	87	70	38	108	67	40	107
5	Jagran-III	35	162	4	50	2022	23	38	61	25	40	65	27	45	72
6	Gumat	50	227	5	50	2023	125	30	155	131	30	161	125	32	157
7	Phander	80	367	3	50	2024	74	58	132	82	64	146	85	69	154
8	Harpo	35	177	4	50	2024	29	53	82	34	61	95	35	66	101
9	Mohmand Dam	800	3,051	6	50	2024	1,675	638	2,314	2,124	638	2,762	1,992	653	2,644
10	Basho	40	153	4	50	2025	53	45	98	67	57	124	53	63	116
11	Azad Pattan	701	3,258	6	50	2026	416	882	1,298	416	1,100	1,516	372	1,134	1,506
12	Ashkot HPP	300	1,197	5	50	2026	314	311	625	314	371	685	293	393	686
13	Kohala	1,124	5,149	7	50	2027	-	2,339	2,339	-	2,760	2,760	-	2,844	2,844
14	Diamer Basha	4,500	18,100	9	50	2027	6,383	4,583	10,966	8,714	4,583	13,297	8,216	4,810	13,027
15	Lower Palas	665	2,581	5	50	2028	492	584	1,076	680	584	1,264	640	613	1,252
16	Lower Spat Gah	496	2,106	5	50	2028	425	463	888	559	463	1,022	577	501	1,078
17	Chakothi-Hittian	500	2,410	5	50	2028	-	1,070	1,070	-	1,176	1,176	-	1,360	1,360
18	Mahl	640	2,934	6	50	2029	-	1,261	1,261	-	1,450	1,450	-	1,522	1,522
19	Pattan	2,400	12,625	6	50	2030	1,561	1,624	3,185	2,239	2,331	4,570	2,106	2,472	4,578
20	Thakot	4,000	21,290	8	50	2030	5,952	3,968	9,920	**7,691**	**5,127**	**12,819**	7,549	5,434	12,984
21	Shyok Dam	640	3,749	6	50	2030	894	481	1,375	1,206	650	1,856	1,092	670	1,762
22	Bunji	7,100	24,212	9	50	2030/2032	5,497	4,379	9,876	9,120	4,379	13,498	9,270	4,740	14,009
23	Taunsa	135	651	4	50	2023	216	157	373	235	171	406	221	179	400

Annexure B-5: Screening Curve for Candidate Thermal Plants



Annexure B-6: Annual Fuel Consumption 2018-40

Year	Gas (BCF)	Imp. RLNG (BCF)	Local Coal (1000 Tonnes)	Imp. Coal (1000 Tonnes)	RFO (1000 Tonnes)
2018	279	359	156	4,962	2,836
2019	279	318	156	6,512	1,472
2020	279	267	3,813	9,565	344
2021	277	215	3,813	9,424	164
2022	234	238	9,169	6,854	111
2023	180	227	10,996	8,391	44
2024	173	217	19,875	7,534	32
2025	136	190	19,868	4,880	8
2026	134	188	19,712	4,612	8
2027	136	203	19,715	5,297	15
2028	90	212	18,782	3,132	0
2029	105	220	19,114	4,052	7
2030	105	220	19,135	4,348	9
2031	59	198	17,858	3,635	0
2032	82	219	19,143	6,271	22
2033	91	59	32,957	9,926	1
2034	94	58	47,335	9,816	3
2035	97	72	58,507	10,572	12
2036	95	64	72,554	10,229	10
2037	91	49	93,416	9,318	13
2038	89	38	114,438	8,280	10
2039	87	53	120,898	8,988	8
2040	85	37	145,341	7,998	7

Annexure B-7: Year-wise Present Worth and Un-Discounted Cost

Year	Present Worth Cost of the Year (K$)						No. of Discounting Years	Un Discounted Cost of the Year (K$)					
	Construction Cost	Salvage Value	Operation Cost	Energy Not Served Cost	TOTAL	OBJ.FUN. (CUMM.)		Construction Cost	Salvage Value	Operation Cost	Energy Not Served Cost	TOTAL	OBJ.FUN. (CUMM.)
2018	-	-	8,648,783	418,452	9,067,235	9,067,235	0.5	-	-	9,070,920	438,876	9,509,796	9,509,796
2019	-	-	6,933,536	104,644	7,038,180	16,105,415	1.5	-	-	7,999,149	120,727	8,119,876	17,629,672
2020	179,246	14,048	5,764,374	4,397	5,933,969	22,039,384	2.5	227,474	17,828	7,315,329	5,580	7,530,555	25,160,227
2021	261,308	23,305	4,756,825	422	4,995,250	27,034,634	3.5	364,777	32,533	6,640,359	589	6,973,192	32,133,419
2022	757,773	37,339	4,372,421	172	5,093,026	32,127,660	4.5	1,163,607	57,336	6,714,119	264	7,820,652	39,954,072
2023	577,643	29,090	3,901,278	49	4,449,880	36,577,540	5.5	975,707	49,136	6,589,716	83	7,516,369	47,470,440
2024	983,259	93,067	3,634,506	25	4,524,724	41,102,264	6.5	1,826,924	172,921	6,753,017	46	8,407,068	55,877,508
2025	5,383,741	785,977	2,915,065	-	7,512,828	48,615,092	7.5	11,003,461	1,606,405	5,957,902	-	15,354,956	71,232,464
2026	1,407,295	235,829	2,617,278	-	3,788,744	52,403,836	8.5	3,163,902	530,194	5,884,203	-	8,517,911	79,750,375
2027	-	-	2,484,238	185	2,484,424	54,888,260	9.5	-	-	6,143,611	458	6,144,071	85,894,446
2028	4,161,750	892,078	2,104,868	4	5,374,544	60,262,804	10.5	11,321,375	2,426,756	5,725,957	11	14,620,587	100,515,033
2029	1,009,921	244,560	2,016,187	61	2,781,608	63,044,412	11.5	3,022,061	731,815	6,033,186	183	8,323,612	108,838,645
2030	1,459,075	398,888	1,851,122	591	2,911,900	65,956,312	12.5	4,802,708	1,312,984	6,093,174	1,945	9,584,843	118,423,488
2031	3,720,494	1,147,532	1,532,792	6	4,105,760	70,062,072	13.5	13,471,063	4,154,952	5,549,891	22	14,866,023	133,289,512
2032	-	(3)	1,592,256	693	1,592,952	71,655,024	14.5	-	(12)	6,341,717	2,760	6,344,489	139,634,000
2033	2,454,422	800,881	1,281,182	30	2,934,752	74,589,776	15.5	10,753,154	3,508,768	5,613,031	131	12,857,544	152,491,544
2034	814,069	320,273	1,307,791	213	1,801,800	76,391,576	16.5	3,923,201	1,543,475	6,302,570	1,026	8,683,322	161,174,866
2035	555,047	250,651	1,350,374	1,734	1,656,504	78,048,080	17.5	2,942,400	1,328,744	7,158,566	9,192	8,781,415	169,956,281
2036	1,120,651	570,597	1,325,699	2,399	1,878,152	79,926,232	18.5	6,534,842	3,327,317	7,730,536	13,989	10,952,050	180,908,330
2037	966,617	571,287	1,315,082	2,940	1,713,352	81,639,584	19.5	6,200,287	3,664,474	8,435,488	18,858	10,990,159	191,898,489

Year	Present Worth Cost of the Year (K$)						No. of Discounting Years	Un Discounted Cost of the Year (K$)					
	Construction Cost	Salvage Value	Operation Cost	Energy Not Served Cost	TOTAL	OBJ.FUN. (CUMM.)		Construction Cost	Salvage Value	Operation Cost	Energy Not Served Cost	TOTAL	OBJ.FUN. (CUMM.)
2038	927,602	625,826	1,303,784	3,600	1,609,160	83,248,744	20.5	6,545,031	4,415,742	9,199,319	25,401	11,354,010	203,252,499
2039	1,199,212	945,870	1,270,883	2,255	1,526,480	84,775,224	21.5	9,307,621	7,341,320	9,863,892	17,502	11,847,695	215,100,194
2040	867,091	761,374	1,258,983	3,052	1,367,752	86,142,976	22.5	7,402,870	6,500,301	10,748,684	26,057	11,677,309	226,777,503

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