National Electric Power Regulatory Authority
Islamic Republic of Pakistan

Registrar

NEPRA Tower, Attaturk Avenue (East), G-5/1, Islamabad
Ph: +92-51-9206500, Fax: +92-51-2600026
Web: www.nepra.org.pk, E-mail: registrar@nepra.org.pk

No. NEPRA/DG(Lic)/LAT-01/ 37702-29 September 24, 2021

Managing Director,
National Transmission & Despatch Co. Ltd. (NTDC)
414 WAPDA House
Shaharah-e-Qauid-e-Azam
Lahore
Tele: 042 - 9920 2229

Subject: **Submission of Revised Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30**

This is in continuation to NTDC's Letter No. MD/NTDC/2377-84 dated September 08, 2021, the Determination of the Authorithy in the subject matter (11 Pages) along with Additional Note of Mr. Tauseef H. Farooqi, Chairman NEPRA (02 Pages) & Dissent Note of Mr. Rafique Ahmad Shaikh, Vice Chairman/Member NEPRA (01 Page) and a copy of the approved IGCEP-2021-30 (130 Pages) are forwarded for your reference and Record. The said documents are also available at NEPRA website (www.nepra.org.pk).

Encl: As above

(Syed Safeer Hussain) 24.09
Registrar

CC:

Secretary Cabinet Division Government of Pakistan Cabinet Secretariat Constitution Avenue, Islamabad	Secretary Ministry of Energy (Power Division) 'A' Block, Pak Secretariat, Islamabad
Secretary Economic Affairs Division 'C' Block, Pak Secretariat, Islamabad	Secretary Ministry of Planning & Development 'P' Block, Pak Secretariat, Islamabad
Secretary Ministry of Privatization Privatization Commission Government of Pakistan 4th Floor, Kohsar Block, New Secretariat, Islamabad Tele: 051 – 920 7197	Secretary Water & Power Government of Gilgit Baltistan Near Kara Kuram International University, Gilgit Tele: 05811 – 920306

Secretary, Energy Department. Government of the Punjab. 8th Floor, EFU House, Main Gulberg, Jail Road, Lahore	Secretary Energy Department Government of Sindh 3rd Floor, State Life Building No. 3, Opposite CM House, Dr. Zai-ud-din Ahmad Road, Karachi
Secretary Energy and Power Department Government of Khyber Pakhtunkhwa, First Floor, A-Block, Abdul Wali Khan Multiplex, Civil Secretariat, Peshawar	Secretary Energy Department Government of Balochistan Civil Secretariat, Zarghoon Road, Quetta
Chief Executive Officer Central Power Purchasing Agency Guarantee Limited (CPPA-G) Shaheen Plaza, 73-West, Fazl-e-Haq Road, Islamabad	Chairman, Water & Power Development Authority (WAPDA) WAPDA House, Shahra-e-Quaid-e-Azam, **Lahore**
Managing Director Private Power and Infrastructure Board (PPIB) Plot No. 10, 2nd Floor, Emigration Tower, Mauve Area, Sector G-8/1, Islamabad	Chief Executive Officer Alternative Energy Development Board (AEDB) 2nd Floor, OPF Building, Sector G-5/2, Shahrah-e-Jamhuriat, Islamabad
Member (Power), Pakistan Atomic Energy Commission, P.O. Box No. 1114, Islamabad	Managing Director, Punjab Power Development Board (PPDB) Old Anarkali, 1st Floor, Irrigation Secretariat, Lahore Tele: 042 - 9921 3878
Chief Executive Officer Pakhtunkhwa Energy Development Organization (PEDO) Government of Khyber Pakhtunkhwa 221-PEDO House, Plot # 38, Sector B/2, Phase-V, Hayatabad, Peshawar Ph: 091-9217446	Chief Executive Officer K-Electric Limited (KEL) KE House, Punjab Chowrangi, 39 – B, Sunset Boulevard, Phase-II Defence Housing Authority, Karachi.
Chief Executive Officer, Faisalabad Electric Supply Company Abdullahpur, Canal Bank Road Faisalabad	Chief Executive Officer, Lahore Electric Supply Company Ltd. 22-A, Queens Road, Lahore

Chief Executive Officer, Gujranwala Electric Power Company Ltd. 565/A, Model Town, G.T. Road, Gujranwala	Chief Executive Officer Multan Electric Power Co. Ltd. MEPCO Headquarter, Khanewal Road, Multan
Chief Executive Officer, Hyderabad Electric Supply Co. Ltd. WAPDA Offices Complex, Hussainabad, Hyderabad	Chief Executive Officer, Peshawar Electric Supply Company WAPDA House, Shami Road, Sakhi Chashma, Peshawar
Chief Executive Officer Islamabad Electric Supply Co. Ltd. Street # 40, Sector G-7/4, Islamabad.	Chief Executive Officer Quetta Electric Supply Company Zarghoon Road, Quetta
Chief Executive Officer, Sukkur Electric Power Company Ltd. Administration Block, Thermal Power Station, Old Sukkur.	Chief Executive Officer Tribal Areas Electricity Supply Company Limited (TESCO) Room No. 213, 1st Floor, WAPDA House, Shami Road, Sakhi Chashma, Peshawar

National Electric Power Regulatory Authority
(NEPRA)

Determination of the Authority
in the Matter of Indicative Generation Capacity Expansion Plan
of National Transmission and Despatch Company Limited

September 24, 2021
Case No. LAT-01

(A). Background

(i). The Authority granted a Transmission Licence-TL No.TL/01/2002, dated December 31, 2002 (as amended from time to time to National Transmission and Despatch Company Limited (NTDC) as National Grid Company (NGC). According to the said licence, NTDC was required to have in place a Grid Code to perform its various function under the above Transmission Licence.

(ii). In consideration of the above, NTDC prepared a Grid Code and the Authority approved the same on June 09, 2005. According to the Planning Code (PC4) of the Grid Code, NTDC is required to prepare and submit a Ten (10) Year Indicative Generation Capacity Expansion Plan (IGCEP), covering 0-10 years' time frame, identifying the new capacity requirement. According to the above approved Grid Code, NTDC was to bring the very first ten (10) Years based IGCEP to NEPRA for approval in the Year 2006. However, NTDC submitted first such IGCEP on April 20, 2020.

(iii). The Authority after internal review conducted a Public Hearing on IGCEP-2020 on July 15, 2020 and returned the same with serious reservations especially in light of objections from provinces and other key stakeholders. The Authority directed NTDC to submit the revised IGCEP after addressing all the reservations as communicated vide letter dated August 20, 2020.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
★ NEPRA ★

(B). Submission & Processing of IGCEP

(i). Instead of revising the IGCEP-2020 in light of the observations of the Authority, NTDC prepared and submitted IGCEP for the period 2021-30 herein called IGCEP-2021-30 vide its letter No. GMT/NTDC/T-48/568-73, dated May 31, 2021 for the consideration and approval of the Authority.

(ii). The Authority considered the matter in its Regulatory Meeting held on June 02, 2021 and decided to seek comments of the general public, affected, interested parties and other stakeholders. Further, the Authority also decided to hold a Public Hearing in the matter. In consideration of the said, a public notice in the matter was published in the press on June 03, 2021 informing about submission of the IGCEP and for submitting comments in the matter before or during the Public Hearing.

(iii). In light of the above, the Authority received comments of around twenty (20) stakeholders including various developers, representative organizations, Govt. Ministries and attached departments. The stakeholders included Saifco Hydropower Limited, Renewable & Alternative Energy Association of Pakistan, Pakistan Renewable Energy Coalition, Sani Power (Private) Limited, Alternative Law Collective, Uzghor Hydro Power Company (Private) Limited, Alternative Energy Development Board, Azad Jammu & Kashmir Power Development Organization, LUMS Energy Institute, Pakhtunkhwa Energy Development Organization, K Electric Limited, Korea South-East Power Company, Sindh Solar Energy Project Energy Department Government of Sindh, Oracle Power PLC, Engro Energy Limited, Ministry of Planning, Development, and Special Initiatives Energy Wing Government of Pakistan, UCH Power (Private) Limited and UCH-II Power (Private) Limited Etc.

(iv). The above stakeholders *inter alia* raised various observations on the set of assumptions approved by Cabinet Committee on Energy (CCoE) for preparation of the IGCEP specially; (a). the criteria for selection of projects as

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
NEPRA

committed ones; (b). submission of IGCEP without Transmission System Expansion Project-TSEP; (c). demand projections; (d). concentration of hydro projects (large hydro and associated issues specially); (e). contradictions with Alternative Renewable Energy-ARE Policy regarding its targets; (f). drastic reduction in utilization of newly commissioned efficient plants; (g). some projects fulfilling the prescribed criteria are missing from the list of the committed projects; (h). huge local projects and environmental concerns; and (i). lack of consultation with relevant stakeholders etc.

(v). The Public Hearing in the matter was held on June 15, 2021 wherein in addition to the sponsors of the above organizations and companies, representatives of NTDC, Central Power Purchasing Agency (Guarantee) Limited and Pakistan Atomic Energy Commission participated and expressed their views highlighting the observations in this regard as explained above. The Authority considered the matter and observed that Council of Common Interest (CCI) in its meeting held on June 21, 2021 *inter alia* had decided that it will be approving the assumptions of the IGCEP. In view of the said, the Authority decided to return the submitted IGCEP to NTDC directing it resubmit the same in light of the above decision of the CCI duly considering the projects (a). having achieved Financial Close or secured financing arrangements; (b). already under construction; (c). having PC-I approved at relevant forum of the Federal and Provincial levels; (d). having generation licence and tariff approved by the Authority; and (e). strategic projects under G2G initiatives.

(C). <u>Submission of Revised IGCEP</u>

(i). In consideration of the above, Ministry of Energy Power Division (MoEPD) decided to initiate consultative sessions with provincial Governments of the federating units as well as Govt. of Gilgit Baltistan and Azad Jammu and Kashmir. Further to the said, MoEPD submitted a summary for the consideration of the CCoE for the approval of the assumptions of the revised IGCEP.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
★ NEPRA ★

Accordingly, CCoE considered the matter in its meeting held on August 26, 2021 and approved the assumption for the preparation of revised IGCEP.

(ii). After the approval of the assumptions of the IGCEP by CCoE, the MoEPD moved a summary to the CCI for the ratification/approval of the assumptions for the IGCEP. CCI considered the matter and approved the same *inter alia* consisting of (a). the provincial public sector projects with approved PC-I(s) with secured financing (as of March 2021) shall be included in "committed projects"; (b). hydel projects shall be included in the definition of Renewable Energy (RE) and the ARE Policy may suitably be amended; (c). historical Gross Domestic Product (GDP) and Consumer Price Index-CPI is obtained from Economic Survey of Pakistan, published by Ministry of Finance, Government of Pakistan; (d). the long-term GDP projections are developed in the light of data provided by Finance Division; (e) sale and prices of electricity are to obtained from Power Distribution Book, June 2020, the annual publication of PEPCO; (f). Planning horizon of the study will be 2021-30 (10 Years) with annual updating; (g). Reserve and Reliability requirements (LOLP = 1%) will be considered as per Grid Code; (h). retirement of existing thermal power plants including GENCOs will be considered as per expiry of contractual term of corresponding PPA(s) and relevant decisions of the CCoE; (i). till the expiry of contractual term of corresponding PPA and GSA, existing RLNG and imported coal based projects will be given a minimum dispatch as per contractual obligations; (j). a project will be input as 'committed' and its capital cost or CAPEX will be not entered in the model, provided the project fulfils at least one of the pre-requisites (i). has obtained LOS as of December 2020 for private sector projects; (ii). for Federal and Provincial public sector projects, the PC-I has been approved and funding secured (as of March 2021). However, Jamshoro Unit-2 and Chashma-5 Nuclear Plants shall be modeled as candidate projects to be evaluated under Least Cost Principle"; (iii). G2G project; Power Generation projects which are listed under Federal Government's international (bilateral or multilateral) commitments, if project/financing agreements signed;

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
NEPRA

(iv). where timelines of completion of a project under G2G are not firmed up yet, the software shall determine the timeline by which such a project must come online based on its tariff optimization with respect to other available options; (v). RE plants (Wind, Solar, Bagasse) enlisted in Category I & II of decision of the CCoE decision dated April 04, 2019; (vi). the on-grid power projects for RE will be according to the ARE Policy 2019 i.e., 20 % by year 2025 and 30% by year 2030 (including net-metering). Further, candidate block will be considered on respective wind/solar/hybrid technologies from the year 2023-24 onwards on least cost principle. The iteration of the revised IGCEP for RE projects will be done under existing targets as per ARE Policy 2019, subject to least cost principle, and including hydro projects in the definition of RE (for the purpose of meeting such targets) to be ratified through an amendment to the ARE Policy 2019 by CCI in due course.

(vi). In consideration of the above, NTDC through its letter No.MD/NTDC/2377-84, dated September 8, 2021 submitted the revised IGCEP in terms of the relevant provisions of the Grid Code for the consideration and approval of the Authority.

(D). Observations/Findings of the Authority

(i). The Authority considered the revised IGCEP and has observed that according to the revised IGCEP, the GDP of Pakistan is expected to grow at a rate of 5.134% annually over the period 2021-30. Due to the said, the peak demand in the year 2030 will be 37,129 MW against 23,792 MW in 2021. Further, the total energy consumption in 2030 is expected to reach 207,418 GWh, against 130,652 GWh in 2021. The current installed capacity of the system is 34,776 MW which will become 61,112 MW in the year 2030. This will include the existing capacity of the system (34,776 MW), addition of the already committed projects of 22,415 MW and candidate projects of 10,062 MW. Further to the said, existing projects of 6,447 MW will be retired on completion of the term of their agreements during the period of the revised IGCEP.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
NEPRA

(ii). The Authority has observed that the revised IGCEP has considered a total of seventy-three (73) committed projects of various technologies including Hydel, Local Coal, Imported Coal, Nuclear and ARE including Wind, Solar, and Bagasse. Further, to the said, the committed projects also include a 1000 MW Cross Border import (CASA Project). The Authority has reviewed the list of the committed projects and has observed that the same includes projects in the Private Sector having LOS, the projects in Public Sector have their PC-I approved and the financing secured which is in compliance with the provisions of the decision of the CCI.

(iii). Further to the above, the Authority has observed that the revised IGCEP has considered a total of 148 projects of various technologies along with different blocks of wind and solar for the optimization of the candidate projects during the period 2024-2030. In this regard, the revised IGCEP has optimized a total of 10,062 MW of Solar and Wind Projects as candidate projects on the criteria of least cost option. In this regard, the Authority feels extremely satisfied that in future over 60% of the installed capacity of Pakistan will be consisting of ARE technologies of Hydel, Wind, Solar and Bagasse. Further, there is emphasis to develop and utilize local coal which will result in increasing its contribution to around 6% by 2030. The dependence on imported coal is likely to reduce from current 11% to around 8% in the year 2030. Similarly, the use of plants running on Furnace Oil/RFO will decrease from the current usage of 19% to only 2% in the year 2030. In view of the said, it is clear that the revised IGCEP is not only based on environment friendly ARE technologies but has also envisaged to utilize other locally available resources, resulting in energy security of Pakistan.

(iv). In consideration of the above, the Authority has observed that existing power plants with expensive or imported fuel will have lower despatch especially with the induction of low cost wind and solar projects during the period 2024-30. The Authority has also observed that some of the existing power plants

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR

using indigenous low BTU gas, will have relatively low despatch due to the induction of the low cost wind and solar power plants. In this regard, OGDCL which is operator of the UCH gas field located in the district of Dera Murad Jamali in the province of Balochistan, has highlighted that this reduction in the plant factor will not be suitable as the aquifer there may overtake the available gas. In this regard, the Authority considers that the indigenous low BTU gas should be utilized in an optimum manner for which necessary coordination between different agencies should be ensured to capitalize on this cheaper natural resource of national importance which has the best utilization in producing cheaper electricity.

(v). Further to the above, the Authority has observed that there is drastic reduction in the plant factor of the newly set up RLNG power plants which are one of the most efficient in their technology and have also been earmarked for privatization. The despatch of these power plants needs to be reviewed so that our highest efficiency plants are utilized to capitalize on fuel savings for reducing the cost of electricity. Same arguments may be considered for the newly commissioned 747 MW Block of TPS Guddu and 525 MW of Nandipur which are also being considered for privatization.

(vi). The Authority has observed that it had granted generation licence and determined tariff for fourteen (14) different projects of Hydro, Wind and Solar to the tune of 820.40 MW which have not been considered in the current iteration of the revised IGCEP. These include five (05) projects of wind with cumulative capacity of 274.40 MW, seven (07) Projects of Solar with installed capacity of 341.70 MW and two (02) Projects of Hydro with installed capacity of 204.30 MW. In this regard, the Authority considers that it had determined the tariff for wind projects, proposed to be located in the province of Sindh , in the range of U.S. ¢ 3.12 – 3.58/kWh, which is the lowest tariff in the history of Pakistan. The solar projects to be set up in the province of KPK had a tariff of the tune of U.S. ¢ 3.95 U.S. cents/kWh which is also very competitive considering the fact that the province of KPK is lower in radiation due to its location as compared to the rest

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR

of the country. Further to the said, one (01) project for solar technology to be located in the province of Punjab has a tariff of U.S. ¢ 3.6414/kWh which is highly competitive.

(vii). Regarding, the two (02) hydro projects (i.e. 102.00 MW Shigo Kas and 102.30 MW Arkari Gol) for which the Authority had determined the tariff, Pakhtunkhwa Energy Development Organization carried out an International Competitive Bidding in which a number of leading companies of the world participated and the award was made to the lowest bidder. However, their tariff was not notified by MoEPD and resultantly the projects could not move ahead despite having a reasonable tariff in terms of their technology. Further to the above, the Authority determined tariff for three (03) projects based on solar technology. Out of the said projects, two projects with a tariff of U.S. ¢ 3.82/kWh are proposed to be located in the vicinity of the proposed Special Economic Zone of Bostan, Balochistan whereas the other one (01) project with tariff of U.S. ¢ 3.7/kWh, is planned to be set up near the port city of Gwadar, Balochistan which is actually the center stage of the whole CPEC initiative.

(viii). The Authority considers that all the above projects should be considered as committed projects as already directed, failing which it will send a very negative message to the market that the cheapest and the greenest projects of Pakistan couldn't see the day light. This will also be extremely detrimental in the context of the proposed Competitive Trading Bilateral Contract Market (CTBCM) targeted to be operational by next year.

(ix). The Authority has a special consideration for the province of Balochistan which currently has the lowest density of electricity, is the least developed in terms of industrialization and has a zero footprint of RE. In view of the said, the Authority is of the considered opinion that two (02) solar projects to be located near the Special Economic Zone of Bostan and one (01) project of Gwadar should be implemented on top priority. The projects located near Special Economic Zone of Bostan, shall not only act as a catalyst for the

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR

industrialization of the province but will also result in attracting more direct investment. The above two (02) solar projects will have a very positive impact on the quality and stability of supply for the Special Economic Zone of Bostan. This is particularly important considering the fact that system of the relevant utility i.e. QESCO is very weak, and system stability and reliability is a grave concern which can only be addressed with the setting up of power plants in the nearby location of the load center of QESCO and the nearby proposed Special Economic Zone. The setting up of these plants will also have a very positive impact on the voltage profile of the area which is particularly critical to run the industrial units proposed to be set up in the Special Economic Zone. Regarding, the project of Gwadar, the Authority considers it extremely critical considering the fact that area of Makran is currently not connected to the National Grid and the only source of supply is from Iran, the quantum of which has drastically reduced due to a number of reasons including the increase of use within Iran. The said situation is causing severe load shedding thus giving rise to serious law and order situation in the area due to shortage in supply of electricity as well as water. In this regard, the Authority has observed that the solar project at Gwadar only requires half a kilometer of transmission line to get it connected to the main transmission line which will also make it the least cost option. It is pertinent to mention that the proposed project is not only in very close proximity to the Gwadar Industrial Grid but can come online in a very short span of 5-6 months and thus can be a source of great help in the stability of the said grid. Further to the said, it is worth stating that the supply from Iran is being purchased at U.S. ¢ 7.5/kWh which is very expensive as compared to the levelized cost of U.S. ¢ 3.7/kWh of the Gwadar project thereby replacing the costly electricity from Iran. In view of the above, the Authority is of the considered opinion that the construction of the above mentioned projects in the province of Balochistan is extremely critical and of paramount importance as it will not only result in stable supply to area(s) but will also result in appearance of the province on the map of RE and therefore must be considered for implementation on top priority basis and must be included in the list of committed projects.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR

(x). The Authority has received comments from the Govt. of Sindh wherein it has been emphasized that various projects of the province (including wind, solar and coal) be considered as committed for this revised IGCEP iteration. In light of the explanation given in the preceding paragraph, the Authority is of the considered opinion that projects for which the tariff had been determined should be considered for implementation on priority. Regarding the observations of the Govt. of Sindh for inclusion of 400 MW solar project at Manjhan, the Authority has considered the provisions of PC-I and other related documentation and has observed that the initial pilot project of 50 MW was considered for implementation in the public sector and the same has already been included in the list of committed in this revised IGCEP. Regarding the observation of the Govt. of Sindh to include the coal project of the Oracle UK, the Authority has considered the relevant documents and has observed that the same is included in the list of priority projects of CPEC. Reportedly, the progress achieved so far is not very encouraging and that caused the removal of this from the list of committed projects. However, the Authority is of the considered opinion that the project can be considered for next iteration of the IGCEP to be carried out in due course of time.

(xi). Further to the above, the Authority has also considered the observations of the Govt. of Khyber Pakhtunkhwa wherein it has been stated that the provincial Govt. had entered into an MoU with the Govt. of South Korea for the development of about 500 MW Lower Spatgah project on PPP mode. The Govt. of Khyber Pakhtunkhwa has already issued the Letter of Intent for the development of the project and the Korean sponsors have already started work on the same to complete the feasibility study of the project. The Authority has considered the above submissions and is of the view that such projects must be given due consideration on merit in the next iteration of the IGCEP as candidate projects.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
NEPRA

(xii). In light of the above, the Authority is pleased to approve Pakistan's first ever IGCEP (i.e. IGCEP 2021-30) in line with the relevant provisions of the applicable Grid Code and based on above observations.

Authority

Engr. Maqsood Anwar Khan
(Member)

Engr. Rehmatullah Baloch
(Member)

Engr. Rafique Ahmed Shaikh (X)
(Member/Vice Chairman)

XX

Engr. Tauseef H. Farooqi
(Chairman)

(X) My dissent is enclosed/attached.

24/9/21

24092

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
NEPRA

XX My additional note attached.

24/9/2021

Additional note of Engr. Tauseef H. Farooqi Chairman NEPRA in the matter of approval of IGCEP 2021-30

The Authority in its meeting held on September 21, 2021 considered the matter for the approval of IGCEP 2021-30 submitted by NTDC, the basic assumptions of which had already been approved by the CCI in its 48th Meeting held on September 06, 2021.

(2). In this regard, myself being the Chairman, Member (KPK) and Member (Balochistan) are of the view that in order to add future power capacity in Pakistan on a scientifically projected demand and supply basis, approval of IGCEP is imperative. However, Mr. Rafique Ahmed Shaikh, Member representing the province of Sindh made certain observations, which I respect, yet I feel these need to be responded for clarification.

(3). In this regard, I would like to highlight that committed projects given in the IGCEP are those projects which are at an advance stage of implementation having approval of the PC-I by their competent forum, issuance of LOS, having firm commitments of funds that has either been arranged through local funding or through multilateral financing institutions like World Bank, Asian Development Bank, OPIC, CPEC and most of them have already gone ahead with the construction. It is due to this very reason that NTDC while preparing the IGCEP did not even consider their CAPEX as an input to the modeling and optimization software called PLEXOS.

(4). In the view of the above, the contention of Member (Sindh) that an upfront financial analysis should have been carried out to determine the deviation of these projects from the least cost principle is not pragmatic. It is worth mentioning that out of the list of 73 committed projects, more than 95% are those for which NEPRA Authority had already granted Generation Licence and issued Tariff Determination after going through a rigorous consultative process. Therefore, re-opening of these cases for the sake of financial viability does not make much sense given that the committed projects have already gone ahead in the implementation phase.

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR

(5). It is worth mentioning that some of the projects which may not be on the least cost but have vital national importance for the overall development of the country. These include multi-purpose dams which will not only provide low cost environment friendly energy/electricity but will help in providing water to the tune of 7.00 MAF which is absolutely essential for the food security of Pakistan. This aspect is particularly important considering the fact that the current storage at Mangla, Tarbela and Chashma has decreased significantly to the tune of 30-40% and we have to make up on urgent basis for this lost capacity which all the federating units will be benefitting from.

(6). I have observed that Member (Sindh) made the observation that necessary public consultation has not been done in the case of IGCEP. In this regard, I would like to highlight that the revised IGCEP which the Authority has now approved, is in fact a continuation of previous version for which Authority not only invited public consultation at a large scale but conducted a full day Public Hearing. Myself and other Members of the Authority except Member (Sindh) are of the considered opinion that objections of the provinces have already been addressed in NEPRA consultative sessions as well as in the meetings at the highest and the most honorable forum of the CCI. Therefore, conducting a fresh Public Hearing will not add any value but seriously undermine the entire approval process of the said august forum.

(7). I wish to also highlight that provinces and other relevant stakeholders have already been consulted at the level of Ministry of Energy (Power Division) and CCoE, therefore, there is absolutely no need to repeat this exercise. It is true that Government of Sindh has written a letter to the Authority wherein it has raised certain observations on the submitted IGCEP which the Authority has already addressed it in its Determination of the IGCEP.

(8). Therefore, I am of the considered opinion that observations made by worthy Member (Sindh) are not tenable and that is why the Authority has approved the IGCEP-2021-30 with majority as stipulated in the NEPRA Act.

(Engr. Tauseef H. Farooqi)
(Chairman)
NEPRA

24/9/2021

NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
REGISTRAR
NEPRA

Power sector of Pakistan is under burden of heavy circular debt which has already reached to more than Rs. 2.3 trillion till to date. Over the last few years, the power purchaser and other stakeholders are of the view that Pakistan is in a **"capacity trap"** and for this reason, the tariffs of several renewable projects, which were determined by the Authority on least cost basis, were not notified.

To combat with the situation of increasing circular debt and coming out of the menace of capacity trap, the regulator is striving to explore the options of cleaner and **"inexpensive energy"** while focusing their efforts on developing market oriented power sector by pursing a shift of regime from "take or pay" to **"take and pay"** while balancing demand and supply, powered by Indicative Generation Capacity Expansion Plan (IGCEP).

In view of the importance of IGCEP for financially viable power sector, it is fundamental that IGCEP should be developed with the accurate data and after detailed financial analysis so that any possible financial burden on power sector could be avoided. The importance of first IGCEP in the power market to be operational in April, 2022 becomes more important, therefore, processing and approval of the IGCEP requires detail due diligence as well as consultation from all stakeholders. The financial burden of leaving the least cost generation capacity should not only be calculated but their reason should also be recorded while developing the IGCEP so that informed decision could be made. NTDC has submitted the IGCEP earlier twice. In processing of the submitted IGCEP, NEPRA consulted with all stakeholders through public hearing and as result of consultation, NEPRA reached an informed decision and the submitted IGCEP was returned un-approved by the NEPRA twice mainly for the reasons that proposed generation capacity addition was not optimized commercially based on **"least-cost principles"**.

It is relevant to mention that NEPRA Rules, Regulations, Code etc. emphasize on induction of the generation capacity on least cost; though, there may be an exception for the strategic projects. The importance of least cost generation induction has also been acknowledged in the National Electricity Policy 2021 (the Policy), approved by Council of Common Interests, which state that in case of strategic projects, the relevant sponsoring Government shall provide the funding to bridge the incremental cost (beyond least cost) of any such project.

The minutes of the CCI meeting were issued on September 13, 2021. In the meantime, on September 06, 2021, Ministry of Energy (Power Division) directed NTDCL to prepare the IGCEP on assumptions approved by CCI for its submission to NEPRA. The NTDCL submitted the revised IGCEP before Regulator vide letter dated September 08, 2021.

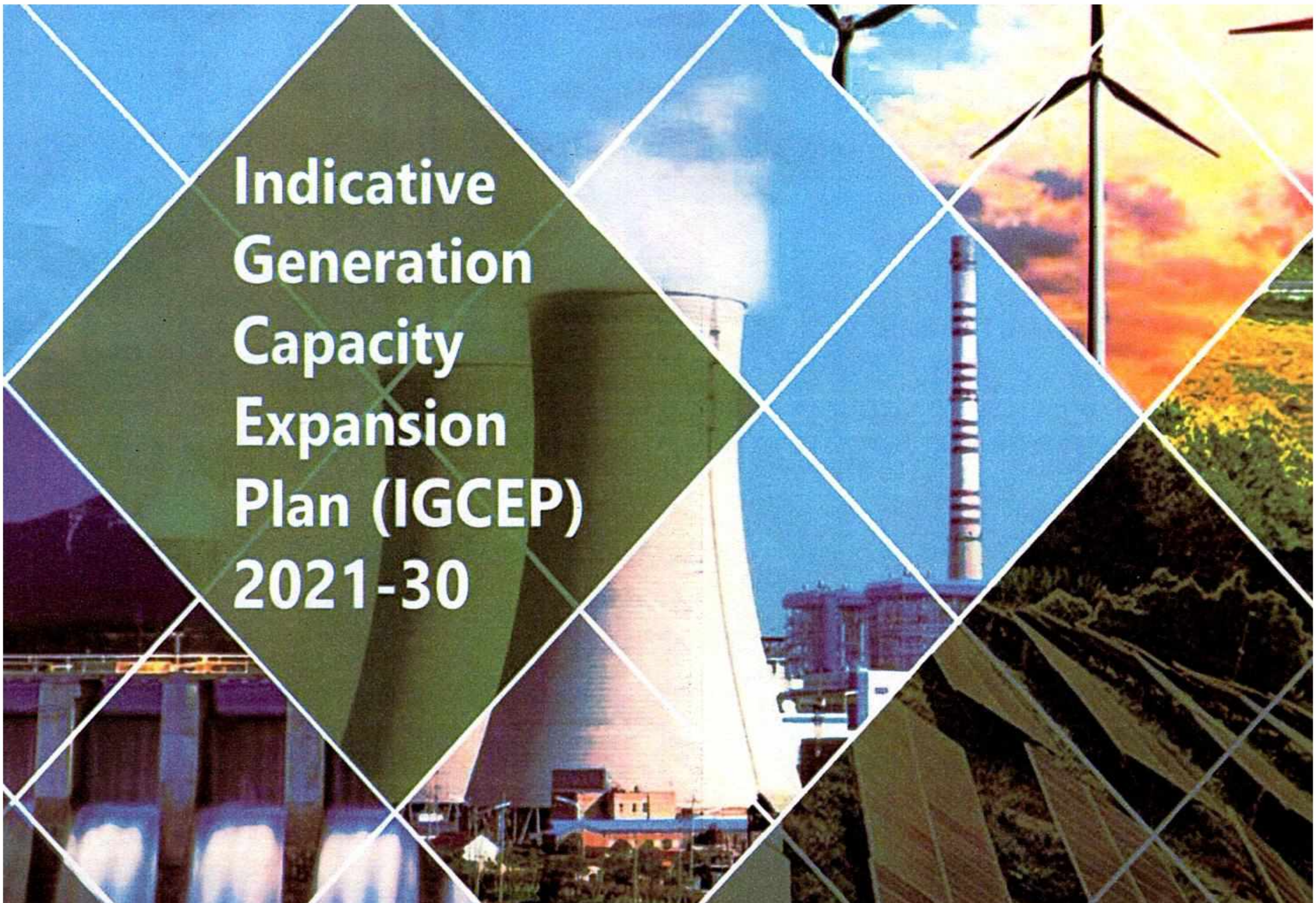
NEPRA received a letter dated September 12, 2021 from Minister of Energy, Government of Sindh whereby the concerns were raised that the revised IGCEP has not been developed on least cost basis as several costlier projects have been taken into committed list. The Energy Minister, Sindh also stated the potential financial implications for those committed projects, in the said letter minister also urged and requested the Authority for public consultation and informed decision making.

Later, on September 17, 2021, Chief Secretary, Government of Sindh conveyed the dissent of Chief Minister of Sindh stating that the committed projects in the IGCEP do not fulfill the criteria of least cost principle. It was stated in the letter that the CCI decision was taken by majority and not by unanimity. In conclusion of the letter, it is mentioned that being aggrieved with the referred decision, which will have far reaching implications for the entire nation, the Government of Sindh will be presenting this matter before the joint sitting of the Parliament under Article 154(7) of the Constitution and until the decision is taken by the Parliament, it is requested that the said Policy is not brought into force.

Furthermore, some of the stakeholders also approached NEPRA and other entities, highlighting that the IGCEP is supporting expensive electricity which will cost huge loss to national exchequer in coming years.

The approval of the CCI to the assumptions of the revised IGCEP does not stop the Authority from carrying out the due diligence in the matter rather the already approved Policy adds emphasis for the due diligence of the IGCEP. Therefore, I am of the considered opinion that **"the revised IGCEP cannot be approved"** without having the financial analysis and the prudent practice of consulting the stakeholders. Further, it also considers appropriate that such financial analysis should also have been presented before the CCI for informed decision making.

NER REGULATORY AUTHORITY
GISTRAR



Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30

SEPTEMBER 2021

Driven by the Future

Load Forecast and Generation Planning
Power System Planning
National Transmission and Despatch Company, Pakistan

Indicative Generation Capacity Expansion Plan

IGCEP 2021-30

(Revised)

September 2021

Driven by the Future

Power System Planning
National Transmission and Despatch Company

Acknowledgements

Commissioning of a study and preparation of a country wide power generation plan, such as the IGCEP, rely extensively on the input data provided by a wide range of stakeholders. In case of IGCEP 2021-30, these stakeholders include Pakistan Atomic Energy Commission (PAEC), Alternative Energy Development Board (AEDB), National Electric Power Regulatory Authority (NEPRA), Private Power Infrastructure Board (PPIB), Pakhtunkhwa Energy Development Organization (PEDO), Punjab Power Development Board (PPDB), Sindh Energy Board, Sindh Transmission & Dispatch Company (STDC), Azad Jammu & Kashmir Private Power Cell (AJKPPC), Azad Jammu & Kashmir Power Development Organization (AJKPDO), Central Power Purchasing Agency-Guarantee (CPPA-G) and Water and Power Development Authority (WAPDA); this output could have not been materialized without the contribution by these stakeholders.

The IGCEP has also been benefited from advice, suggestions, and value addition from various entities including Ministry of Energy (Power Division), CPPA-G and various power sector professionals.

The LF&GP-PSP Team is, therefore, highly grateful to all those who have contributed for the preparation, revision and finalization of the IGCEP 2021-30.

Disclaimer

This Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30 is prepared by NTDC under the obligations set in the chapter Planning Code of the Grid Code, major regulatory instrument for NTDC. The plan, as mentioned in its name, is indicative in nature, to be reviewed and approved by NEPRA – the electricity regulator, and is to be updated every year. The IGCEP 2021-30 is developed to thereafter enable project executing entities for procurement of power from generation facilities from both public and private sectors subject to the fulfillment of other pre-requisites; NTDC to formulate its Transmission System Expansion Plan and Transmission Investment Plan; and assist policy makers for aligning the prevailing policies with the ongoing challenges and/or technological advancements.

The information contained herein exclusively does not make the power sector stakeholders including NTDC and CPPA-G liable to inter-alia procure power, allow commissioning of future power plants, regulate electricity tariff, perform economic dispatch of electric power and determine targets of any sort for the power sector of Pakistan. Confirmation of any new generation project(s) other than the committed ones for future implementation and procurement would only be made subject to its evacuation scheme included in the upcoming NTDC's Transmission System Expansion Plan based on the IGCEP 2021-30 and applicable policies, rules, regulations and SOPs. It is further highlighted that not all candidate projects may possibly be evacuated owing to technical and/or economic viabilites and/or higher cost which may not leave it as part of the least cost scheme; activities subsequent to IGCEP may therefore lead to certain changes for the candidate projects optimized by the generation planning tool, PLEXOS.

The IGCEP 2021-30 has been prepared based on the proprietary input data provided by various entities, reference data/practices of international entities, tariff determinations by NEPRA, etc. NTDC, is in no way responsible for the integrity of any such data considered for the IGCEP 2021-30.

Any other party using this plan for any purpose, or relying on this plan in any way, does so at its own risk. No representation or warranty, express or implied, is made in relation to the accuracy or completeness of the information presented herein or its suitability for any particular purpose.

Copyrights © NTDC 2021. All rights reserved.

List of Contents

Acknowledgements i

Disclaimer ii

List of Contents iii

List of Figures vii

List of Charts viii

List of Tables ix

List of Acronyms x

Stakeholder Entities xiv

Foreword xvi

Executive Summary xvii

1. Setting the Perspective 1

1.1. Generation Planning – A Subset of Power System Planning 1

1.2. Preamble 2

1.3. Introduction 2

1.4. Objectives of the IGCEP 3

1.5. Scope and Planning Horizon 3

1.6. Nature of the IGCEP 4

1.7. Rationale for Preparation of the IGCEP 4

2. Power System of Pakistan 9

2.1. Economics of Pakistan Power Sector 9

2.2. Power Generation 9

2.3. Power Distribution 11

3. The IGCEP Methodolgy 17

3.1. Regulatory Compliance 17

3.2. Data Collection Process 17

3.3. The IGCEP Data Sources and Associated Data Types 17

3.4. Financial Parameters 19

3.5. The IGCEP Preparation Process Map 19

3.6. Criteria and Other Important Considerations for the IGCEP 19

3.6.1. Planning Timeframe 19
3.6.2. Economic Parameters 19
3.6.3. Generation System Reliability 20
3.6.4. Hydrological Risk 20
3.6.5. Renewable Energy (RE) Generation 20
3.6.6. System Reserve Requirement 20
3.6.6.1. Contingency Reserve 20
3.6.6.2. Secondary Reserve 21
3.6.7. Scheduled Maintenance of the Generation Projects 21
3.6.8. System Load Characteristics 21
3.6.9. Fuel Prices Indexation 21
3.6.10. CAPEX of Renewable Energy Technology 22
4. Long Term Energy and Demand Forecast 27
4.1. Energy and Power Demand Forecast 27
4.2. Long-Term Demand Forecasting Methodology 27
4.3 Data Sources 28
4.4 Key Considerations 28
4.4.1 Demand Side Management 28
4.4.2. Power Export to K Electric 29
4.4.3. Load Management 29
4.5. Preparation of Demand Forecast 29
4.6. Demand Forecast Numbers 31
4.7. Hourly Demand Forecast 32
5. Inside the IGCEP 35
5.1. Introduction 35
5.2. Assumption Set approved by CCI 35
5.3. Adherence to Contractual Obligations 37
5.4. Approach and Methodology 37
5.5. Planning Basis 38
5.6. Existing Power Generation of Pakistan 38
5.7. Retirement of Existing Power Plants 39
5.8. Committed Generating Units 40
5.8.1. Committed Projects 41

5.9. New Generation Options 45
5.10. Hydro Projects and Screening 46
5.11. Performance Characteristics of Generic Thermal Candidates 46
5.12. Economic Parameters of the Candidate REs 48
6. The IGCEP Study Output 51
6.1. Introduction 51
6.2. Future Demand and Capacity Additions 51
6.3. Annual Capacity Factors 63
6.4. Year-wise Discounted and Un-Discounted Cost 69
6.5. Indigenization of Energy Mix 70
6.6. Clean and Green Power for Pakistan 71
6.7. Salient Features of the IGCEP 72
6.8. Strategy for Feedback 79
7. The Way Forward 83
7.1 Must Do Actions for the Future Generation Plans 83
7.2 Making Way for the High Share of Renewables in the Grid 83
7.2.1 Hybridization of Variable Renewable Energy Projects 83
7.2.2 Upcoming Wind Power Projects 84
7.3 Future is Here - Time to Understand, Accept and Adopt the New Norms 84
7.4 Focusing on Indigenization through Harnessing the Potential of Local Coal 86
7.5 Thinking, Synergizing and Enhancing the Vision Beyond the Borders 86
7.6 Preparation and Submission of TSEP alongwith IGCEP 87
Annexure A. Load Forecast Data 97
A-1. Projected GDP Growth by Sector 97
A-2. Historical GDP at Factor Cost Constant 2005-06, Consumer Price Index 97
A-3. Category-Wise Nominal Tariff 100
A-4. Category wise Real Tariff 101
A-5. Electricity Consumption by Category (Excluding K Electric) 102
A-6. Category Wise Number of Consumers (Exclduing K Electric) 104
Annexure B. Generation Planning Data 106
B-1. Existing Installed Capacity (As of September 2021) 106
B-2. Cost Data of Existing, Committed and Candidate Thermal Plants 110
B-3. Indexed Capital Cost Calculations of Candidate Hydro Power Plants 114

B-4. Screening Curve for Candidate Thermal Plants 122
B-5. Annualized Cost of Candidate Hydro Power Plants 123

List of Figures

Figure 1-1: Planning Cycle Leading to Procurement 1

Figure 1-2: The IGCEP Objectives 3

Figure 3-1: The IGCEP Preparation Process 19

Figure 4-1: Process Flow of Methodology of Long-Term Demand Forecast 28

Figure 5-1: The IGCEP Data Modelling Approach 37

Figure 5-2: Committed Projects Criteria 40

Figure 6-1: IGCEP 2021-30: Generation Sequence (2021-30) 55

List of Charts

Chart 2-1: GDP (million PKR) vs Sale of Electricity (GWh) 9

Chart 2-2: Installed Capacity (MW) as of September 2021 10

Chart 2-3: Annual Energy Generation (GWh) as of 2020-21 10

Chart 2-4: Historical Annual Energy Generation (GWh) from 2013-14 to 2020-21 11

Chart 2-5: Historical Peak Electricity Demand (MW) from 2013-14 to 2020-21 11

Chart 2-6: Percentage Mix of Number of Electricity Consumers 12

Chart 2-7: Percentage Mix of Category-wise Sale (GWh) of Electricity 12

Chart 4-1 Peak Demand (MW) Forecast 2021-2030 32

Chart 4-2: Load Duration Curve (2025 & 2030) 32

Chart 5-1: Fuel-wise Generation Mix (MW) as of September 2021 38

Chart 6-1: Installed Capacity vs Peak Demand (MW) 2021-30 51

Chart 6-2: Annual Energy Generation vs Annual Energy Demand (GWh) 2021-30 52

Chart 6-3: % wise Share of Total Installed capacity (MW) - 2030 53

Chart 6-4: IGCEP 2021-30 Indigenization Ratio of Primary Energy 71

Chart 6-5: IGCEP 2021-30 Annual CO_2 Emission and Emission per Unit of Generation 72

Chart 6-6: The IGCEP Generation Mix 2021 (MW) 74

Chart 6-7: The IGCEP Generation Mix 2025 (MW) 74

Chart 6-8: The IGCEP Generation Mix 2030 (MW) 75

Chart 6-9: The IGCEP Generation Mix 2021 (GWh) 75

Chart 6-10: The IGCEP Generation Mix 2025 (GWh) 76

Chart 6-11: The IGCEP Generation Mix 2030 (GWh) 76

Chart 6-12 The IGCEP Monthly Generation Mix 2021-25 (GWh) 77

Chart 6-13: The IGCEP Monthly Generation Mix 2026-30 (GWh) 78

List of Tables

Table E1: Summary of Load Forecast (2021-30) xvii

Table E2: Summary of Installed Capacity (MW) by 2030 xix

Table E3: Summary of Energy Generation (GWh) by 2030 xix

Table 3-1: Fuel Price Indexation Factors 21

Table 3-2: CAPEX Indexation of Solar and Wind Based Technologies 22

Table 4-1: NEECA Energy Efficiency Targets 29

Table 4-2: Description of Dependent and Independent Variables 30

Table 4-3: Annual Long-Term Energy and Power Demand Forecast 31

Table 5-1: Generation Planning Criteria 38

Table 5-2: Retirement Schedule of Existing Power System 39

Table 5-3: List of Committed Projects 41

Table 5-4: Performance Characteristics of Generic Thermal Power Plants 46

Table 5-5: Economic Parameters of Generic Power Plants 47

Table 5-6: Economic Parameters of Candidate Wind and Solar Blocks 48

Table 6-1: Candidate Generation Capacity Additions (2021-30) 54

Table-6-2: Break-up of Blocks for Hydro, Solar, Wind and Bagasse Power Plants 56

Table 6-3: PLEXOS Annual Addition of Power Plants 2021-30 58

Table 6-4: Annual Capacity Factors (%age) 63

Table 6-5: Year wise Discounted Cost 69

Table 6-6: Year wise Un-Discounted Cost 69

Table 6-7: Year wise Installed Capacity Addition (MW) 73

List of Acronyms

Acronym	Description
$/GJ	US Dollar per Giga joule
$/kW	US Dollar per kilowatt
$/MWh	US Dollar per Mega Watt hour
ACGR	Annual Compound Growth Rate
ADB	Asian Development Bank
AEDB	Alternative Energy Development Board
AGL	Attock Generation Limited
Agr	Agriculture
AJKPDO	Azad Jammu & Kashmir Power Development Organization
AJKPPC	Azad Jammu and Kashmir Private Power Cell
ARE	Alternative and Renewable Energy
AT&C	Aggregate Techical & Commercial
BCF	Billion Cubic Feet
BESS	Battery Energy Storage System
c/Gcal	Cents per Giga calorie
c/kWh	Cents per Kilowatt hour
ckm	Circuit Kilo Metre
CAPEX	Capital Expenditure
CASA	Central Asia South Asia
CCGT	Combined Cycle Gas Turbine
CCI	Council of Common Interests
CCoE	Cabinet Committee on Energy
CFPP	Coal Fired Power Project
COD	Commercial Operation Date
Com	Commercial
CPEC	China Pakistan Economic Corridor
CPI	Consumer Price Index
CPPA-G	Central Power Purchasing Agency – Guarantee
Cumm.	Cumulative
Cus.	Customer
DISCO	Distribution Company
DOM	Domestic
DSM	Demand Side Management
EIA	US Energy Information Agency
EOI	Expression of Interest
EPA	Energy Purchase Agreement
EV	Electric Vehicle
FC	Financial Closure
FCC	Fixed Cost Component
FESCO	Faisalabad Electric Supply Company
FKPCL	Fauji Kabirwala Power Company Limited
FS	Feasibility Studies

Acronym	Description
G.R.	Growth Rate
G/s	Grid Station
G2G	Government to Government
GDP	Gross Domestic Product
GENCOs	Generation Companies
GEPCO	Gujranwala Electric Power Company
GoP	Government of Pakistan
GoS	Government of Sindh
GT	Gas Turbine
GTPS	Gas Thermal Power Station
GWh	Gigawatt-hour
HCPC	Habibullah Coastal Power Company
HESCO	Hyderabad Electric Supply Company
HFO	Heavy Furnace Oil
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
Ind	Industry
IPP	Independent Power Producer
JICA	Japan International Corporation Agency
K2	Karachi Coastal Nuclear Unit 2
KAPCO	Kot Addu Power Company
kcal/kWh	kilo calorie per Kilowatt hour
KE	K-Electric
KKI	KANUPP Karachi Interconnection
KPI	Key Performance Indicator
KPK	Khyber Pakhtunkhawa
kV	kilo volts
LCP	Least Cost Plan
LED	Light Emitting Diode
LESCO	Lahore Electric Supply Company
LF&GP-PSP Team	Load Forecast and Generation Planning of Power System Planning, NTDC
LNG	Liquified Natural Gas
LOI	Letter of Intent
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability

Acronym	Description
LOS	Letter of Support
LT	Long-term
M/s	Messers
MEPCO	Multan Electric Power Company
MEPS	Minimum Energy Performance Standards
MoPD & R	Ministry of Planning Development & Reforms
MT	Medium Term
MVA	Mega volt ampere
MW	Megawatt
NEECA	National Energy Efficiency and Conservation Authority
NEPRA	National Electric Power Regulatory Authority
NPCC	National Power Control Center
NPHS	Naya Pakistan Housing Scheme
NPP	National Power Plan
NPSEP	National Power System Expansion Plan
NTDC	National Transmission and Despatch Company
O&M	Operation and Maintenance
OECD	Organization for Economic Coorporation and Development
OLS	Ordinary Least Squares
PAEC	Pakistan Atomic Energy Commission
PASA	Projected Assessment System Adequacy
PC	Planning Code
PEDO	Pakhtunkhwa Energy Development Organization
PEPCO	Pakistan Electric Power Company
PESCO	Peshawar Electric Supply Company
PITC	Power Information Technology Company
PKR	Pakistan Rupee
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
RFO	Residual Furnace Oil
RLNG	Re-gasified Liquid Natural Gas
ROR	Run of the river
RP	Resource Planning
Rs./kWh	Rupees per Kilowatt hour
RTPSS	Real Time Power System Simulator
SCADA	Supervisory Control & Data Acquisition
SEPCO	Sukkur Electric Power Company
SS	System Studies
SSRL	Sino Sindh Resources Limited
STs	Steam Turbines

Acronym	Description
T&D	Transmission and Distribution
TEL	Thar Energy Limited
TESCO	Tribal Electric Supply Company
TRP	Transmission Planning
TSEP	Transmission System Expansion Plan
TWh	Terawatt hour
USA	United States of America
USAID	United States Agency for International Development
VRE	Variable Renewable Energy
WAPDA	Water and Power Development Authority
WPP	Wind Power Project

Stakeholder Entities

Stakeholder Entities	Cyber Link
Alternative 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/
International Monetary Fund	https://www.imf.org/en
Islamabad Electric Supply Company (IESCO)	http://www.iesco.com.pk/
K-Electric (KE)	https://www.ke.com.pk/

Stakeholder Entities	Cyber Link
Lahore Electric Supply Company (LESCO)	http://www.lesco.gov.pk/
Multan Electric Power Company (MEPCO)	http://www.mepco.com.pk/
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) 2021-30" presents the results of the latest expansion planning studies conducted by the Load Forecast and Generation Planning (LF&GP) team of Power System Planning (PSP), National Transmission and Despatch Company (NTDC) as per the criteria specified in the Assumption Set approved by Cabinet Committee on Energy (CCoE) and Council of Common Interests (CCI) on 26th August & 6th September, 2021 respectively.

This report facilitates a comprehensive view of the future electricity demand forecast, existing generating system and future power generation options in addition to the expansion study results. It is pertinent to highlight that annual updating of this plan remains 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 list of stakeholder entities who have shared the input data for the IGCEP; software tools used; 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.

I am extremely pleased to share that IGCEP 2021-30 has been prepared through the exclusive efforts of NTDC professionals precisely the LF&GP-PSP Team. This team is young yet upbeat and committed to continue learning, delivering and growing. In view of their enthusiastic willingness to learn and contribute in the best interest of NTDC and Pakistan, I envisage this team, in a short span of time, to shape into a bench of professionals complementing towards securing and sustaining self-sufficiency in terms of outputs at par with the international standards.

Farooq Rashid

Engr. Farooq Rashid
Chief Engineer, Load Forecast and Generation Planning
National Transmission and Despatch Company

September, 2021

Executive Summary

Pursuant to the provisions of the National Electric Power Regulatory Authority (NEPRA) Grid Code i.e., Planning Code (PC) – 4 and PC 4.1, National Transmission and Despatch Company (NTDC) has prepared Indicative Generation Capacity Expansion Plan (IGCEP) 2021-30 covering 0 – 10 years time frame i.e., from 2021 to 2030 encapsulating power generation additions required to meet the future energy and power demand of NTDC system.

The report presents the results of the generation capacity expansion planning study carried out by Load Forecast and Generation Planning (LF&GP) team of Power System Planning (PSP), NTDC.

This generation planning study is composed of two key processes: 1) Load forecast; followed by 2) Generation capacity expansion and despatch optimization. Both processes involve complex statistical and computation efforts performed using dedicated softwares.

Table E1 shows a summary of the forecast results for the horizon 2021 to 2030.

Table E1: Summary of Load Forecast (2021-30)

Year	Normal	
	Energy	Peak Demand
	GWh	MW
2020-21	130,652	23,792
2023-24	159,319	28,027
2026-27	181,834	32,276
2029-30	207,418	37,129
ACGR 2021-30	**5.27%**	**5.07%**

The least cost, long-term generation expansion plan for NTDC system for the period 2021 to 2030 is developed using generation planning software - PLEXOS. The IGCEP 2021-30 is developed through a rigorous data modelling and optimization exercise based on the existing and future generation power plants, existing policy framework, existing contractual obligations, natural resource allocations, relevant provisions of Grid Code, CCI approved Assumption Set.

For the study, 6,447 MW of existing power generation capacity is retired during the plan horizon.

Catering to the software pre-requisites, hourly demand forecast is developed specially to account for the intermittency of variable renewable energy resources such as wind and solar.

The results show that to meet a demand of 37,129 MW by the year 2030, a generation capacity of 61,112 MW is proposed, which include utilization of existing generation facilities, consideration of committed power plants and optimization of candidate power plants by the tool. It is to highlight that to meet the demand by the year 2030, the share from variable renewable energy (VRE) resources stands out to be 7,932 MW, 5,005 MW and 749 MW of Solar, Wind and Bagasse, respectively.

Salient features of this plan include i) inclusion of VREs; ii) Minimal reliance on imported fuels i.e. imported coal, Re-gasified Liquid Natural Gas (RLNG) and Residual Furnace Oil (RFO) based technologies; and iii) increased share of hydropower as well as local coal. Inclusion of VREs, hydro and Thar coal will help in lowering the basket price of the overall system thus providing much needed relief, though in the long run, to the end consumers.

Figure E1: Summary of Results

The self-sufficient ratio of primary energy i.e. the contribution of energy generation by indigenous power sources stands at 60% in the year 2021, where, as per results, indigenization of energy generation is envisaged to achieve 90.8% by 2030 which corresponds to higher energy security in the country.

Similarly, the IGCEP 2021-30 also addresses the impact of carbon emissions due to addition of power generation in future. Carbon emissions in the country by power generation accounts for 0.356 kg-CO_2/kWh in the year 2021 and this indicator reduces to 0.198 kg-CO_2/kWh by 2030 which is even less than average of Organization for Economic Co-operation & Development (OECD) countries.

It is evident from the results of the simulation that during the coming five years, the contribution of gas fired power plants in the generation mix (GWh) will decrease from present 15% to mere 6%. Similarly, with the induction of new local coal based committed power plants in Thar, during the next 5 years, share of local coal in the generation mix will enhance to 15%;

The RLNG based plants, though installed and available are envisaged to have a decreasing share in the energy mix from 2021 to 2030 i.e. from 18% to 2% in 2025 and then eventually falling nearly to 0% in 2030. Similar trend is there for imported coal-based plants whose contribution in the overall generation mix falls from 21% in 2021 to only 9% by the year 2030. Moreover, the share of solar and wind in the overall energy mix increases from about 3% in 2021 to 16% in 2030. Tables E2 & E3 show the Installed Capacity (MW) & Energy Generation (GWh) respectively by year 2030.

Table E2: Summary of Installed Capacity (MW) by 2030

Technology	Installed Capacity (MW)
Imported Coal	4,920
Local Coal	3,630
RLNG	6,786
Gas	2,582
Nuclear	3,635
Bagasse	748.6
Solar	7,932
Hydro	23,653
Cross Border	1,000
Wind	5,005
RFO	1,220
Total (MW)	**61,112**

Table E3: Summary of Energy Generation (GWh) by 2030

Technology	Energy Generation (GWh)
Imported Coal	18,448
Local Coal	23,145
RLNG	686
Gas	5,623
Nuclear	24,910
Baggase	3,380
Solar	15,916
Hydro	94,649
Cross Border	3,436
Wind	17,225
RFO	-
Total (GWh)	**207,418**

The overall generation capacity in the system increases from 34,776 MW in 2021 to 61,112 MW in 2030. Major increase in the capacity is observed in the hydropower, solar and wind plants. New solar and wind plants are optimized by PLEXOS being cheaper source of energy. This results in the capacity addition of 7,000 MW of solar & 3,062 MW of Wind up till 2030.

PLEXOS also computes Net Present Value (NPV) of the power generation operations and investments of existing and future power plants by 2030, based on the objective function for the optimization exercise. The total NPV of investment required to manage generation infrastructure construction and operations by 2030 is 39.2 Billion US $. It is pertinent to mention that NPV includes CAPEX and OPEX. It is pertinent to mention here that the total NPV cost neither includes the existing capacity payments nor the CAPEX of committed plants.

The generation planning exercise demands extensive data collection and strenuous efforts to streamline access to data for future exercises pertaining to forecasting and generation capacity expansion and despatch optimization. The team look forward to proactive response by the input data providing entities for this purpose.

The IGCEP 2021-30 also facilitates a food for thought through 'The Way Forward' with respect to structural changes in the power sector planning process with enhanced role of distributed generation and reduction in the large plants distant from the load centers. Further, indigenization of RE technologies through local manufacturing is also suggested to lower the basket price and thus providing a relief to the end consumer as well as saving precious foreign exchange while maximizing the utilization of nature's endowment bestowed upon Pakistan.

1. SETTING THE PERSPECTIVE

1. Setting the Perspective

1.1. Generation Planning – A Subset of Power System Planning

Power system planning is an important 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.

Generation expansion planning concerns decisions for investment pertaining to development of different types of power plants over the long-term horizon – 10 years for IGCEP 2021-30. The goal of this plan is to improve decision-making under different long-term uncertainties while assuring a robust generation expansion plan with least cost and minimum risk.

As depicted in the Figure 1-1, generation planning is at the heart of planning cycle. In an idealistic scenario, the Integrated Energy Plan (IEP), a mandate of Ministry of Planning, Development and Special Initiatives 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 natural resource allocation targets for power generation, 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.

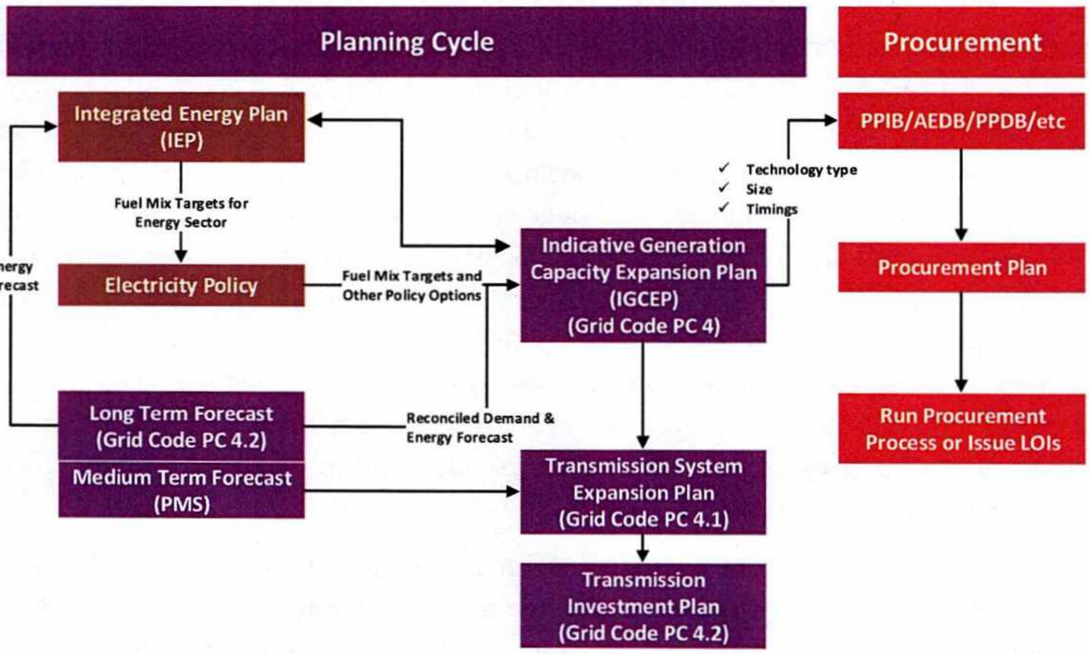


Figure 1-1: Planning Cycle Leading to Procurement

1.2. Preamble

Looking back at the relevant previous milestones, following five (05) major generation expansion plans have been formulated by the then WAPDA and now NTDC with the assistance of foreign/local consultants coupled with in-house efforts:

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;
c. Least Cost Plan (LCP 2016-2035) developed by Japanese Consultant, M/s International Institute of Electric Power, Ltd. (IIEP); and
d. Indicative Generation Capacity Expansion Plan (IGCEP) 2040
e. Indicative Generation Capacity Expansion Plan (IGCEP) 2047

In compliance to the directions of the Authority, NTDC developed and submitted the IGCEP 2021-30 in May 2021, based on the Assumption Set approved by CCoE dated 22nd April 2021. However, the Authority returned the same with the directions to seek prior approval of Assumption Set from CCI. Furthermore, National Electricty Policy (NEP) approved by CCI on June 21, 2021 also requires approval of IGCEP assumptions set by the CCI.

In view of the above and after detailed deliberations and consensus among NTDC, MoE (Power Division), CPPA-G, provinces and AJK, the IGCEP Assumption Set initiated by MoE (PD) was finally approved by CCI on September 6, 2021.

This revised version of IGCEP 2021-30 (Sept. 2021) has been developed based on the Assumption Set approved by CCI, using generation capacity expansion planning tool i.e. PLEXOS, by considering all the existing, committed and candidate power plants.

1.3. Introduction

In view of its rapidly increasing dependence for enhanced access thereof, electricity is today recognized as the most critical pre-requisite for improving the lives of people of a country and 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 economic strength of a country. 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 generation 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 best utility practices pertaining to planning methodologies are there for all the three main components of a power system, and each one is in itself a major field of study. Least cost generation planning is one of the important elements 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 the 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.

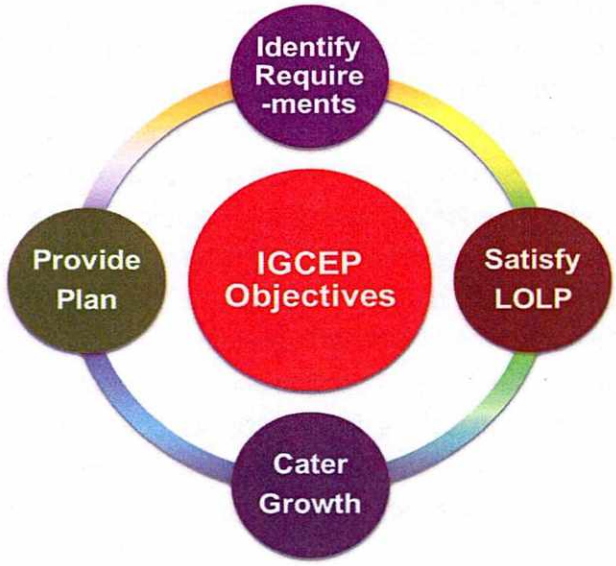


Figure 1-2: The IGCEP Objectives

1.4. Objectives of the IGCEP

The IGCEP is envisioned to meet the following objectives, as highlighted in the Figure 1-2:

a. **Identify** new generation requirements by capacity, fuel 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 requirements pursuant to the Grid Code; and
d. **Provide** a least cost optimal generation expansion plan for development of hydroelectric, thermal, nuclear and renewable energy resources to meet the expected load demand up to the year 2030

1.5. Scope and Planning Horizon

The IGCEP covers the whole country except 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 2021-30 includes an export of 1,100 MW from NTDC system to K-Electric in summer months upto 2023, which is further increased to 2,050 MW after commissioning of 500 kV KANUPP Karachi Interconnection (KKI) grid station by K-Electric, as detailed in proposed tri-partite agreement among K-Electric, NTDC & CPPA-G, till the end of study horizon. The planning horizon of the IGCEP is from the year 2021 to 2030.

1.6. Nature of the IGCEP

Overall purpose of the IGCEP is the fulfillment of outlines, actions, and strategies as stipulated in the relevant policies and decisions of Government of Pakistan, latest generation technologies, constraints and certain 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 governmental policies, investment costs, operation costs, contractual obligations, fuels, reserve requirements, maintenance allowance, etc. For this purpose, generation optimization model based on the state-of-the-art generation planning tool i.e. PLEXOS include elaboration of projected electric power demand upto the year 2021-30 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, and optimization of all options. The IGCEP is developed as a suggested starting point for the preparation of a determinative Transmission System Expansion Plan as next step for 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 agencies and project sponsors in developing the generation facilities, etc.

1.7. 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."

The IGCEP plays a key role in the expansion of the power system. The Plan ensures that the demand in the system is adequately met by adding generation capacity on least cost basis. The plan takes long term view and therefore is indicative in nature in the long run, however, it provides a perspective to potential investors and other players in the market regarding the future demand and supply situation and the probable generation mix.

Along with serving as guiding document for procurement of power for regulated consumers, the IGCEP will also provide basis for the expansion of the transmission network. The IGCEP identifies the types of generation to be added to the system and also the location in case of hydro power plants. The IGCEP is used as one of the main inputs to the TSEP along with spatial demand growth to work out the power evacuation requirements and serving the load in a reliable manner.

2. POWER SYSTEM OF PAKISTAN

2. Power System of Pakistan

2.1. Economics of Pakistan Power Sector

Electricity is a critical input for economic development and correspondingly power sector comprises an indispensable infrastructure in any economy. Providing adequate, reliable 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 affordable power 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.

As an emerging economy, country's demand for electricity is enormous and its GDP is positively related with the sale of electricity as shown in Chart 2-1. This is in concurrence with a similar trend with all developing nations where GDP and sale of electricity have a direct relationship and growth in GDP causes increased sale of electricity as opposed to the developed nations where the causal relationship between GDP and sale of electricity is either opposite than that of developing countries or the two determinants of economic growth are decoupled from each other.

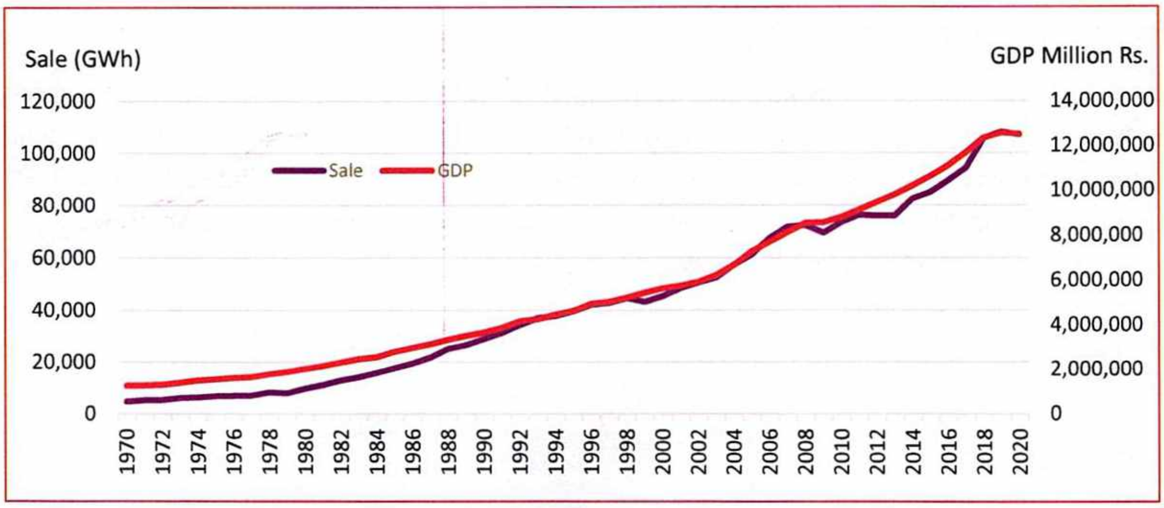


Chart 2-1: GDP (million PKR) vs Sale of Electricity (GWh)

During the fiscal year 2020-21, the country has seen 3.94% growth rate in total GDP (source: Economic Survey of Pakistan) whereas growth rates of 2.77%, 3.57% and 4.43% was observed in agriculture, industrial and commercial/services sectors, respectively. During the same period, 7.09% growth rate in consumption of electricity has been observed. This increase in GDP as well as in usage of electricity shows strong association between GDP and electricity.

2.2. Power Generation

By the end of September, 2021, the total installed generation capacity of NTDC system reached to 34,776 MW of which 34% remains RE comprising of hydro, solar, wind and bagasse-based technologies, and 66% thermal plants which comprises of natural gas, local coal, imported coal, RFO, RLNG and nuclear based technologies, as shown in the Chart 2-2.

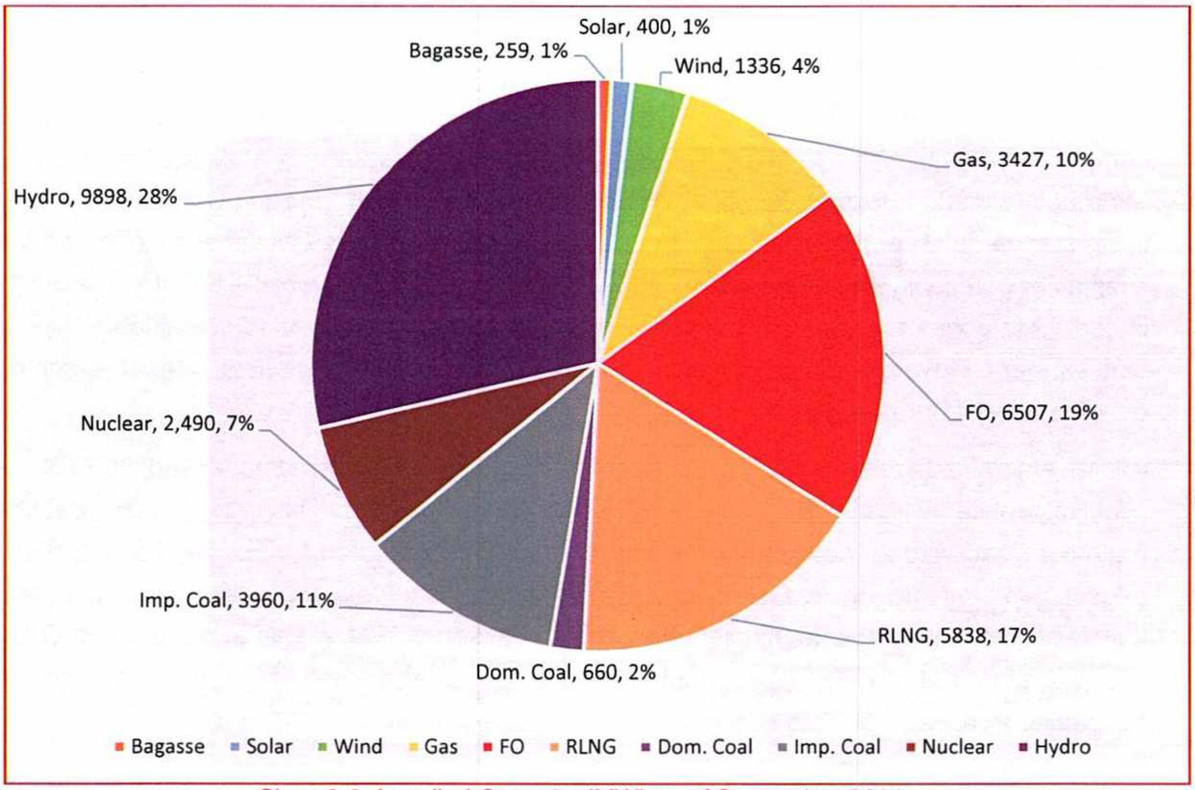


Chart 2-2: Installed Capacity (MW) as of September 2021

The energy produced by power generation fleet during the fiscal year 2020-21 totaled 129,991 GWh and was contributed approximately 30% by hydroelectric plants, 59% by thermal plants which contains natural gas, local coal, imported coal, RFO and RLNG based technologies, 8% by nuclear plants, and 3% by renewable energy power plants which covers solar, wind and bagasse-based technologies as shown in the Chart 2-3.

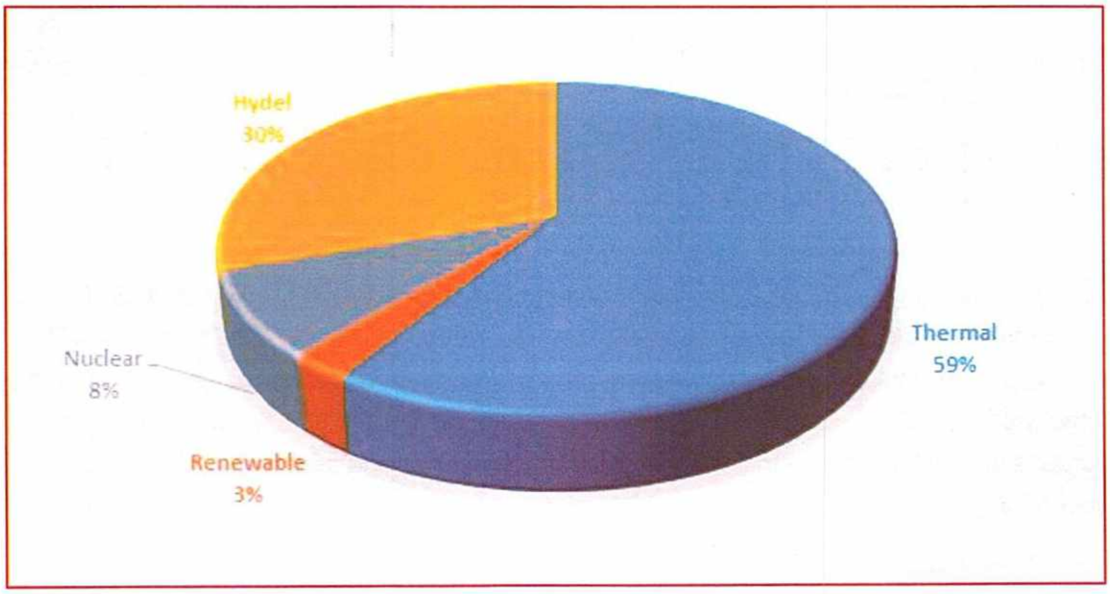


Chart 2-3: Annual Energy Generation (GWh) as of 2020-21

Furthermore, there has been an increasing trend in the electricity generation (GWh) statistics from 2014 to 2019, however, a slight decrease is observed in the year 2020 due to lesser demand owing to struggling economy coupled with the impacts of Covid-19 pandemic. However, in 2021, the trend is again increasing as shown in the Chart 2-4.

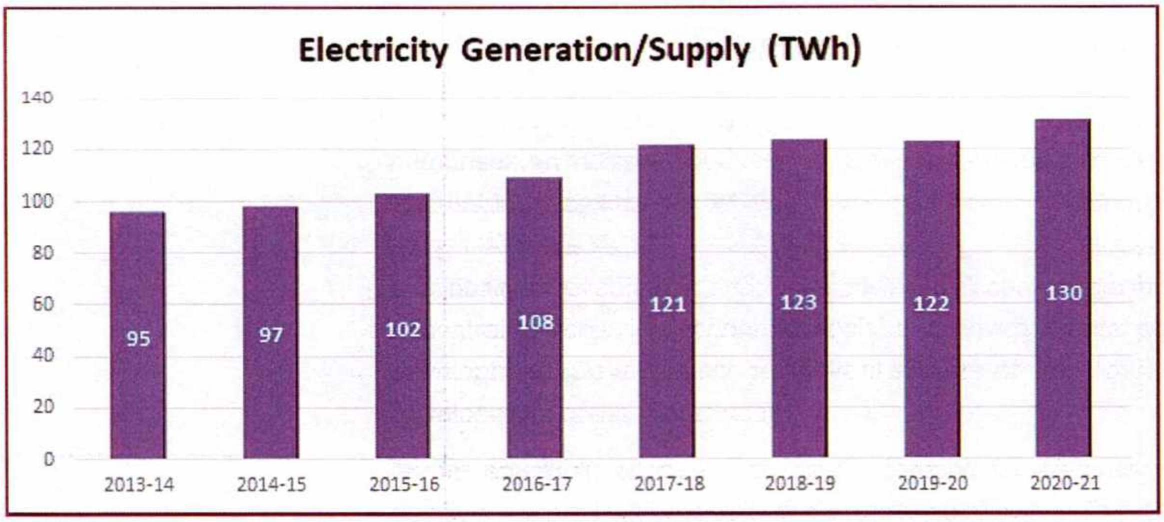


Chart 2-4: Historical Annual Energy Generation (GWh) from 2013-14 to 2020-21

Overall, the power demand (MW) has been growing steadily with improved development of electricity supply in the country as it is evident from the electricity peak demand trend as shown in the Chart 2-5.

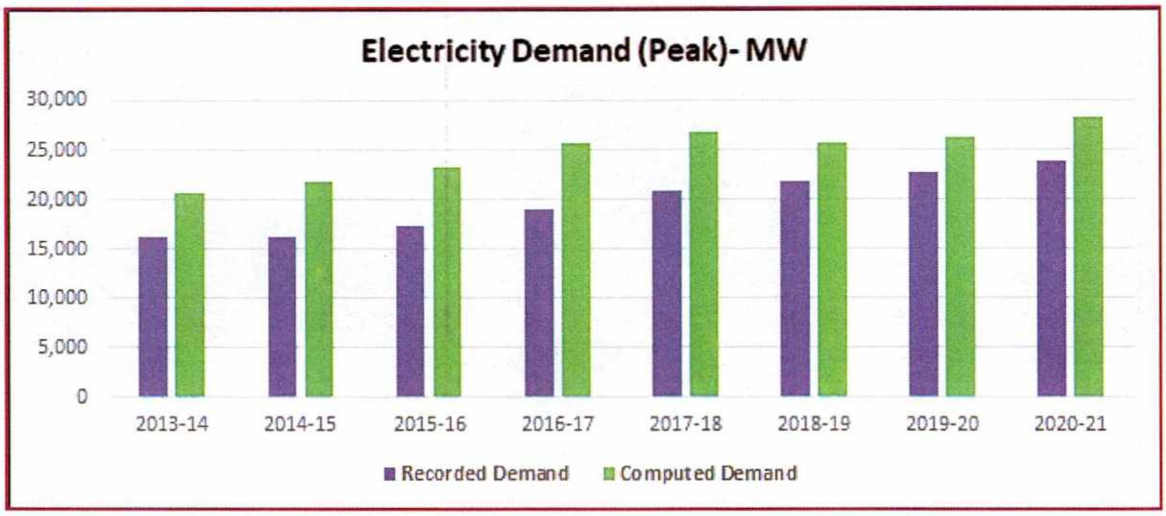


Chart 2-5: Historical Peak Electricity Demand (MW) from 2013-14 to 2020-21

Peak demand in the country during 2020-21 is 23,792 MW - recorded during the month of June 2021.

2.3. Power Distribution

By the year 2021, total number of electricity consumers have reached to 31,529,568 out of which 27,227,283 belong to domestic category, 3,359,777 belong to commercial category, 357,366 consumers fall under industries, there are 359,124 agriculture consumers, bulk supply consumers are 4,417, public lighting connections have been recorded as 11,284 and 210,353 consumers are categorized as general services consumers as shown in Chart 2-6.

During the year 2021, domestic consumption had a share of 49,814 GWh, commercial consumption was 6,688 GWh, industrial consumption was 24,663 GWh, agriculture consumption had a share of 10,116 GWh and 8,089 GWh has been consumed by other categories as shown in Chart 2-7.

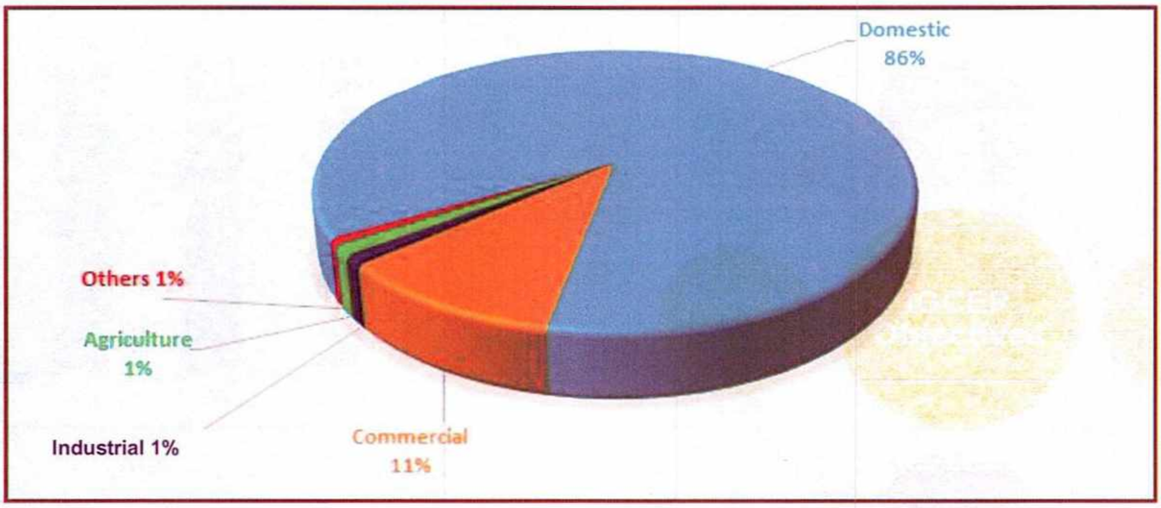


Chart 2-6: Percentage Mix of Number of Electricity Consumers

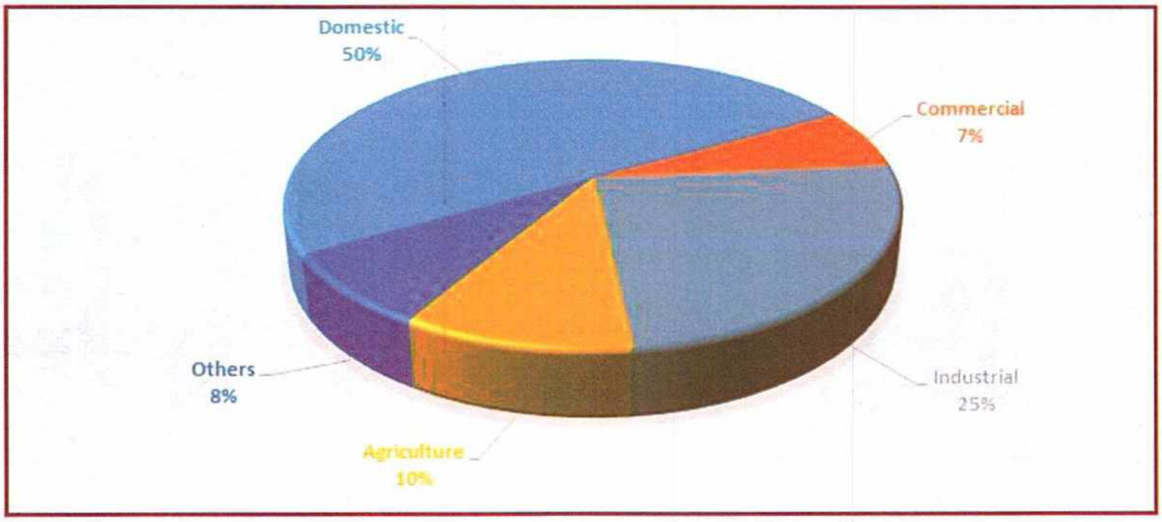


Chart 2-7: Percentage Mix of Category-wise Sale (GWh) of Electricity

Electricity consumption in Pakistan is dominated by the domestic sector followed by industrial and agricultural sector as shown in chart 2-7.

3. THE IGCEP METHODOLOGY

B Canck

3. The IGCEP Methodolgy

3.1. Regulatory Compliance

Pursuant to the Grid Code, the IGCEP covers the future development of hydroelectric, thermal, nuclear and renewable energy resources to meet the anticipated load demand up to the year 2030. It identifies new capacity requirements by capacity, technology, fuel and commissioning dates on year-by-year basis by complying with the various regulatory requirements as set out through the provisions of the Grid Code including Loss of Load Probability (LOLP), the long-term load growth forecast and system reserve requirements.

3.2. Data Collection Process

The data gathering process for the purpose of this study was quite rigorous; all the concerned project executing entities were approached to provide the requisite data on the prescribed format. For the first time, the data proformas were made available Online on NTDC website through Google Forms (available at the web link *http://ntdc.gov.pk/planning-power*) for providing the requisite input data on the prescribed format, the said link was shared with all the concerned project executing entities. The following process was followed for the collection of various inputs / data / information pertaining to power plants from the concerned entities:

a. Specific data input formats were customized, involving suitable conversions, as per requirements of the generation planning modelling tool i.e. PLEXOS.

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

c. Three awareness workshops on “Data Preparation and Submission by the Project Execution Agencies for Inclusion in the Indicative Generation Capacity Expansion Plan – IGCEP” were organized in Lahore during October-Novemeber 2020.

d. All the data received was precisely analyzed for accuracy and completeness, and gaps were identified and rectified / adjusted accordingly.

e. The data was developed / formulated as per requirement of the generation planning tool.

3.3. The IGCEP Data Sources and Associated Data Types

Following agencies shown in Figure 3-1 have contributed for the preparation of input data to be used in IGCEP 2021-30 as listed below:

a. Alternative Energy Development Board (AEDB)
   - Existing and future renewable energy projects

b. Azad Jammu Kashmir Power Development Organization (AJKPDO)
   - Existing and future hydro power plants under the jurisdiction of AJ&K

c. Azad Jammu Kashmir Private Power Cell (AJKPPC)
   - Existing and future hydro power plants under the jurisdiction of AJ&K

d. Central Power Purchasing Agency Guarantee Limited (CPPA-G)

- Fuel prices and existing system merit order

e. Energy Department Sindh / Sindh Transmission and Dispatch Company (STDC)

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

f. Finance Division (Economic Adviser Wing)

- Sector wise GDP projections

g. GENCOs

- Existing and future thermal power plants in the public sector

h. National Electric Power Regulatory Authority (NEPRA)

- Different types of input data were collected from NEPRA's publications / website i.e. the latest values from NEPRA quarterly indexation were used to update the costs.

i. National Power Control Centre (NPCC)

- Monthly energy and MW capacities for existing wind and solar power plants

j. Pakhtunkhwa Energy Development Organization (PEDO)

- Existing and future hydro power plants under the jurisdiction of KPK

k. Pakistan Atomic Energy Commission (PAEC)

- Existing and future nuclear power plants

l. Pakistan Bureau of Statistics

- Input data for long-term forecast such as historic GDP and its components, Consumer Price Index (CPI), etc.

m. Pakistan Electric Power Company (PEPCO)

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

n. Private Power Infrastructure Board (PPIB)

- Existing and future hydro and thermal power plants under IPP mode

o. Punjab Power Development Board (PPDB)

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

p. Water and Power Development Authority (WAPDA)

- Existing and future hydro power plants to be developed by WAPDA

3.4. Financial Parameters

For existing system, cost data has been obtained from the latest merit order provided by CPPA-G whereas for the future power plants, cost data shared by the concerned project executing agencies, after indexation, have been considered.

3.5. The IGCEP Preparation Process Map

The IGCEP is prepared after following the process illustrated through Figure 3-2 and is submitted to NEPRA for review and approval, following an extensive internal consultative process.

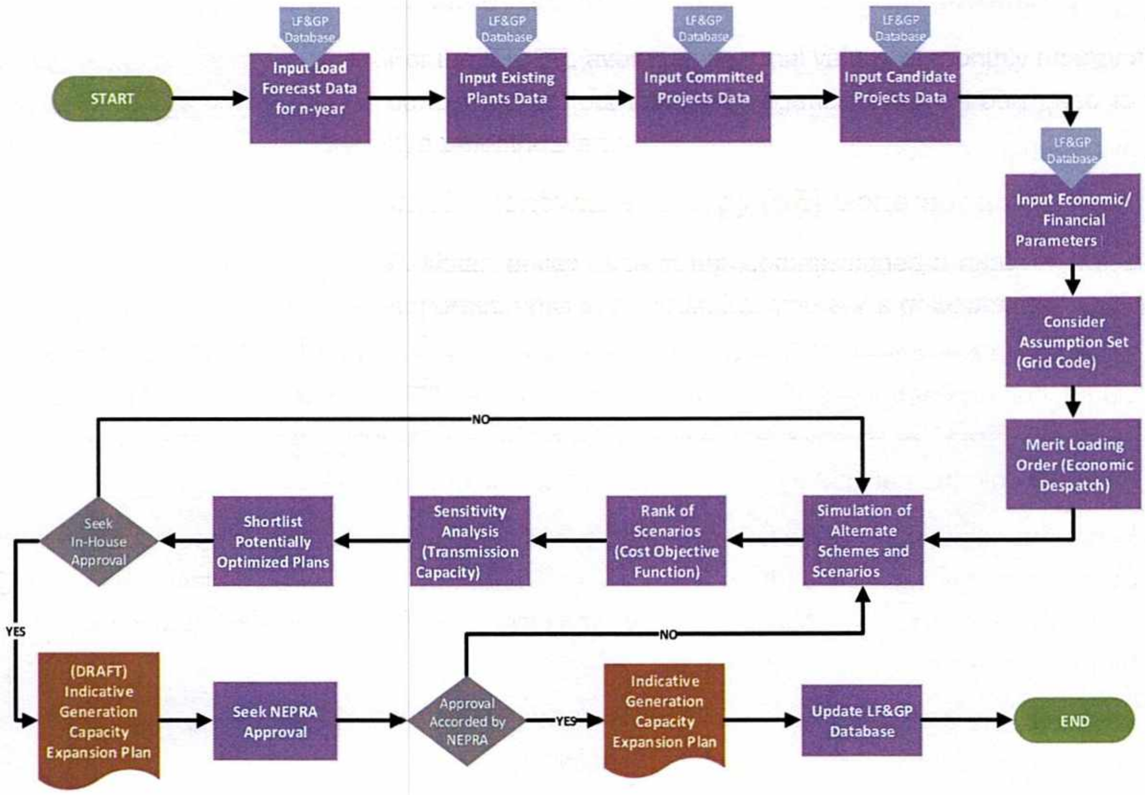


Figure 3-1: The IGCEP Preparation Process

3.6. Criteria and Other Important Considerations for the IGCEP

3.6.1. Planning Timeframe

The planning period taken for this study is 10 years i.e from July 1, 2020 to June 30, 2030.

3.6.2. Economic Parameters

The governing economic parameters considered for IGCEP 2021-30 are presented in Annexure B-2 and B-3.

3.6.3. Generation System Reliability

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

Loss of Load Expectation (LOLE-days) or equivalently Loss of Load Probability (LOLP-%) is considered as generating system reliability criteria. For the purpose of the IGCEP, yearly LOLP criteria of not more than 1%, as stipulated in the Grid Code, has been adopted.

3.6.4. Hydrological Risk

For the IGCEP, average seasonal values of monthly energy and capacity, as conveyed by the concerned project executing agencies, have been used to capture the seasonality for the hydroelectric plants.

3.6.5. Renewable Energy (RE) Generation

Pakistan power system has commissioned a relatively fair quantum of RE generation in the generation mix in the past few years. As of September, 2021, 400 MW utility scale solar and 1,336 MW wind power on-grid projects, have been commissioned. Subsequent to Cabinet Committee on Energy (CCoE) decision of April 4, 2019, defined under Category-I & II, several wind, solar and bagasse power projects at different stages of development are envisaged to be added into the national grid during the next couple of years.

Furthermore, pursuant to the CCI approved assumption set, current IGCEP iteration has been done under existing targets (20% by 2025 and 30% by 2030 of installed capacity) as per ARE Policy 2019, subject to least cost principle, and including hydro projects in the definition of RE for the purpose of meeting such targets.

Based on the available data, plant factors of 42.5% and 23% for candidate wind and solar power projects have been considered, respectively.

3.6.6. System Reserve Requirement

Reserve of a generating system is a measure of the system's ability to respond to a rapid increase in load or loss of the generating unit(s). In this study, two types of reserves have been modelled as per provisions of the Grid Code i.e. contingency and secondary.

3.6.6.1. Contingency Reserve

The contingency reserve is the level of generation over the forecasted demand which is required from real time plus 24 hours so as to cover for uncertainties. This reserve is provided by the generators which are not required to be synchronized but they can be synchronized within 30 minutes of the initiation of the Contingency and the corresponding fall in frequency. As per best industry practices, this is equal to the capacity of the largest thermal generator in the system. In this model, the Contingency Reserve is considered equivalent to 1,145 MW in view of the induction of Karachi Nuclear (K-2), being the largest thermal unit in the system.

3.6.6.2. Secondary Reserve

The secondary reserve is a type of spinning reserve and it is the increase in power output of the online generators following the falling frequency and is fully sustainable for 30 minutes after achieving its maximum value in 30 seconds. It is equal to the one third of the largest unit in the system. Hence, in this model 382 MW of the Secondary Reserve is considered throughout the planning horizon.

3.6.7. 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, except for VRE, will undergo an annual maintenance program as provided by the concerned project executing agency.

3.6.8. System Load Characteristics

From the planning perspective, the system load to be met by the generating system is represented by the system's hourly load for each year up till 2030 which totals to 87,648 hours of load for the entire planning horizon. The load forecast provides the hourly load demands. Normal scenario of the load forecast has been adopted in this study. The load forecast is presented in Table 4-3.

3.6.9. Fuel Prices Indexation

Pakistan's electricity generation mix relies heavily on fossil fuels including RLNG, imported / domestic coal, natural gas and furnace oil, hence, fuel price uncertainty is one of the major determinants for a long-term generation expansion plan. Increase in demand and fear of supply disruption exert an upward pressure on fuel prices. In this regard, the base fuel prices have been taken as per latest Merit Order. These fuel prices are then indexed for future years as per the Energy Information Authority (EIA) Annual Energy Outlook 2021 (except for domestic coal where Thar Coal & Energy Board tariff was applied). The variable price index for each of the fuel-based technologies is given in Table 3-2.

Table 3-1: Fuel Price Indexation Factors

Year	Fuel Oil	Natural Gas/ RLNG	Imported Coal	Uranium	Thar Coal
	Variable Price Index for Fuel Based Technologies				
2021	1.00	1.00	1.00	1.00	1.00
2022	1.09	1.19	1.02	1.00	1.00
2023	1.21	1.17	1.00	1.00	0.99
2024	1.34	1.10	0.98	1.01	1.01
2025	1.43	1.07	0.97	1.01	0.94
2026	1.51	1.10	0.95	1.01	0.95

Year	Fuel Oil	Natural Gas/ RLNG	Imported Coal	Uranium	Thar Coal
	Variable Price Index for Fuel Based Technologies				
2027	1.57	1.13	0.95	1.01	0.95
2028	1.61	1.15	0.94	1.01	0.94
2029	1.65	1.19	0.93	1.02	0.95
2030	1.69	1.21	0.93	1.02	0.93

3.6.10. CAPEX of Renewable Energy Technology

Fuel prices volatility have encouraged calls for investments in renewables. Renewable energy, including wind and solar, are quickly becoming cheapest forms of new electricity generation across the globe. They have started replacing the conventional fuels to great extent for power generation to meet the future demand growth throughout the world. The cheaper and widely accessible renewable energy has the potential to substantially decrease the reliability of power sector on expensive imported fuels.

Trend of cost reduction for the renewable technology is set to continue in the future and will inevitably reduce the cost burdens, reliance on increasingly expensive fuels and hence lowering the overall generation cost. The costs of renewables especially solar, wind and hybrid are expected to be driven down further through energy policies, global trends and continuous developments in solar and wind technologies. Renewables are needed to mitigate the negative externalities of fossil fuels since primary energy consumption will grow into the future, and this growing demand is currently dependent on fossil fuels.

It is apprised that for the IGCEP 2021-30, the CAPEX is degraded by 3.6% and 1% for solar and wind respectively every year up till 2030 in line with various international projections including Lazard, IRENA, etc. As compared to today's solar power plant CAPEX i.e. 531 $/kW, it is gradually lowered to 382 $/kW by the year 2030. The CAPEX of wind is currently 955 $/kW which is steadily decreased to 872 $/kW in 2030. Similarly, CAPEX of BESS is currently 386 $/kW which is steadily decreased to 221 $/kW in 2030.

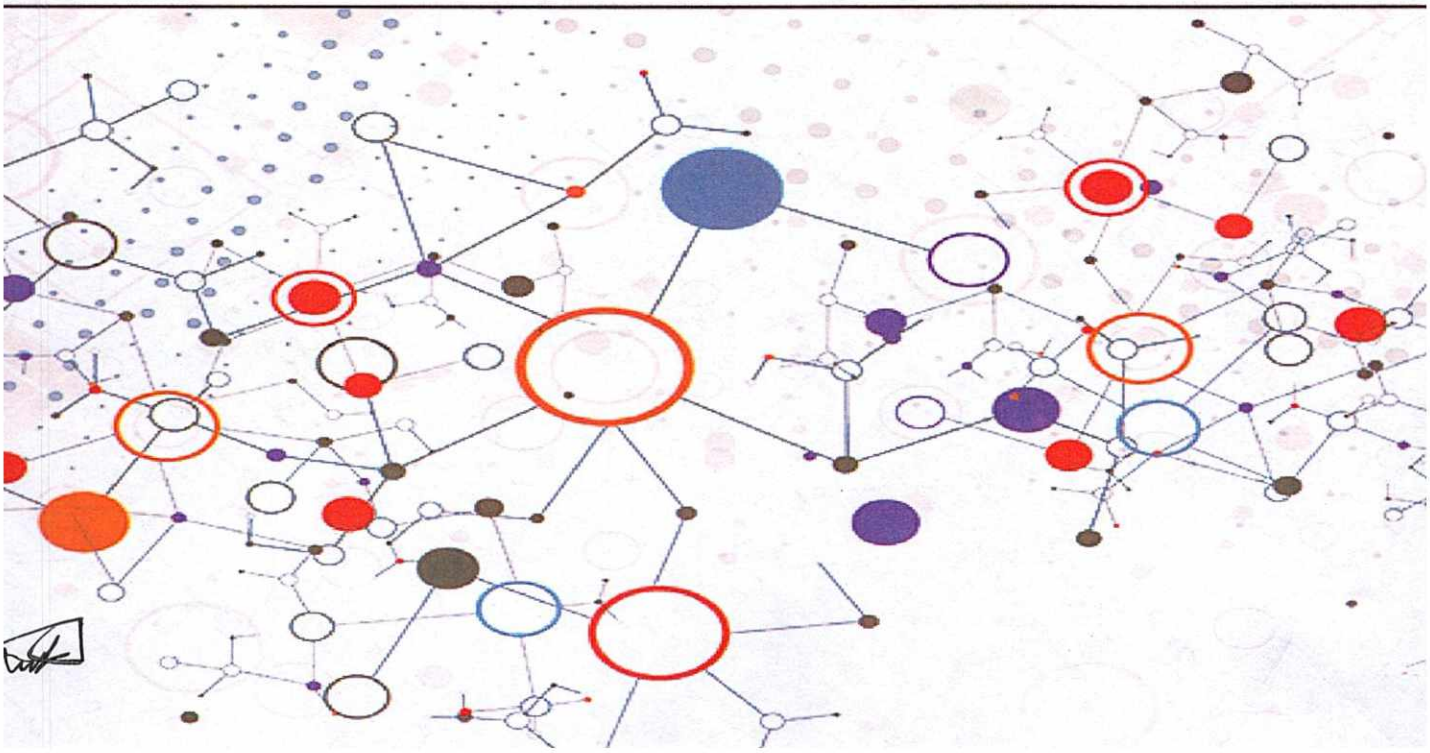
Future prices up till the year 2030, pertaining to REs i.e. Wind, Solar and BESS are given below:

Table 3-2: CAPEX Indexation of Solar and Wind Based Technologies

Year	Solar PV (3.6%)	Wind (1%)	BESS (~6%)
	($/kW)	($/kW)	($/kW)
2021	531	955	386
2022	512	945	363

Year	Solar PV (3.6%)	Wind (1%)	BESS (~6%)
	($/kW)	($/kW)	($/kW)
2023	493	936	341
2024	476	927	321
2025	458	917	301
2026	442	908	283
2027	426	899	266
2028	411	890	250
2029	396	881	235
2030	382	872	221

4. LONG TERM ENERGY AND DEMAND FORECAST



4. Long Term Energy and Demand Forecast

4.1. Energy and Power Demand Forecast

Energy and power 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:

Three levels of load forecasts i.e. high growth, medium growth and low growth projections should be employed for a time horizon of at least next twenty years for the long-term.

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

4.2. Long-Term Demand Forecasting Methodology

The long-term demand forecast is based on multiple regression analysis, which is practiced internationally as an econometric technique to develop robust mathematical relationship between dependent and independent variables. Electricity sale is the variable under study. The electricity consumption pattern varies for different economic sectors of the country namely domestic, industrial, commercial and agriculture. In regard to this, multiple variables most likely to affect the electricity sales were studied, for every sector individually, and tested for significant quantitative relationships. These include electricity prices, GDP, population, number of consumers, lag variables etc. The variables that impacted the sales most significantly were selected for the final equations for electricity sales. Electricity consumption (GWh) is then regressed on these independent variables using historical data for the period 1970-2020. The methodology of long-term load forecast is illustrated in the process flow map in Figure 4-1.

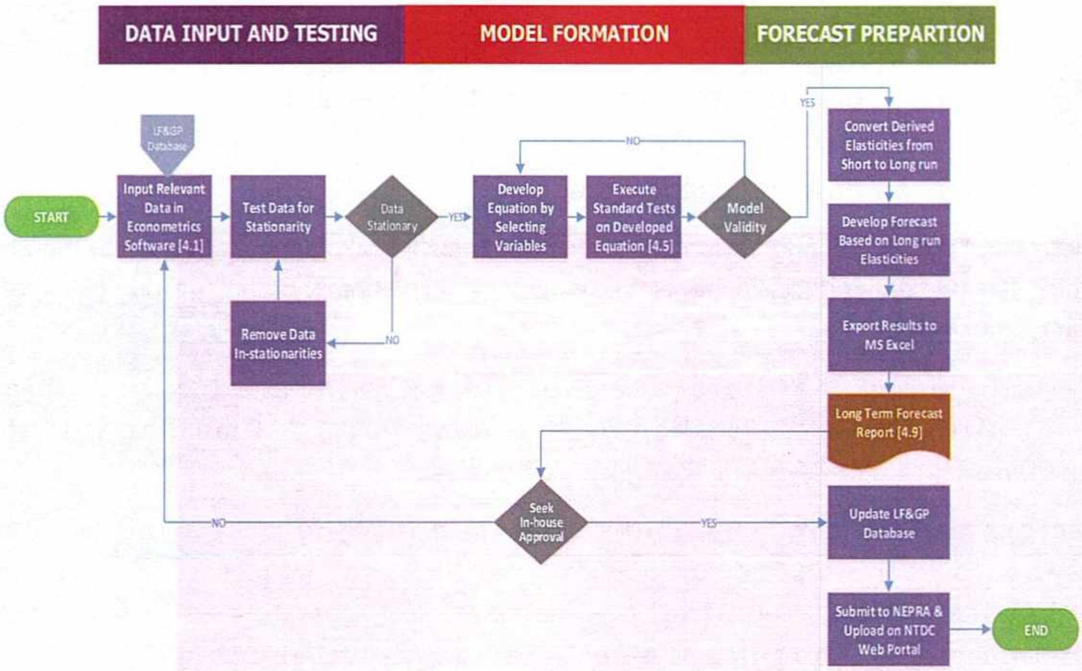


Figure 4-1: Process Flow of Methodology of Long-Term Demand Forecast

4.3 Data Sources

The data sources for the long-term demand forecast are as under:

a. GDP and Consumer Price Index (CPI) is obtained from Economic Survey of Pakistan 2020-21 published by Finance Division, Government of Pakistan.
b. The GDP projections from 2022 to 2030 have been provided by the Finance Division of Pakistan (Economic Adviser Wing). (Annexure A-1)
c. Energy Sales, Transmission & Distribution Losses and Energy Purchased data is obtained from DISCOs Performance Statistics by PEPCO – June 2021
d. Category-wise average tariff is obtained from DISCOs Performance Statistics by PEPCO – June 2021.
e. Peak Demand (MW) and Load management data is obtained from NPCC and PITC
f. The demand side management targets have been provided by NEECA.

4.4 Key Considerations

4.4.1 Demand Side Management

The impact in terms of energy (GWh) pertaining to demand side management has been provided by NEECA considering an improvement in the energy efficiency of the electric fixtures i.e. LEDs, fans, air conditioning, refrigeration etc. According to the study conducted by NEECA, there will be an increase of upto 3% in the use of LEDs every year. NEECA has also predicted an increase in usage of energy efficient fans and other equipments complying to Minimum Energy Performance Standard (MEPS). The annual targets set by NEECA are given in Table 4-1.

Table 4-1: NEECA Energy Efficiency Targets

Year	Energy Saving through Energy Standards & Labeling (GWh/Year)
2020-21	2,190
2021-22	3,765
2022-23	5,340
2023-24	6,916
2024-25	8,491
2025-26	10,066
2026-27	11,642
2027-28	13,217
2028-29	14,792
2029-30	16,368

4.4.2. Power Export to K Electric

The IGCEP 2021-30 includes an export of 1,100 MW from NTDC system to K-Electric in summer months upto 2023, which is further increased to 2,050 MW after commissioning of 500 kV KANUPP Karachi Interconnection (KKI) grid station by K-Electric, till the end of study horizon.

4.4.3. Load Management

For preparation of the Long Term Demand Forecast, Load management is incorporated to account for the impact of load shedding being enforced in the country. Currently, multiple factors are contributing towards load being shed such as emergency situations, DISCOs Industrial cut and the technical constraints of NTDC and DISCOs. Hence, the impact of these factors has been accounted for in the load management data.

4.5. Preparation of Demand Forecast

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

a. Domestic;
b. Commercial;
c. Industrial; and
d. Agriculture

These aforesaid sectors typically show different consumption patterns throughout the year. Hence, they are forecasted separately. The load demand forecast of these sectors is then combined to obtain the forecast of total electrical energy demand. In order to forecast the annual consumption of electricity up to the year 2030, a multiple regression model has been 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 total 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. Lag of dependent and independent variables;
e. Consumer Price Index; and
f. Dummy variables

Considering the above mentioned factors, four equations are selected, one for each category of electricity consumption. For statistical analysis, popular statistical software namely EViews is used.

Ordinary Least Square technique is selected for the estimation of regression equation. The equations are written in logarithmic form to evaluate elasticity in percentage. 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, etc. 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.

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

Table 4-2 provides the description of all the variables used in this equation:

Table 4-2: Description of Dependent and Independent Variables

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 demand forecast results of the four categories were combined to calculate the sale forecast at the country level. It is important to mention here that, in order to calculate the elasticities of commercial and industrial sectors the impact of load shedding on their historical data has been considered for the study, provided the fact that load shedding does not hinder or majorly affect the activities in these sectors. This is due to the alternative energy supplies widely used in the sectors which keep their activities going.

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. The calculated load factor was then projected for the future years. The projected load factor was then used along with projected energy generation to forecast the peak demand.

4.6. Demand Forecast Numbers

Based on the variables and methodology explained above, the Table 4-3 highlights forecast result for the Normal growth; which is also graphically illustrated in Chart 4-1.

Table 4-3: Annual Long-Term Energy and Power Demand Forecast

Year	Normal Demand	
	Generation	Peak Demand
	GWh	MW
2020-21*	130,652	23,792
2021-22	136,151	24,574
2022-23	142,563	25,779
2023-24	159,319	28,027
2024-25	166,550	29,389
ACGR 2021-25	**6.26%**	**5.42%**
2025-26	174,102	30,814
2026-27	181,834	32,276
2027-28	190,037	33,829
2028-29	198,622	35,457
2029-30	207,418	37,129
ACGR 2026-30	**4.47%**	**4.77%**
ACGR 2021-30	**5.27%**	**5.07%**

* Actual Demand (MW) & Energy Generation (GWh)

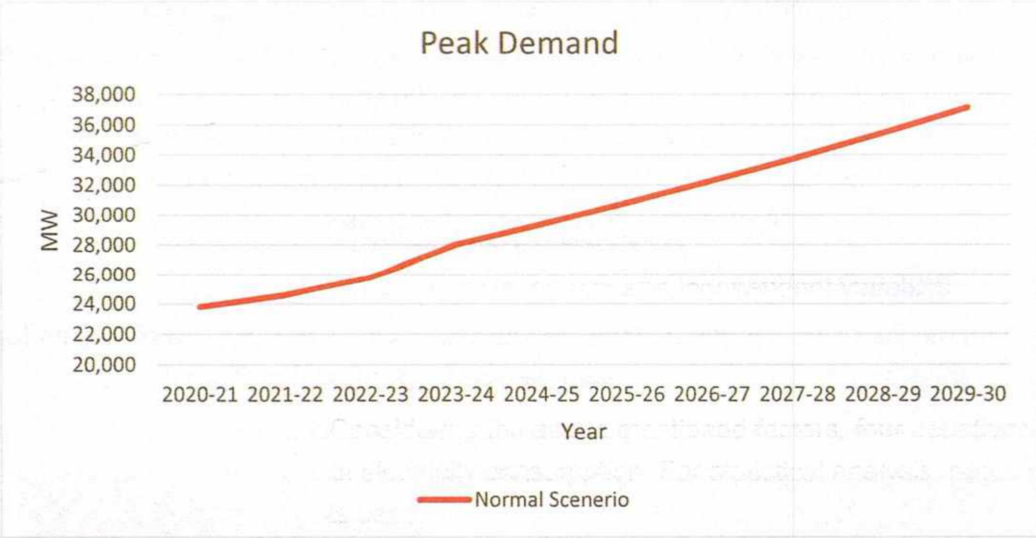


Chart 4-1 Peak Demand (MW) Forecast 2021-2030

4.7. Hourly Demand Forecast

Hourly demand forecast has been developed to cater for the intermittency of variable renewable energy sources. This is particularly important in view of the aggressive targets envisioned by the GoP pertaining to renewable energy. Hence, the demand forecast of 87,648 hours have been estimated for the plan horizon. In this process, the forecasted annual peak demand was converted into hourly demand based on the recent historical hourly demand and generation pattern. The load duration curve for the year 2025 and 2030 is given Chart 4-2.

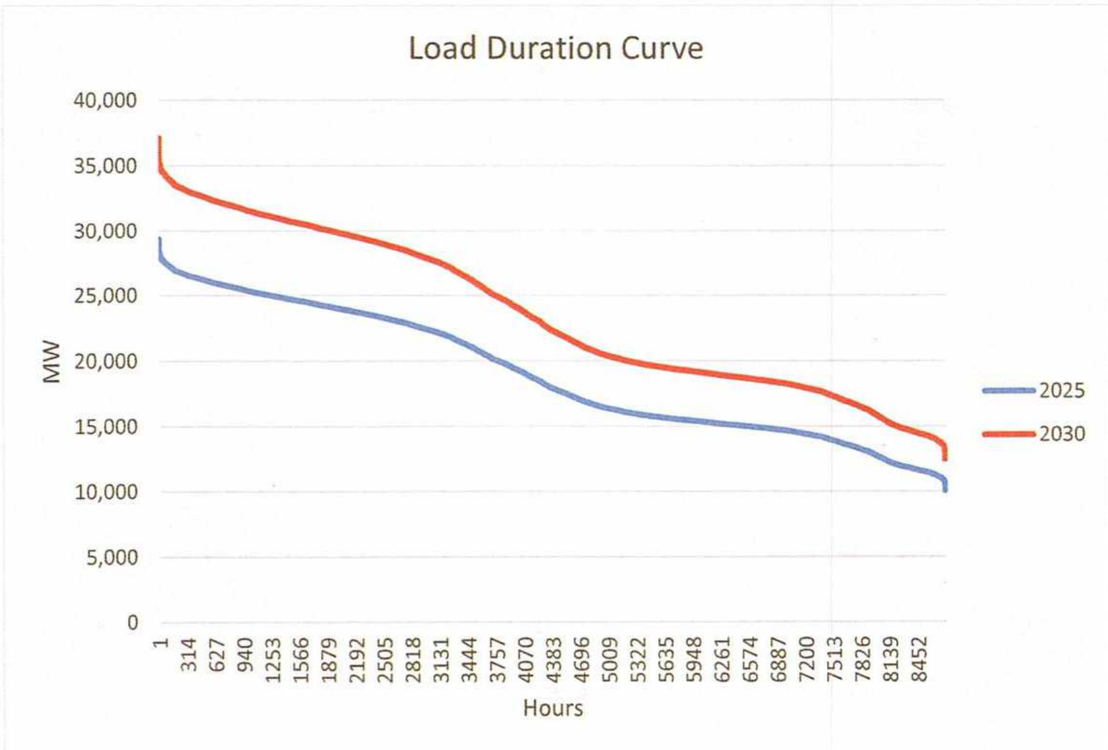
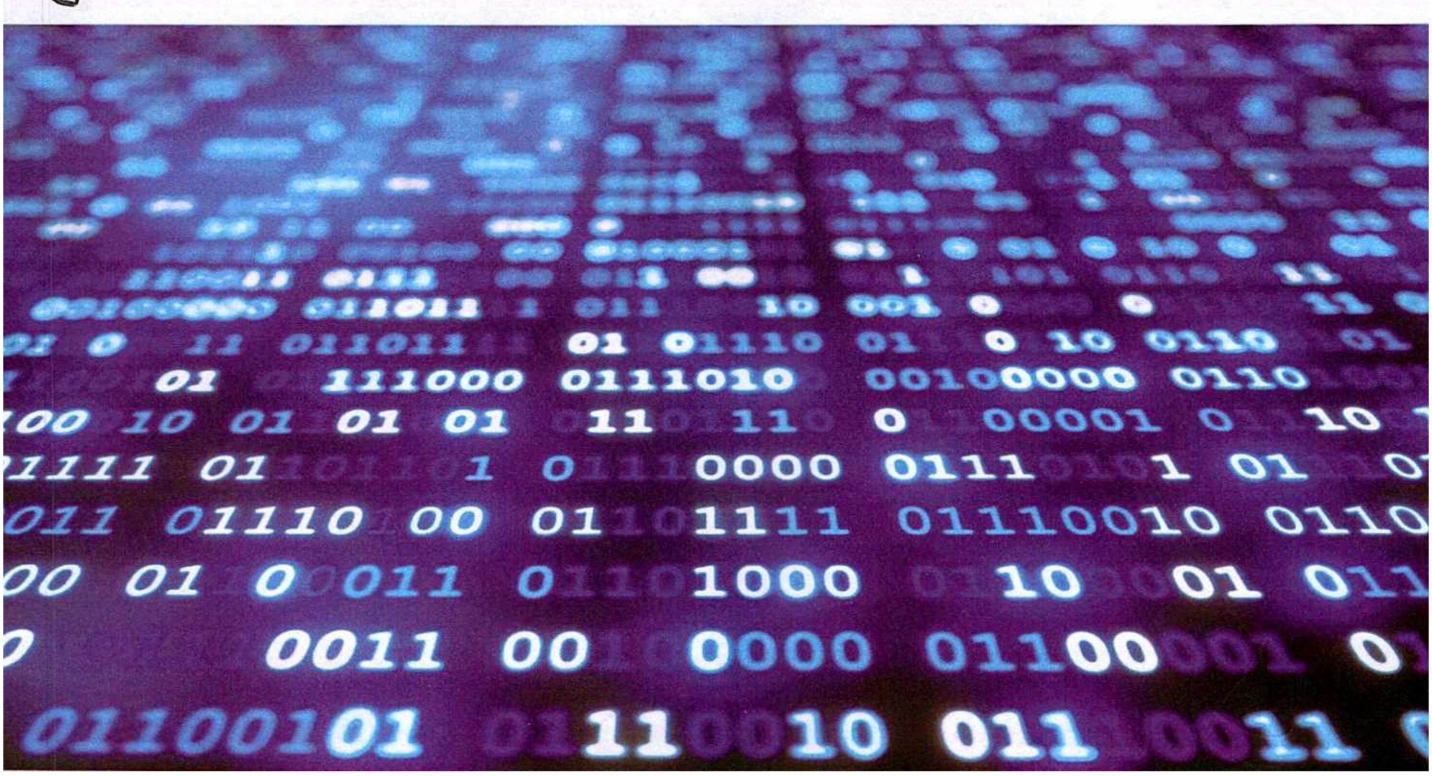


Chart 4-2: Load Duration Curve (2025 & 2030)

5. INSIDE THE IGCEP



5. Inside the IGCEP

5.1. Introduction

The key objective of the generation expansion planning activity is to develop a least cost, long-term generation expansion plan for NTDC system for the period 2021-30 to meet the maximum load and energy demand whilst taking into account the regulatory requirements as stipulated under PC 4 of the Grid Code, Assumption Set approved by CCoE and identified constraints. The following section describes the key parameters and results of the generation planning study.

5.2. Assumption Set approved by CCI

The IGCEP 2021-30 has been developed as per following assumption set:

Demand Projection Assumptions:

1. Use 'normal' served demand forecast scenario for base case, out of the three load forecast scenarios (Low, Normal, High) developed based on the following inputs:
    i. Historical Gross Domestic Product (GDP) and Consumer Price Index (CPI) is obtained from Economic Survey of Pakistan, published by Ministry of Finance, Government of Pakistan.
    ii. The long term GDP projections are developed in the light of data provided by Finance Division.
    iii. Sale and prices of electricity is obtained from Power Distribution Book, June 2020 - an annual publication by PEPCO.
2. Planning horizon of the study will be 2021-30 (10 years) with annual updation.
3. Reserve and reliability requirements (LOLP = 1%) will be considered as per Grid Code.
4. Retirement of existing thermal power plants including GENCOs will be considered as per expiry of contractual term of corresponding PPA and relevant CCoE decisions.
5. Till the expiry of contractual term of corresponding PPA and GSA, existing RLNG and imported coal based projects will be given a minimum dispatch as per contractual obligations.

Assumptions for Cost Data for Existing System:

6. Fuel costs and variable O&M costs will be based on the latest indexation/determination by NEPRA. Fixed O&M costs will be based on NEPRA's latest quarterly indexation (December 2020), as available on NEPRA's website.
7. Fixed O&M costs of power plants built under 1994 Power Policy are not available on NEPRA's website, so these costs are obtained from previous data available with Power System Planning, NTDC and CPPA (G).

Assumptions/criteria for Project selection:

8. A project will be input as **'committed'** and its capital cost or CAPEX will not be entered in the model, provided the project fulfills at least one of the following pre-requisites:
    i. Has obtained LOS as of December 2020 for private sector projects. For Federal and Provincial public sector projects, the PC-I has been approved and funding

secured (As of March 2021). However, M/s Jamshoro Unit-2 & M/s Chashma-5 Nuclear Plants shall be modelled as candidate projects to be evaluated under "Least Cost Principle".

ii. G2G project: Power Generation projects which are listed under Federal Government's international (bilateral or multilateral) commitments, if project / financing agreements signed.

iii. Where timelines of completion of a project under G2G are not firmed up yet, the software shall determine the timeline by which such a project must come online based on its tariff optimization with respect to other available options.

iv. RE plants (Wind, Solar, Bagasse) enlisted in Category I & II of CCoE's decision dated 4th April 2019.

v. RE on-grid power projects in balance target block share as stipulated in the ARE Policy 2019 i.e. 20% by year 2025 and 30% by year 2030 (including net-metering), candidate block will be considered on respective wind/solar/hybrid technologies from the year 2023-24 onwards on least cost principle. The current IGCEP iteration for RE projects will be done under existing targets as per ARE Policy 2019, subject to least cost principle, and including Hydro Candidate projects in the definition of RE (for the purpose of meeting such targets) to be ratified through an amendment to the ARE Policy 2019 by CCI in due course.

vi. CODs for **'committed power projects'** will be taken as per project security documents (PPA/IA) or as conveyed by the competent forum / concerned organization / entity.

Cost Data for Committed Power Projects:

9. Cost data of committed projects would be taken as per data/information provided by the concerned project executing agency and NEPRA determined tariff.
10. For nuclear power plants, Variable O&M cost and Fixed O&M cost and operational data as conveyed by Pakistan Atomic Energy Commission (PAEC) will be considered.

Cost Assumptions for Candidate Power Plants:

11. For nuclear power plants: Capital cost, Variable O&M cost and Fixed O&M cost and operational data as conveyed by Pakistan Atomic Energy Commission (PAEC) will be considered.
12. Local and imported coal power plant: Capital Cost, Variable O&M cost, Fixed FCC and Fixed O&M cost will be taken from the latest NEPRA determined tariff for respective technology.
13. RLNG based CCGT power plant: Capital cost, Variable O&M cost and Fixed O&M cost will be taken from the latest NEPRA determined tariff for RLNG based CCGT.
14. RLNG based OCGT power plant: Fuel cost, Fixed O&M cost and Variable O&M cost of latest available OCGT plant be considered while Capital cost for OCGT will be considered as conveyed by the concerned project executing agency or as per best international practice.
15. Wind, Solar and Bagasse based power plants: Capital cost, Variable O&M cost and Fixed O&M cost will be taken from the latest available NEPRA's tariff determination. Fuel

price of bagasse based power plants will be considered as per latest available NEPRA determined tariff.

16. Hybrid RE resources based power plant: Capital Cost, Variable O&M cost and Fixed O&M cost shall be considered as conveyed by the concerned project executing agencies.
17. Hydro power plant: Capital cost and Fixed O&M cost will be considered as shared by the concerned project executing entities.

Process Assumptions:

18. All years correspond to fiscal years e.g. 2025 is the fiscal year July 1, 2024 to June 30, 2025.
19. All costs will be indexed as of December 2020.

For Hydro, the cost data shared by concerned project execution agencies has been indexed and are given in Annexure B-3. The values for indexation were obtained from NEPRA's website.

5.3. Adherence to Contractual Obligations

In order to develop an effective least cost generation capacity expansion plan that will meet the future power needs of the country, the IGCEP adheres to the existing constraints such as take or pay contractual obligations of at least minimum annual despatch of 66% for three RLNG based power plants (Bhikki, Balloki & Haveli Bahadur Shah), 50% for existing imported coal-based power plants (Sahiwal, China HUBCO & Port Qasim),and three low btu gas-based plants(Uch-II, Engro and Foundation).

5.4. Approach and Methodology

The development of the least cost generation capacity expansion plan is the process of optimizing i) existing and committed generation facilities and ii) addition of generation from available supply technologies/options, which would balance the projected demand while satisfying the specified reliability criteria. For the purpose of the IGCEP, following methodology has been adopted as illustrated in Figure 5-1:

a. First Step: Review the existing generation facilities, committed power projects and explore the range of generation addition options available to meet the future demand.
b. Second Step: Determine the economically attractive / viable generation option (s).
c. Third Step: Define the Base Case subsequent to identification of the economically attractive options.
d. Fourth Step: Develop the least cost plan whilst considering the reliability criteria and reserve requirements under the already defined Base Case using the PLEXOS tool.

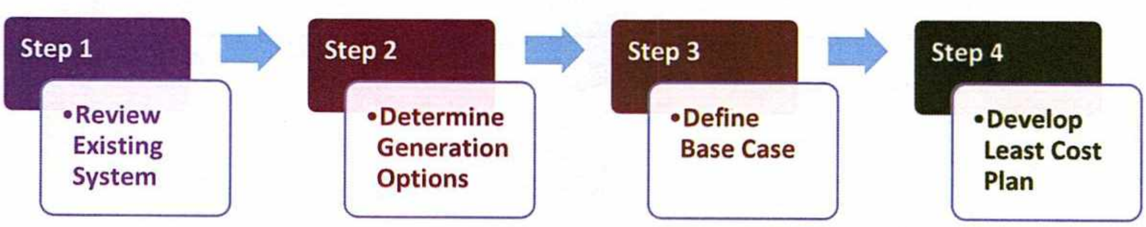


Figure 5-1: The IGCEP Data Modelling Approach

5.5. Planning Basis

The generation planning criteria tabulated in the Table 5-1 is adopted for this study.

Table 5-1: Generation Planning Criteria

Parameter	Value
Discount Rate	10%
Reliability Criteria (LOLP)	1%
Dollar Rate	Rs. 158.3
CPI (US)	269.195
CPI (Local)	269.27

5.6. Existing Power Generation of Pakistan

Total installed capacity of existing NTDC system is 34,776 MW as of September 2021 whereas the de-rated capacity is equivalent to 32,660 MW. The fuel wise break-up is shown in Chart 5-1:

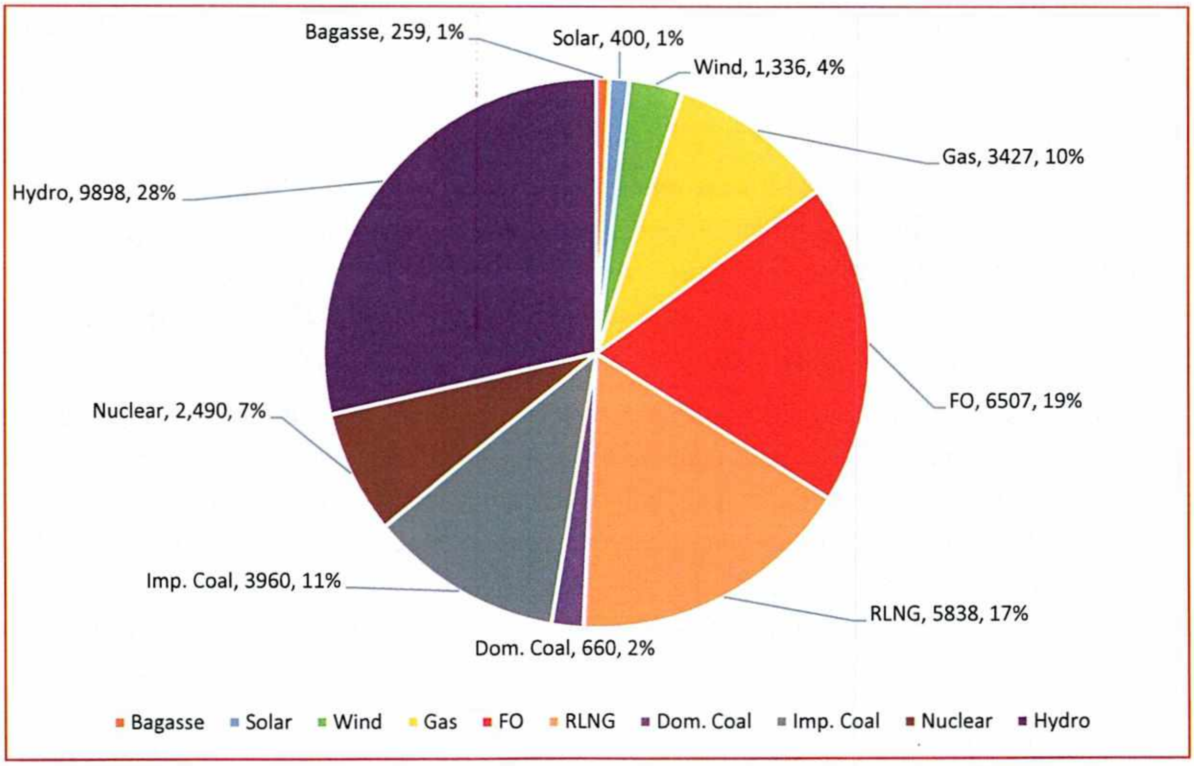


Chart 5-1: Fuel-wise Generation Mix (MW) as of September 2021

5.7. Retirement of Existing Power Plants

A significant quantum i.e. 6,447 MW of existing thermal power plants are scheduled to be retired during the planning horizon of the IGCEP 2021-30. The retirement schedule for the IGCEP 2021-30 is provided in the Table 5-2. For the purpose of the IGCEP, a power plant stands retired either as per its PPA/EPA term or relevant CCoE decision. Major retirement of generation capacity for the IGCEP 2021-30 corresponds to RFO based power plants, followed by natural gas and then RLNG based power plants.

Table 5-2: Retirement Schedule of Existing Power System

Name of the Power Station	Installed Capacity (MW)	Fuel Type	Retirement Year (FY)						
			21	22	23	27	28	29	30
GTPS Block 4 U (5-9)	144	RLNG		✓					
KAPCO 1	400	RFO			✓				
KAPCO 2	900	RFO			✓				
KAPCO 3	300	RFO			✓				
Guddu-II U(5-10)	620	Gas			✓				
Jamshoro-I U1	250	RFO			✓				
Jamshoro-II U4	200	RFO			✓				
Muzaffargarh-I U1	210	RFO			✓				
Muzaffargarh-I U2	210	RFO			✓				
Muzaffargarh-I U3	210	RFO			✓				
Muzaffargarh-II U4	320	RFO			✓				
HUBCO	1,292	RFO				✓			
Kohinoor	131	RFO				✓			
Liberty	225	Gas				✓			
Lalpir	362	RFO						✓	
AES Pakgen	365	RFO						✓	
FKPCL	172	RLNG							✓
Saba	136	RFO							✓
Total (MW)	**6,447**								

5.8. Committed Generating Units

Power Plants considered as committed projects based on the criteria stipulated in Assumption Set approved by CCoE is shown in the Figure 5-3.

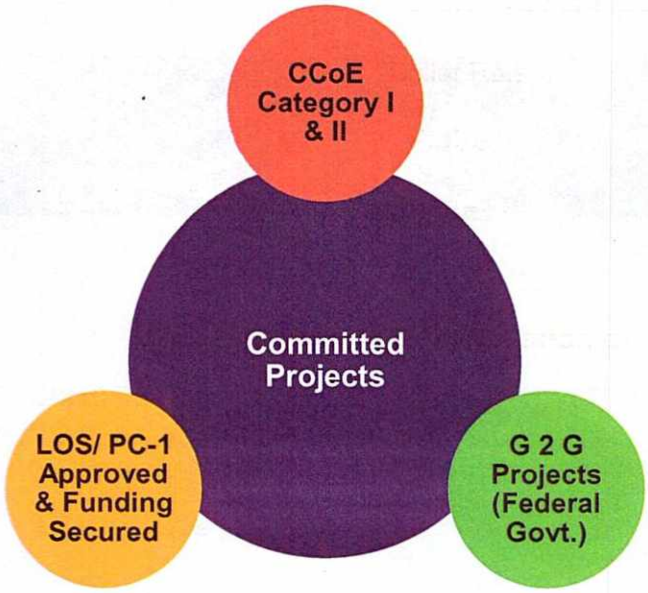


Figure 5-2: Committed Projects Criteria

5.8.1. Committed Projects

Committed projects considered in the IGCEP are listed in the Table 5-3.

Table 5-3: List of Committed Projects

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
1	Ranolia	Hydro	PEDO	17	PC-I Approved. & Financing Secured	Dec-21
2	Jabori	Hydro	PEDO	10.2	PC-I Approved. & Financing Secured	Dec-21
3	Metro_Wind	Wind	AEDB	60	Category-II Project	Dec-21
4	Lakeside	Wind	AEDB	50	Category-II Project	Dec-21
5	NASDA	Wind	AEDB	50	Category-II Project	Dec-21
6	Artistic_Wind_2	Wind	AEDB	50	Category-II Project	Dec-21
7	Din	Wind	AEDB	50	Category-II Project	Dec-21
8	Gul_Electric	Wind	AEDB	50	Category-II Project	Dec-21
9	Act_2	Wind	AEDB	50	Category-II Project	Dec-21
10	Liberty_Wind_1	Wind	AEDB	50	Category-II Project	Dec-21
11	Liberty_Wind_2	Wind	AEDB	50	Category-II Project	Dec-21
12	Indus_Energy	Wind	AEDB	50	Category-II Project	Dec-21
13	Zhenfa	Solar	AEDB	100	Category-II Project	Dec-21
14	Koto	Hydro	PEDO	40.8	PC-I Approved. & Financing Secured	Dec-21
15	Chianwali HPP	Hydro	PPDB	5.38	PC-I Approved. & Financing Secured	Dec-21
16	Lucky	Local Coal	PPIB	660	LOS (Issued)	Jan-22

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
17	Trimmu	CCGT_RLNG	PPIB	1,263	LOS (Issued)	Apr-22
18	K-3	Nuclear	PAEC	1,145	G2G	Apr-22
19	Karora	Hydro	PEDO	11.8	PC-I Approved. & Financing Secured	Mar-22
20	Thar TEL	Local Coal	PPIB	330	LOS (Issued)	Mar-22
21	Helios	Solar	AEDB	50	Category-II Project	Mar-22
22	HNDS	Solar	AEDB	50	Category-II Project	Mar-22
23	Meridian	Solar	AEDB	50	Category-II Project	Mar-22
24	Chamfall	Hydro	AJK	3.2	PC-I Approved. & Financing Secured	Mar-22
25	Thar-I (SSRL)	Local Coal	PPIB	1,320	LOS (Issued)	May-22
26	Jagran-II	Hydro	AJK	48	PC-I Approved. & Financing Secured	May-22
27	Thal Nova	Local Coal	PPIB	330	LOS (Issued)	Jun-22
28	Deg Outfall	Hydro	PPDB	4.04	PC-I Approved. & Financing Secured	Jun-22
29	Access_Electric	Solar	AEDB	11	Category-I Project	Aug-22
30	Access_Solar	Solar	AEDB	12	Category-I Project	Aug-22
31	Jamshoro Coal (Unit-I)	Imported Coal	GENCO	660	PC-I Approved. & Financing Secured	Oct-22
32	Karot	Hydro	PPIB	720	LOS (Issued)	Jun-23
33	Zorlu	Solar	PPDB	100	Category-II Project	Jun-23

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
34	Siachen	Solar	AEDB	100	Category-II Project	Jun-23
35	Gwadar	Imported Coal	PPIB	300	LOS (Issued)	Jun-23
36	Siddiqsons	Local Coal	PPIB	330	LOS (Issued)	Jun-23
37	Gorkin Matiltan	Hydro	PEDO	84	PC-I Approved. & Financing Secured	Jul-23
38	Suki Kinari	Hydro	PPIB	884	LOS (Issued)	Jun-23
39	Riali-II	Hydro	PPIB	7	LOS (Issued)	Jul-23
40	Safe	Solar	AEDB	10	Category-I Project	Sep-23
41	Manjhand	Solar	GOS	50	PC-I Approved. & Financing Secured	Sep-23
42	Western	Wind	AEDB	50	Category-II Project	Nov-23
43	Trans_Atlantic	Wind	AEDB	48	Category-II Project	Dec-23
44	Alliance	Bagasse	AEDB	30	Category-I Project	Dec-23
45	Bahawalpur	Bagasse	AEDB	31.2	Category-I Project	Dec-23
46	Faran	Bagasse	AEDB	27	Category-I Project	Dec-23
47	Hamza-II	Bagasse	AEDB	30	Category-I Project	Dec-23
48	HSM	Bagasse	AEDB	26.5	Category-I Project	Dec-23
49	Hunza	Bagasse	AEDB	50	Category-I Project	Dec-23
50	Indus	Bagasse	AEDB	31	Category-I Project	Dec-23
51	Ittefaq	Bagasse	AEDB	31	Category-I Project	Dec-23
52	Kashmir	Bagasse	AEDB	40	Category-I Project	Dec-23
53	Mehran	Bagasse	AEDB	27	Category-I Project	Dec-23

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
54	RYK_Energy	Bagasse	AEDB	25	Category-I Project	Dec-23
55	Shahtaj	Bagasse	AEDB	32	Category-I Project	Dec-23
56	Sheikhoo	Bagasse	AEDB	30	Category-I Project	Dec-23
57	TAY	Bagasse	AEDB	30	Category-I Project	Dec-23
58	Two_Star	Bagasse	AEDB	50	Category-I Project	Dec-23
59	Chapari Charkhel	Hydro	PEDO	10.56	PC-I Approved. & Financing Secured	Mar-24
60	Lawi	Hydro	PEDO	69	PC-I Approved. & Financing Secured	Apr-24
61	Tarbela_Ext_5	Hydro	WAPDA	1,530	PC-I Approved. & Financing Secured	May-24
62	CASA	Cross Border Interconnection	GOP	1000	G2G	Aug-24
63	Kathai-II	Hydro	PPIB	8	LOS (Issued)	Dec-24
64	Dasu_1	Hydro	WAPDA	2160	PC-I Approved. & Financing Secured	Unit 1-3: Apr-25 Unit 4-6: Nov-25
65	Mohmand	Hydro	WAPDA	800	PC-I Approved. & Financing Secured	Apr-26
66	Keyal Khwar	Hydro	WAPDA	128	PC-I Approved. & Financing Secured	Feb-27
67	Harpo	Hydro	WAPDA	34.5	PC-I Approved. & Financing Secured	Apr-27
68	Azad Pattan	Hydro	PPIB	700.7	LOS (Issued)	Sep-27

#	Name of Committed Project	Fuel Type	Agency	Installed Capacity (MW)	Status	Expected Schedule of Commissioning
69	Gabral Kalam	Hydro	PEDO	88	PC-I Approved. & Financing Secured	Oct-27
70	Madyan	Hydro	PEDO	157	PC-I Approved. & Financing Secured	Oct-27
71	Balakot	Hydro	PEDO	300	PC-I Approved. & Financing Secured	Nov-27
72	Kohala	Hydro	PPIB	1,124	LOS (Issued)	Dec-28
73	Diamer Bhasha	Hydro	WAPDA	4,500	PC-I Approved. & Financing Secured	Feb-29
			Total (MW):	22,415		

5.9. New Generation Options

The candidate generation technologies, selected to be fed into the model, are as follows:

a. Steam PP on Imported Coal (660 MW); reference - China HUBCO

b. Steam PP on Thar Coal (660 MW); reference - SSRL (operational data) and Siddiq Sons (cost data)

c. Combined Cycle PP on RLNG (1,263 MW); reference - Trimmu

d. Gas Turbine on RLNG (400 MW); reference – Trimmu Open Cycle (operational data) and CAPEX as per data available with PSP

e. Nuclear Steam PP on Uranium (1,100 MW); reference - PAEC candidate

f. Wind Turbine (Block of ≤ 1,000 MW); reference – Latest Tariff

g. Solar PV (Block of ≤ 1,000 MW); reference – Latest Tariff

h. Bagasse (Block of ≤ 100 MW); reference - Upfront Tariff 2017

i. Battery Energy Storage System (BESS), (100 MW with 100 MWh storage); reference - Lazard Report 2020

j. Rahim Yar khan Imported Coal Based Power Plant (660 MW)

k. Hybrid Re-powering of Existing Muzaffargarh (Unit-4), CCGT-RLNG (933 MW)

l. KAPCO Imported Coal (660 MW)

m. Jamshoro Imported Coal Unit-II (660 MW)

n. C-5 Nuclear Power Plant (1,221 MW)

o. Thar Block VI-Oracle- Local Coal Based Power Plant (1,320 MW)

5.10. Hydro Projects and Screening

Data for hydro power projects was obtained from the relevant project executing agencies. A total of 133 Hydro Candidates are given to the model for optimization. The Annualized Cost for all candidate hydro plants are indexed as per latest NEPRA available indexation and is presented in Annexure B-5.

5.11. Performance Characteristics of Generic Thermal Candidates

Generic Candidate thermal options include Gas Turbines (GTs), Combined Cycle Gas Turbines (CCGTs) using RLNG and Steam Turbines (STs) using Imported Coal, Local Coal and Nuclear Fuel. In order to develop a least cost generation expansion plan, it is necessary to examine the economic viability of each thermal option and select the least cost supply options taking into account technical characteristics, economic and financial parameters and operational requirements. Table 5-4 shows the performance characteristics of the thermal candidate plants.

Table 5-4: Performance Characteristics of Generic Thermal Power Plants

	Performance Characteristics	Imported Coal Fired Steam	Coal Fired Steam Thar	Combined Cycle on RLNG	Combustion Turbine on RLNG	Generic Nuclear PP
		660 MW	660 MW	1,263 MW	400 MW	1,100 MW
A	Net Capacity (MW)	625	607	1,243	396	1,018
	Technical Parameters					
B	Heat Rate at Maximum Load	9.3	9.23	5.88	9.464	9.73
C	Scheduled Outage (d/year)	36	36	36	30	40
D	Forced Outage (Hours)	594 (6.78%)	596 (6.8%)	350 (4%)	438 (5%)	87.6 (1%)
E	Economic Life (years)	30	30	30	30	60
	O & M Cost					
F	Fixed ($/kW/year)	25.6	26.16 + 314.2*	13.47	13.47	43
	Variable ($/MWh)	3.07	5.61	2.98	2.98	0

*314.2 is the Fixed Fuel Cost Component (FCC) of Engro Thar Coal.

The economic parameters of thermal candidate plants are highlighted in the Table 5-5.

Table 5-5: Economic Parameters of Generic Power Plants

#	Technology	Capital Cost with IDC ($/kW)	Discount Rate (%)	Fuel Price ($/Giga Joule)
1	Nuclear (1,100 MW)	4,378	10%	0.49
2	OCGT. (400 MW)	461		12.38
3	CCGT. (1,263 MW)	616		12.38
4	Imported Coal (660 MW)	1,661		2.92
5	Thar Coal (660 MW)	1,374		1.67
6	RYK Imp. Coal (660 MW)	1,240		5.40
7	Hybrid Muzaffargarh RLNG (933 MW)	421		5.54
8	KAPCO Imported Coal (660 MW)	1,394		2.94
9	Jamshoro Coal Unit 2 (660 MW)	650		4.35
10	C-5 Nuclear (1,221 MW)	4,036		0.49
11	Oracle (1,320 MW)	1,300		--
12	Battery Energy Storage System (100 MW/ 100 MWh)	386		2.39
13	Bagasse (100 MW)	930		0.49

All candidate thermal technologies are assessed and ranked in terms of annualized unit cost by using screening curve analysis. Screening curves are used to determine the best possible technology to be inducted at a particular time frame from the available supply options. Two types of screening curves are given below:

a. Annualized Cost ($/kW/yr) - Screening Curve (Annexure B-4.1)
b. Unit Generation Cost (cents/kWh) - Screening Curve (Annexure B-4.2)

Although the mechanism of plant selection by the tool is done through complex computations and optimization techniques, however, these curves give the generic idea / trend about the selection / viability of different candidate thermal power plants at various plant factors.

These curves are the plots of unit generation cost on the y-axis and the plant capacity factors on the x-axis. The total cost includes the annual capital recovery factor, fuel cost and annual

O&M cost. The plants are ranked for each range of operating factors i.e. base load, intermediate and peak load operation. The plant ranked lowest is introduced / selected first and remaining plants follow based on increasing order of merit / rank as per the system's requirement.

5.12. Economic Parameters of the Candidate REs

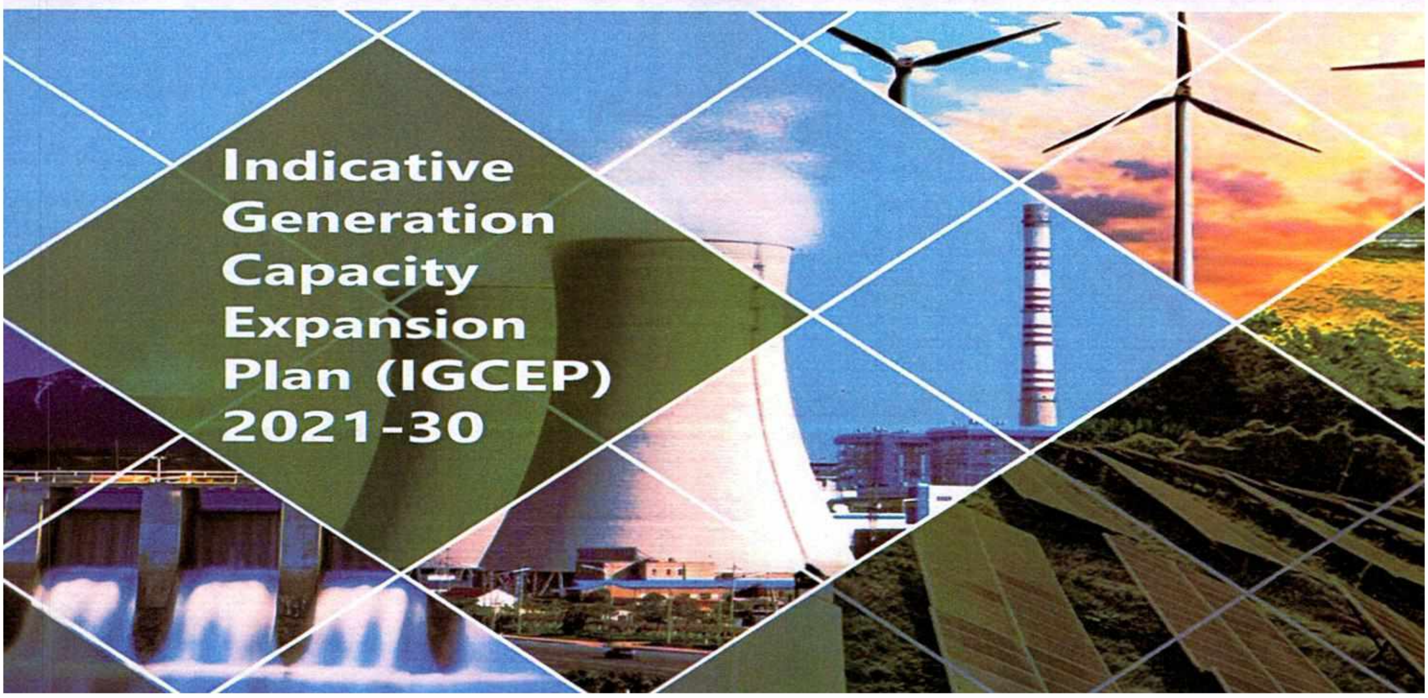
Other viable RE generation options include Solar, Wind, Battery Energy Storage System (BESS), hybrid and bagasse-based projects. In this perspective, it is important to highlight that pursuant to Assumption Set approved by CCoE, hybrid technologies are also to be modelled as candidate along with solar and wind, subject to data provision by the relevant agencies. In this regard, in response to NTDC's request to relevant agencies, AEDB has recently launched a technical & financial feasibility study for this purpose. Based on the output of the study, hybrid RE technologies will be considered for the next iteration of the IGCEP.

Consequently, due to non avilaibility of data (cost, hourly profile, etc.), hybrid technologies are not modelled in the current iteration of the IGCEP. It is to add here that apart from BESS, for all other technologies yearly block wise allocation have been made. Table 5-6 shows the economic parameters of the candidate wind and solar projects.

Table 5-6: Economic Parameters of Candidate Wind and Solar Blocks

#	Technology	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Plant Factor	Annualized Cost of Energy	
		(MW)	(Year)	($/kW/Yr)	($/KW)	(GWh)	(%)	(c/kWh)	($/kW/Yr)
1	Solar	50	2024	8.18	531	100.74	23%	3.31	66.68
2	Wind	50	2024	19.48	955	186.15	43%	3.35	124.69

6. THE IGCEP STUDY OUTPUT



6. The IGCEP Study Output

6.1. Introduction

Based on the input data and assumptions, the model was developed and simulated using the PLEXOS tool. The results obtained through optimization, based on least cost criteria and given existing system constraints are discussed in this section.

6.2. Future Demand and Capacity Additions

Chart 6-1 depicts the relationship between the projected peak demand of the system and the future installed capacity of the system, in terms of different types of energy sources for the period 2021 – 2030. 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 horizon of this plan. In the year 2021, the Installed capacity from all generation sources is around 34,776 MW whereas the demand is equivalent to 23,792 MW. From the year 2021, gap between the demand and installed capacity is steadily widening. Let us take the snapshot of two random years i.e. 2025 and 2030 to closely assess the demand and capacity situation. In the year 2025, the projected peak load stands at 29,389 MW, whereas cumulative installed capacity of the system turns out to be 48,521 MW, including 21,048 MW from REs; similarly, in the year 2030, to meet a demand of 37,129 MW an installed capacity of 61,112 MW is envisaged including a capacity of 38,339 MW from RE sources. Chart 6-1 shows that sufficient generation has been added to satisfy the specified reliability criteria and reserve requirements of the system.

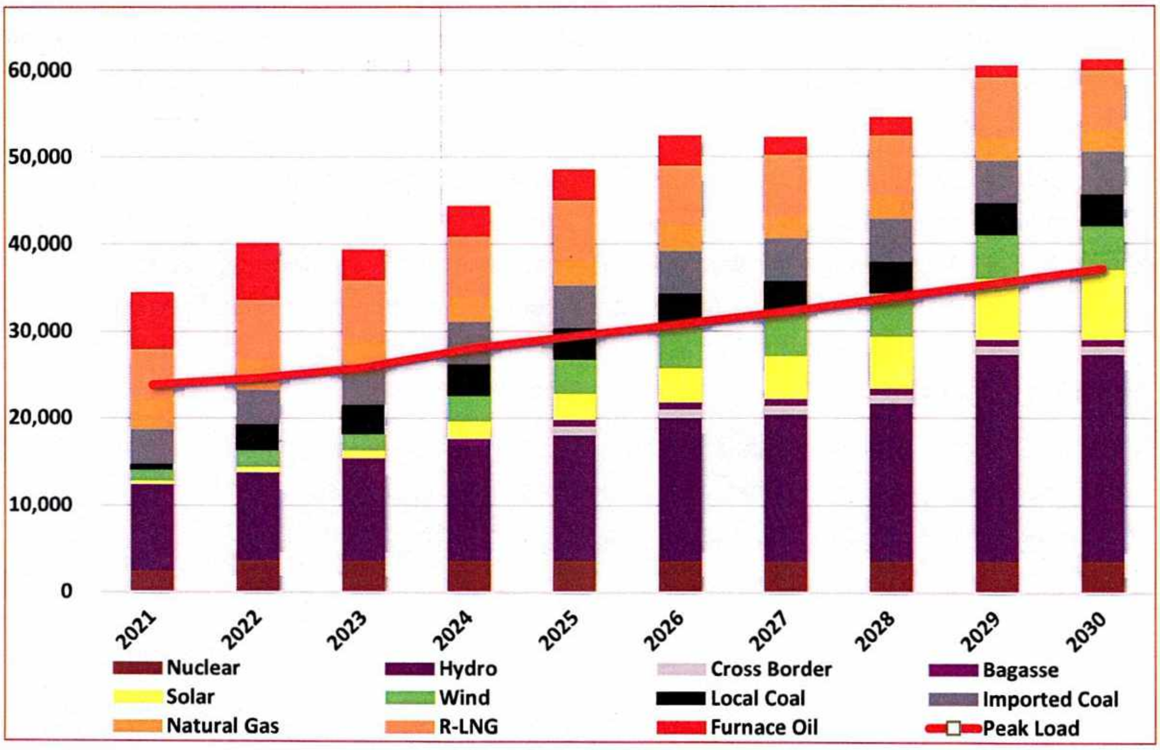


Chart 6-1: Installed Capacity vs Peak Demand (MW) 2021-30

On the other hand, energy generation by the power plants has been optimized equally with the energy forecast required by the year 2030 as shown in Chart 6-2. By the year 2030, 207,418 GWh of energy demand is met, in which 65% of generation is contributed by RE sources comprising of 1%, 8%, 8% and 46% by bagasse, wind, solar and hydro respectively.

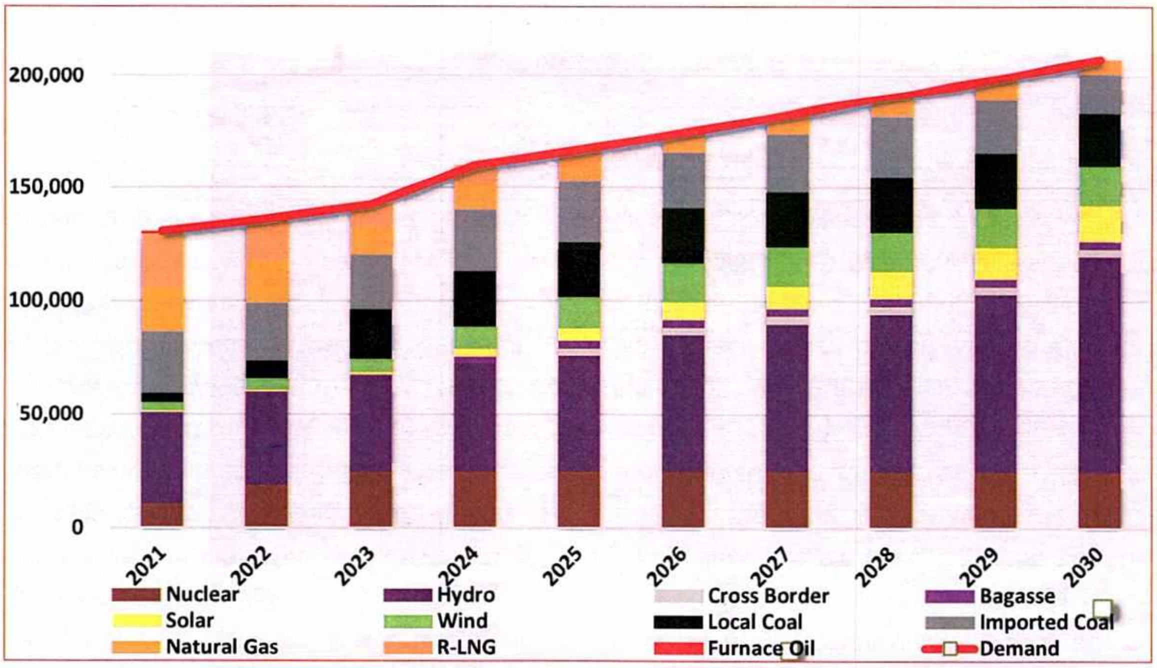


Chart 6-2: Annual Energy Generation vs Annual Energy Demand (GWh) 2021-30

The PLEXOS model optimizes wind and solar from the year 2024 in view of the techno economic viability of the technology. It is worth mentioning here that the tool optimizes 10,062 MW of candidate solar & wind power projects till 2030 and does not select any other candidate technology. Table 6-1 shows the technology wise yearly future candidate generation capacity additions by the year 2030.

Chart 6-1 shows that the capacity selected by PLEXOS after satisfying reliability criteria i.e. LOLP and reserves is sufficient enough to balance power (MW) as well as energy (GWh) demand of NTDC system by the year 2030. Energy generation by different sources / fuel types is shown in Chart 6-2. It is to be noted that although the system does have Furnace Oil (FO) based capacity available but its share in despatch from the year 2021 declines drastically, being low in merit order it is being replaced by the cheaper fuels.

Chart 6-3 shows the total share of the existing (excluding retirements), committed and candidate power plants in the installed capacity as of the year 2030. It can be seen that apart from existing installed capacity, major share is of committed power plants.

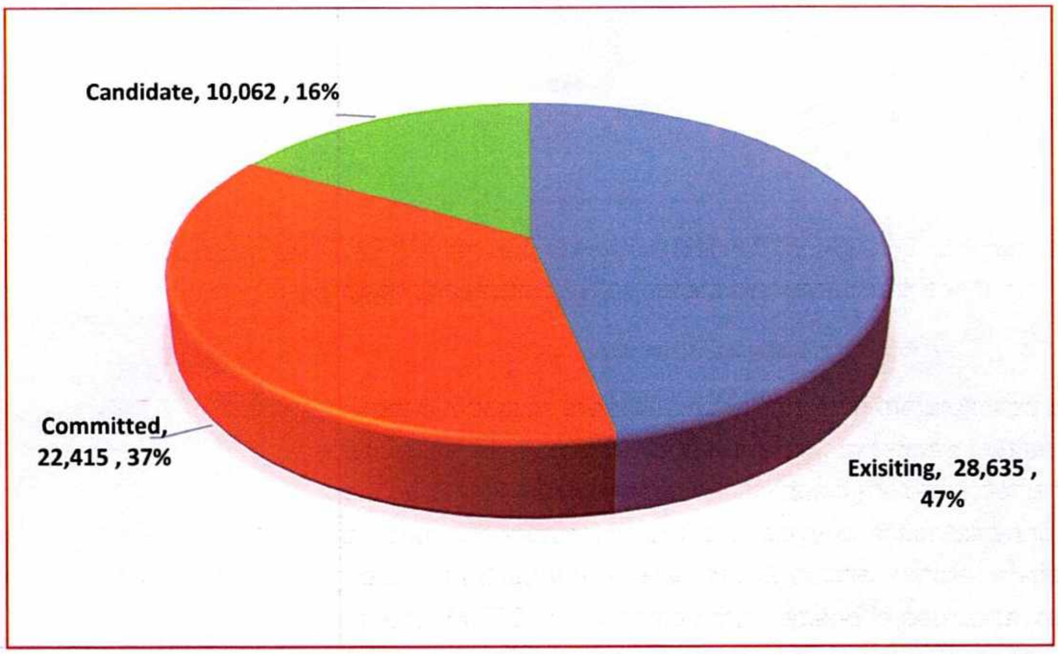
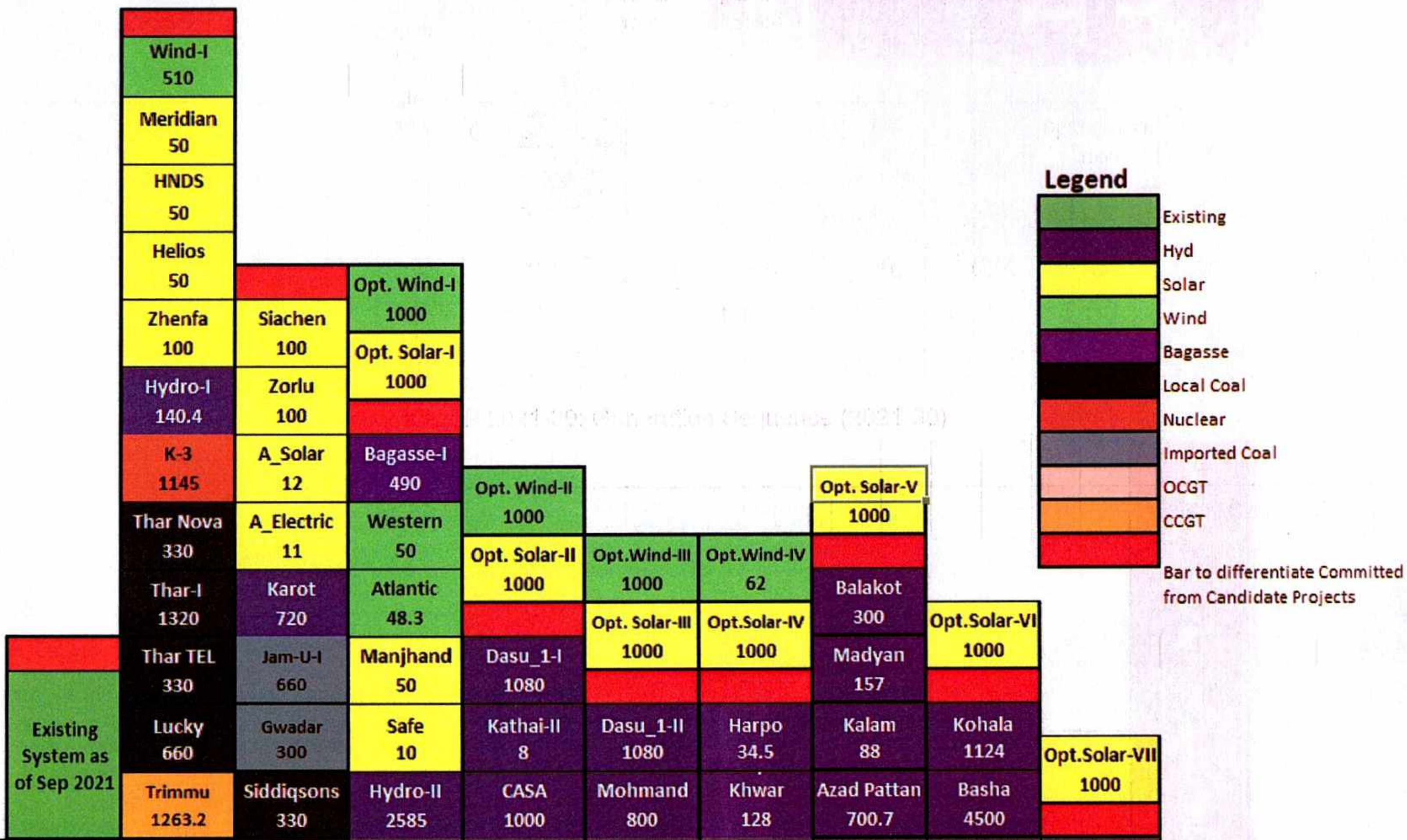


Chart 6-3: % wise Share of Total Installed capacity (MW) - 2030

Table 6-1: Candidate Generation Capacity Additions (2021-30)

Fiscal Year	Coal Fired Steam Imported Coal	Coal Fired Steam Local Coal	Combined Cycle on RLNG	Combustion Turbine on RLNG	Nuclear	Hydro	Solar	Wind	Bagasse	BESS	Per Year Capacity Addition	Cumulative Capacity Addition
	MW											
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	1,000	1,000	-	-	2,000	2,000
2025	-	-	-	-	-	-	1,000	1,000	-	-	2,000	4,000
2026	-	-	-	-	-	-	1,000	1,000	-	-	2,000	6,000
2027	-	-	-	-	-	-	1,000	62	-	-	1,062	7,062
2028	-	-	-	-	-	-	1,000	-	-	-	1,000	8,062
2029	-	-	-	-	-	-	1,000	-	-	-	1,000	9,062
2030	-	-	-	-	-	-	1,000	-	-	-	1,000	10,062
Total	-	-	-	-	-	-	**7,000**	**3,062**	-	-	**10,062**	



Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	
Commited MW	0	5,949	2,233	3,233	2,088	1,880	163	1,246	5,624	0	22,415
Candidate MW	0	0	0	2,000	2,000	2,000	1,062	1,000	1,000	1,000	10,062
Total MW	0	5,949	2,233	5,233	4,088	3,880	1,225	2,246	6,624	1,000	32,477

Figure 6-1: IGCEP 2021-30: Generation Sequence (2021-30)

Due to limited space, several committed RE projects (Hydro, Wind & Bagasse) getting commissioned in the same year are combined together in the form of blocks for the purpose of reporting in Figure 6-1. The detail of these blocks, as modelled in PLEXOS, is provided in Table 6-2.

Table-6-2: Break-up of Blocks for Hydro, Solar, Wind and Bagasse Power Plants

Sr.No.	Year	Block	Name of Project	Installed Capacity MW
1	2022	Hydro-I	Ranolia	17
2			Jabori	10
3			Koto	41
4			Chianwali HPP	5
5			Karora	12
6			Chamfall	3
7			Jagran-II	48
8			Deg Outfall	4
9		Wind-I	Act_2	50
10			Artistic_Wind_2	50
11			Din	50
12			Gul_Electric	50
13			Indus_Energy	50
14			Lakeside	50
15			Liberty_Wind_1	50
16			Liberty_Wind_2	50
17			Metro_Wind	60
18			NASDA	50
Total (2022)				650
19	2024	Hydro-II	Gorkin Matiltan	84
20			Suki Kinari	884.0
21			Riali-II	7
22			Chapari Charkhel	11
23			Lawi	69
24			Tarbela_Ext_5	1,530
20		Bagasse-I	Alliance	30.0

Sr.No.	Year	Block	Name of Project	Installed Capacity
				MW
			Bahawalpur	31.2
21			Faran	26.5
22			Hamza-II	30
23			HSM	26.5
24			Hunza	49.8
25			Indus	31
26			Ittefaq	31.2
27			Kashmir	40
28			Mehran	26.5
29			RYK_Energy	25
30			Shahtaj	32
31			Sheikhoo	30
32			Tay	30
33			Two_Star	50
Total (2024)				**3,074**

PLEXOS final output comprising year-wise addition of all committed and candidate power plants is given below in Table 6-3.

Table 6-3: PLEXOS Annual Addition of Power Plants 2021-30

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
2022							
1	Act_2	Wind	50	50	AEDB	Committed	Dec-21
2	Artistic_Wind_2	Wind	50	50	AEDB	Committed	Dec-21
3	Chianwali HPP	Hydro	5.38	5.38	PPDB	Committed	Dec-21
4	Din	Wind	50	50	AEDB	Committed	Dec-21
5	Gul_Electric	Wind	50	50	AEDB	Committed	Dec-21
6	Indus_Energy	Wind	50	50	AEDB	Committed	Dec-21
7	Jabori	Hydro	10.2	10.2	PEDO	Committed	Dec-21
8	Koto	Hydro	40.8	40.8	PEDO	Committed	Dec-21
9	Lakeside	Wind	50	50	AEDB	Committed	Dec-21
10	Liberty_Wind_1	Wind	50	50	AEDB	Committed	Dec-21
11	Liberty_Wind_2	Wind	50	50	AEDB	Committed	Dec-21
12	Metro_Wind	Wind	60	60	AEDB	Committed	Dec-21
13	NASDA	Wind	50	50	AEDB	Committed	Dec-21
14	Ranolia	Hydro	17	17	PEDO	Committed	Dec-21
15	Zhenfa	Solar	100	100	AEDB	Committed	Dec-21
16	Lucky	Local Coal	660	607	PPIB	Committed	Jan-22
17	Helios	Solar	50	50	AEDB	Committed	Mar-22
18	HNDS	Solar	50	50	AEDB	Committed	Mar-22
19	Karora	Hydro	11.8	11.8	PEDO	Committed	Mar-22
20	Meridian	Solar	50	50	AEDB	Committed	Mar-22
21	Thar TEL	Local Coal	330	300	PPIB	Committed	Mar-22
22	Chamfall	Hydro	3	3	AJK	Committed	Mar-22
23	K-3	Nuclear	1,145	1,059	PAEC	Committed	Apr-22

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
24	Trimmu	RLNG	1263	1243	PPIB	Committed	Apr-22
25	Jagran-II	Hydro	48	48	AJK	Committed	May-22
26	Thar-I (SSRL)	Local Coal	1,320	1,214	PPIB	Committed	May-22
27	Deg Outfall	Hydro	4	4	PPDB	Committed	Jun-22
28	Thal Nova	Local Coal	330	300	PPIB	Committed	Jun-22
	Generation Additions in 2022 (MW)		5,948	5,623			
	Cumulative Addition uptill 2022 (MW)		5,948	5,623			
			2023				
1	Access_Electric	Solar	11	11	AEDB	Committed	Aug-22
2	Access_Solar	Solar	12	12	AEDB	Committed	Aug-22
3	Jamshoro Coal (Unit-I)	Imported Coal	660	629	GENCO	Committed	Oct-22
4	Gwadar	Imported Coal	300	273	PPIB	Committed	Jun-23
5	Karot	Hydro	720	720	PPIB	Committed	Jun-23
6	Siachen	Solar	100	100	AEDB	Committed	Jun-23
7	Zorlu	Solar	100	100	PPDB	Committed	Jun-23
8	Siddiqsons	Local Coal	330	304	PPIB	Committed	Jun-23
	Generation Additions in 2023 (MW)		2,233	2,149			
	Cumulative Addition up till 2023 (MW)		8,181	7,772			
			2024				
1	Gorkin Matiltan	Hydro	84	84	PEDO	Committed	Jul-23
2	Riali-II	Hydro	7	7	PPIB	Committed	Jul-23
3	Suki Kinari	Hydro	884	884	PPIB	Committed	Jul-23
4	Manjhand	Solar	50	50	GOS	Committed	Sep-23
5	Safe	Solar	10	10	AEDB	Committed	Sep-23
6	Western	Wind	50	50	AEDB	Committed	Nov-23
7	Alliance	Bagasse	30	30	AEDB	Committed	Dec-23

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
8	Bahawalpur	Bagasse	31.2	31.2	AEDB	Committed	Dec-23
9	Faran	Bagasse	27	27	AEDB	Committed	Dec-23
10	Hamza-II	Bagasse	30	30	AEDB	Committed	Dec-23
11	HSM	Bagasse	26.5	26.5	AEDB	Committed	Dec-23
12	Hunza	Bagasse	50	50	AEDB	Committed	Dec-23
13	Indus	Bagasse	31	31	AEDB	Committed	Dec-23
14	Ittefaq	Bagasse	31	31	AEDB	Committed	Dec-23
15	Kashmir	Bagasse	40	40	AEDB	Committed	Dec-23
16	Mehran	Bagasse	27	27	AEDB	Committed	Dec-23
17	RYK_Energy	Bagasse	25	25	AEDB	Committed	Dec-23
18	Shahtaj	Bagasse	32	32	AEDB	Committed	Dec-23
19	Sheikhoo	Bagasse	30	30	AEDB	Committed	Dec-23
20	TAY	Bagasse	30	30	AEDB	Committed	Dec-23
21	Trans_Atlantic	Wind	48	48	AEDB	Committed	Dec-23
22	Two_Star	Bagasse	50	50	AEDB	Committed	Dec-23
23	Chapari Charkhel	Hydro	10.56	10.56	PEDO	Committed	Mar-24
24	Lawi	Hydro	69	69	PEDO	Committed	Apr-24
25	Tarbela_Ext_5	Hydro	1,530	1530	WAPDA	Committed	May-24
26	Candidate_Solar	Solar	1000	1000	To be Decided	Optimized	2024
27	Candidate_Wind	Wind	1000	1000	To be Decided	Optimized	2024
	Generation Additions in 2024 (MW)		5,233	5,233			
	Cumulative Addition up till 2024 (MW)		13,415	13,006			
			2025				
1	CASA	Cross Border Interconnection	1,000	1,000	GOP	Committed	Aug-24
2	Kathai-II	Hydro	8	8	PPIB	Committed	Dec-24
3	Dasu_1 Unit 1-3	Hydro	1,080	1,080	WAPDA	Committed	Apr-25

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
4	Candidate_Solar	Solar	1000	1000	To be Decided	Optimized	2025
5	Candidate_Wind	Wind	1000	1000	To be Decided	Optimized	2025
	Generation Additions in 2025 (MW)		4,088	4,088			
	Cumulative Addition up till 2025 (MW)		17,503	17,094			
			2026				
1	Mohmand	Hydro	800	800	WAPDA	Committed	Apr-26
2	Dasu_1 Unit 4-6	Hydro	1,080	1,080	WAPDA	Committed	Nov-25
3	Candidate_Solar	Solar	1000	1000	To be Decided	Optimized	2026
4	Candidate_Wind	Wind	1000	1000	To be Decided	Optimized	2026
	Generation Additions in 2026 (MW)		3,880	3,880			
	Cumulative Addition up till 2026 (MW)		21,383	20,974			
			2027				
1	Keyal Khwar	Hydro	128	128	WAPDA	Committed	Feb-27
2	Harpo	Hydro	34.5	34.5	WAPDA	Committed	Apr-27
3	Candidate_Solar	Solar	1000	1000	To be Decided	Optimized	2027
4	Candidate_Wind	Wind	62	62	To be Decided	Optimized	2027
	Generation Additions in 2027 (MW)		1224.5	1224.5			
	Cumulative Addition up till 2027 (MW)		22,607	22,198			
			2028				
1	Azad Pattan	Hydro	700.7	700.7	PPIB	Committed	Sep-27
2	Gabral Kalam	Hydro	88	88	PEDO	Committed	Oct-27
3	Madyan	Hydro	157	157	PEDO	Committed	Oct-27
4	Balakot	Hydro	300	300	PEDO	Committed	Nov-27
5	Candidate_Solar	Solar	1000	1000	To be Decided	Optimized	2028
	Generation Additions in 2028 (MW)		2,246	2,246			
	Cumulative Addition up till 2028 (MW)		24,853	24,444			

#	Name of Project	Fuel Type	Installed Capacity	Nominal Capacity	Agency	Status	Schedule of Commissioning
2029							
1	Kohala	Hydro	1,124	1,124	PPIB	Committed	Dec-28
2	Diamer Bhasha	Hydro	4,500	4,500	WAPDA	Committed	Feb-29
3	Candidate_Solar	Solar	1000	1000	To be Decided	Optimized	2029
Generation Additions in 2029 (MW)			6,624	6,624			
Cumulative Addition up till 2029 (MW)			31,477	31,068			
2030							
1	Candidate_Solar	Solar	1000	1000	To be Decided	Optimized	2030
Generation Additions in 2030 (MW)			1,000	1,000			
Cumulative Addition up till 2030 (MW)			32,477	32,068			

6.3. Annual Capacity Factors

The annual capacity factors information based on the Installed Capacity for the corresponding year, as shown in the Table 6-4 is one of the most important output of the PLEXOS tool. The drastic change in capacity factor of some plants between the years 2021 to 2030 is due to certain rationale. For example, up to January 2022, the power purchaser is obligated to utilize / despatch 66% of the three (03) RLNG based power plants i.e. Haveli Bahadur Shah, Balloki and Bhikki, under contractual binding. Beyond January 2022, these RLNG based plants will be despatched as per merit order. Similarly, for the existing imported coal-based power plants (Sahiwal CFPP, China HUBCO CFPP and Port Qasim CFPP) as well as three (03) existing local gas based power plants (Engro, Foundation & Uch-II), a minimum annual despatch of 50% is modelled as per contractual obligation, from the date of their respective CODs till the expiry of their PPAs.

Table 6-4: Annual Capacity Factors (%age)

#	Plant Name	Fuel	21	22	23	24	25	26	27	28	29	30
			(%)									
1	Engro	Gas	81.26	79.37	50.60	50.47	50.59	50.58	50.59	50.46	50.60	50.59
2	Foundation	Gas	78.04	77.86	76.59	73.02	62.64	50.47	50.47	50.35	50.48	50.47
3	Guddu-I	Gas	0.00	0.00	2.80	16.39	6.32	4.05	1.74	6.35	11.44	0.00
4	Guddu-II	Gas	60.17	55.68	41.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Guddu-V (747)	Gas	72.93	72.79	49.39	50.81	49.45	11.67	12.09	17.70	19.32	5.47
7	Liberty	Gas	69.99	63.16	40.36	38.11	39.01	38.11	37.63	0.00	0.00	0.00
8	Uch	Gas	78.29	75.19	41.66	36.33	35.92	33.88	33.88	33.89	36.67	33.89
9	Uch-II	Gas	81.80	81.39	80.26	77.49	77.10	49.62	49.63	49.47	49.67	49.67
10	KAPCO 1	RFO	14.68	16.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	KAPCO 2	RFO	3.11	4.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12	KAPCO 3	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13	Balloki	RLNG	65.72	42.45	3.56	1.19	0.10	0.11	0.12	0.39	1.32	0.00
14	Bhikki	RLNG	65.70	26.22	0.44	0.00	0.00	0.00	0.00	0.00	0.44	0.00
15	FKPCL	RLNG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	GTPS Block 4	RLNG	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	Halmore	RLNG	24.06	11.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	Haveli	RLNG	65.69	53.48	12.35	6.77	1.05	0.53	1.06	2.04	2.78	0.00
19	Nandipur	RLNG	15.21	4.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Orient	RLNG	31.94	17.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	Rousch	RLNG	9.27	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	Saif	RLNG	24.47	13.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	Saphire	RLNG	26.11	16.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	Trimmu	RLNG	0.00	92.54	78.28	64.11	25.94	14.26	15.41	18.06	19.45	6.20
25	AGL	RFO	7.61	10.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	Atlas	RFO	0.12	1.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

#	Plant Name	Fuel	21	22	23	24	25	26	27	28	29	30
			(%)									
27	HuB N	RFO	0.00	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	Kohinoor	RFO	0.12	1.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	Liberty Tech	RFO	0.87	1.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	Nishat C	RFO	1.45	1.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	Nishat P	RFO	6.11	9.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	Davis	RLNG	1.76	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	Altern	Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	China HUBCO	Imp.Coal	80.18	80.12	79.92	79.40	78.71	59.38	68.32	77.64	52.15	50.25
35	Gwadar	Imp.Coal	0.00	0.00	0.00	77.17	76.99	75.73	76.41	76.87	76.74	13.04
36	Jamshoro Coal	Imp.Coal	0.00	0.00	72.00	74.42	74.05	71.99	72.40	74.39	69.97	11.42
37	Port Qasim	Imp.Coal	79.19	79.15	50.35	50.26	50.33	50.33	50.33	50.21	50.32	50.29
38	Sahiwal Coal	Imp.Coal	75.22	62.18	50.41	50.25	50.35	50.35	50.35	50.17	50.35	50.32
39	Engro Thar	Local Coal	67.97	67.89	67.77	67.92	67.97	67.72	67.83	68.01	67.90	66.33
40	Lucky	Local Coal	0.00	77.39	77.85	77.96	78.09	77.43	77.72	77.92	77.81	63.35
41	Siddiqsons	Local Coal	0.00	0.00	0.00	78.15	78.17	78.22	78.23	78.22	78.27	78.28
42	Thal Nova	Local Coal	0.00	0.00	76.93	77.08	77.12	76.92	77.18	77.19	77.24	75.91
43	Thar TEL	Local Coal	0.00	81.00	76.93	77.08	77.12	77.13	77.19	77.19	77.24	75.76
44	Thar-I (SSRL)	Local Coal	0.00	84.21	77.87	78.04	78.03	78.08	78.09	78.09	78.14	77.84
45	C-1	Nuclear	73.45	73.44	73.45	73.47	73.46	73.47	73.47	73.46	73.49	73.48
46	C-2	Nuclear	70.21	70.20	70.21	70.22	70.22	70.23	70.23	70.21	70.24	70.24
47	C-3	Nuclear	73.72	73.71	73.71	73.73	73.73	73.74	73.74	73.72	73.75	73.75
48	C-4	Nuclear	73.72	73.71	73.71	73.73	73.73	73.74	73.74	73.72	73.75	73.75
49	K-2	Nuclear	86.75	81.13	81.11	81.40	81.29	81.32	81.33	81.31	81.39	81.42
50	K-3	Nuclear	0.00	86.39	81.01	81.39	81.25	81.32	81.33	81.31	81.39	81.41
51	AES Pakgen	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	HUBCO	RFO	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
53	Jamshoro-I U1	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
54	Jamshoro-II U4	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
55	Lalpir	RFO	0.12	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	Muzaffargarh-I U1	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57	Muzaffargarh-I U2	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
58	Muzaffargarh-I U3	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
59	Muzaffargarh-II U4	RFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	Saba	RFO	0.04	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	Allai Khwar	Hydro	43.46	43.46	43.60	43.58	43.63	43.63	43.60	43.54	43.63	43.63

#	Plant Name	Fuel	21	22	23	24	25	26	27	28	29	30
			(%)									
62	Chashma	Hydro	46.62	46.62	46.62	46.63	46.62	46.62	46.62	46.63	46.62	46.62
63	Daral Khwar	Hydro	46.38	46.56	46.18	46.59	46.69	46.87	46.82	46.85	46.84	46.95
64	Dubair Khwar	Hydro	48.80	48.99	48.73	48.89	48.99	49.00	48.99	48.90	49.00	49.00
65	Ghazi Brotha	Hydro	51.16	51.16	51.16	51.14	51.16	51.16	51.16	51.14	51.16	51.16
66	Golen Gol	Hydro	10.58	10.58	10.58	10.56	10.58	10.58	10.58	10.56	10.58	10.58
67	Gulpur	Hydro	53.27	53.47	53.60	53.46	53.31	53.54	53.65	53.73	53.75	53.75
68	Jagran-I	Hydro	48.85	48.74	48.28	48.74	48.85	48.85	48.85	48.74	48.85	48.85
69	Jhing	Hydro	48.83	48.83	48.83	48.72	48.83	48.83	48.83	48.72	48.83	48.83
70	Jinnah	Hydro	23.98	23.98	23.98	23.95	23.98	23.98	23.98	23.95	23.98	23.98
71	Khan Khwar	Hydro	43.36	43.35	43.35	43.31	43.34	43.36	43.35	43.33	43.37	43.37
72	Malakand-III	Hydro	51.30	51.23	50.91	51.21	51.30	51.30	51.30	51.21	51.30	51.30
73	Mangla	Hydro	51.97	52.29	53.10	52.13	52.17	52.27	52.95	52.13	52.09	52.09
74	Marala	Hydro	64.17	64.32	64.15	64.46	64.48	64.54	64.56	64.53	64.61	64.61
75	Neelum Jehlum	Hydro	57.14	57.34	57.17	57.48	57.51	57.49	57.61	57.47	57.52	57.63
76	New Bong	Hydro	63.68	63.62	63.75	63.88	63.91	63.91	63.91	63.88	63.91	63.91
77	Pak Pattan	Hydro	64.21	64.33	64.22	64.45	64.47	64.53	64.54	64.51	64.61	64.58
78	Patrind	Hydro	47.67	47.58	47.55	47.58	47.66	47.68	47.69	47.62	47.71	47.73
79	Small Hydel	Hydro	34.14	34.14	33.96	34.20	34.22	34.22	34.23	34.26	34.29	34.29
80	Tarbela 1-14	Hydro	48.10	48.13	48.10	48.07	48.13	48.13	48.13	48.07	48.13	48.12
81	Tarbela_Ext_4	Hydro	30.35	30.35	30.36	30.31	30.36	30.36	30.36	30.31	30.36	30.36
82	Warsak	Hydro	45.99	45.87	45.78	46.06	46.12	46.12	46.12	46.03	46.12	46.12
83	Azad Pattan	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.17	52.17	52.17
84	Balakot	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.09	38.13	38.09
85	Chamfall	Hydro	0.00	48.79	48.79	48.68	48.79	48.79	48.79	48.68	48.79	48.79
86	Chapari Charkhel	Hydro	0.00	0.00	0.00	80.52	80.47	80.52	80.57	80.58	80.56	80.72
87	Chianwali	Hydro	0.00	64.54	64.20	64.49	64.52	64.54	64.52	64.50	64.61	64.59
88	Dasu_1	Hydro	0.00	0.00	0.00	0.00	60.13	54.48	60.13	60.04	60.14	60.19
89	Deg Outfall	Hydro	0.00	64.48	64.19	64.48	64.48	64.54	64.52	64.50	64.61	64.61
90	Diamer Bhasha	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.23	44.23
91	Gabral Kalam	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.32	41.35	41.32
92	Gorkin Matiltan	Hydro	0.00	0.00	0.00	44.73	44.73	44.68	44.52	44.37	44.73	44.65
93	Harpo	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	50.24	50.24	50.30	50.23
94	Jabori	Hydro	0.00	76.80	76.76	77.15	77.12	77.13	77.14	77.17	77.18	77.22
95	Jagran-II	Hydro	0.00	48.84	48.84	48.73	48.84	48.84	48.84	48.73	48.84	48.84
96	Karora	Hydro	0.00	64.68	64.22	64.62	64.58	64.62	64.68	64.67	64.67	64.79
97	Karot	Hydro	0.00	0.00	48.44	48.37	48.43	48.44	48.44	48.38	48.43	48.44

#	Plant Name	Fuel	21	22	23	24	25	26	27	28	29	30
			(%)									
98	Kathai-II	Hydro	0.00	0.00	0.00	0.00	60.38	60.47	60.44	60.38	60.51	60.50
99	Keyal Khwar	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	29.28	29.28	29.36	29.35
100	Kohala	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.39	63.39
101	Koto	Hydro	0.00	57.40	56.53	57.45	57.53	57.40	57.37	57.28	57.30	57.54
102	Lawi	Hydro	0.00	0.00	0.00	48.08	48.08	48.08	48.08	47.99	48.08	48.05
103	Madyan	Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.66	52.66	52.66
104	Mohmand	Hydro	0.00	0.00	0.00	0.00	0.00	42.94	43.01	42.94	43.01	43.01
105	Ranolia	Hydro	0.00	61.89	61.69	61.78	61.88	61.89	61.86	61.79	61.94	61.94
106	Riali-II	Hydro	0.00	0.00	0.00	55.44	55.54	55.55	55.54	55.44	55.57	55.57
107	Suki Kinari	Hydro	0.00	0.00	40.38	40.30	40.38	40.38	40.38	40.30	40.38	40.38
108	Tarbela_Ext_5	Hydro	0.00	0.00	0.00	0.00	10.05	10.05	10.05	10.02	10.05	10.05
109	CASA	Cross Border	0.00	0.00	0.00	0.00	39.52	39.25	39.26	39.12	39.27	39.22
110	Act	Wind	31.41	31.41	31.41	31.35	31.41	31.41	31.41	31.35	31.41	31.41
111	Act_2	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
112	Artistic_wind	Wind	35.24	35.24	35.24	35.20	35.24	35.24	35.24	35.20	35.24	35.24
113	Artistic_Wind_2	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
114	Dawood	Wind	31.41	31.41	31.41	31.35	31.41	31.41	31.41	31.35	31.41	31.41
115	Din	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
116	FFC	Wind	33.50	33.50	33.50	33.46	33.50	33.50	33.50	33.46	33.50	33.50
117	FWEL-I	Wind	33.50	33.50	33.50	33.46	33.50	33.50	33.50	33.46	33.50	33.50
118	FWEL-II	Wind	33.50	33.50	33.50	33.46	33.50	33.50	33.50	33.46	33.50	33.50
119	Gul Ahmed	Wind	31.41	31.41	31.41	31.35	31.41	31.41	31.41	31.35	31.41	31.41
120	Gul_Electric	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
121	Hawa	Wind	35.24	35.24	35.24	35.20	35.24	35.24	35.24	35.20	35.24	35.24
122	Indus_Energy	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
123	Jhimpir	Wind	35.24	35.24	35.24	35.20	35.24	35.24	35.24	35.20	35.24	35.24
124	Lakeside	Wind	0.00	39.00	39.00	38.92	39.00	39.00	39.00	38.92	39.00	39.00
125	Liberty_Wind_1	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
126	Liberty_Wind_2	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
127	Master	Wind	31.41	31.41	31.41	31.35	31.41	31.41	31.41	31.35	31.41	31.41
128	Master_Green	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
129	Metro_Power	Wind	32.00	32.00	32.00	31.95	32.00	32.00	32.00	31.95	32.00	32.00
130	Metro_Wind	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
131	NASDA	Wind	0.00	38.92	39.00	38.92	39.00	39.00	39.00	38.92	39.00	39.00
132	New_Wind	Wind	0.00	0.00	0.00	41.79	41.88	41.88	41.88	41.79	41.88	41.88
133	Sachal	Wind	31.41	31.41	31.41	31.35	31.41	31.41	31.41	31.35	31.41	31.41

#	Plant Name	Fuel	21	22	23	24	25	26	27	28	29	30
			(%)									
134	Sapphire_Wind	Wind	31.41	31.41	31.41	31.35	31.41	31.41	31.41	31.35	31.41	31.41
135	Tenaga	Wind	31.41	31.41	31.41	31.35	31.41	31.41	31.41	31.35	31.41	31.41
136	Three_Gorges_I	Wind	32.00	32.00	32.00	31.95	32.00	32.00	32.00	31.95	32.00	32.00
137	Three_Gorges_II	Wind	35.24	35.24	35.24	35.20	35.24	35.24	35.24	35.20	35.24	35.24
138	Three_Gorges_III	Wind	35.24	35.24	35.24	35.20	35.24	35.24	35.24	35.20	35.24	35.24
139	Trans_Atlantic	Wind	0.00	0.00	0.00	41.88	41.88	41.88	41.88	41.79	41.88	41.88
140	Tricom	Wind	0.00	38.55	38.55	38.47	38.55	38.55	38.55	38.47	38.55	38.55
141	Tricon_A	Wind	35.24	35.24	35.24	35.20	35.24	35.24	35.24	35.20	35.24	35.24
142	Tricon_B	Wind	35.24	35.24	35.24	35.20	35.24	35.24	35.24	35.20	35.24	35.24
143	Tricon_C	Wind	35.24	35.24	35.24	35.20	35.24	35.24	35.24	35.20	35.24	35.24
144	UEP	Wind	31.41	31.41	31.41	31.35	31.41	31.41	31.41	31.35	31.41	31.41
145	Western	Wind	0.00	0.00	0.00	38.55	38.55	38.55	38.55	38.47	38.55	38.55
146	Yunus	Wind	31.41	31.41	31.41	31.35	31.41	31.41	31.41	31.35	31.41	31.41
147	Zephyr	Wind	35.24	35.24	35.24	35.20	35.24	35.24	35.24	35.20	35.24	35.24
148	Zorlu_Wind	Wind	32.00	32.00	32.00	31.95	32.00	32.00	32.00	31.95	32.00	32.00
149	Access_Electric	Solar	0.00	0.00	19.75	19.70	19.75	19.75	19.75	19.70	19.75	19.75
150	Access_Solar	Solar	0.00	0.00	19.75	19.70	19.75	19.75	19.75	19.70	19.75	19.75
151	Appolo	Solar	17.50	17.50	17.50	17.45	17.50	17.50	17.50	17.45	17.50	17.50
152	Best	Solar	17.50	17.50	17.50	17.45	17.50	17.50	17.50	17.45	17.50	17.50
153	Crest	Solar	17.50	17.50	17.50	17.45	17.50	17.50	17.50	17.45	17.50	17.50
154	Helios	Solar	0.00	23.27	23.27	23.21	23.27	23.27	23.27	23.21	23.27	23.27
155	HNDS	Solar	0.00	23.27	23.27	23.21	23.27	23.27	23.27	23.21	23.27	23.27
156	Manjhand	Solar	0.00	0.00	0.00	23.13	23.27	23.27	23.27	23.21	23.27	23.27
157	Meridian	Solar	0.00	23.27	23.27	23.21	23.27	23.27	23.27	23.21	23.27	23.27
158	New_Solar	Solar	0.00	0.00	0.00	23.21	23.27	23.27	23.27	23.21	23.27	23.27
159	QA_Solar	Solar	17.50	17.50	17.50	17.45	17.50	17.50	17.50	17.45	17.50	17.50
160	Safe	Solar	0.00	0.00	0.00	21.87	22.00	22.00	22.00	21.94	22.00	22.00
161	Siachen	Solar	0.00	0.00	23.27	23.21	23.27	23.27	23.27	23.21	23.27	23.27
162	Zhenfa	Solar	0.00	22.12	22.00	21.94	22.00	22.00	22.00	21.94	22.00	22.00
163	Zorlu	Solar	0.00	0.00	19.75	19.70	19.75	19.75	19.75	19.70	19.75	19.75
164	Alliance	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
165	Almoiz	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
166	Bahawalpur	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
167	Chanar	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
168	Chiniot	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
169	Faran	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68

#	Plant Name	Fuel	21	22	23	24	25	26	27	28	29	30
			(%)									
170	Hamza	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
171	Hamza-II	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
172	HSM	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
173	Hunza	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
174	Indus	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
175	Ittefaq	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
176	JDW-II	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
177	JDW-III	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
178	Kashmir	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
179	Mehran	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
180	RYK_Energy	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
181	Ryk_Mills	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
182	Shahtaj	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
183	Sheikhoo	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
184	TAY	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68
185	Thal_Layyah	Bagasse	45.62	45.62	45.62	45.77	45.62	45.62	45.62	45.77	45.62	45.62
186	Two_Star	Bagasse	0.00	0.00	0.00	54.68	54.68	54.68	54.68	54.81	54.68	54.68

(All numbers in red color, in this table, represent retirement of the corresponding plant.)

6.4. Year-wise Discounted and Un-Discounted Cost

The year wise cost breakup is shown in Table 6-5 and 6-6.

Table 6-5: Year wise Discounted Cost

Year	Present Worth Cost for Each Year of the Plan Horizon				
	Annualized Construction Cost	FO&M Cost	Generation Cost	Total Cost	Objective Function (Cumulative)
	(k$)				
2021	-	1,719,673	4,762,535	6,482,208	6,482,208
2022	-	1,795,475	4,098,146	5,893,620	12,375,828
2023	-	2,002,553	2,553,122	4,555,675	16,931,503
2024	116,128	1,891,232	2,273,541	4,280,901	21,212,404
2025	209,034	1,753,384	1,820,069	3,782,487	24,994,891
2026	282,379	1,630,282	1,435,285	3,347,946	28,342,837
2027	286,638	1,482,832	1,327,244	3,096,713	31,439,551
2028	283,815	1,352,689	1,260,264	2,896,768	34,336,319
2029	278,366	1,251,811	1,111,128	2,641,305	36,977,624
2030	270,908	1,167,534	830,136	2,268,578	39,246,201

Table 6-6: Year wise Un-Discounted Cost

Year	Un-Discounted Cost for Each Year of the Plan Horizon				
	Annualized Construction Cost	FO&M Cost	Generation Cost	Total Cost	Objective Function (Cumulative)
	(k$)				
2021	-	1,719,673	4,762,535	6,482,208	6,482,208
2022	-	1,975,022	4,507,960	6,482,982	12,965,190
2023	-	2,423,090	3,089,278	5,512,367	18,477,557
2024	154,566	2,517,230	3,026,084	5,697,879	24,175,436
2025	306,047	2,567,130	2,664,762	5,537,940	29,713,376

Year	Un-Discounted Cost for Each Year of the Plan Horizon				
	Annualized Construction Cost	FO&M Cost	Generation Cost	Total Cost	Objective Function (Cumulative)
	(k$)				
2026	454,774	2,625,586	2,311,541	5,391,901	35,105,276
2027	507,796	2,626,927	2,351,293	5,486,017	40,591,293
2028	553,075	2,636,009	2,455,898	5,644,982	46,236,275
2029	596,702	2,683,368	2,381,802	5,661,871	51,898,146
2030	638,786	2,752,985	1,957,416	5,349,187	57,247,333

6.5. Indigenization of Energy Mix

World Energy Council defines energy security as the management of primary energy supply from domestic/indigenous and external sources, reliability of energy infrastructure, ability to meet current and future demand. Energy security reflects a nation's capacity to meet current and future demand reliably and bounce back swiftly from system shocks with minimal disruption to supplies. Pakistan ranks #99 among 110 countries in terms of energy security by the World Energy Council for the year 2020.

Pakistan imports nearly one third of its energy resources in the form of oil, coal, and RLNG, and currently 47% of existing installed capacity relies on imported fuel for energy generation. Pakistan remains an energy insecure country in context of the on-going economic situation of Pakistan. Large reliance on imported fuel for firm supply of energy not only increases the import bill of the country, but also put Pakistan susceptible to ever changing global and geo politics.

The IGCEP 2021-30 deals with long-term energy security with timely investments to supply energy in line with economic developments and environmental needs. According to IGCEP 2021-30 simulation results, indigenization ratio, which is ratio of electrical energy generated by indigenize generation resources to the electrical energy generated by all generation resources, has been computed as shown in Chart 6-4, the IGCEP aims to achieve by the year 2030 pertaining to electric power generation. In 2020-21, the indigenization ratio of energy is 60% that increases with a steep slope to 75.9% by the year 2023 due to inclusion of local coal, hydro, wind and solar based power plants. Subsequently, the indigenization ratio turns out to be around 90.8% until 2030. This remains an invaluable aspect for Pakistan power sector on the part of IGCEP 2021-30.

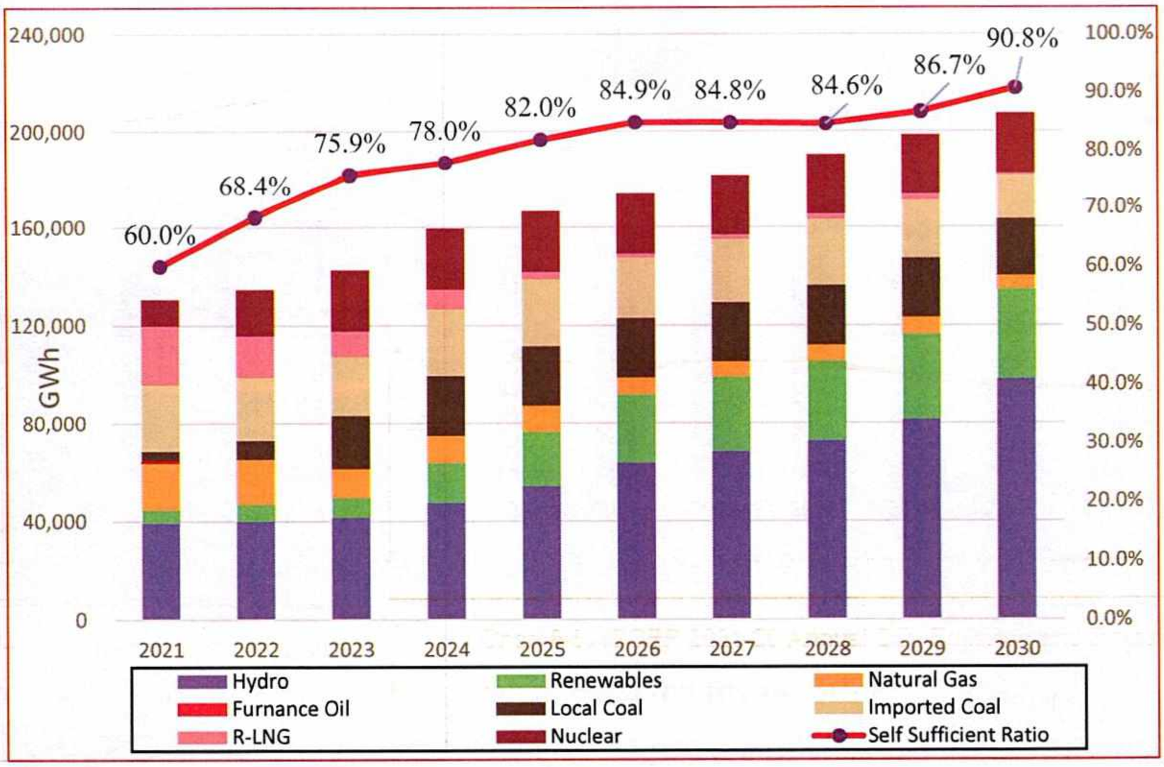


Chart 6-4: IGCEP 2021-30 Indigenization Ratio of Primary Energy

6.6. Clean and Green Power for Pakistan

Pakistan, like other South Asian countries, grapples with the challenges of a large and growing population, combined with rapidly growing energy needs. Heavily dependent on fossil-fuel imports, the country finds itself vulnerable to global oil price volatility and effects of increased carbon footprint due to power generation by fossil-fuel based technologies.

Pakistan has abundant renewable energy resources that can be utilized for power generation. Hydropower, with its potential in the northern part of the country, has traditionally been the most prominent source of renewable energy in Pakistan. In addition to hydropower potential, Pakistan is blessed with huge variable renewable resources, however, its harnessing, in true sense, is yet to be materialized.

Pakistan ranks #26 globally, #10 in Asia, #2 among SAARC member states in carbon emissions index, with 249 $MtCO_2$ territorial emissions, all GHG emissions from a country's territory, apart from those associated with international aviation and shipping, in 2019 according to the Global Carbon Atlas.

The IGCEP 2021-30 addresses the pursuit of low-carbon energy alternatives for electric power generation, to sustain the relatively low carbon emissions levels, to bolster energy security and to spur sustainable economic growth in the country. Based on the IGCEP output, carbon emissions have been calculated for existing and upcoming power generation which is shown in Chart 6-4. Carbon emissions in the country by power generation accounts for 0.356 kg-CO_2/kWh in year 2021 and this indicator reduces to 0.198 kg-CO_2/kWh by year 2030 which is even less than current average of the OECD countries.

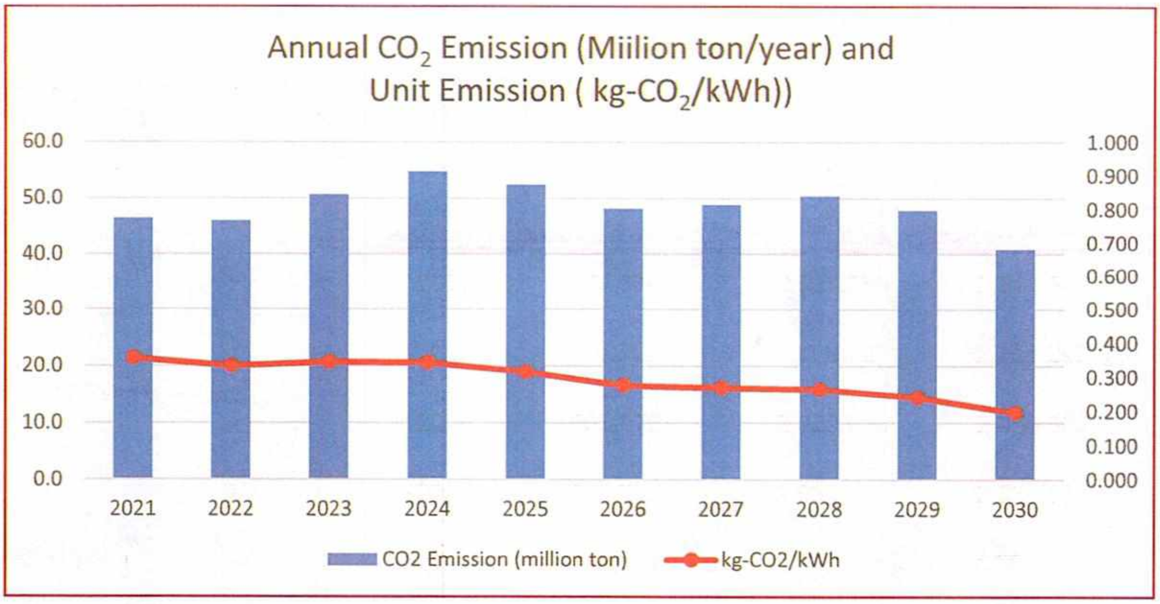


Chart 6-5: IGCEP 2021-30 Annual CO_2 Emission and Emission per Unit of Generation

6.7. Salient Features of the IGCEP

In order to balance a projected peak load of 37,129 MW by the year 2030, the PLEXOS model proposes 61,112 MW of installed generation capacity; salient features of the study are as follows:

a. Significant Induction of REs (clean and indigenous)
b. Tapping of indigenous coal-based power
c. Balancing the overall basket price with increased share of hydro power
d. Optimal indigenization: less reliance on imported fuel i.e. coal, RFO, RLNG etc.
e. Substantial reduction in carbon emission owing to induction of REs and hydro

Meanwhile, by the year 2030, a capacity of 6,447 MW is meant to be retired. In order to provide a quick understanding of the generation mix of the IGCEP 2021-30, the report includes the Table 6-7 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 period of this plan, are further illustrated by the Chart 6-5 through 6-7, Chart 6-8 through 6-10 and Chart 6-11 through 6-13 respectively.

Table 6-7: Year wise Installed Capacity Addition (MW)

Year	Net Capacity Addition Over the Plan Period (2021-30)										
	Local Coal	Hydro	RLNG	Nuclear	Imported Coal	RE	Natural Gas	Furnace Oil	Cross Border	Yearly Addition	Cumulative Total
	(MW)										
2021	660	9,698	5,839	2,490	3,960	1,995	3,427	6,506	0	34,575	-
2022	2,310	210	1,119	1,145	0	760	0	0	0	5,544	40,119
2023	330	1,674	0	0	660	222	-620	-3,000	0	-734	39,385
2024	330	1,701	0	0	300	2,648	0	0	0	4,978	44,363
2025	0	1,158	0	0	0	2,000	0	0	1,000	4,158	48,521
2026	0	1,950	0	0	0	2,000	0	0	0	3,950	52,471
2027	0	393	0	0	0	1,061	-225	-1,423	0	-194	52,277
2028	0	1,246	0	0	0	1,000	0	0	0	2,246	54,523
2029	0	5,624	0	0	0	1,000	0	-727	0	5,897	60,420
2030	0	0	-172	0	0	1,000	0	-136	0	692	61,112
Total	3,630	23,653	6,786	3,635	4,920	13,685	2,582	1,220	1,000	61,112	

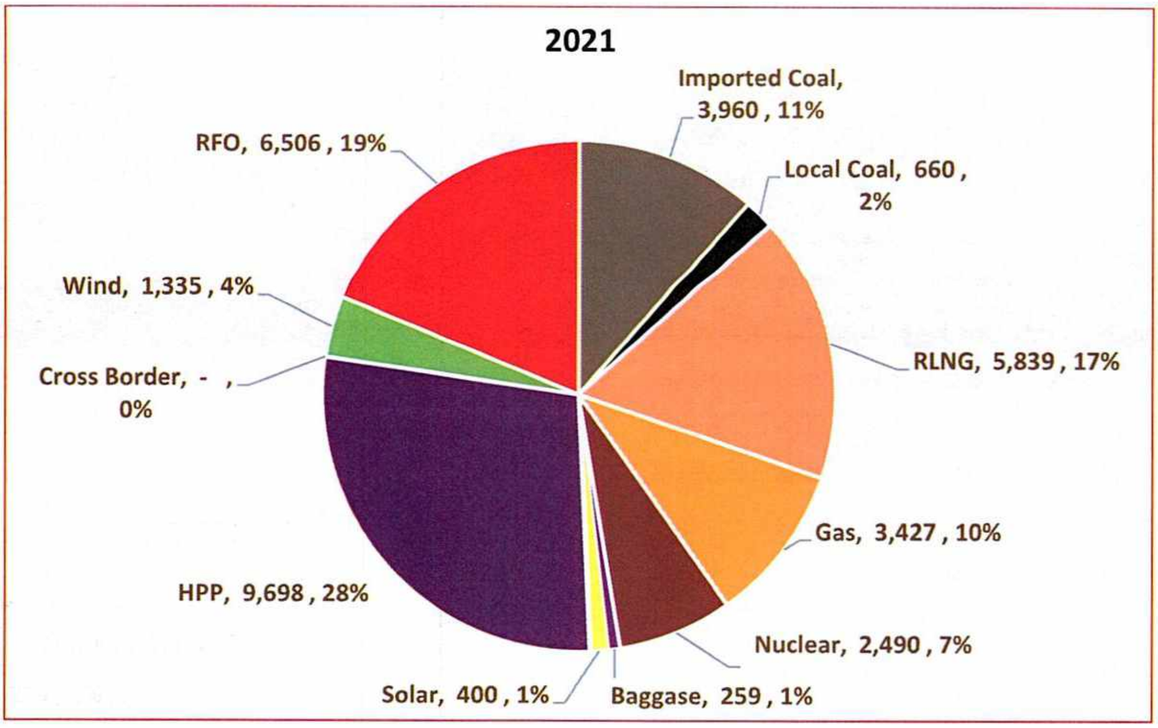


Chart 6-6: The IGCEP Generation Mix 2021 (MW)

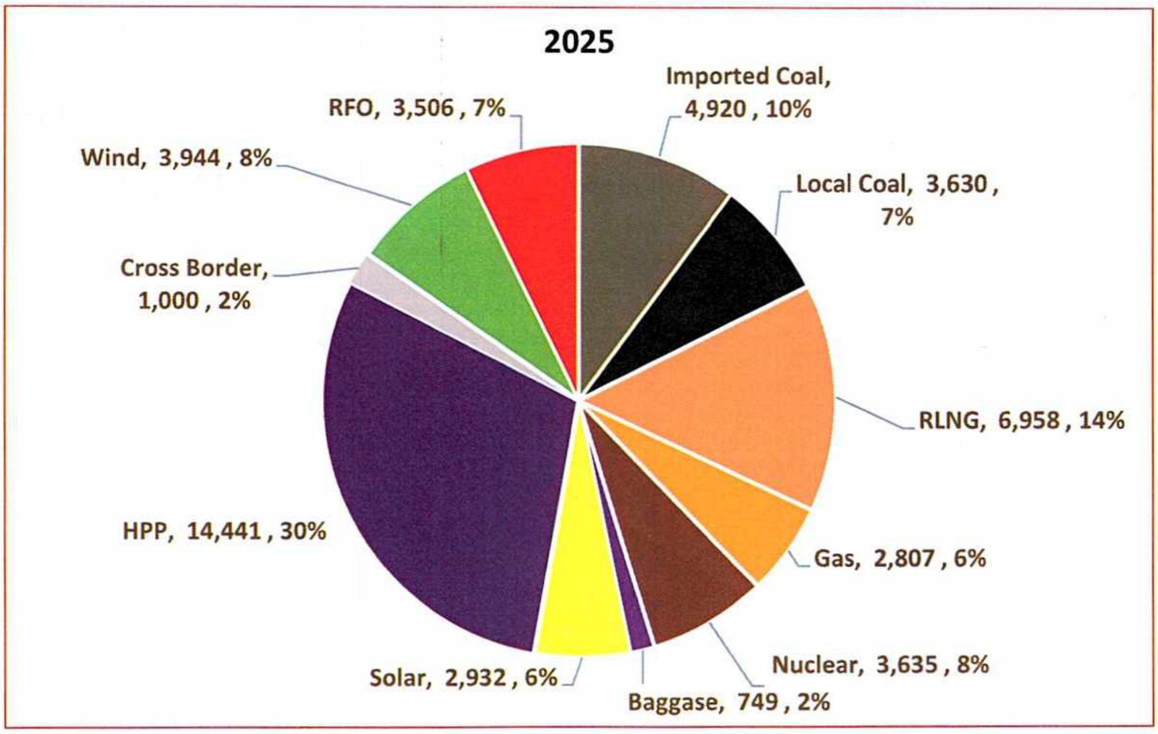


Chart 6-7: The IGCEP Generation Mix 2025 (MW)

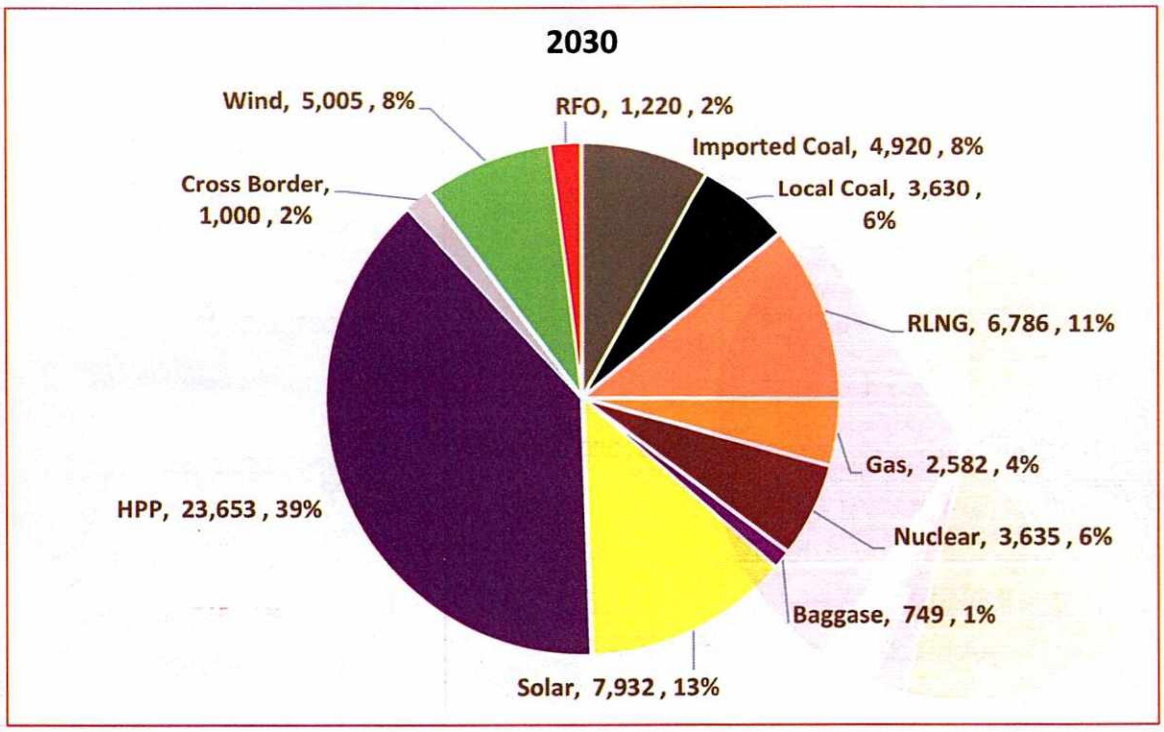


Chart 6-8: The IGCEP Generation Mix 2030 (MW)

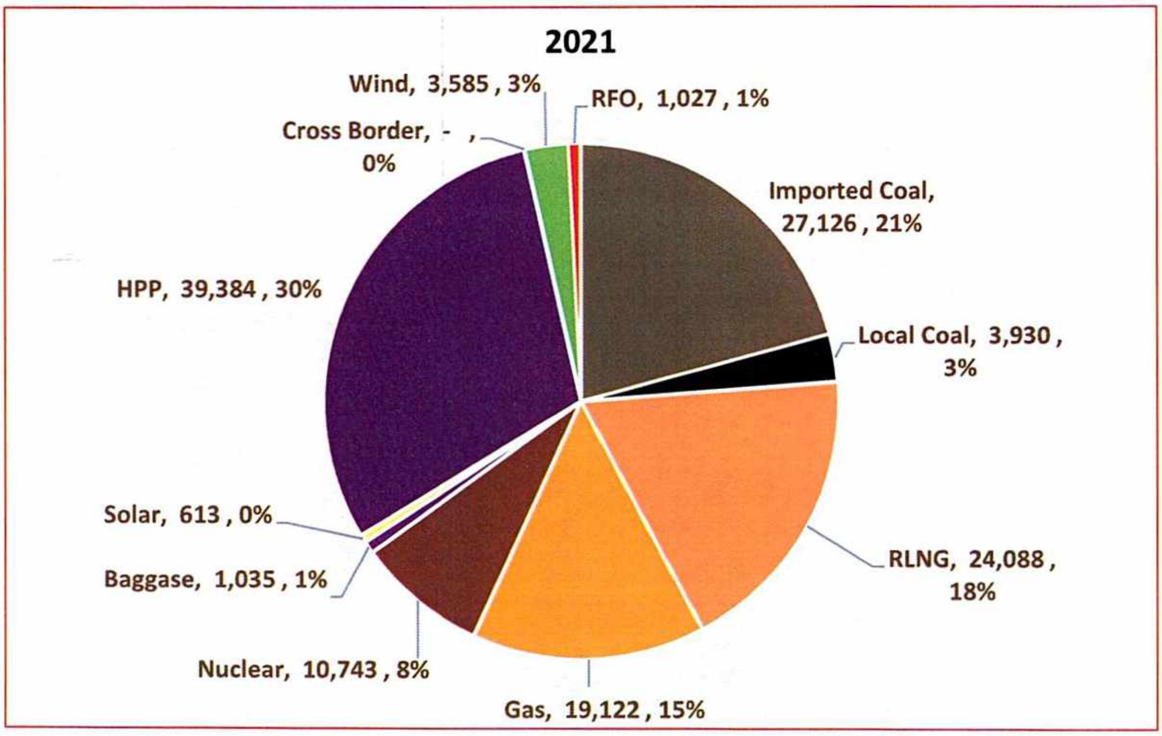


Chart 6-9: The IGCEP Generation Mix 2021 (GWh)

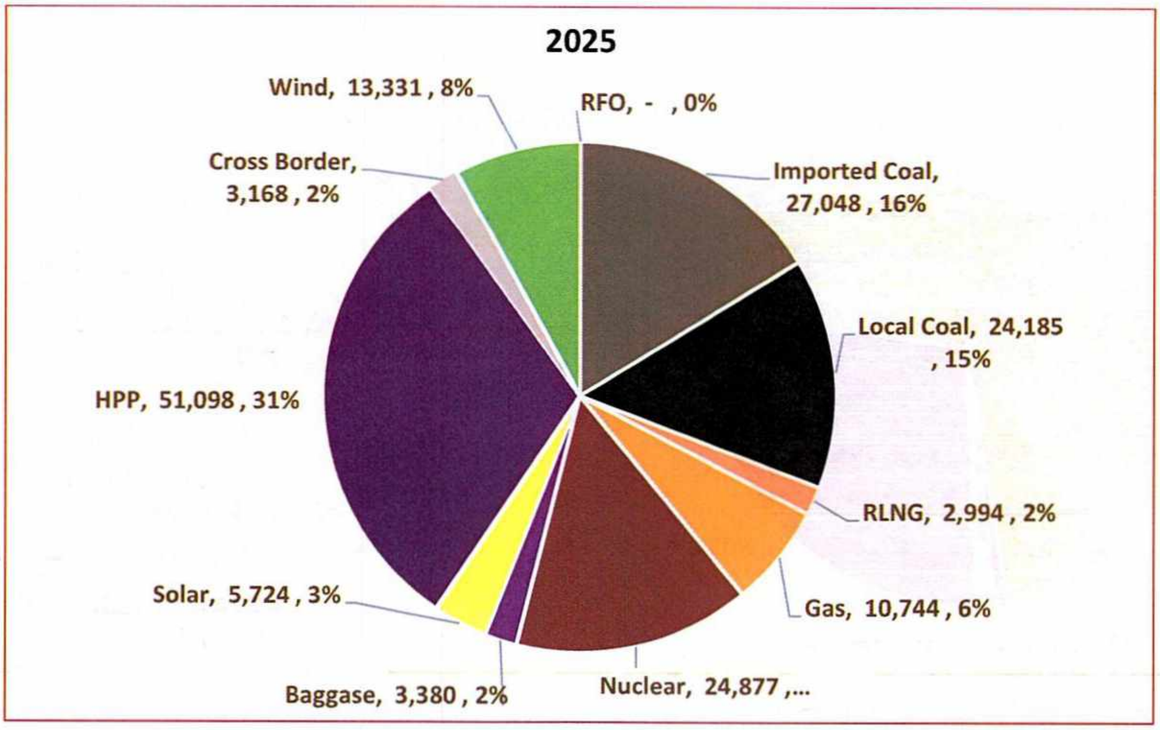


Chart 6-10: The IGCEP Generation Mix 2025 (GWh)

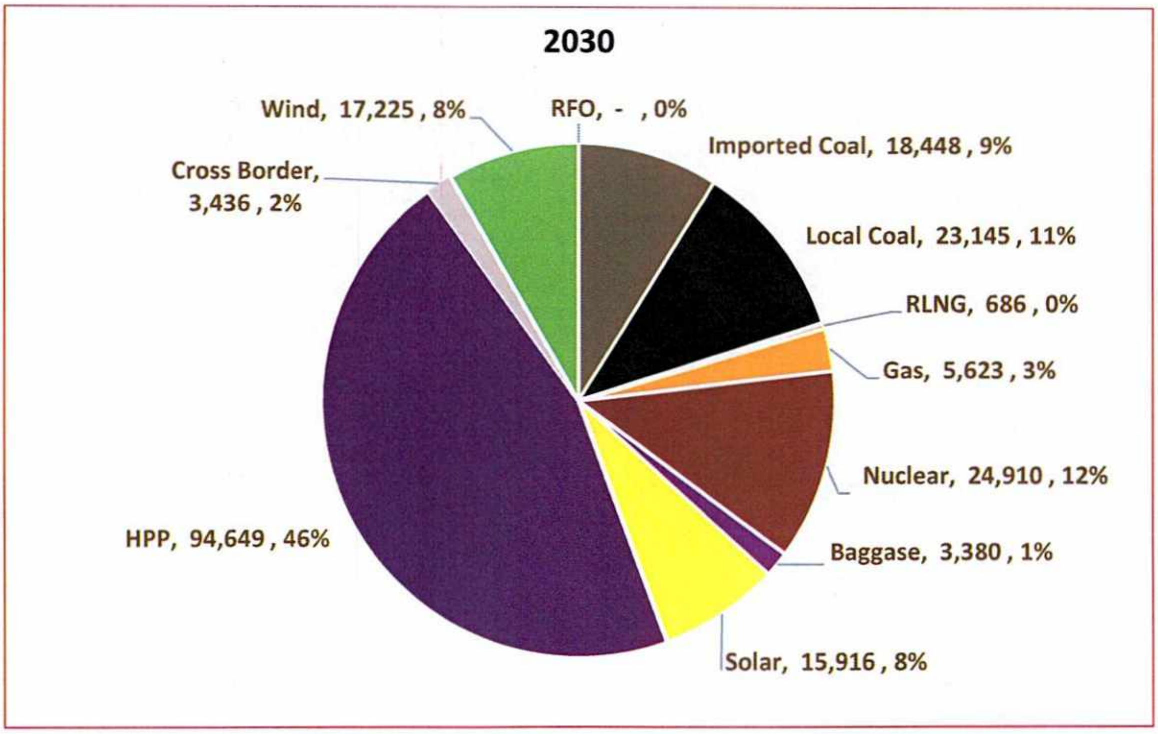


Chart 6-11: The IGCEP Generation Mix 2030 (GWh)

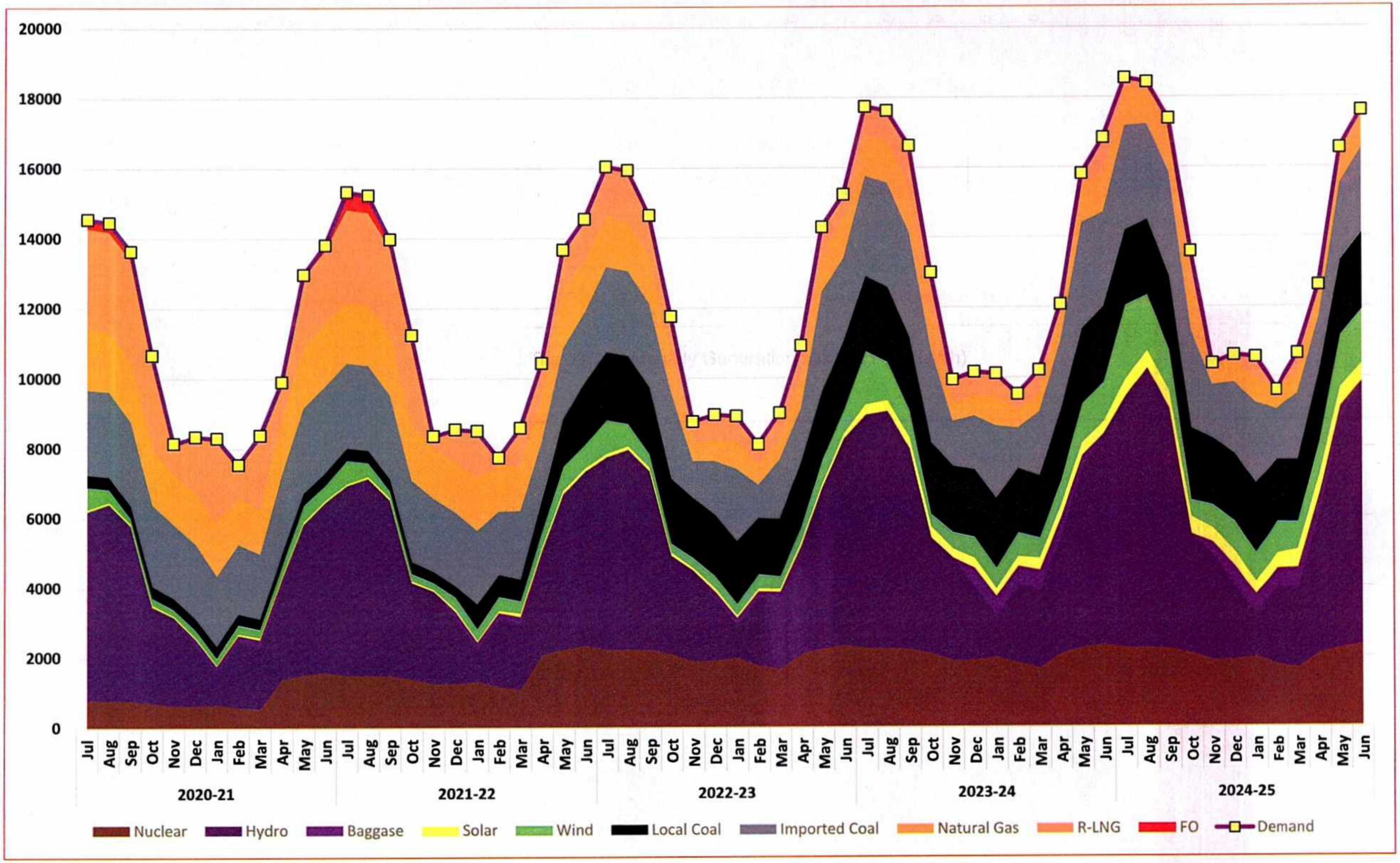


Chart 6-12 The IGCEP Monthly Generation Mix 2021-25 (GWh)

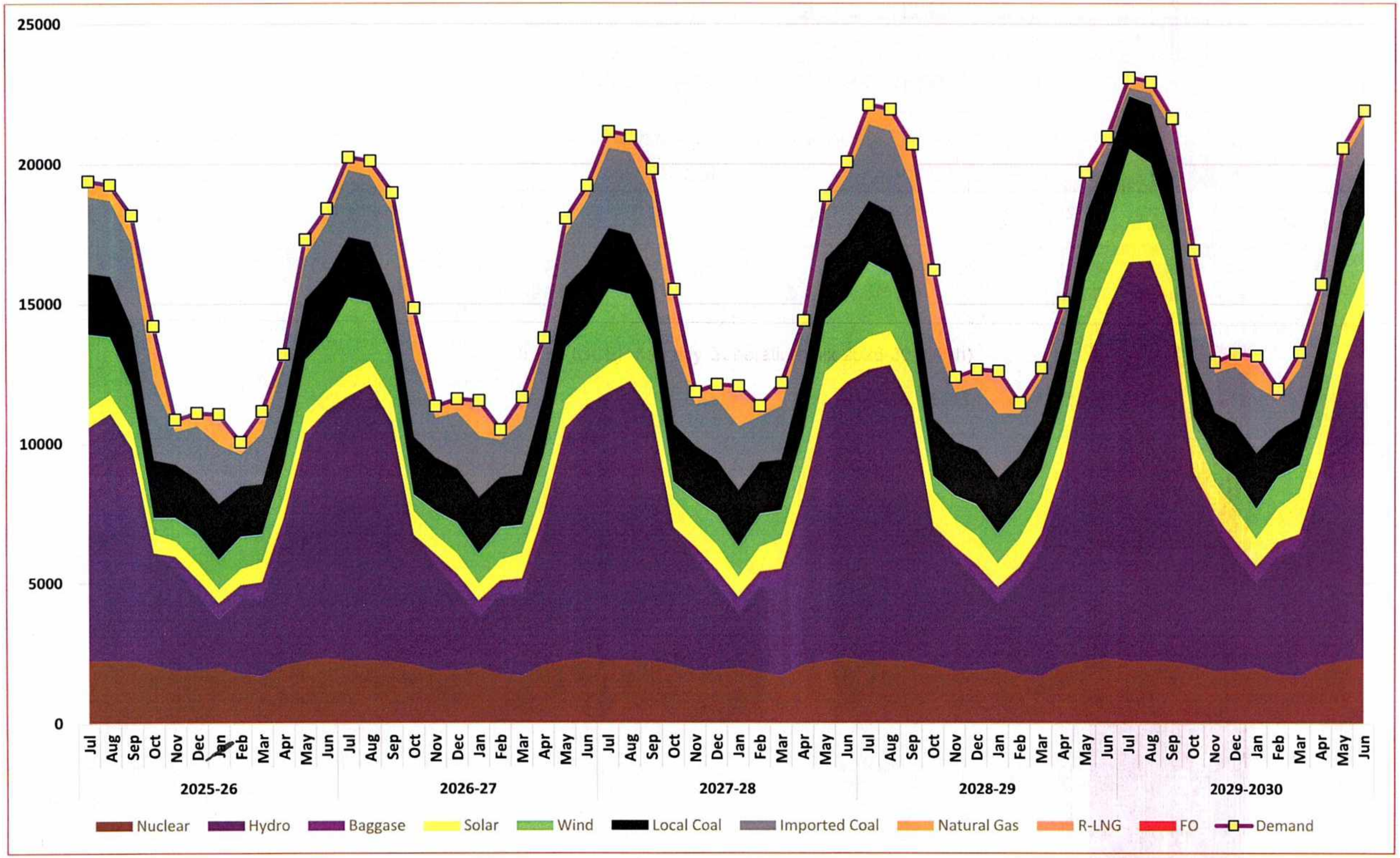


Chart 6-13: The IGCEP Monthly Generation Mix 2026-30 (GWh)

6.8. Strategy for Feedback

There is no room bigger than the room for improvement. The IGCEP has been prepared after taking inputs from all the relevant agencies; the LF&GP-PSP Team is more than willing to discuss and incorporate further suggestions from the stakeholders to shape it into a meaningful output. As per PC4 of the Grid Code, NEPRA will review and approve the IGCEP. All kind of suggestions, comments and concerns are most welcome at **ce.glfp@ntdc.com.pk**; **+92-42-99200695**. For wider dissemination and seeking generous feedback, the IGCEP 2021-30 would be published on the NTDC website.

7. THE WAY FORWARD

7. The Way Forward

A few suggestions are offered in this section to further enhance the contents and quality of the future editions of the IGCEP as well as the planning process on the whole.

7.1 Must Do Actions for the Future Generation Plans

a. Demand Side Management (DSM) options other than energy efficiency targets, provided by NEECA for the IGCEP 2021-30, should also be studied and incorporated in the next iterations of the IGCEP by coordinating and working closely with all relevant entities in the country.

b. Power generation policies should be regularly reviewed and updated to align the policy instruments with the latest trends in generation technologies and other factors that can influence both the demand and supply side of the electricity business.

c. Planning process should be more comprehensive, both in scope and depth. Instead of yearly updating, the IGCEP should be revised every three (03) years. It will reduce unpredictability and will also minimize risks for the potential investors. Appropriate modification to this effect should be made in the Grid Code.

d. Access to relevant and quality data must be facilitated. A central data repository may be formed to facilitate planners and policy makers, having specific data privileges and to ensure access to quality data, for data modeling and decision making. In a similar vein, project execution entities should enhance and accelerate their response, with respect to provision of project data to NTDC, for updating of the IGCEP, in a precise and timely manner.

e. Keeping in view the latest technological changes and latest advancements in the power supply and delivery business, customized trainings should be provided, especially for the power system planners, system operators, and DISCO staff.

7.2 Making Way for the High Share of Renewables in the Grid

In order to ensure indigenization of energy mix with higher share of clean energy, future plans are required to be aligned with international best practices pertaining to renewable enrgy.

7.2.1 Hybridization of Variable Renewable Energy Projects

a. Though not envisaged in the prevailing schemes, wind power projects can provide grid support such as frequency regulation, voltage regulation, and reserve power provided hybridization is opted with solar PV as well as battery energy storage. Grid impact and economic implication studies for individual wind power plant will need to be carried out by the stakeholders.

b. The combination of wind and solar has the advantage that the two sources will complement each other since the peak operating times for each system occur at different times of the day and year. The power generation of such a hybrid system including battery storage, is more continuous i.e. fluctuates less in terms of time and frequency if these are developed and operated jointly. Enabling environment including regulatory and commercial arrangements as well as technical studies should be undertaken for this purpose to maximize the value of indigenous energy resources.

c. All the stakeholders including the sponsors should join hands on setting up and sustaining an energy forecasting system with consensus on some suitable business model for the above purpose. This will significantly help in combatting the existing challenges with respect to despatch of renewable energy.

For the IGCEP 2021-30, NTDC was set to model hybrid RE technologies pursuant to Assumption Set approved by CCoE and for this purpose relevant project execution agencies were approached to provide input data. AEDB has recently launched a technical & financial feasibility study for this purpose. Based on the output of the study, hybrid RE technologies will be considered for the next iteration of the IGCEP.

7.2.2 Upcoming Wind Power Projects

In order to utilize huge renewable resources potential of Pakistan in a sustainable manner, the wind power projects supported by appropriate energy storage should be able to provide the following grid support:

a. Base load operation for certain number of hours

b. Support in frequency control and regulation

c. Reserve power even when the renewable resource is not available

d. Support in maintaining the reactive power balance

Further, those technologies should be promoted which can be manufactured locally with the ultimate goal of achieving manufacturing of complete WTG including sophisticated control equipment. All stakeholders should try to maximize local value addition.

7.3 Future is Here - Time to Understand, Accept and Adopt the New Norms

A fundamental transformation is currently underway around the world in the way electricity is produced, transmitted, and delivered to end-users. The 'utility of the past' that relied primarily on large and central-station power generating facilities intertied through extensive and complex T&D grids to serve demand located far away from generation sites is now giving way to a new 'utility of the future' concept that strives to serve demand right at the spot through a blend of options including energy conservation, demand-side management, and distributed sources of power generation.

Power sector in Pakistan is also at a crossroads at the moment and in fact faces a defining moment in its history. Ample evidence already exists to suggest that the former approach to managing the power sector entities and their affairs is not proving successful. A continuation of business-as-usual approach in the power sector will be akin to inviting trouble not only for this particular sector but for the nation on the whole. It is high time, therefore, to abandon the old approach and replace it with a new flexible and adaptable approach to running this critical sector of the economy.

Pakistan's transition to 'utility of the future' will require a thorough revamping of the power sector's legal and regulatory frameworks, institutional structure, physical systems, business operating model, and leadership and managerial styles. As planning holds a critical enabling link in smoothly managing the above transition, the LF&GP-PSP Team would like to propose a brief description of how planning's role and scope should change in the future.

Unlike the past, the strategic horizon for the power sector has shrunk considerably, in particular, for power generation schemes. Five years is now a long-term for generation capacity expansion planning as small-scale and modular generation technologies, both conventional and non-conventional, are available for quick deployment with cost and performance features comparable, and in some cases even superior, to their large-sized competitors.

Though the typical lead-times for T&D schemes still remain more-or-less the same, the availability of inexpensive information and communication technologies (ICTs) is changing their role in a number of important ways. From just a conduit to transmit electricity from generating stations to end-users in the recent past, the T&D grid is now being designed to function as a smart and intelligent platform to enable a host of actors and business interests to come together in serving the society's electricity demands more cost-effectively, with superior reliability and quality, and in socially and environmentally sustainable ways.

Both planning and plans are assuming a new and critical role in the 'utility of the future'. Instead of providing their leaderships with iron-clad strategic plans for the next 10 years or so, planners are now called upon to help them in refining and crystallizing their crude and sketchy business ideas by studying the viability and implications of these ideas, in strategizing based on these insights, and in taking informed decisions on key business issues. The three critical building blocks of the future power sector planning will necessarily include: (i) a strong strategic foresight and technical expertise; (ii) an appropriate set of tools and skills; and (iii) a frequently updated data and information base on local conditions and emerging business and technology trends in the market.

Focus of planning should also shift now. From its previous concentration mainly on generation expansion schemes and planning the T&D systems just as add-ons and addendums to these plans, T&D systems will have to take a center-stage in the future planning of the power sector. While some large central-station power generation options such as hydroelectric, coal, and nuclear plants will continue to maintain their relevance in the 'utility of the future', a major share of future power generation will come from small, distributed, and dispersed technologies to be connected with the grid at its tail end at distribution voltage levels.

A new source of demand as well as supply will come from the electrified transportation sector of the country. The battery packs on the future electrical vehicles (EVs), if carefully planned and managed, will not only be a source of new demand on the system but could also contribute to improving the overall utilization of generation assets in the system by flattening the load curve. These EV-based battery-packs can also contribute to system support (ancillary) services to the grid which to this day are largely supplied by central-station power plants.

The future planning efforts will necessarily have to be evenly distributed among three levels: 'central planning', 'operational planning', and 'distributed resource planning', each requiring its own skills, tools, and data and information bases, and complementing the other two. Essentially, it builds on the idea that in the future the power system will be composed of micro- and mini-grids (studies as well as pilot projects are required to be launched sooner than later for this purpose), mostly operating in an autonomous manner, but tied with each other through the national grid of the country.

Central Planning will mainly be of an indicative nature identifying the future electricity needs of the consumers in different parts of the country, assessing the resource and technology options available for serving the demands as much as possible at the spot and complementing the remaining demands from other regions and central-station facilities, and planning a robust transmission grid to facilitate that objective. Sufficient freedom should be provided to potential investors and developers to offer innovative, cost-competitive, and socio-economically acceptable power supply solutions. Coordination with other stakeholders of policy planning especially Planning Commission (or Ministry of Planning), Ministries of Oil & Gas, Finance, Industry & Commerce, and respective Ministries/Departments of Provinces, would be very essential for realistic central planning.

Operational Planning will essentially focus on optimal scheduling and despatch of transmission-connected generation to serve the residual demand that is left on the system after despatch of all local plants in the distribution systems. Operational planning will also be responsible with weather and renewable resource availability forecasting to maximize use of the intermittent and variable output from these plants and backing these up from the central grid resources for mitigating the intermittency and variability effects of RE generation.

Distributed Resource Planning will be carried out at the DISCO levels and will involve much more sophistication than the other two planning efforts stated above. It will be based on rigorous load research as well as local energy resource endowments and operating conditions to identify the most feasible option of serving consumer demand, through demand management options, behind-the-meter supplies, from a nearby located distributed plant, or from neighboring DISCO or central-station facilities.

7.4 Focusing on Indigenization through Harnessing the Potential of Local Coal

Thar coal reserves are estimated by the Geological Survey of Pakistan to be approximately 175 billion tons – making it one of the largest lignite coal reserves in the world. Thar coalfield, Block II area has exploitable lignite coal reserves of 1.57 billion tons. The total mining capacity of the project is due to be 20.6 MT/annum. (Source: Engro).

The power system planners should be communicated, by the project execution agencies, of the study-based analysis of block-wise potential of Thar coal that can be exploited for generation of electric power so it can be adequately modelled in the generation capacity expansion software for the next iterations. Similarly, the precision and authnticty of data and information pertaining to hydrology of upcoming hydro power projects needs to be validated by the concerned project execution agencies in the most meticulous manner.

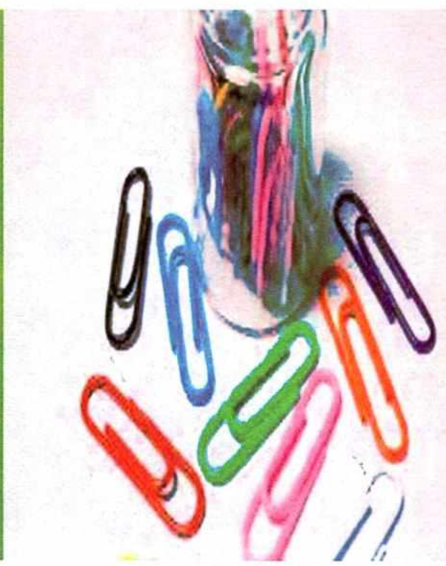
7.5 Thinking, Synergizing and Enhancing the Vision Beyond the Borders

It is a well-known fact that there is a severe lack of research culture in the country. It is high time that concrete initiatives are taken to inculcate a thinking culture in the power sector of Pakistan. It is believed that initiatives like NEPRA Energy Week 2020 may pave the way for this very purpose provided NEPRA sustains its focus in this direction. Role of academia, which is currently restricted to at best a couple of initiatives, may be further encouraged and enhanced by launching certain projects especially envisioned for this purpose. Academia along with the established think-tanks may add much needed value to the power sector interventions in all three segments. For this purpose, securing maximum benefits from the regional and international experience is critical. Power sector professionals need to know the success as well as failure stories of rest of the world in order to customize the best strategies for power sector of Pakistan. Perhaps our professionals and decision makers need to understand that borders are not the hurdles but opportunities for exponential growth.

7.6 Preparation and Submission of TSEP alongwith IGCEP

Pursuant to the directions by NEPRA dated 15th October 2020, NTDC is obligated to prepare TSEP along with IGCEP for submission to NEPRA, to maintain the true least cost principle at least for candidate projects optimized by the PLEXOS model. However, subsequent to approval of Assumption Set by CCI and its notification on 6th September 2021, highly stringent timeline was set by Power Division for finalizing the report; TSEP will, therefore, be submitted to NEPRA after carrying out detailed studies on the basis of IGCEP 2021-30. For the next submission of the IGCEP, NTDC would ensure simultaneous submission of TSEP to NEPRA.

ANNEXURES
(A – B)



IGCEP 2021-30

ANNEXURES

Annexure A. Load Forecast Data

A-1. Projected GDP Growth by Sector

Year	Gross Domestic Product (%)			
	Total	Agriculture	Industrial	Commercial
2020-21	3.94	4.43	3.57	2.77
2021-22	4.80	4.70	6.50	3.50
2022-23	5.30	5.30	6.80	3.40
2023-24	5.70	5.60	7.60	4.00
2024-25	5.60	5.60	6.30	4.50
2025-26	5.30	5.30	6.80	3.70
2026-27	5.10	5.10	6.10	3.90
2027-28	5.40	5.30	6.60	4.10
2028-29	5.20	5.10	6.50	4.00
2029-30	5.00	5.10	5.80	4.00

A-2. Historical GDP at Factor Cost Constant 2005-06, Consumer Price Index

Year	GDP (Rs. Million)				Consumer Price Index (CPI)	CPI (G.R)
	Total	Agriculture	Industrial	Commercial		
1970	1,267,148	521,916	186,873	579,134	2	-
1971	1,282,783	505,894	198,788	593,912	2	7.4%
1972	1,312,525	523,451	195,834	614,983	2	11.4%
1973	1,401,790	532,168	216,100	674,281	2	14.6%
1974	1,506,259	554,416	234,278	740,292	3	26.3%
1975	1,564,685	542,669	238,861	814,601	4	22.6%
1976	1,615,587	566,951	250,572	826,442	4	5.9%
1977	1,661,513	581,271	257,955	851,476	4	9.0%
1978	1,789,964	597,667	282,498	940,936	4	7.2%
1979	1,888,907	616,179	304,037	998,416	5	9.3%

Year	GDP				Consumer Price Index (CPI)	CPI (G.R)
	Total	Agriculture	Industrial	Commercial		
	(Rs. Million)					
1980	2,027,311	656,898	336,778	1,057,387	5	11.2%
1981	2,157,094	680,931	368,373	1,126,941	6	15.0%
1982	2,320,205	713,097	407,931	1,215,949	7	7.8%
1983	2,477,711	744,506	428,075	1,328,322	7	7.0%
1984	2,576,152	708,587	458,308	1,433,216	8	6.7%
1985	2,800,486	785,995	494,209	1,546,770	8	7.8%
1986	2,978,681	832,752	534,241	1,636,012	8	3.5%
1987	3,151,767	859,847	580,428	1,731,923	9	5.6%
1988	3,354,619	883,332	637,433	1,849,120	10	7.4%
1989	3,515,920	944,020	667,081	1,919,566	10	8.1%
1990	3,677,255	972,630	709,973	2,005,528	11	9.1%
1991	3,881,980	1,020,893	758,666	2,110,021	13	12.6%
1992	4,181,463	1,117,891	817,322	2,252,633	14	9.4%
1993	4,276,440	1,058,799	862,378	2,357,019	15	9.1%
1994	4,470,624	1,114,148	901,548	2,456,064	17	11.9%
1995	4,655,373	1,187,322	907,776	2,573,905	19	12.1%
1996	4,962,585	1,326,513	950,655	2,702,388	21	10.3%
1997	5,047,083	1,328,153	947,564	2,799,969	24	12.5%
1998	5,223,424	1,388,155	1,005,511	2,846,025	25	6.5%
1999	5,441,961	1,415,205	1,054,993	2,988,080	26	3.7%
2000	5,654,536	1,501,445	1,068,409	3,112,150	27	5.1%
2001	5,765,774	1,468,754	1,112,558	3,208,310	28	2.5%
2002	5,945,199	1,470,272	1,142,575	3,361,116	29	3.7%
2003	6,226,156	1,531,248	1,190,981	3,536,447	30	1.9%
2004	6,692,079	1,568,451	1,384,670	3,743,003	32	8.5%
2005	7,291,537	1,670,176	1,552,429	4,060,859	35	8.7%

Year	GDP				Consumer Price Index (CPI)	CPI (G.R)
	Total	Agriculture	Industrial	Commercial		
	(Rs. Million)					
2006	7,715,777	1,775,346	1,616,157	4,324,274	38	7.6%
2007	8,142,969	1,836,125	1,741,085	4,565,759	40	7.0%
2008	8,549,148	1,869,310	1,888,600	4,791,238	35	-13.2%
2009	8,579,987	1,934,691	1,790,263	4,855,033	38	7.6%
2010	8,801,394	1,939,132	1,851,565	5,010,697	40	7.0%
2011	9,120,336	1,977,178	1,935,022	5,208,136	72	78.0%
2012	9,470,255	2,048,794	1,984,316	5,437,145	80	11.0%
2013	9,819,055	2,103,600	1,999,207	5,716,248	86	7.4%
2014	10,217,056	2,156,117	2,089,776	5,971,163	93	8.6%
2015	10,631,649	2,202,043	2,198,027	6,231,579	97	4.5%
2016	11,116,802	2,205,433	2,323,169	6,588,200	100	2.9%
2017	11,696,934	2,253,565	2,428,902	7,014,467	105	4.8%
2018	12,344,266	2,343,614	2,540,894	7,459,758	110	4.7%
2019	12,600,651	2,356,827	2,501,345	7,742,479	117	6.8%
2020	12,541,834	2,432,850	2,407,093	7,699,891	130	10.7%
2021	13,036,381	2,502,181	2,493,031	8,041,169	141	8.3%

A-3. Category-Wise Nominal Tariff

Nominal Tariff (Excluding K Electric)									
Year	Dom	Com	Ind	Agr	Year	Dom	Com	Ind	Agr
	Paisa/kWh								
1972	20	26	14	9	1997	156	566	375	163
1973	20	27	14	10	1998	185	655	411	187
1974	20	32	18	11	1999	235	718	448	233
1975	21	36	21	12	2000	233	704	416	231
1976	23	46	28	16	2001	259	704	416	258
1977	25	53	34	16	2002	318	708	419	293
1978	24	60	37	14	2003	334	703	442	333
1979	29	72	46	21	2004	434	685	446	351
1980	35	95	57	28	2005	340	660	425	349
1981	40	100	63	32	2006	345	1,003	425	340
1982	42	108	68	36	2007	376	821	517	364
1983	43	118	76	38	2008	464	946	568	429
1984	44	121	76	43	2009	540	1,154	748	502
1985	44	123	78	38	2010	656	1,324	894	615
1986	49	143	92	43	2011	731	1,490	960	799
1987	48	140	89	37	2012	841	1,664	1,090	935
1988	52	171	111	40	2013	873	1,793	1,220	1,003
1989	62	213	133	46	2014	948	2,127	1,583	1,202
1990	66	246	150	55	2015	1,022	2,224	1,539	1,400
1991	76	276	166	57	2016	1,048	2,017	1,375	1,266
1992	81	316	189	63	2017	1,065	2,022	1,412	1,064
1993	84	331	199	66	2018	1,114	2,104	1,492	1,125
1994	96	386	229	74	2019	1,300	2,600	1,800	1,100
1995	110	427	268	94	2020	1,362	2,977	2,318	1,060
1996	136	537	336	131	2021	1,429	3,110	2,248	1,365

A-4. Category wise Real Tariff

Real Tariff (Excluding K Electric)									
Year	Dom	Com	Ind	Agr	Year	Dom	Com	Ind	Agr
	Paisa/kWh								
1971	543	685	353	210	1996	318	1,254	785	305
1972	494	635	338	221	1997	323	1,174	778	338
1973	421	567	305	213	1998	361	1,277	801	365
1974	336	538	298	181	1999	441	1,351	843	439
1975	288	499	293	165	2000	417	1,259	745	413
1976	300	605	366	202	2001	452	1,228	726	450
1977	299	638	401	188	2002	536	1,192	704	493
1978	270	665	417	160	2003	551	1,160	730	550
1979	291	731	471	214	2004	661	1,043	679	534
1980	317	868	524	261	2005	476	924	595	489
1981	316	798	503	256	2006	449	1,304	553	442
1982	308	797	501	265	2007	457	998	628	442
1983	299	816	522	266	2008	464	946	568	429
1984	284	786	495	276	2009	461	986	639	429
1985	264	737	472	231	2010	509	1,028	694	477
1986	288	830	534	251	2011	499	1,017	656	546
1987	262	768	490	203	2012	517	1,024	670	575
1988	268	878	570	204	2013	500	1,027	699	575
1989	295	1,012	631	217	2014	500	1,122	835	634
1990	287	1,068	653	237	2015	516	1,122	777	706
1991	294	1,066	639	218	2016	514	990	675	621
1992	284	1,113	666	223	2017	502	952	665	501
1993	272	1,070	643	214	2018	505	954	676	510
1994	277	1,113	661	213	2019	549	1,098	760	465
1995	284	1,101	691	241	2020	521	1,138	886	405

A-5. Electricity Consumption by Category (Excluding K Electric)

Year	Dom	Com	Ind	Agr	Street-Light	Bulk	Others	Exp to KE	Total
	GWh								
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

Year	Dom	Com	Ind	Agr	Street-Light	Bulk	Others	Exp to KE	Total
	GWh								
1996	14,792	1,648	10,335	6,657	301	2,377	20	795	36,925
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
2018	46,114	6,753	23,274	9,978	319	5,014	450	5,128	97,030
2019	45,590	6,629	24,285	9,676	291	5,082	2,335	4,957	98,844
2020	47,643	6,260	21,489	9,642	273	4,887	2,597	5,426	98,197
2021	49,814	6,688	24,663	10,116	314	4,973	2,802	6,118	99,370

A-6. Category Wise Number of Consumers (Excldiung K Electric)

Year	Dom	Com	Ind	Agr	Street Light	Bulk & Others	Total
	Numbers						
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

Year	Dom	Com	Ind	Agr	Street Light	Bulk & Others	Total
	Numbers						
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
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
2018	23,173,856	3,028,054	339,853	315,021	10,426	149,335	27,016,545
2019	24,465,300	3,144,247	342,949	326,656	10,567	183,350	28,473,069
2020	25,803,759	3,245,508	348,087	344,690	10,932	204,393	29,957,369
2021	27,227,283	3,359,777	357,366	359,124	11,284	210,353	31,529,604

Annexure B. Generation Planning Data

B-1. Existing Installed Capacity (As of September 2021)

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
	Public Sector			
	WAPDA Hydro			
1	Allai Khwar	Hydro	121	121
2	Chashma	Hydro	184	184
3	Dubair Khwar	Hydro	130	130
4	Ghazi Brotha	Hydro	1,450	1,450
5	Golen Gol	Hydro	108	108
6	Jinnah	Hydro	96	96
7	Khan Khwar	Hydro	72	72
8	Mangla	Hydro	1,000	1,000
9	Nelum Jehlum	Hydro	969	969
10	Small Hydel	Hydro	128	128
11	Tarbela 1-14	Hydro	3,478	3,478
12	Tarbela_Ext_04	Hydro	1,410	1,410
13	Warsak	Hydro	243	243
	Sub Total: WAPDA Hydro (MW)		**9,389**	**9,389**
	GENCOs			
14	Jamshoro - I U1	RFO	250	200
15	Jamshoro - II U4	RFO	200	170
	Sub Total: GENCOs – I (MW)		**450**	**370**
16	Guddu - I U(11-13)	Gas	415	391
17	Guddu - II U(5-10)	Gas	620	537
18	Guddu 747	Gas	747	721
	Sub Total: GENCOs – II (MW)		**1,782**	**1,649**
19	Muzaffargarh - I U1	RFO	210	190
20	Muzaffargarh - I U2	RFO	210	183
21	Muzaffargarh - I U3	RFO	210	184

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
22	Muzaffargarh - II U4	RFO	320	272
23	GTPS Block 4 U(5-9)	RLNG	144	114
24	Nandipur	RLNG	525	491
	Sub Total: GENCOs – III (MW)		**1,619**	**1,434**
	Total GENCOs (Public Sector) (MW)		**3,851**	**3,453**
	Private Sector			
	Nuclear			
25	CHASHNUPP - I	Nuclear	325	300
26	CHASHNUPP-II	Nuclear	340	300
27	CHASHNUPP-III	Nuclear	340	315
28	CHASHNUPP-IV	Nuclear	340	315
29	K-2	Nuclear	1,145	1,059
	Sub Total: Nuclear (MW)		**2,490**	**2,289**
	Hydel IPPs			
30	Jagran - I	Hydro	30.4	30.4
31	Malakand - III	Hydro	81	81
32	New Bong	Hydro	84	84
33	Darwal Khwar	Hydro	36.6	36.6
34	Gul Pur	Hydro	102	102
35	Patrind	Hydro	150	150
36	Jhing*	Hydro	14.4	14.4
37	Marala HPP*	Hydro	7.64	7.64
38	Pakpattan HPP*	Hydro	2.82	2.82
	Sub Total: IPPs Hydro (MW)		**508.86**	**508.86**
	Thermal IPPs			
39	AES Pakgen	RFO	365	335
40	AGL	RFO	163	153
41	Altern	Gas	31	26
42	Atlas	RFO	219	209
43	Balloki	RLNG	1,223	1,147

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
44	Bhikki	RLNG	1,180	1,108
45	China HUBCO	Imp. Coal	1,320	1,249
46	Davis	RLNG	14	10
47	Engro	Gas	226	205
48	Engro Thar	Local Coal	660	545
49	FKPCL	RLNG	172	147
50	Foundation	Gas	184	161
51	Halmore	RLNG	225	191
52	Haveli	RLNG	1,231	1,158
53	HuB N	RFO	225	208
54	HUBCO	RFO	1,292	1,108
55	KAPCO 1	RFO	400	344
56	KAPCO 2	RFO	900	743
57	KAPCO 3	RFO	300	258
58	Kohinoor	RFO	131	117
59	Lalpir	RFO	362	338
60	Liberty	Gas	225	208
61	Liberty Tech	RFO	202	192
62	Nishat C	RFO	209	191
63	Nishat P	RFO	202	191
64	Oreint	RLNG	225	197
65	Port Qasim	Imp. Coal	1,320	1,243
66	Rousch	RLNG	450	389
67	Saba	RFO	136	112
68	Sahiwal Coal	Imp. Coal	1,320	1,244
69	Saif	RLNG	225	197
70	Sapphire	RLNG	225	196
71	Uch	Gas	586	535
72	Uch-II	Gas	393	370
	Sub Total (IPPs Fossil Fuels) (MW)		**16,541**	**15,025**

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
	Bagasse Based Power Projects			
73	Almoiz	Bagasse	36	36
74	Chanar	Bagasse	22	22
75	Chiniot	Bagasse	63	63
76	Hamza	Bagasse	15	15
77	JDW - II	Bagasse	26	26
78	JDW - III	Bagasse	26	26
79	Ryk_Mills	Bagasse	30	30
80	Thal_Layyah	Bagasse	41	41
	Sub Total Bagasse (MW)		**259**	**259**
	Wind Power Projects			
81	Act	Wind	30.0	30.0
82	Artistic_wind	Wind	49.3	49.3
83	FFC	Wind	49.5	49.5
84	FWEL-I	Wind	50.0	50.0
85	FWEL-II	Wind	50.0	50.0
86	Gul Ahmed	Wind	50.0	50.0
87	Hawa	Wind	49.7	49.7
88	Jhimpir	Wind	49.7	49.7
89	Master	Wind	52.8	52.8
90	Metro_Power	Wind	50.0	50.0
91	Sachal	Wind	49.5	49.5
92	Sapphire_Wind	Wind	52.8	52.8
93	Three_Gorges_I	Wind	49.5	49.5
94	Three_Gorges_II	Wind	49.5	49.5
95	Three_Gorges_III	Wind	49.5	49.5
96	Tricon_A	Wind	49.7	49.7
97	Tricon_B	Wind	49.7	49.7
98	Tricon_C	Wind	49.7	49.7
99	UEP	Wind	99.0	99.0

#	Name of Power Plant	Fuel	Installed Capacity	De-rated Capacity
			(MW)	
100	Yunus	Wind	50.0	50.0
101	Zorlu_Wind	Wind	56.4	56.4
102	Master Green	Wind	50.0	50.0
103	Tricom	Wind	50.0	50.0
104	Tenaga	Wind	50.0	50.0
105	Dawood	Wind	50.0	50.0
106	Zephyr	Wind	50.0	50.0
	Sub Total Wind Power Plants (MW)		**1,336**	**1,336**
		Solar Power Projects		
107	Appolo Solar	Solar	100	100
108	Best	Solar	100	100
109	Crest	Solar	100	100
110	QA_Solar	Solar	100	100
	Sub Total Solar Power Plants (MW)		**400**	**400**
	Total Public Sector (MW)		**13,240**	**12,842**
	Total Private Sector (MW)		**21,536**	**19,818**
	Total Installed Capacity / Capability (MW)		**34,776**	**32,660**

Note: *Not mentioned in NPCC DLR because connected at DISCOs level

B-2. Cost Data of Existing, Committed and Candidate Thermal Plants

#	Plant Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	Unit Cost
			($/KW/Year)	($/MWh)	($/GJ)	(GJ/MWh)	($/MWh)
				Existing Power Plants			
				GENCOs			
1	GTPS Faisalabad-Block 4 U(5-9)	RLNG	29.31	1.26	12.38	9.56	119.66
2	Guddu 747 CC	Gas	181.72	3.43	5.13	7.32	40.98
3	Guddu-I U(11-13)	Gas	19.52	0.44	5.13	9.00	46.63
4	Guddu-II U(5-10)	Gas	19.52	0.44	5.13	10.00	51.76

#	Plant Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	Unit Cost
			($/KW/Year)	($/MWh)	($/GJ)	(GJ/MWh)	($/MWh)
5	Jamshoro-I U1	RFO	784.53	0.58	11.69	11.42	134.10
6	Jamshoro-II U4	RFO	784.53	0.58	12.87	11.89	153.65
7	Muzaffargarh-I U1	RFO	29.31	1.26	12.38	11.92	148.85
8	Muzaffargarh-I U2	RFO	29.31	1.26	12.38	12.08	150.80
9	Muzaffargarh-I U3	RFO	29.31	1.26	12.38	11.67	145.78
10	Muzaffargarh-II U4	RFO	29.31	1.26	12.38	11.66	145.57
11	Nandipur	RLNG	18.24	3.87	13.71	7.35	104.60
				IPPs			
12	AES Pakgen	RFO	22.71	1.58	13.42	9.54	129.67
13	AGL	RFO	27.91	9.41	12.07	8.63	113.53
14	Altern	Gas	106.84	7.28	13.14	9.79	135.90
15	ATLAS	RFO	23.48	9.28	13.54	8.37	122.56
16	Balloki	RLNG	17.65	1.37	12.38	6.57	82.65
17	Bhikki	RLNG	18.51	3.43	12.38	6.59	85.04
18	C-1	Uranium	145.00	0.00	0.55	10.91	6.00
19	C-2	Uranium	135.00	0.00	0.55	10.91	6.00
20	C-3	Uranium	110.00	0.00	0.55	10.91	6.00
21	C-4	Uranium	110.00	0.00	0.55	10.91	6.00
22	K-2	Uranium	35.00	0.00	0.49	9.73	4.77
23	China HUBCO	Imported Coal	25.60	3.22	4.23	9.31	42.63
24	Davis	RLNG	43.09	5.34	13.14	9.90	135.40
25	Engro	Gas	18.54	3.38	5.69	8.17	49.87
26	Engro Thar*	Local Coal	27.39	6.81	1.63	9.61	22.51
27	FKPCL	RLNG	22.71	6.95	7.17	15.87	120.66
28	Foundation	Gas	25.83	3.82	5.68	7.68	47.46
29	Halmore	RLNG	20.25	3.92	13.71	7.16	102.11
30	Haveli	RLNG	17.49	1.22	12.38	6.53	82.05
31	HuB N	RFO	23.74	8.38	14.42	7.98	123.43
32	HUBCO	RFO	37.67	1.64	12.45	9.98	125.92
33	KAPCO 1	RFO	23.74	2.45	12.38	8.38	106.21

tuk

#	Plant Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	Unit Cost
			($/KW/Year)	($/MWh)	($/GJ)	(GJ/MWh)	($/MWh)
34	KAPCO 2	RFO	23.74	2.87	12.38	9.19	116.68
35	KAPCO 3	RFO	23.74	5.53	12.38	9.51	123.24
36	Kohinoor	RFO	22.71	5.53	13.22	8.70	120.64
37	Lalpir	RFO	22.71	1.58	13.45	9.16	124.79
38	Liberty (Above 61GWh)	Gas	3.44	81.11	7.09	7.96	137.57
39	Liberty (Below 61GWh)	Gas	3.44	81.11	1.42	7.96	92.40
40	Liberty Tech	RFO	24.36	10.21	13.29	8.40	121.91
41	Nishat C	RFO	24.29	9.26	13.38	8.33	120.78
42	Nishat P	RFO	24.34	9.28	13.15	8.13	116.26
43	Orient	RLNG	27.53	2.29	13.71	7.17	100.54
44	Port Qasim	Imported Coal	27.39	1.21	5.81	9.01	53.51
45	Rousch	RLNG	22.71	2.59	12.38	8.84	112.01
46	Saba	RFO	22.71	1.58	13.26	9.60	128.92
47	Sahiwal Coal	Imported Coal	25.60	1.19	7.83	9.64	76.62
48	Saif	RLNG	20.73	3.90	13.71	7.17	102.16
49	Saphire	RLNG	19.97	3.86	13.71	7.16	102.04
50	Uch (Above 152GWh)	Gas	3.54	2.48	5.86	7.66	47.42
51	Uch (Below 152GWh)	Gas	3.54	2.48	1.22	7.66	11.84
52	Uch-II	Gas	26.41	2.22	5.35	8.14	45.76
	Committed Power Plants						
53	Gwadar	Imported Coal	34.67	1.18	3.15	9.66	31.60
54	Jamshoro Coal U-I	Imported Coal	4.30	2.52	4.35	8.71	40.37
55	K-3	Uranium	35.00	0.00	0.55	9.73	5.35
56	Lucky*	Local Coal	26.20	3.08	2.72	9.23	28.20
57	Siddiqsons*	Local Coal	25.80	5.65	0.79	9.23	12.90
58	Thal Nova*	Local Coal	28.02	5.97	1.67	9.73	22.17
59	Thar TEL*	Local Coal	28.02	5.97	1.67	9.73	22.17
60	Thar-I (SSRL)*	Local Coal	26.16	5.97	0.76	9.23	12.95
61	Trimmu	RLNG	13.47	3.08	12.38	6.59	84.57

#	Plant Name	Fuel	Fixed O&M	Variable O&M	Fuel Cost	Heat Rate	Unit Cost
			($/KW/Year)	($/MWh)	($/GJ)	(GJ/MWh)	($/MWh)
Candidate Power Plants							
62	C-5	Uranium	43.00	0.00	0.49	9.73	4.77
63	Hybrid Muzaffargarh	RLNG	17.01	2.16	5.54	6.00	35.43
64	Jamshoro Coal Unit 2	Imported Coal	4.15	2.44	4.35	8.71	40.28
65	K-4	Uranium	43.00	0.00	0.49	9.73	4.77
66	K-5	Uranium	43.00	0.00	0.49	9.73	4.77
67	KAPCO Coal	Imported Coal	29.37	1.33	2.94	9.23	28.44
68	M-1	Uranium	43.00	0.00	0.49	9.73	4.77
69	M-2	Uranium	43.00	0.00	0.49	9.73	4.77
70	New_CCGT	RLNG	13.47	2.98	7.27	5.89	45.76
71	New_Imp.Coal	Imported Coal	25.60	3.07	2.92	9.23	30.05
72	New_Local_Coal*	Local Coal	26.16	5.61	1.67	9.23	20.98
73	New_Nuclear	Uranium	43.00	0.00	0.49	9.73	4.77
74	New_OCGT	RLNG	13.47	2.98	7.27	9.46	71.78
75	RYK Coal	Imported Coal	33.20	0.94	5.40	9.01	49.61
76	Oracle CFPP*	Local Coal	33.20	0.94	2.58	8.57	23.09

* Fixed FCC equals to 314.2 $/kW/yr should be added in Fixed O&M of these power plants.

B-3. Indexed Capital Cost Calculations of Candidate Hydro Power Plants

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Sep '21 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
1	Alka	1.8	2.5	2	4.5	2.17	2.26	4.44	2,464
2	Arkari Gol	99	137.25	77.3	214.55	118.66	86.62	205.28	2,074
3	Artistic-I	62.606	187.47	49.37	236.84	187.94	51.67	239.61	3,827
4	Artistic-II	55.032	101.8646	31.9815	133.8461	102.12	33.47	135.59	2,464
5	Ashkot	300	0	780.306	780.306	0.00	894.68	894.68	2,982
6	Asrit Kedam	215	266.9667	143.75	410.7167	268.90	153.09	421.99	1,963
7	Athmuqam	450	0	1301.3	1301.3	0.00	1389.88	1389.88	3,089
8	Balakot-II	100	283	94.33	377.33	283.71	98.73	382.44	3,824
9	Balkani	7.7	17	7	24	17.04	7.33	24.37	3,165
10	Balmi	2	2.24	0.96	3.2	2.25	1.00	3.25	1,625
11	Bankhwar	35	67.17	25.91	93.08	67.34	27.12	94.46	2,699
12	Basho	40	72.3	37.85	110.15	62.75	42.83	105.58	2,639
13	Bata Kundi	96	108.42	79.87	188.29	95.32	90.39	185.72	1,935
14	Batdara	4.8	5.3	2.3	7.5	5.26	2.35	7.62	1,587
15	Bhango	2.1	2.35	1.01	3.36	2.36	1.06	3.41	1,625
16	Bhedi Doba	1	1.2	0.5	1.7	1.01	0.57	1.58	1,580
17	Bheri -II	2.85	4.422	1.56	5.982	4.19	1.86	6.05	2,121
18	Bhimbal Katha	26	30	32	62	30.24	34.18	64.42	2,478

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Sep '21 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
19	BS Link Tail	9	11.34	7.56	18.9	9.90	8.57	18.47	2,053
20	Bunji	7100	9119.6	4378.6	13498.2	8708.14	5076.96	13785.10	1,942
21	Chakoti Hatian	500	0	983.12	983.12	0.00	1127.22	1127.22	2,254
22	Chenawan	3	4.5	3	7.5	5.03	3.73	8.76	2,919
23	Chicha Watni	1.6	2.2	1.8	4	1.90	2.02	3.92	2,449
24	Chiniot_HPP	80	188.85	25.75	214.6	196.68	27.02	223.70	2,796
25	Chowkel Khwar	60	70	50	120	70.18	52.33	122.51	2,042
26	CJ	25	28.5	19	47.5	23.96	21.19	45.16	1,806
27	Daar	3	3.36	1.44	4.8	3.37	1.51	4.88	1,625
28	Daral Khwar-II	9.5	21.257	7.862	29.119	21.41	8.37	29.78	3,135
29	Dasu (Stage-I & II)	2160	2924.326	2185.475	5109.801	2537.91	2472.97	5010.88	2,320
30	DG Khan	4.65	5.85	3.906	9.756	5.40	4.17	9.57	2,057
31	Dhadar	18.18	36.75	12.25	49	31.77	13.73	45.50	2,503
32	Dhani	48	53.76	23.04	76.8	53.90	24.11	78.01	1,625
33	Dowarian	40	42.0	18.0	60.0	42.11	18.84	60.94	1,524
34	Gabral Utror	79	147.01	52.64	199.65	147.38	55.09	202.47	2,563
35	Gahret	377	1351.03	486.59	1837.62	1190.40	557.91	1748.31	4,637
36	Garhi Habibullah	100	252.9	84.3	337.2	253.54	88.23	341.76	3,418
37	Gharata	1.7	2.98	1.28	4.26	2.99	1.34	4.33	2,545

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Sep '21 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
38	Ghorband	20.6	0	69.366	69.366	0.00	80.12	80.12	3,889
39	Gugera	3.6	5.16	3.44	8.6	4.34	3.84	8.18	2,271
40	Gumat Nar	49.5	0	163.453	163.453	0.00	186.32	186.32	3,764
41	Gurha	1.5	1.68	0.72	2.4	1.68	0.75	2.44	1,625
42	Gwaldai	20.4	51.37	0	51.37	51.50	0.00	51.50	2,524
43	Harigehl-Majeedgala	40.32	70.301	37.858	108.159	61.01	42.84	103.85	2,576
44	Hundi	3.5	3.92	1.68	5.6	3.93	1.76	5.69	1,625
45	Istaro-Booni	72	150	110	260	144.95	126.61	271.56	3,772
46	Jabri Bedar	3.6	10.435	1.95	12.385	9.19	2.24	11.43	3,175
47	Jagran-III	35	64.64	60.98	125.62	61.26	72.46	133.72	3,820
48	Jagran-IV	22	27.4	11.8	39.2	27.48	12.30	39.78	1,808
49	Jamshil	610	844	691.2	1535.2	878.98	725.25	1604.23	2,630
50	Janawai	12	13.44	5.76	19.2	13.47	6.03	19.50	1,625
51	Javed-III	65	119.34	39.78	159.12	119.64	41.63	161.27	2,481
52	Javed-IV	45	82.6	27.5	110.2	82.83	28.82	111.65	2,481
53	Jhing-II	6.05	10.0	8.1	18.1	8.79	9.12	17.90	2,959
54	Kaigah-II	39.6	59.23	60.69	119.92	50.51	66.23	116.74	2,948
55	Kalam Asrit	238	281.613	152.522	434.135	282.32	159.63	441.95	1,857
56	Kalamula	2.2	2.46	1.06	3.52	2.47	1.11	3.58	1,625

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Sep '21 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
57	Kalkot Barikot	47	113.1	29.4	142.5	105.82	33.98	139.80	2,974
58	Kappa-II	2	2.1	0.9	3.0	2.11	0.94	3.05	1,524
59	Kari Mashkur	495	761.04	403.53	1164.57	865.87	424.18	1290.04	2,606
60	Kasorkot Talwari	2.9	3.05	1.31	4.36	3.06	1.37	4.43	1,527
61	Kasur	2.45	2.9	2.0	4.9	2.47	2.19	4.66	1,901
62	Kathai-III	1.2	1.9	0.5	2.4	1.64	0.57	2.21	1,838
63	Khanewal	1	1.5	1	2.5	1.24	1.10	2.34	2,338
64	Khanki Barrage	14	17.7	11.8	29.5	13.23	14.52	27.75	1,982
65	Khokhra	2.8	3.08	2.52	5.6	2.66	2.82	5.49	1,960
66	Laspur Murigram	232	453.03	177.1	630.13	515.43	186.16	701.59	3,024
67	LCC	7.55	10.872	7.248	18.12	9.40	8.12	17.52	2,321
68	Lower Palas	665	680.2	583.7	1263.9	593.75	662.05	1255.81	1,888
69	Lower Spat Gah	496	558.8	462.87	1021.67	525.68	534.90	1060.58	2,138
70	Luat	49	0.0	197.2	197.2	0.00	220.00	220.00	4,490
71	Lucky_HPP	20	27.304	14.162	41.466	23.73	16.24	39.97	1,998
72	Machai-III	1.72	3.215	1.45	4.665	3.22	1.52	4.74	2,756
73	Mahandri	10.04	19.69	10.29	29.98	17.02	11.53	28.55	2,844
74	Mahl	640	0	992.98	992.98	0.00	1088.74	1088.74	1,701
75	Makari	1	1.1	0.5	1.5	1.05	0.47	1.52	1,524

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Sep '21 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
76	Malkan	2.2	2.46	1.06	3.52	2.47	1.11	3.58	1,625
77	Mandi	3.3	4.356	3.564	7.92	3.80	4.04	7.84	2,377
78	Mastuj	48.6	92.2	27.35	119.55	80.48	31.02	111.50	2,294
79	Mehar	10.49	15.735	10.485	26.22	13.74	11.89	25.63	2,443
80	Meragram	70	172.5	57.5	230	172.93	60.18	233.11	3,330
81	Mujigram	64.26	142.477	35.619	178.096	134.03	41.16	175.19	2,726
82	Murree	12	14.5	9.5	24	12.23	10.50	22.72	1,894
83	Nagdar	35	36.8	15.8	52.5	36.84	16.48	53.33	1,524
84	Nairy Bela	3.2	3.36	1.44	4.8	3.37	1.51	4.88	1,524
85	Nandihar	12.3	0	47.097	47.097	0.00	54.40	54.40	4,423
86	Nandihar-II	10.97	13.37	15.5	28.87	14.05	16.05	30.11	2,745
87	Naran	188	269.35	161.93	431.28	260.28	186.38	446.66	2,376
88	Nardagian	3.2	3.4	1.4	4.8	3.37	1.51	4.88	1,524
89	Nausari	48	50.4	21.6	72	50.53	22.61	73.13	1,524
90	Naushera	1.95	3.901	1.671	5.572	3.65	1.93	5.58	2,862
91	Nila Da Katha	34	17.539	70.158	87.697	17.67	74.72	92.38	2,717
92	Okara	4.8	6.65	4.39	11.04	5.61	4.85	10.46	2,179
93	Paddar	3	3.36	1.44	4.8	3.37	1.51	4.88	1,625
94	Panagh	1.8	2.02	0.86	2.88	2.03	0.90	2.93	1,625

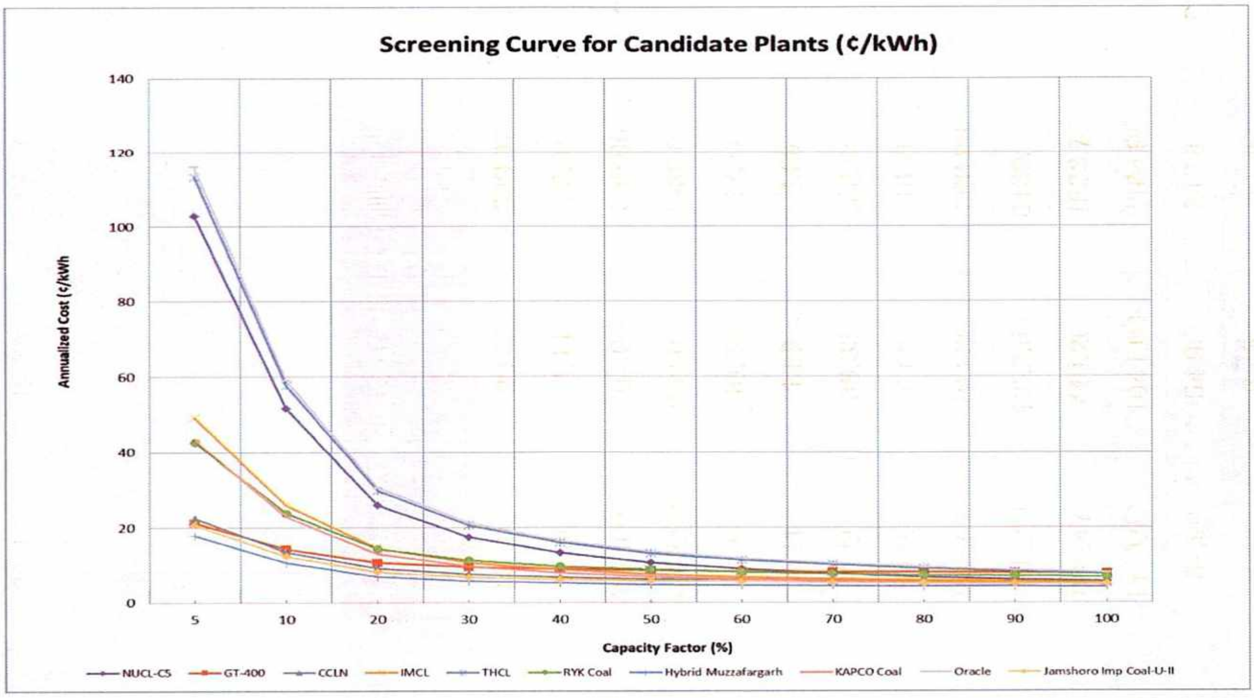
#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Sep '21 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
95	Patan	2400	2235	2331	4566	1936.49	2638.69	4575.18	1,906
96	Patrak Sheringhal	22	63.7	16.7	80.3	59.57	19.27	78.83	3,583
97	Phandar	80	71.6	80.7	152.3	67.83	96.03	163.85	2,048
98	Punjnad	15	18.9	12.6	31.5	18.23	15.75	33.98	2,265
99	Qadirabad	23	29.1	19.4	48.5	21.75	23.87	45.62	1,983
100	QB Link	9.18	11.6	7.7	19.3	9.78	8.51	18.29	1,992
101	Rajdhani	132	0	173	173	0.00	256.31	256.31	1,942
102	Rasul	18	22.68	15.12	37.8	21.88	18.90	40.78	2,265
103	Ravi	4.6	11.04	0	11.04	9.59	0.00	9.59	2,085
104	Riali-I	1.6	1.68	0.72	2.4	1.68	0.75	2.44	1,524
105	Sahiwal	4.8	6.9	4.6	11.5	4.71	5.46	10.17	2,119
106	Sammargah	28	41.024	25.795	66.819	27.72	30.73	58.45	2,087
107	Sandoa	1.75	1.96	0.84	2.8	1.96	0.88	2.84	1,625
108	Sarral-Dartiyan	8.51	26.44	4.25	30.69	21.83	4.67	26.50	3,114
109	Serai	6.9	9.591	1.28	10.871	9.62	1.34	10.95	1,588
110	Shalfalam	60	137.22	34.3	171.52	138.21	36.53	174.74	2,912
111	Sharda-II	5	5.25	2.25	7.5	5.26	2.35	7.62	1,524
112	Sharmai	152.12	143.45	257.33	400.78	122.33	280.83	403.16	2,650
113	Shigo Kas	102	202.17765	104.594174	306.771824	174.80	117.20	292.00	2,863

#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Sep '21 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
114	Shogosin	137	254.06	112.182	366.242	216.65	122.43	339.07	2,475
115	Shounter	48	53.76	23.04	76.8	53.90	24.11	78.01	1,625
116	Shushghai	144	238.129	102.055	340.184	248.00	107.08	355.08	2,466
117	SHYOK	640	1206	650	1856	1255.99	682.02	1938.00	3,028
118	Soan	25	37	15	52	31.19	16.58	47.77	1,911
119	Tajian	4	4.2	1.8	6	4.21	1.88	6.09	1,524
120	Tangar	25.91	35.28	34.209	69.489	30.50	38.33	68.84	2,657
121	Taobut	10	11.2	4.8	16	11.23	5.02	16.25	1,625
122	Taunsa	135	235.5	170.5	406	205.57	193.39	398.96	2,955
123	Thakot-I	2220	2031.3	1224.2	3255.5	1815.91	1323.54	3139.45	1,414
124	Thakot-II	963	990.5	692.1	1682.6	885.47	748.26	1633.73	1,697
125	Thakot-III	1490	1279.6	962.9	2242.5	1143.92	1041.03	2184.95	1,466
126	Torkhow	70	157.5	52.5	210	157.90	54.95	212.84	3,041
127	TP	9	8.28	5.52	13.8	7.93	6.45	14.39	1,598
128	Trappi	32	77.37	19.33	96.7	71.37	20.64	92.01	2,875
129	Trimmu_HPP	13	16.4	10.9	27.3	14.18	12.21	26.39	2,030
130	Turtonas Uzghor	82.25	94.798	84.066	178.864	87.44	89.75	177.20	2,154
131	UCC Bhambhwal	5	7.2	4.8	12	6.07	5.30	11.37	2,275
132	Wari	43.7	77.84	57.63	135.47	64.46	63.19	127.65	2,921

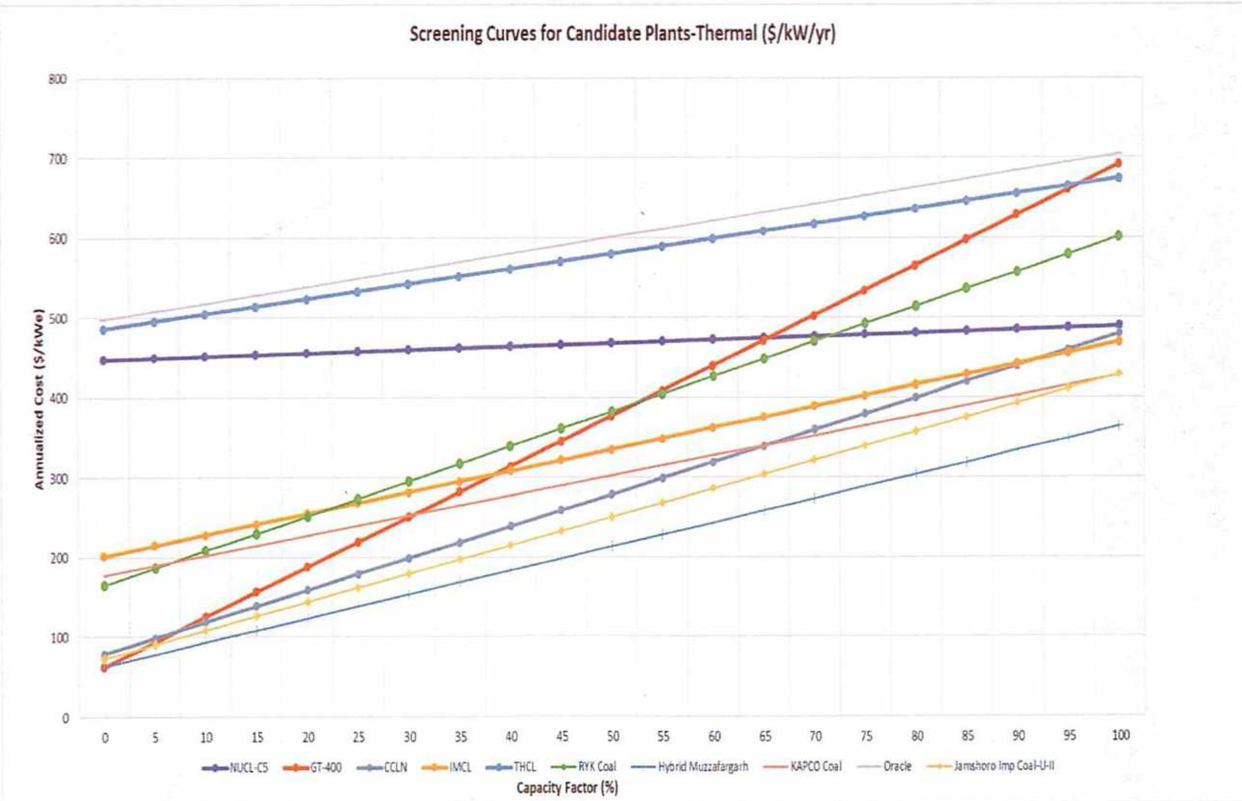
#	Name of Project	Capacity (MW)	Capital Cost with IDC (Million US$)			Rev. Sep '21 Capital Cost with IDC (Million US$)			Build Cost
			Local	Foreign	Total	Local	Foreign	Total	$/kW
133	Wazirabad	90	148	98.7	246.7	149.07	105.11	254.18	2,824

B-4. Screening Curve for Candidate Thermal Plants

B - 4.1. Screening Curve For Candidate Plants (c/kWh)



B - 4.2 Screening Curve for candidate Plants ($/kW/Yr)



B-5. Annualized Cost of Candidate Hydro Power Plants

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/KW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
1	Alka	PPDB	1.8	2025	52.68	2,464	12	50	75%	4.58	301.21
2	Arkari Gol	PEDO	99	2029	36.98	2,074	373	40	43%	6.61	249.02
3	Artistic-I	PEDO	62.606	2028	42.31	3,827	301	50	55%	8.92	428.33
4	Artistic-II	PEDO	55.032	2027	47.37	2,464	208	50	43%	7.81	295.88
5	Ashkot	PPIB	300	2030	30.64	2,982	1249	50	48%	7.96	331.43
6	Asrit Kedam	PEDO	215	2028	12.48	1,963	931	50	49%	4.86	210.44
7	Athmuqam	PPIB	450	2029	43.26	3,089	1953	50	50%	8.17	354.77
8	Balakot-II	PEDO	100	2028	47.99	3,824	538	50	61%	8.06	433.71
9	Balkani	PEDO	7.7	2028	43.75	3,165	44	50	65%	6.38	362.95
10	Balmi	AJK	2	2025	15.28	1,625	9	30	49%	4.38	187.68
11	Bankhwar	PEDO	35	2028	23.35	2,699	122	50	40%	8.50	295.54
12	Basho	WAPDA	40	2030	1.56	2,639	148	50	42%	7.23	267.77
13	Bata Kundi	PEDO	96	2028	8.49	1,935	358	50	43%	5.46	203.60
14	Batdara	AJK	4.8	2025	15.28	1,587	21	30	51%	4.13	183.64
15	Bhango	AJK	2.1	2033	15.28	1,625	9	30	49%	4.39	187.68
16	Bhedi Doba	AJK	1	2022	16.01	1,580	4	30	49%	4.30	183.66
17	Bheri -II	AJK	2.85	2027	32.41	2,121	16	50	63%	4.44	246.34
18	Bhimbal Katha	PEDO	26	2028	34.38	2,478	114	50	50%	6.47	284.27
19	BS Link Tail	PPDB	9	2035	17.01	2,053	48	50	61%	4.18	224.04
20	Bunji	WAPDA	7100	2040	194.79	1,942	25937	50	42%	10.69	390.62
21	Chakoti Hatian	PPIB	500	2030	27.52	2,254	2392	50	55%	5.33	254.90

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/KW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
22	Chenawan	PPDB	3	2030	18.63	2,919	21	50	81%	4.40	313.07
23	Chicha Watni	PPDB	1.6	2028	23.03	2,449	11	50	82%	3.76	270.07
24	Chiniot_HPP	WAPDA	80	2028	6.82	2,796	273	50	39%	8.47	288.84
25	Chowkel Khwar	PEDO	60	2028	64.89	2,042	244	30	46%	6.92	281.48
26	CJ	PPDB	25	2026	22.92	1,806	108	50	49%	4.76	205.10
27	Daar	AJK	3	2035	15.28	1,625	13	30	49%	4.39	187.68
28	Daral Khwar-II	PEDO	9.5	2027	27.69	3,135	44	30	53%	7.80	360.26
29	Dasu_2	-	2160	2032	12.20	2,320	12046	50	64%	4.41	246.18
30	DG Khan	PPDB	4.65	2027	21.94	2,057	21	50	51%	5.18	229.44
31	Dhadar	PEDO	18.18	2027	40.77	2,503	96	50	60%	5.56	293.19
32	Dhani	AJK	48	2031	15.28	1,625	205	30	49%	4.39	187.68
33	Dowarian	AJK	40	2026	15.28	1,524	171	30	49%	4.13	176.90
34	Gabral Utror	PEDO	79	2029	33.28	2,563	306	50	44%	7.53	291.78
35	Gahret	PEDO	377	2031	62.87	4,637	1713	50	52%	11.67	530.60
36	Garhi Habibullah	PEDO	100	2028	53.27	3,418	514	50	59%	7.74	397.97
37	Gharata	AJK	1.7	2034	15.28	2,545	7	30	49%	6.67	285.29
38	Ghorband	PEDO	20.6	2027	43.75	3,889	131	50	72%	6.87	436.01
39	Gugera	PPDB	3.6	2026	22.70	2,271	21	50	66%	4.36	251.75
40	Gumat Nar	AJK	49.5	2026	489.88	3,764	280	50	65%	15.39	869.53
41	Gurha	AJK	1.5	2034	15.28	1,625	6	30	49%	4.39	187.68
42	Gwaldai	PEDO	20.4	2029	38.82	2,524	82	50	46%	7.34	293.43
43	Harigehl-Majeedgala	AJK	40.32	2027	0.01	2,576	226	50	64%	4.63	259.78

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/KW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
44	Hundi	AJK	3.5	2032	15.28	1,625	15	30	49%	4.38	187.68
45	Istaro-Booni	PEDO	72	2031	46.76	3,772	284	50	45%	10.83	427.17
46	Jabri Bedar	PEDO	3.6	2027	71.66	3,175	26	30	83%	5.64	408.47
47	Jagran-III	AJK	35	2026	0.04	3,820	159	30	52%	8.90	405.31
48	Jagran-IV	AJK	22	2027	15.28	1,808	94	30	49%	4.84	207.07
49	Jamshil	PEDO	610	2029	35.69	2,630	2678	50	50%	6.86	300.94
50	Janawai	AJK	12	2031	15.28	1,625	51	30	49%	4.39	187.68
51	Javed-III	PEDO	65	2027	34.59	2,481	266	50	47%	6.96	284.83
52	Javed-IV	PEDO	45	2027	36.63	2,481	195	50	49%	6.62	286.88
53	Jhing-II	AJK	6.05	2023	0.72	2,959	34	50	63%	5.39	299.17
54	Kaigah-II	PEDO	39.6	2028	17.92	2,948	190	30	55%	6.90	330.64
55	Kalam Asrit	PEDO	238	2029	12.27	1,857	931	50	45%	5.10	199.56
56	Kalamula	AJK	2.2	2031	15.28	1,625	9	30	49%	4.38	187.69
57	Kalkot Barikot	PEDO	47	2026	12.28	2,974	197	50	48%	7.47	312.28
58	Kappa-II	AJK	2	2027	15.28	1,524	9	30	49%	4.13	176.90
59	Kari Mashkur	PEDO	495	2028	24.18	2,606	2171	50	50%	6.54	287.03
60	Kasorkot Talwari	AJK	2.9	2028	15.28	1,527	12	30	49%	4.14	177.28
61	Kasur	PPDB	2.45	2026	11.77	1,901	11	50	50%	4.66	203.53
62	Kathai-III	AJK	1.2	2023	0.50	1,838	5	50	48%	4.39	185.86
63	Khanewal	PPDB	1	2027	16.50	2,338	6	50	74%	3.88	252.35
64	Khanki Barrage	PPDB	14	2036	25.28	1,982	38	50	31%	8.31	225.18
65	Khokhra	PPDB	2.8	2025	23.03	1,960	17	50	69%	3.63	220.66

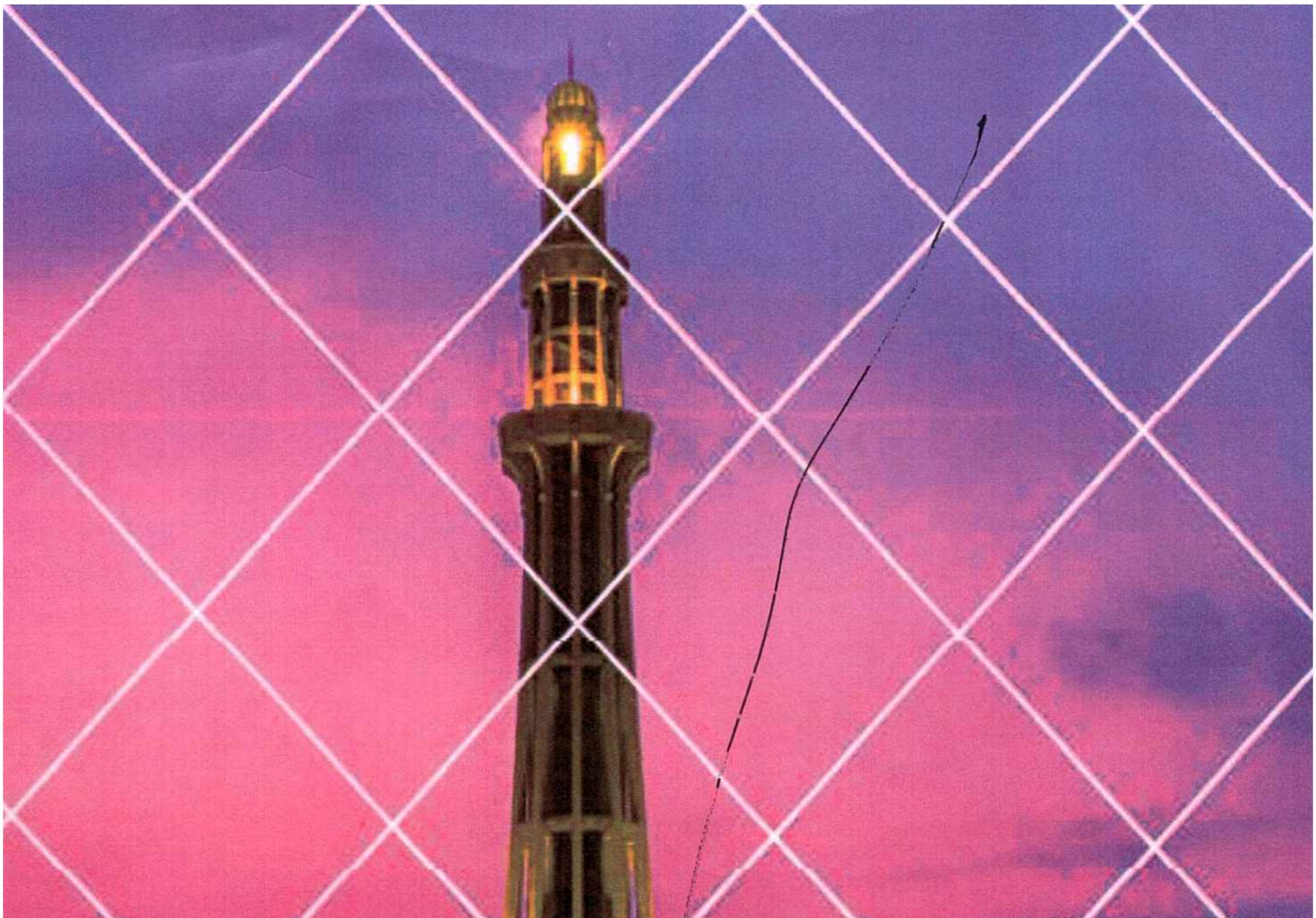
#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/KW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
66	Laspur Murigram	PEDO	232	2031	28.38	3,024	843	30	41%	9.61	349.18
67	LCC	PPDB	7.55	2025	23.03	2,321	43	50	65%	4.51	257.09
68	Lower Palas	WAPDA	665	2042	17.92	1,888	2444	50	42%	5.67	208.39
69	Lower Spat Gah	WAPDA	496	2040	14.79	2,138	2059	50	47%	5.55	230.45
70	Luat	AJK	49	2025	65.75	4,490	211	50	49%	12.07	518.59
71	Lucky_HPP	PPDB	20	2026	66.57	1,998	86	50	49%	6.23	268.13
72	Machai-III	PEDO	1.72	2027	44.54	2,756	10	30	67%	5.74	336.92
73	Mahandri	PEDO	10.04	2028	50.92	2,844	43	50	49%	7.93	337.76
74	Mahl	PPIB	640	2029	26.22	1,701	3670	50	65%	3.45	197.79
75	Makari	AJK	1	2024	15.28	1,524	4	30	49%	4.14	176.90
76	Malkan	AJK	2.2	2035	15.28	1,625	9	30	49%	4.38	187.69
77	Mandi	PPDB	3.3	2024	23.31	2,377	18	50	62%	4.83	263.07
78	Mastuj	PEDO	48.6	2028	47.07	2,294	238	30	56%	5.93	290.45
79	Mehar	PPDB	10.49	2026	23.02	2,443	66	50	72%	4.28	269.43
80	Meragram	PEDO	70	2030	46.42	3,330	257	50	42%	10.40	382.30
81	Mujigram	PEDO	64.26	2031	39.50	2,726	294	50	52%	6.87	314.47
82	Murree	PPDB	12	2028	22.71	1,894	64	50	61%	4.01	213.69
83	Nagdar	AJK	35	2027	15.28	1,524	150	30	49%	4.13	176.90
84	Nairy Bela	AJK	3.2	2027	15.28	1,524	14	30	49%	4.14	176.90
85	Nandihar	PEDO	12.3	2026	49.75	4,423	81	50	75%	7.55	495.80
86	Nandihar-II	PEDO	10.97	2029	22.68	2,745	64	50	67%	5.14	299.49
87	Naran	PEDO	188	2028	8.63	2,376	693	50	42%	6.73	248.26

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/KW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
88	Nardagian	AJK	3.21	2023	15.28	1,524	14	30	49%	4.15	176.90
89	Nausari	AJK	48	2029	15.28	1,524	205	30	49%	4.14	176.90
90	Naushera	AJK	1.95	2027	34.18	2,862	10	50	59%	6.23	322.84
91	Nila Da Katha	PEDO	34	2028	17.83	2,717	147	30	49%	7.08	306.06
92	Okara	PPDB	4.8	2033	22.71	2,179	29	50	69%	4.00	242.45
93	Paddar	AJK	3	2030	15.28	1,625	13	50	49%	4.19	179.20
94	Panagh	AJK	1.8	2034	15.28	1,625	8	30	49%	4.38	187.67
95	Patan	WAPDA	2400	2032	64.64	1,906	12301	50	59%	5.01	256.91
96	Patrak Sheringhal	PEDO	22	2028	10.74	3,583	93	50	48%	8.81	372.15
97	Phandar	WAPDA	80	2026	2.26	2,048	360	50	51%	4.64	208.84
98	Punjnad	PPDB	15	2037	16.45	2,265	58	50	44%	6.38	244.95
99	Qadirabad	PPDB	23	2034	25.28	1,983	51	50	25%	10.21	225.33
100	QB Link	PPDB	9.18	2028	16.58	1,992	30	50	37%	6.63	217.51
101	Rajdhani	PPIB	132	2029	38.52	1,942	666	50	58%	4.65	234.36
102	Rasul	PPDB	18	2027	12.33	2,265	96	50	61%	4.53	240.83
103	Ravi	PPDB	4.6	2025	53.45	2,085	27	50	66%	4.54	263.69
104	Riali-I	AJK	1.6	2025	15.28	1,524	7	30	49%	4.13	176.90
105	Sahiwal	PPDB	4.8	2030	12.66	2,119	29	50	68%	3.78	226.35
106	Sammargah	PEDO	28	2028	65.32	2,087	100	50	41%	7.72	275.85
107	Sandoa	AJK	1.75	2035	15.28	1,625	7	30	49%	4.40	187.68
108	Sarral-Dartiyan	PEDO	8.51	2027	75.61	3,114	47	30	63%	7.38	405.99
109	Serai	PEDO	6.9	2029	22.25	1,588	30	50	50%	4.14	182.38

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/KW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
110	Shalfalam	PEDO	60	2027	28.75	2,912	264	30	50%	7.66	337.70
111	Sharda-II	AJK	5	2030	15.28	1,524	21	30	49%	4.13	176.90
112	Sharmai	PEDO	152.12	2028	54.02	2,650	680	50	51%	7.19	321.32
113	Shigo Kas	PEDO	102	2029	34.03	2,863	461	50	52%	7.14	322.77
114	Shogosin	PEDO	137	2031	30.56	2,475	535	30	45%	7.51	293.10
115	Shounter	AJK	48	2031	15.28	1,625	205	30	49%	4.39	187.68
116	Shushghai	PEDO	144	2031	30.43	2,466	501	30	40%	8.39	292.00
117	SHYOK	WAPDA	640	2037	24.34	3,028	3731	50	67%	5.66	329.76
118	Soan	PPDB	25	2035	22.71	1,911	107	50	49%	5.02	215.43
119	Tajian	AJK	4	2030	15.28	1,524	17	30	49%	4.14	176.90
120	Tangar	PEDO	25.91	2029	50.77	2,657	127	50	56%	6.49	318.72
121	Taobut	AJK	10	2030	15.28	1,625	49	30	56%	3.82	187.68
122	Taunsa	PPDB	135	2026	23.08	2,955	640	50	54%	6.77	321.15
123	Thakot-I	WAPDA	2220	2039	44.00	1,414	10352	50	53%	4.00	186.63
124	Thakot-II	WAPDA	963	2037	22.70	1,697	4713	50	56%	3.96	193.81
125	Thakot-III	WAPDA	1490	2029	30.27	1,466	7280	50	56%	3.65	178.17
126	Torkhow	PEDO	70	2030	41.86	3,041	262	50	43%	9.30	348.54
127	TP	PPDB	9	2032	17.54	1,598	38	50	48%	4.26	178.76
128	Trappi	PEDO	32	2028	37.58	2,875	162	30	58%	6.75	342.58
129	Trimmu_HPP	PPDB	13	2036	16.81	2,030	57	50	50%	5.04	221.58
130	Turtonas Uzghor	PPIB	82.25	2028	26.02	2,154	377	50	52%	5.31	243.30
131	UCC Bhambhwal	PPDB	5	2033	16.58	2,275	30	50	68%	4.12	246.02

#	Power Plant	Project Executing Agency	Installed Capacity	Earliest Availability	FO&M	Installed Cost	Annual Energy	Economic Life	Plant Factor	Annualized Cost of Energy	
			(MW)	(Year)	($/kW/Yr)	(($/KW))	(GWh)	(Years)	(%)	c/kWh	$/kW/Yr
132	Wari	PEDO	43.7	2028	20.80	2,921	256	50	67%	5.38	315.40
133	Wazirabad	WAPDA	90	2030	3.30	2,824	376	50	48%	6.89	288.15

Blank



Driven by the Future

For comments, suggestions and concerns, please contact at +92 42 99200696 | ce.glfp@ntdc.com.pk

Load Forecast and Generation Planning, Power System Planning

National Transmission & Despatch Company, Pakistan